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March 12, 2015

via RESS – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges – Wireline Rate Interrogatory Responses – Confidentiality Request
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Pursuant to the OEB's Rules of Practice and Procedure and Practice Direction On Confidential Filings Toronto Hydro requests confidential treatment of the hourly labour rates included in its responses to interrogatories Carriers-12 part (e) and Carriers-14 part (i).

Toronto Hydro submits that this information is commercially sensitive and that its disclosure could interfere significantly in Toronto Hydro's negotiations with external contractors, as it may put upward pressure on contract prices. Such interference could result in a significant cost to the utility and, by extension, reduced value for rate payers. In addition, the utility notes that this information has not been previously disclosed in the public domain, and that it is consistently treated as confidential by Toronto Hydro.

Toronto Hydro notes in the Decision on Confidentiality and Procedural Order No. 4 (January 7, 2014), the OEB granted the utility's request to maintain in confidence the cost differences between internal and external construction of projects. The current request for confidentiality is analogous. Toronto Hydro respectfully submits that the information should therefore be kept confidential.

Please contact me if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
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encl.:DC\acc

cc: Charles Keizer, Torys LLP
Crawford Smith, Torys LLP
Amanda Klein, Toronto Hydro
Intervenors of Record for EB-2014-0116

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February 6, 2015

via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting ("Custom IR") Application for 2015-2019 Electricity Distribution Rates and Charges – Confidentiality Request – OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Pursuant to Rule 10.01 of the OEB's Rules of Practice and Procedure, Toronto Hydro requests confidential treatment of the annual increases for labour and electrical design and construction contractors for the years 2015-2017, in its Supplemental Response to Technical Conference Undertaking J2.29-CUPE-9. This information relates to the cost differences between internal and external construction of projects. Confidential treatment of this type of information was previously granted by the OEB in this proceeding[1].

In addition, Toronto Hydro requests confidential treatment of certain portions of its updated evidence regarding the Copeland Transformer Station project (Exhibit 2B, Section E7.9). The redacted information pertains to commercially sensitive issues between Toronto Hydro and its general contractor on the project. Public disclosure of this information could interfere significantly with on-going dealings between the parties and could prejudice Toronto Hydro's legal position and its ability to resolve contract and performance related issues. Toronto Hydro respectfully submits that this information should be kept confidential.

---

[1] EB-2014-0116, Decision on Confidentiality and Procedural Order No. 4 (January 7, 2015).

Please do not hesitate to contact if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Lead Regulatory Counsel
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:encl.

:JL\acc

cc: Charles Keizer, Torys LLP
Crawford Smith, Torys LLP
Amanda Klein, Toronto Hydro
Intervenors of Record for EB-2014-0116

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September 23, 2014

via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting ("Custom IR") Application for 2015-2019 Electricity Distribution Rates and Charges – Confidential Revisions - OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

On July 31, 2014, Toronto Hydro filed its 2015 – 2019 Custom IR Application, and requested confidential treatment of certain information in its pre-filed evidence.

Pursuant to Rule 11.03 of the OEB's Rules of Practice and Procedure, enclosed are revisions to the following Schedules over which the Toronto Hydro requests confidential treatment in its original filing on July 31, 2014. The revisions are marked DC and provided in blue paper:

- Exhibit 2B, Section E8.3, Appendix A;
- Exhibit 2B, Section E8.3, Appendix B;
- Exhibit 8, Tab 3, Schedule 2;
- Exhibit 8, Tab 3, Schedule 3; and
- Exhibit 9, Tab 3, Schedule 1.

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Regulatory Counsel
Toronto Hydro-Electric System Limited
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cc: Charles Keizer and Crawford Smith
Intervenors of Record for EB-2014-0116

Rob Barrass
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July 31st, 2014

via RESS e-filing ±signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro- (O H F W U L F 6 \ V W H P /H D G ³ Toronto Hydro Electric System Limited's Custom Incentive Rate- V H W W L Q J , 5 & Application for 2015 ±2019 Electricity Distribution Rates and Charges, OEB File No. EB-2014-0116 Confidentiality Request

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Toronto Hydro Z U L W H V W R W K H 2 Q W D U L R (Q H U J \ % R D U G ³2(%´ L Q U H V S H Amended matter.

3 X U V X D Q W W R 5 X O H *Rules of Practice and Procedure*, Toronto Hydro requests that certain information in the pre-filed evidence be kept confidential. Details about the particular information and the basis of the request for confidential treatment are provided below.

1. Forecast Proceeds from Sale of Properties

- *Exhibit 2B, Section E8.3, pages 9, 12, 18, 23-24, 33-34*
- *Exhibit 2B, Section E8.3, Appendices A and B*
- *Exhibit 8, Tab 1, Schedule 1, page 13*
- *Exhibit 8, Tab 3, Schedule 2, pages 1, 3, 5, 7, 9, 11, 14, 16*
- *Exhibit 8, Tab 3, Schedule 3, pages 1-6 and 8-9*
- *Exhibit 9, Tab 3, Schedule 1, lines 39, 41 and 62*

Toronto Hydro seeks confidential treatment of the forecasted proceeds from the disposition of properties R Z Q H G E \ 7 R U R Q W R + \ G U R D Q G R I W K H 1 H W 3 U H V H Q W 9 D O X H ³1 3 9´ proposed sale transactions (Appendices A and B) on the basis that the forecasted proceeds may be deduced from these calculations. As described in the evidence, Toronto Hydro proposes to record the gains on the proceeds of sale with respect to the subject properties in a deferral account, and to return these amounts to rate payers through the clearance of that account.

Toronto Hydro has provided information relating to the forecasted proceeds of sale in its rate design (Exhibit 8) and deferral and variance account (Exhibit 9) evidence. Toronto Hydro seeks confidential treatment of the applicable in I R U P D W L R Q L Q W K H V H H [K L E L W V 7 R U R Q W R + \ G U R ¶ keeping confidential only that information necessary to protect the forecast proceeds from sale ±the remainder of the referenced schedules are unaffected.

Toronto Hydro respectfully submits that confidential treatment should be granted with respect to the forecasted proceeds of sale, because disclosure of this information poses the following potential harms:

- D D SUHMXGLFH WR 7RURQWR¶V +\GUR¶V DEOLW\ WR VH
  respective properties, as the forecasts may be used by potential buyers to undercut Toronto +\GUR¶V DVNLQJ SULFH IRU WKH SURSHUWLHV
- E D VLJQLILFDQW LQWHUIHUHQFH LQ 7RURQWR +\GUR¶V
  the respective properties, as the forecasts may be used by potential buyers to compromise 7RURQWR +\GUR¶V EDUJDLQLQJ SRVLWLRQ DQG
- c) since Toronto Hydro proposes to return gains on sale to rate payers, disclosure of the LQIRUPDWLRQ FRXOG KDUP UDWH SD\HUV¶ LQWHUHVWV LI L
  competitive or negotiating positions regarding those properties.

2. Cost Difference between Internal and External Construction of Projects

- *Exhibit 2B, Section C, page 24*

Toronto Hydro seeks confidential treatment of the average cost differences between constructing projects internally versus using external contractors. Toronto Hydro submits that this information is F R P P H U F L D O O \ V H Q V L W L Y H D Q G W K D W L W V G L V F O R V X U H F R X O G L C negotiations with construction contractors, as it may put upward pressure on contract prices. Such interference could result in a significant cost to the utility and, by extension, reduced value for rate payers. Toronto Hydro respectfully submits that this information should be kept confidential.

3. Personal Information

- *Exhibit 4B, Tab 2, Schedule 3, Part 1, Introduction*
- *Exhibit 4B, Tab 2, Schedule 3, Part 1,Schedules 29, 550, 552 and 569*
- *Exhibit 4B, Tab 2, Schedule 3, Part 2, Schedules 1 and 2*

7RURQWR +\GUR VHHNV FRQILGHQWLDO WUHDWPHQW RI SHUVRQ
income tax return. Consistent with the definition of personal information under the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, C.F.31, the redacted information includes: the names, phone numbers, job titles, professional designations and years of experience of employees; the

names and addresses of external individuals; and the names of, students and apprentices. Toronto Hydro notes that this information has previously been held confidential by the OEB.[1]

3. Business Numbers

- *Exhibit 4A, Tab 2, Schedule 3, Part 1, Introduction*
- *Exhibit 4A, Tab 2, Schedule 3, Part 1, Schedules 1-3, 5-10, 23, 29, 31, 50, 53, 55, 506, 508, 510-511, 546, 550, 552, and 568-569*
- *Exhibit 4A, Tab 2, Schedule 3, Part 2, Schedule 2*

For security and fraud protection reasons, Toronto Hydro seeks confidential treatment of any business QXPEHUV FRQWDLQHG LQ WKH XWLOLW\¶V FRUSRUDWH LQFRPH WD[this information can expose the utility and other parties to the risk of fraud, and notes that this information has previously been held confidential by the OEB.[2]

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

[Daliana Coban on behalf of]

Rob Barrass
Manager and Counsel, Regulatory Affairs
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:RB/DC

cc: Charles Keizer and Crawford Smith of Torys LLP, Counsel for THESL, by electronic mail only

[1] EB-2014-0002, Procedural Order No. 1 (June 9, 2014) at page 4.
[2] EB-2013-0196,0197,0198, Decision on Confidentiality Request and Procedural Order No. 5 (September 27, 2013) at pages 7 ±8.

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February 27, 2015

via RESS – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges – Wireline Pole Attachments Update
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Pursuant to Rule 11.03 of the OEB's Rules of Practice and Procedure, enclosed are corrections and updates to the following Schedules, marked by OEB and provided in blue paper:

- Exhibit 3, Tab 2, Schedule 1, pages 1, 4, and 5;
- Exhibit 3, Tab 2, Schedule 2, Appendix 2-H;
- Exhibit 8, Tab 2, Schedule 1, page 2; and
- Exhibit 8, Tab 2, Schedule 1, Appendix B, page 1.

The enclosed updates reflect a reduction to the proposed wireline attachment rate, and corresponding revenue offset forecasts for 2015. The reduction is due to an adjustment to one of the inputs to the wireline cost model. More specifically, Toronto Hydro has adjusted the 2015 net book value of the assets that support wireline attachments to exclude the street lighting poles that it proposes to transfer into rate base in 2015, as these assets are generally not capital supporting wireline attachments.

The revenue requirement and bill impacts associated with the above-noted change are immaterial. Therefore, Toronto Hydro has not updated those parts of the evidence, but proposes to do so as part of the Draft Rate Order process, following the OEB's decision with respect to the proposed wireline rate.

Please do not hesitate to contact if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Lead Regulatory Counsel
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:encl.

:DC\acc

cc: Charles Keizer, Torys LLP
Crawford Smith, Torys LLP
Amanda Klein, Toronto Hydro
Intervenors of Record for EB-2014-0116

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April 24, 2015

via RESS ±signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited (³Toronto Hydro ´)
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges ±Wireline Pole Attachments Update
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board (³OEB ´) in respect of the above-noted matter.

3 X U V X D Q W W R 5 X O H Rules of Practice and Procedure, enclosed are updates to the following Schedules, marked by /C and provided in blue paper:

- Exhibit 3, Tab 2, Schedule 1, pages 1, 4, and 5;
- Exhibit 3, Tab 2, Schedule 2, Appendix 2-H;
- Exhibit 8, Tab 2, Schedule 1, page 2;
- Exhibit 8, Tab 2, Schedule 1, Appendix B, page 1, 2 and 4;
- Interrogatory Response to 8-OEB-100(a), pages 4-5 and 5-A;
- Interrogatory Response to WR-Carriers-7 part (c), page 2;
- Interrogatory Response to WR-Carriers-13 part (a), pages 3 to 7; and
- Interrogatory Response to WR-Carriers-15 part (a), pages 2 and 3.

The enclosed materials reflect the following updates to the proposed wireline attachment rate:

- **Administration Cost Methodology**. Upon a closer review of the record in the CCTA proceeding (RP-2003-0249), Toronto Hydro has adjusted its methodology for calculating the Administration Cost per pole to more closely align itself with the methodology used in that proceeding. In particular, Toronto Hydro had calculated Administration Cost per pole by dividing the total administration costs by the number of invoiced attachments, rather than by dividing the total administration costs by the number of poles, and further by the number of average attachers per pole. The updated Administration Cost per pole reflects this methodological change.
- **Administration Cost Inputs**. The Administration Costs per pole was also updated to exclude costs related to field inspectors in the Asset Attachment and Leases function because Toronto Hydro determined that these costs are recovered through other means (e.g., permit and make-ready fees, direct costing to specific projects such as the pole inspection program and other distribution projects).
- **Additional Site Visits for Pole Replacement** March 26, 2015, Toronto Hydro agreed that additional site visit costs for pole replacements with wireline attachments should be removed from the indirect Net Embedded Cost per Pole. These costs are directly attributable to the presence of wireline attachments on the pole, and therefore should be recovered as direct costs under Loss in Productivity. The updated Net Embedded Cost per pole and related Depreciation Expense reflects this change.

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Manager, Regulatory Law
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

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cc: Charles Keizer, Torys LLP
Crawford Smith, Torys LLP
Amanda Klein, Toronto Hydro
Intervenors of Record for EB-2014-0116

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March 12, 2015

via RESS – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges – Wireline Pole Attachments Update
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Pursuant to Rule 11.03 of the OEB's Rules of Practice and Procedure, enclosed are updates to the following Schedules, marked by Attachment and provided in blue paper:

- Exhibit 3, Tab 2, Schedule 1, pages 1, 4, and 5;
- Exhibit 3, Tab 2, Schedule 2, Appendix 2-H;
- Exhibit 8, Tab 2, Schedule 1, page 2;
- Exhibit 8, Tab 2, Schedule 1, Appendix B, pages 1 and 5; and
- Interrogatory Response to 3-SIA-30 part (d).

The enclosed updates reflect two changes to the proposed wireline attachment rate that were identified by Toronto Hydro in the course of preparing responses to the interrogatories filed earlier today:

- The Pole Maintenance Expense was updated to address a discrepancy between the between the figures used to derive the Annualized Total OM Inspection and Treatment Program cost per pole and the amounts planned for the program in 2015. This change was identified in the response to interrogatory Carries-12(a).

- The Capital Carrying Cost was updated to reflect the proposed WACC rate of 6.19%. This change was identified in the response to interrogatory Carriers-16(b).

The revenue requirement and bill impacts associated with the above-noted changes are immaterial. Therefore, Toronto Hydro has not updated those parts of the evidence, but proposes to do so as part of the Draft Rate Order process, following the OEB's decision with respect to the proposed wireline rate.

Please do not hesitate to contact if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Lead Regulatory Counsel
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

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cc: Charles Keizer, Torys LLP
Crawford Smith, Torys LLP
Amanda Klein, Toronto Hydro
Intervenors of Record for EB-2014-0116

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March 5, 2015

via RESS – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges – Undertaking Responses
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Further to my letter dated March 3, 2015, please find enclosed the responses to Oral Hearing Undertakings J9.1 and J9.3 to J9.6. Response to J9.1 and J9.2 will be submitted tomorrow.

Toronto Hydro's response to the Letters of Comment received in this Application is also enclosed.

Please contact me if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Lead Regulatory Counsel
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

encl.:DC\acc

cc: Charles Keizer, Torys LLP
Crawford Smith, Torys LLP
Amanda Klein, Toronto Hydro
Intervenors of Record for EB-2014-0116

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February 13, 2015

via RESS – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges – Update re Monthly Billing and Regulatory Costs
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Pursuant to Rule 11.03 of the OEB's *Rules of Practice and Procedure*, Toronto Hydro is filing an evidentiary update to:

1. request a new deferral account for the costs and savings associated with the implementation of monthly billing, as outlined in the OEB's proposed DSC amendments issued on February 5, 2015; and
2. inform the OEB that the utility proposes to record the amortized regulatory costs, as described in Exhibit 4A, Tab 2, Schedule 17, in Account 1525.

Enclosed are updates to the following Schedules, marked by /C and provided in blue paper:

- Exhibit 1B, Tab 1, Schedule 1, pages 4-5;
- Exhibit 4A, Tab 2, Schedule 17, page 9;
- Exhibit 9, Tab 1, Schedule 1, pages 30-31; and
- Exhibit 9, Tab 1, Schedule 1, Appendix B, pages 4-5.

Toronto Hydro will provide electronic copies of the updated consolidated Application and Evidence to parties upon request.

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Lead Regulatory Counsel
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

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cc: Charles Keizer, Torys LLP
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Intervenors of Record for EB-2014-0116

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February 6, 2015

via RESS – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges – Updates and Corrections
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Toronto Hydro is filing an evidentiary update. The primary purpose of this update is to provide a revised forecast with respect to the Copeland Transformer Station ("TS") project schedule. More specifically, Toronto Hydro expects the construction of Copeland TS to be completed in the second quarter of 2016. The project's overall cost is expected to remain within the OEB-approved amount.

For a complete summary of the updates being filed, please refer to the enclosed table of revisions (Appendix A), which describes the original evidence, each revision to the evidence, and if the change was numerical, the difference between the original evidence and the revision(s).

Pursuant to Rule 11.03 of the OEB's Rules of Practice and Procedure, enclosed are corrections and updates to the following Schedules, marked by and provided in blue paper:

- Exhibit 1A, Tab 1, Schedule 1, Table of Contents/Index;
- Exhibit 1A, Tab 2, Schedule 1, pages 15-17, 20-21, and 24-26;
- Exhibit 1B, Tab 2, Schedule 3, pages 9 to 11 and 13;
- Exhibit 1B, Tab 2, Schedule 4, pages 4 and 6;

- Exhibit 1B, Tab 2, Schedule 4, Appendix C [previously filed in an incorrect exhibit];
- Exhibit 2A, Tab 1, Schedule 1, pages 1, 3-6, and 9-14;
- Exhibit 2A, Tab 1, Schedule 2, pages 1-2;
- Exhibit 2A, Tab 1, Schedule 2, Appendix A;
- Exhibit 2A, Tab 3, Schedule 1;
- Exhibit 2A, Tab 6, Schedule 2;
- Exhibit 2A, Tab 6, Schedule 3;
- Exhibit 2B, Section 00, pages 6, 8, 17, 26 and 35;
- Exhibit 2B, Section B, page 7;
- Exhibit 2B, Section E1, pages 4 and 5;
- Exhibit 2B, Section E2, pages 7, 10 and 21;
- Exhibit 2B, Section E4, pages 1, 7-8, 11 and 15;
- Exhibit 2B, Section E6.1, pages 13, 45, 81, 114, 140-141, 218-219, 257, 278-279, 291, 297-298, and 304-305;
- Exhibit 2B, Section E6.4, page 13;
- Exhibit 2B, Section E6.6, page 5;
- Exhibit 2B, Section E6.7, pages 9, 28, and 52-69;
- Exhibit 2B, Section E6.8, page 6;
- Exhibit 2B, Section E7, page 3;
- Exhibit 2B, Section E7.3, pages 12, 40 and 44;
- Exhibit 2B, Section E7.6, pages 4 and 13;
- Exhibit 2B, Section E7.9, pages 4-5, 11, 28, and 40-41 [redacted version];
- Exhibit 3, Tab 1, Schedule 1, page 1;
- Exhibit 3, Tab 1, Schedule 1, Appendices E-1, E-2 and E-3;
- Exhibit 4B, Tab 1, Schedule 1, Appendix A;
- Exhibit 4B, Tab 2, Schedule 1, page 1 and 5-6;
- Exhibit 4B, Tab 2, Schedule 2, pages 2-3, 12-13, 16-21 and 24-27 [Excel version of the model is also provided];
- Exhibit 6, Tab 1, Schedule 1, pages 1, and 3-4;
- Exhibit 6, Tab 1, Schedule 2;
- Exhibit 7, Tab 1, Schedule 1, pages 1 and 7;
- Exhibit 7, Tab 1, Schedule 2, pages 6-16 of required pages only [Excel version of the model is also provided];
- Exhibit 7, Tab 2, Schedule 1;
- Exhibit 8, Tab 1, Schedule 1, pages 2 and 4-6;
- Exhibit 8, Tab 1, Schedule 2;
- Exhibit 8, Tab 3, Schedule 2;
- Exhibit 8, Tab 3, Schedule 3;
- Exhibit 8, Tab 4, Schedule 1; and
- Exhibit 8, Tab 7, Schedule 1.

In addition, enclosed are the following new Schedules:

- Exhibit 1B, Tab 2, Schedule 5, Appendix C [previously filed as a confidential document];
- Exhibit 2B, Section B, Appendix D – IESO Letter of Comment; and
- Exhibit 2B, Section B, Appendix E – Planning Status Letter.

Toronto Hydro is also providing corrections to the following interrogatory and undertaking responses:

- Issue 2B, CCC Interrogatory 2-24 [corrected reference on line 19]
- Issue 2B, CCC Interrogatory 2-25 [corrected reference on line 12]
- Issue 2B, VECC Interrogatory 1-8 [corrected header]
- Issue 4A, SIA Interrogatory 3-9 [corrected reference on line 12]
- November 17, 2014 Technical Conference Undertaking Response to J1.2-EP-50, Appendix A; and
- November 18, 2014 Technical Conference Undertaking Response to J2.29-CUPE-9, Supplemental Response.

Please note that the enclosed evidentiary updates to Exhibit 2B, Section 7.9 and the Supplemental Response to Undertaking J2.29-CUPE-9 are redacted versions. Under separate cover, Toronto Hydro requests confidential treatment of these materials.

In advance of the Oral Hearing, Toronto Hydro will file electronic copies of consolidated versions of the Application and Evidence, Interrogatory Responses, and Undertaking Responses, and will send the parties electronic copies of the consolidated materials.

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Lead Regulatory Counsel
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:encl.

:JL\acc

cc: Charles Keizer, Torys LLP
Crawford Smith, Torys LLP
Amanda Klein, Toronto Hydro
Intervenors of Record for EB-2014-0116

Daliana Coban
Lead Regulatory Counsel
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January 15, 2014

via RESS – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges – Updates and Corrections
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Pursuant to Rule 11.03 of the OEB's Rules of Practice and Procedure, enclosed are corrections and updates to the following Schedules, marked Copy 2 and provided in blue paper:

- x Exhibit 1A, Tab 2, Schedule 1, pages 13-14, 26 and 30;
- x Exhibit 1A, Tab 3, Schedule 1, page 6;
- x Exhibit 1B, Tab 2, Schedule 3, pages 9 to 11 and 13;
- x Exhibit 1B, Tab 2, Schedule 6, page 4;
- x Exhibit 1B, Tab 2, Schedule 7, pages 6 to 9;
- x Exhibit 2B, Section C, pages 4 and 4-A;
- x Exhibit 2B, Section D1, page 12;
- x Exhibit 3, Tab 1, Schedule 1, page 1;
- x Exhibit 3, Tab 1, Schedule 1, Appendices E-1, E-2 and E-3;
- x Exhibit 6, Tab 1, Schedule 1, pages 1, and 3-4;
- x Exhibit 6, Tab 1, Schedule 2;
- x Exhibit 7, Tab 1, Schedule 1, pages 1 and 7;
- x Exhibit 7, Tab 1, Schedule 2, pages 6-15; [excel version of the model is also enclosed]
- x Exhibit 7, Tab 2, Schedule 1;

- x Exhibit 8, Tab 1, Schedule 1, pages 2, 4-5 and 11-12;
- x Exhibit 8, Tab 1, Schedule 2;
- x Exhibit 8, Tab 3, Schedule 2;
- x Exhibit 8, Tab 3, Schedule 3;
- x Exhibit 8, Tab 4, Schedule 1;
- x Exhibit 8, Tab 5, Schedule 1;
- x Exhibit 8, Tab 7, Schedule 1;
- x Exhibit 9, Tab 1, Schedule 1 pages 3, 4A-6, 18-A, and 22-25;
- x Exhibit 9, Tab 2, Schedule 1; and
- x Exhibit 9, Tab 3, Schedule 1 (REDACTED).

In addition, enclosed are the following new Schedules:

- x Exhibit 1B, Tab 2, Schedule 7, Appendix D – Sample Key Account Presentation; and
- x Exhibit 9, Tab 1, Schedule 1, Appendix C – OEB Letter dated January 9, 2015 regarding the Audit of THESL's Deferral and Variance Accounts.

Along with these materials, Toronto Hydro has prepared a table of revisions (Appendix A) describing the original evidence, each revision to the evidence, and if the change was numerical, the difference between the original evidence and the revision(s).

Toronto Hydro is also providing an update to its response to interrogatory 4A-VECC-46 part (b), which was filed on November 5, 2014.

Please do not hesitate to contact if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Lead Regulatory Counsel
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:encl.

:JL\acc

cc: Charles Keizer and Crawford Smith
Intervenors of Record for EB-2014-0116

Daliana Coban
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Facsimile: 416.542.3024
regulatoryaffairs@torontohydro.com
www.torontohydro.com

November 24, 2014

via RESS – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges –Evidence and Interrogatory Response Corrections
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Toronto Hydro filed Corrections to its Pre-filed Evidence on September 23, 2014 and November 14, 2014. Further to those corrections and pursuant to Rule 11.03 of the OEB's Rules of Practice and Procedure, enclosed are corrections to the following Schedules, marked by /C and provided in blue paper:

- x Exhibit 2A, Tab 10, Schedule 1, pages 1 and 2;
- x Exhibit 2A, Tab 10, Schedule 3;
- x Exhibit 4A, Tab 1, Schedule 2;
- x Exhibit 4A, Tab 1, Schedule 3;
- x Exhibit 4A, Tab 1, Schedule 4;
- x Exhibit 4A, Tab 2, Schedule 5;
- x Exhibit 4A, Tab 4, Schedule 3, pages 2 and 9
- x Exhibit 8, Tab 2, Schedule 1, pages 2 and 7; and
- x Exhibit 9, Tab 1, Schedule 1, Appendix B page 2, lines 22-23.

Along with these corrections, Toronto Hydro has prepared a table (Appendix A) describing the original evidence, each revision to the evidence, and if the change was numerical, the difference between the original evidence and the revision(s).

Toronto Hydro is also providing corrections to the following interrogatory responses which were filed on November 5, 2014:

- x 1B-SIA-2 Appendix A;
- x 1B-BOMA-72;
- x 2B-CUPE-3; and
- x 4A-Society-5 part (a).

Toronto Hydro has also identified two additional documents which are responsive to interrogatory 1B-SEC-8, and is filing these studies as Appendices N and O to that response.

In addition, Toronto Hydro is filing a redacted copy of the THC Business Plan which was originally filed in confidence, in its entirety, on November 14, 2014, as a Supplemental Response to interrogatory 1A-CCC-1. Toronto Hydro maintains its request for confidentiality over the redacted parts of the Business Plan, as set out in its Confidential Filing Letter dated November 14, 2014.

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Regulatory Counsel
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:encl.

:JL\acc

cc: Charles Keizer and Crawford Smith
Intervenors of Record for EB-2014-0116

Daliana Coban
Regulatory Counsel
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Toronto, ON M5B 1K5

Telephone: 416.542.2627
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regulatoryaffairs@torontohydro.com
www.torontohydro.com

November 14, 2014

via RESS – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges – Corrections and Supplemental Interrogatory Responses
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

Toronto Hydro filed Corrections to its Pre-filed Evidence on September 23, 2014. Further to those corrections and pursuant to Rule 11.03 of the OEB's Rules of Practice and Procedure, enclosed are corrections to the following Schedules, marked "C" and provided in blue paper:

- Exhibit 3A ,Tab 2, Schedule 1, pages 1 and 4;
- Exhibit 3A, Tab 2, Schedule 2; and
- Exhibit 4A, Tab 4, Schedule 2.

Along with these corrections, Toronto Hydro has prepared a table (Appendix A) describing the original evidence, each revision to the evidence, and if the change was numerical, the difference between the original evidence and the revision(s).

Toronto Hydro is also providing its response to interrogatory 1A-VECC-1, and corrections to the following interrogatories:

- 4A-Society-4, Appendix A;
- 4A-SIA-32, Appendix A; and
- 4A-VECC-48, Appendix A.

In addition, Toronto Hydro is filing a supplemental response to interrogatory 1A-CCC-1. Under separate cover, Toronto Hydro requests that this supplemental response be treated confidentially, pursuant to the OEB's Rules of Practice and Procedure and the OEB's Practice Direction on Confidential Filings.

Please do not hesitate to contact me if you have any questions.

Yours truly,

Daliana Coban
Regulatory Counsel
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:encl.

:JL\acc

cc: Charles Keizer and Crawford Smith
Intervenors of Record for EB-2014-0116

Appendix A: Table of Revisions (Nov. 14, 2014), Toronto Hydro 2015-2019 Custom IR Application, OEB File No. EB-2014-0116

<table>
<tr><th>Original Evidence
(Filed July 31, 2014, corrected September 23, 2014)</th><th>Revised Evidence
(Filed November 14, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 3 (Operating Revenue), Tab 2, Schedule 1 (Revenue Offsets), pp 1 and 4</td><td>Corrections to forecasts of revenue offsets generated by specific service charges</td><td>Merchandise and Jobbing Revenue and Expenses ($000s)
<table>
<tr><td>Revenue</td><td>2015 Test Year</td></tr>
<tr><td>Total</td><td><s>29,114.5</s>
29,380.9</td></tr>
<tr><td>Net Revenue</td><td></td></tr>
<tr><td>Total</td><td><s>16,406.0</s>
16,672.4</td></tr>
</table>
Revenue Offset Summary ($000s)
<table>
<tr><td></td><td>2014 Bridge Year</td><td>2015 Test Year</td></tr>
<tr><td>Merchandise and Jobbing Revenue</td><td>No Change</td><td><s>29,114.5</s>
29,380.9</td></tr>
<tr><td>Specific Service Charges</td><td><s>6396.0</s>
6,374.7</td><td><s>8769</s>
9,819.2</td></tr>
<tr><td>Other Distribution Revenue</td><td><s>3,362.3</s>
3,356.6</td><td><s>11,547.2</s>
11,544.3</td></tr>
<tr><td>Other Income & Deductions</td><td><s>12,706.7</s>
12,006.7</td><td><s>20,815.5</s>
20,731.8</td></tr>
<tr><td>Total Revenue Offsets</td><td><s>26,438.0</s>
25,738.0</td><td><s>45,131.6</s>
46,095.3</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014, corrected September 23, 2014)</th><th>Revised Evidence
(Filed November 14, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 3 (Operating Revenue), Tab 2, Schedule 1 (OEB Appendix 2-H: Other Operating Revenue).</td><td>Revised OEB Appendix 2H to align with the above noted changes to revenue offsets.</td><td>Please refer to the row above.</td></tr>
<tr><td>Exhibit 4A (Operating Expenses: OM&A), Tab 4, Schedule 2 (OEB Appendix 2-K: Employee Cost Table)</td><td>Revised FTE numbers to correct an administrative oversight with respect to the pro-ratio of resources in 2011. This correction does not affect the Total Compensation amounts for 2011.</td><td>OEB Appendix 2K
<table>
<tr><td>Number of Employees
(FTEs including Part-Time)</td><td>2011 Actuals</td></tr>
<tr><td>Management</td><td>No Change</td></tr>
<tr><td>Non-Management
(union and non-union)</td><td><s>1757.9</s>
1675.2</td></tr>
<tr><td>Total</td><td><s>1819.7</s>
1737.0</td></tr>
</table></td></tr>
</table>

Daliana Coban
Regulatory Counsel
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September 23, 2014

via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting ("Custom IR") Application for 2015-2019 Electricity Distribution Rates and Charges – Revisions
OEB File No. EB-2014-0116

Toronto Hydro writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

On July 31, 2014, Toronto Hydro filed its 2015 – 2019 Custom IR Application (the "Application"). In the accompanying cover letter, Toronto Hydro advised the OEB that it had identified a number of small changes to be made to the pre-filed evidence, and proposed to file an update in the fall. Further to the July 31, 2014 cover letter, enclosed are revisions to the Application.

The nature of the enclosed evidentiary updates is largely administrative. The majority of updates consist of minor revisions that were necessary to align the underlying financial information with the requested relief, or minor corrections to numerical and narrative evidence. As an example, Toronto Hydro updated its revenue requirement calculations to align with changes to the revenue offset forecasts.

Toronto Hydro confirms that the enclosed updates do not have a material effect on the Application. As a result of the changes, Toronto Hydro's requested revenue requirement for 2015 has decreased by approximately $10 million. From a rates perspective, the combined effect of the enclosed updates is a reduction for most rate classes. For an average residential customer, the reduction is approximately $0.60 in the monthly bill for 2015 and $1.40 by 2019. On average, for each of the next five years (2015-2019), the bill impacts associated with the Application (including all of the proposed rate riders) have decreased from approximately $3.54 to approximately $3.25 per month for residential customers.

For ease of reference, and pursuant to Rule 11.03 of the OEB's Rules of Practice and Procedure, all revisions have been marked by "/C" and are being provided in blue paper. In addition, Toronto Hydro has prepared a table (Appendix A) describing the original evidence, each revision to the evidence, and if the change was numerical, the difference between the original evidence and the revision(s).

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

Daliana Coban
Regulatory Counsel
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:encl.

:DC/acc

cc: Charles Keizer
Crawford Smith
Intervenors of Record for EB-2014-0116

Rob Barrass
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July 31st, 2014

via RESS e-filing ±signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited
Custom Incentive Rate-Setting Application for 2015 ±2019 Electricity Distribution Rates and Charges
OEB File No. EB-2014-0116

Toronto Hydro writes to inform the Board of the above-noted matter.

Please find enclosed an electronic Custom IR Application for 2015 ±2019 Electricity Distribution Rates and Charges. Two physical copies of the Application will follow shortly via courier.

While Toronto Hydro has aligned this Application with the 2015 Filing Requirements[1] was prepared under the 2013 Custom IR Filing Requirements and contains elements. As the Application addresses a five-year period of significant activity, Toronto Hydro requests that the Board convene an Evidence Conference and Settlement Conference preceding the technical conference. The evidence conference would be an opportunity for Toronto Hydro witnesses to provide OEB panel members and other parties with an overview of the central, custom components of the Application. Toronto Hydro proposes that testimony given at the evidence conference would be transcribed and form part of the record of the proceeding. It is hope that this procedural step will help clarify its requests and proposals, ultimately expediting and simplifying subsequent stages of the proceeding.

While finalizing the Application, Toronto Hydro has identified a small number of inconsistencies between the financial information and the relief requested in the Application. For example, Toronto Hydro has requested approval of changes to its specific service charges, resulting in increased revenue offsets. However, the corresponding decrease in revenue requirement is not reflected in the evidence as-filed. Toronto Hydro proposes to update the evidence in the normal course, by the early fall. While

[1] Alignment with the Renewed Regulatory Framework for Electricity Distributors and the Filing Requirements is discussed in detail in Exhibit 1B, Tab 2, Schedule 2.

Toronto Hydro is in the process of addressing these inconsistencies, it does not currently expect that any will have a material effect on the Application.

Toronto Hydro encloses live Excel versions of the following documents:

- PILs model for Bridge and Test Years (Exhibit 4B, Tab 2, Schedule 2)
- Revenue Requirement Workform Model for 2015 Filers (Exhibit 6, Tab 1, Schedule 2)
- Cost Allocation Model (Exhibit 7, Tab 1, Schedule 2)
- Retail Transmission Service Rates Model (Exhibit 8, Tab 6, Schedule 1)
- Fixed Asset Continuity Schedule (Exhibit 2A, Tab 1, Schedule 2)
- Capital Expenditures Summary (Exhibit 2A, Tab 6, Schedule 3)
- Deferral and Variance Accounts Continuity Schedules (Exhibit 9, Tab 2, Schedule 1)

A small number of documents within the Application contain confidential information. Under separate cover, Toronto Hydro requests that this information be treated confidentially in accordance with the *Rules of Practice and Procedure* and *Practice Direction on Confidential Filings*.

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

Rob Barrass
Manager and Counsel, Regulatory Affairs
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:RB/km

cc: Charles Keizer and Crawford Smith of Torys LLP, Counsel for THESL, by electronic mail only

Appendix A: Table of Revisions (February 5, 2015), Toronto Hydro 2015-2019 Custom IR Application, OEB File No. EB-2014-0116

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed February 6, 2015)</th><th>Numerical Differences</th></tr>
<tr><td>Executive Summary
(Exhibit 1A, Tab 2, Schedule 1)</td><td>Updates to summary values for rate base, revenue requirement, and bill impacts to account for changes to the = Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>
<table>
<tr><td></td><td>2015</td><td>2016</td></tr>
<tr><td>Capex</td><td><s>539.6</s>
531.1</td><td><s>504.2</s>
518.8</td></tr>
<tr><td>Revenue Requirements</td><td><s>662.3</s>
655.0</td><td></td></tr>
</table>
Due to the size of the Bill Impacts table, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.
</td></tr>
<tr><td>Rate Framework
(Exhibit 1B, Tab 2, Schedule 3)</td><td>Updated C-factor values to account for changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Table 5: Custom PCI Values Assuming An Inflation Factor Of 1.7% For Each Year
<table>
<tr><td></td><td>2016</td><td>2017</td></tr>
<tr><td>C_n</td><td><s>4.11</s>
4.47</td><td><s>7.57</s>
8.25</td></tr>
<tr><td>S_{cap}</td><td><s>67.2</s>
67.1</td><td><s>69.3</s>
69.3</td></tr>
<tr><td>Custom PCI</td><td><s>4.57</s>
4.94</td><td><s>8.00</s>
8.68</td></tr>
</table>
</td></tr>
<tr><td>Capital Investment
(Exhibit 1B, Tab 2, Schedule 4)</td><td>Updated capital spending graph to account for Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9</td><td>N/A</td></tr>
</table>

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed February 6, 2015)</th><th>Numerical Differences</th></tr>
<tr><td></td><td>(Stations Expansion Program).</td><td></td></tr>
<tr><td>PSE Reply to PEG (Exhibit 1B, Tab 2, Schedule 5, Appendix C)</td><td>Filing a non-confidential public version of the PSE Reply to the PEG Report, now included as a new Appendix C.</td><td>N/A</td></tr>
<tr><td>Rate Base Narrative (Exhibit 2A, Tab 1, Schedule 1)</td><td>Updated to reflect most current forecasts for in-service additions and rate base, as a result of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Due to the size of the Rate Base tables, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
<tr><td>Fixed Assets Continuity Schedule (Exhibit 2A, Tab 1, Schedule 2)</td><td>Updated to reflect most current forecasts, as a result of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Due to the size of the Fixed Asset Continuity tables, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
<tr><td>Working Capital Allowance (Exhibit 2A, Tab 3, Schedule 1)</td><td>Updated working capital allowance due to changes in PILs, as a result of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Table 2: Working Capital Allowance ($millions)<table><tr><th></th><th>2015 Test Year</th></tr><tr><td>Working Capital Allowance</td><td><s>241.7</s>
241.5</td></tr></table></td></tr>
<tr><td>Capex Tables (Exhibit 2A, Tab 6, Schedules 2 and 3)</td><td>Updated to reflect most current forecasts for capital expenditures, as a result of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Due to the size of the Capex tables, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed February 6, 2015)</th><th>Numerical Differences</th></tr>
<tr><td>DSP Preface (Exhibit 2B, Section 00)</td><td>Updated graph to reflect most current forecasts for capital expenditures, as a result of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>N/A</td></tr>
<tr><td>DSP Coordinated Planning (Exhibit 2B, Section B, Appendices D and E)</td><td>Updated to include an IESO Letter of Comment (as a new Appendix D) and a HONI Letter concerning the Regional Planning Status (as a new Appendix E).</td><td>N/A</td></tr>
<tr><td>DSP Capex Plan Summary (Exhibit 2B, Section E1)</td><td>Updated several tables to reflect most current capital expenditures plans, as a result of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>TABLE 1: CAPITAL INVESTMENT BY CATEGORIES
<table><tr><th></th><th>Avg.</th><th>2015</th><th>2016</th><th>Total</th></tr><tr><td>System Service</td><td><s>65.87</s>
66.41</td><td><s>86.84</s>
76.45</td><td><s>56.52</s>
69.60</td><td><s>329.36</s>
332.05</td></tr><tr><td>Other Capex</td><td><s>29.19</s>
29.86</td><td><s>10.28</s>
12.18</td><td><s>19.75</s>
21.22</td><td><s>145.94</s>
149.31</td></tr><tr><td>Total Capex</td><td><s>496.68</s>
497.90</td><td><s>539.61</s>
531.13</td><td><s>504.24</s>
518.79</td><td><s>2483</s>
2489</td></tr></table></td></tr>
<tr><td>DSP Capex Plan Process Overview (Exhibit 2B, Section E2)</td><td>Updated various graphs to reflect changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>N/A</td></tr>
<tr><td>DSP Capex Summary (Exhibit 2B, Section E4)</td><td>Updated various tables to reflect most current capital expenditures plans, as a result of changes to the Copeland TS project schedule, as discussed in Exhibit</td><td><table><tr><th></th><th>Avg.</th><th>2015</th><th>2016</th><th>Total</th></tr><tr><td>System Service</td><td><s>65.87</s></td><td><s>86.84</s></td><td><s>56.52</s></td><td><s>329.36</s></td></tr></table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed February 6, 2015)</th><th>Numerical Differences</th></tr>
<tr><td></td><td>2B, Section 7.9 (Stations Expansion Program).</td><td>
<table>
<tr><td></td><td>66.41</td><td>76.45</td><td>69.60</td><td>332.05</td></tr>
<tr><td>Other Capex</td><td><s>29.19</s>
29.86</td><td><s>10.28</s>
12.18</td><td><s>19.75</s>
21.22</td><td><s>145.94</s>
149.31</td></tr>
<tr><td>Total Capex</td><td><s>496.68</s>
497.90</td><td><s>539.61</s>
531.13</td><td><s>504.24</s>
518.79</td><td><s>2483</s>
2489</td></tr>
</table>
</td></tr>
<tr><td>DSP Capex Plan Renewal Investments (Exhibit 2B, Section E6)</td><td>Administrative update to correct unit replacement counts in the following sections:
x E6.1 UG Circuit Renewal
x E6.4 OH Circuit Renewal
x E6.6 Rear Lot Conversion
x E6.7 Box Construction
x E6.8 SCADAMate R1 Renewal</td><td>Due to the size of the various unit count tables, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedules.</td></tr>
<tr><td>DSP Capex Plan System Service Investments (Exhibit 2B, Section E7)</td><td>Administrative update to correct unit replacement counts in the following sections:
x E7.3 Feeder Automation
x E7.4 Polymer SMD20 Renewal</td><td>Due to the size of the various unit count tables, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedules.</td></tr>
<tr><td>DSP Capex Plan System Stations Expansions (Exhibit 2B, Section E7.9)</td><td>Updated the capital expenditures tables to reflect changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>TABLE C: HISTORICAL AND FUTURE SPENDING
<table>
<tr><td></td><td>2010</td><td>2014</td><td>2015</td><td>2016</td></tr>
<tr><td>Capex ($M)</td><td><s>6.8</s>
6.9</td><td><s>83.0</s>
79.5</td><td><s>53.6</s>
43.8</td><td><s>28.5</s>
41.6</td></tr>
</table>
TABLE 2: SUMMARY OF STATIONS EXPANSION PROJECTS</td></tr>
</table>

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed February 6, 2015)</th><th>Numerical Differences</th></tr>
<tr><td></td><td></td><td><table><tr><td></td><td>Anticipated Project Finish</td></tr><tr><td>Copeland TS –
Phase 1 (carry over)</td><td><s>2015</s>
2016</td></tr></table></td></tr>
<tr><td>Load and Customer Forecasts, Narrative for Forecasts (Exhibit 3, Tab 1, Schedule 1)</td><td>Updated total Distribution revenue to reflect changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Table 1: Total Load, Revenues and Customers<table><tr><th colspan="2">YEAR</th><th>Total Distribution Revenue ($M)</th></tr><tr><td>2012</td><td>Actual</td><td><s>$526.5</s>
$527.9</td></tr><tr><td>2013</td><td>Actual</td><td><s>$528.6</s>
$529.5</td></tr><tr><td>2015</td><td>Test</td><td><s>$661.2</s>
$655.1</td></tr><tr><td>2016</td><td>Test</td><td><s>$696.8</s>
$692.8</td></tr><tr><td>2017</td><td>Test</td><td><s>$753.9</s>
$754.4</td></tr><tr><td>2018</td><td>Test</td><td><s>$809.9</s>
$810.5</td></tr><tr><td>2019</td><td>Test</td><td><s>$857.2</s>
$857.8</td></tr></table></td></tr>
<tr><td>Load and Customer Forecasts, Revenues (Exhibit 3, Tab 1, Schedule 1, Appendices E-1, E-2 and E-3)</td><td>Updated total Distribution revenue to reflect changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed February 6, 2015)</th><th>Numerical Differences</th></tr>
<tr><td>Depreciation Expense (Exhibit 4B, Tab 1, Schedule 1, Appendix A)</td><td>Updated depreciation to reflect changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
<tr><td>PILs Narrative (Exhibit 4B, Tab 2, Schedule 1)</td><td>Updated PILs to reflect changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Table 1: Summary of PILs by Year ($ Millions)<table><tr><th></th><th>2014 Bridge</th><th>2015 Test</th></tr><tr><td>Income Taxes</td><td><s>9.43</s>
9.52</td><td><s>24.45</s>
24.05</td></tr><tr><td>Total PILs</td><td><s>9.43</s>
9.52</td><td><s>24.45</s>
24.05</td></tr></table></td></tr>
<tr><td>PILs Model (Exhibit 4B, Tab 2, Schedule 2)</td><td>Updated PILs Model to reflect changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed February 6, 2015)</th><th>Numerical Differences</th></tr>
<tr><td>Revenue Requirement (Exhibit 6, Tab 1, Schedule 1); Revenue Requirement Workform (Exhibit 6, Tab 1, Schedule 2)</td><td>Updated the revenue requirement calculation to reflect the impact of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Table 1: 2015 Revenue Requirement ($ millions)
<table><tr><td>Amortization/Depreciation</td><td><s>$208.2</s>
$206.5</td></tr><tr><td>Income Taxes (Grossed up)</td><td><s>$22.4</s>
$22.0</td></tr><tr><td>Deemed Interest Expense</td><td><s>$81.8</s>
$80.2</td></tr><tr><td>Return on Deemed Equity</td><td><s>$123.3</s>
$120.8</td></tr><tr><td>Service Revenue Requirement</td><td><s>$707.3</s>
$701.1</td></tr><tr><td>Base Revenue Requirement</td><td><s>$661.2</s>
$655.0</td></tr></table></td></tr>
<tr><td>Cost Allocation Narrative (Exhibit 7, Tab 1, Schedule 1);
Cost Allocation Model (Exhibit 7, Tab 1, Schedule 2);
OEB Appendix 2-P Cost Allocation (Exhibit 7, Tab 2, Schedule 1)</td><td>Updated revenue to cost ratios to reflect the impact of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td><table><tr><th>Rate Class</th><th>2015 Model</th><th>2015 Proposed</th></tr><tr><td>Residential</td><td>N/C</td><td><s>95</s>
94</td></tr><tr><td>General Service 50-999kW</td><td><s>118</s>
119</td><td><s>118</s>
119</td></tr><tr><td>Intermediate 1000-4999kW</td><td><s>101</s>
102</td><td><s>101</s>
102</td></tr></table></td></tr>
<tr><td>Rate Design Overview (Exhibit 8, Tab 1, Schedule 1);
Fixed/Variable Allocation (Exhibit 8, Tab 1, Schedule 2)</td><td>Updated distribution rates to reflect the impact of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
</table>

Original Evidence (as originally filed or subsequently updated)	Revised Evidence (Filed February 6, 2015)	Numerical Differences
Red Line Tariff (Exhibit 8, Tab 3, Schedule 2); OEB Appendix 2-Z Proposed Tariff (Exhibit 8, Tab 3, Schedule 3); OEB Appendix 2-V Revenue Reconciliation (Exhibit 8, Tab 4, Schedule 1)	Updated distribution rates to reflect the impact of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).	Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.

Appendix A: Table of Revisions (Nov. 24, 2014), Toronto Hydro 2015-2019 Custom IR Application, OEB File No. EB-2014-0116

<table>
<tr><th>Original Evidence
(Filed July 31, 2014, corrected September 23, 2014 and November 14, 2014)</th><th>Revised Evidence
(Filed November 24, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 2A (Rate Base), Tab 10, Schedule 1 (Service Quality), pp 1 and 2</td><td>Corrected the Appointment Rescheduling results for 2013 (as identified in Toronto Hydro's response to interrogatory 2A-EP-10)</td><td>
<table>
<tr><td>Appointments Rescheduling Summary</td><td>2013</td></tr>
<tr><td>Appointments Not Rescheduled within 2 business days</td><td><s>3</s>
1</td></tr>
<tr><td>Appointment Rescheduling ESQR</td><td><s>93.5%</s>
98.4%</td></tr>
<tr><td>Appointments Not Rescheduled as a percentage of Total Appointments</td><td><s>99.9997%</s>
99.9999%</td></tr>
</table>
</td></tr>
<tr><td>Exhibit 2A (Rate Base), Tab 10, Schedule 3 (OEB Appendix 2G: Service Reliability Indicators)</td><td>Corrected OEB Appendix 2G to reflect changes to the Appointment Rescheduling metric noted above.</td><td>
<table>
<tr><td>Appointments Rescheduling Summary</td><td>2013</td></tr>
<tr><td>Appointment Rescheduling ESQR</td><td><s>93.5%</s>
98.4%</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014, corrected September 23, 2014 and November 14, 2014)</th><th>Revised Evidence
(Filed November 24, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 4A, Tab 1, Schedule 2 (OEB Appendix 2JA: Summary of Recoverable OM&A Expenses)</td><td>Decreased 2014 Bridge MIFRS cost by $1.3M in the “Administrative and General” section to account for income tax credits which were previously booked in the PILS section but under MIFRS, these credits are booked in OM&A.</td><td>
<table>
<tr><td></td><td>2014 Bridge Year MIFRS</td></tr>
<tr><td>Administrative and General</td><td><s>$81.2M</s>
$ 79.9M</td></tr>
<tr><td>SubTotal</td><td><s>$128.8M</s>
$127.5M</td></tr>
<tr><td>%Change (year over year)</td><td><s>0.0%</s>
-1.0%</td></tr>
<tr><td>Total</td><td><s>$246.6M</s>
$ 245.3M</td></tr>
<tr><td>%Change (year over year)</td><td><s>0.0%</s>
-0.5%</td></tr>
</table>
</td></tr>
<tr><td>Exhibit 4A, Tab 1, Schedule 4 (OEB Appendix 2JC: OM&A Programs Table)</td><td>Decreased 2014 Bridge MIFRS cost by $1.3M in the “Common Corporate Costs and Adjustments” program to account for income tax credits which were previously booked in the PILS section but under MIFRS, these credits are booked in OM&A.</td><td>
<table>
<tr><td>Programs</td><td>2014 Bridge Year MIFRS</td></tr>
<tr><td>Common Corporate Costs and Adjustments</td><td><s>$0.7 M</s>
$2.0 M</td></tr>
<tr><td>SubTotal</td><td><s>$2.3</s>
$1.0 M</td></tr>
<tr><td>Total</td><td><s>$246.6M</s>
$ 245.3M</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014, corrected September 23, 2014 and November 14, 2014)</th><th>Revised Evidence
(Filed November 24, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 4A, Tab 1, Schedule 5 (OEB Appendix 2L: Recoverable OM&A Cost per Customer and per FTE)</td><td>Revised FTE numbers to correct an administrative oversight with respect to the pro-ration of resources in 2011.

Revised the 2014 MIFRS budget by $1.3M to align with the changes noted above.</td><td>
<table>
<tr><th></th><th>Last Rebasing Year (2011 Actuals)</th><th>2014 Bridge Year</th></tr>
<tr><td>Reporting Basis</td><td>CGAAP</td><td>MIFRS</td></tr>
<tr><td>Total Recoverable OM&A from Appendix 2-JB</td><td>No Change</td><td>~~$246.6M~~
$245.3</td></tr>
<tr><td>OM&A cost per customer</td><td>No Change</td><td>~~$334.64~~
$332.91</td></tr>
<tr><td>Number of FTEs</td><td>~~1820~~
1,737</td><td>No Change</td></tr>
<tr><td>Customers/FTEs</td><td>~~$387.83~~
$406.30</td><td>No Change</td></tr>
<tr><td>OM&A Cost per FTE</td><td>~~$131,117.08~~
$137,360.81</td><td>~~$160,517.12~~
$159,671.09</td></tr>
</table>
</td></tr>
<tr><td>Exhibit 4A, Tab 4, Schedule 3, page 9</td><td>Revised FTE numbers to correct an administrative oversight with respect to the pro-ration of resources in 2011.</td><td>2011 FTEs original evidence = ~~1819~~
2011 FTEs revised evidence = 1737</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td></td><td></td><td>Total Load
<table>
<tr><th>Year</th><th>Total Load (GWh)</th></tr>
<tr><td>2011</td><td>~~25,418~~
25,419</td></tr>
<tr><td>2012</td><td>~~25,641~~
25,639</td></tr>
<tr><td>2013</td><td>No Change</td></tr>
<tr><td>2014</td><td>~~24,999~~
25,018</td></tr>
<tr><td>2015</td><td>~~24,357~~
24,993</td></tr>
<tr><td>2016</td><td>~~24,048~~
24,027</td></tr>
<tr><td>2017</td><td>~~24,135~~
24,842</td></tr>
<tr><td>2018</td><td>~~24,274~~
24,697</td></tr>
<tr><td>2019</td><td>~~24,473~~
24,611</td></tr>
</table></td></tr>
<tr><td>Exhibit 1B (Requests and Rationale), Tab 1, Schedule 1, Appendix A (Legal Application).</td><td>Revised contact information for Toronto Hydro’s counsel.</td><td>N/A</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 1B (Requests and Rationale), Tab 2, Schedule 3, (Rate Framework), pp. 2, 7, 9 - 11, 13, and 15.</td><td>Revised C_n values, inputs for the determination of C_n, and the Custom PCI Component to align with updates to various programs in the Distribution System Plan (Exhibit 2B), as described below.</td><td>C_n
<table>
<tr><td>2016</td><td>2017</td><td>2018</td><td>2019</td></tr>
<tr><td><s>5.15</s>
4.10</td><td><s>7.77</s>
7.56</td><td><s>6.75</s>
6.67</td><td><s>4.98</s>
5.01</td></tr>
</table>
Custom PCI Component
<table>
<tr><td></td><td>2016</td><td>2017</td><td>2018</td><td>2019</td></tr>
<tr><td>C_n</td><td><s>5.15</s>
4.10</td><td><s>7.77</s>
7.56</td><td><s>6.75</s>
6.67</td><td><s>4.98</s>
5.01</td></tr>
<tr><td>S_{cap}</td><td><s>66.9</s>
67.1</td><td><s>68.5</s>
69.2</td><td><s>70.22</s>
70.8</td><td><s>71.35</s>
71.9</td></tr>
<tr><td>Custom PCI</td><td><s>5.62</s>
4.56</td><td><s>9.21</s>
7.99</td><td><s>7.17</s>
7.08</td><td><s>5.38</s>
5.40</td></tr>
</table>
C-Factor Inputs (Revenue Requirement Components)
<table>
<tr><td></td><td>2015</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td></tr>
<tr><td>Interest</td><td><s>82.1</s>
81.8</td><td><s>91.3</s>
90.9</td><td><s>98.6</s>
98.2</td><td><s>104.2</s>
103.7</td><td><s>109.6</s>
109.0</td></tr>
<tr><td>ROE</td><td><s>122.9</s>
123.3</td><td><s>136.7</s>
137.1</td><td><s>147.6</s>
148.0</td><td><s>156.1</s>
156.3</td><td><s>164.2</s>
164.3</td></tr>
<tr><td>Depreciation</td><td><s>208.8</s>
208.2</td><td><s>228.5</s>
222.0</td><td><s>256.9</s>
248.2</td><td><s>276.3</s>
266.7</td><td><s>297.3</s>
287.2</td></tr>
<tr><td>PILs/Taxes</td><td><s>22.7</s>
24.4</td><td><s>14.7</s>
14.9</td><td><s>23.1</s>
22.8</td><td><s>41.5</s>
40.5</td><td><s>48.0</s>
46.7</td></tr>
<tr><td>Capital-related RR</td><td><s>436.5</s>
437.8</td><td><s>471.1</s>
465.0</td><td><s>526.3</s>
517.3</td><td><s>578.1</s>
567.2</td><td><s>619.1</s>
607.3</td></tr>
<tr><td>OM&A</td><td><s>270.5</s>
269.5</td><td><s>274.3</s>
273.3</td><td><s>278.1</s>
277.1</td><td><s>282.0</s>
281.0</td><td><s>286.0</s>
284.9</td></tr>
<tr><td>Revenue Offsets</td><td><s>(35.3)</s>
(45.1)</td><td><s>(35.8)</s>
(45.7)</td><td><s>(36.3)</s>
(46.4)</td><td><s>(36.9)</s>
(47.0)</td><td><s>(37.4)</s>
(47.6)</td></tr>
<tr><td>Total RR</td><td><s>671.7</s>
662.2</td><td><s>709.6</s>
692.5</td><td><s>768.1</s>
748.1</td><td><s>823.3</s>
801.2</td><td><s>867.9</s>
844.5</td></tr>
</table></td></tr>
<tr><td>Exhibit 1B (Requests and Rationale), Tab 2, Schedule 4 (Capital Investment), p. 6.</td><td>Revised “Figure 1” to align with Capital Expenditures updates, as described below (see Exhibit 2A, Tab 6, Schedule 2 and 3, and Exhibit 2B).</td><td>See below for a summary of the changes to Capital Expenditures.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td></td><td>Exhibit 1B (Requests and Rationale), Tab 2, Schedule 4, Appendix C (Navigant Addendum Report). The Navigant Addendum Report provides an opinion on the Operational Centers Consolidation Program (Exhibit 2B, Section E8.3), and an opinion on the updates to various programs in the Distribution System Plan (Exhibit 2B), as described below.</td><td>N/A</td></tr>
<tr><td>Exhibit 1B (Requests and Rationale), Tab 2, Schedule 5, Appendix B (PSE Report), pp. 5, 7, 8-12, 31, 34, 39, 46, 50, and 53 (The entire report has been re-filed.).</td><td>Revised econometric benchmarking analysis to align with the revenue requirement updates summarized below in Exhibit 6.</td><td>Minor numerical changes driven by revised calculations reflecting the updated cost forecasts and corrections of a minor calculation in the reliability assessment. The cumulative effect to the study's revision is minor improvement (under 0.5%) in Toronto Hydro's total cost performance relative to the model-predicted levels. There were no changes to the results of the reliability model. No changes were made to the supplemental engineering report filed as an Appendix to the benchmarking study has not changed.</td></tr>
<tr><td>Exhibit 2A (Rate Base), Tab 1, Schedule 1 (Rate Base Overview), pp. 1-6 and 9-14.</td><td>Revised 2014 and 2015 rate base forecasts to align with updates to various programs Distribution System Plan (Exhibit 2B) and the working capital allowance (Exhibit 2A, Tab 3, Schedule 1), as described below.</td><td>Rate Base Overview
<table>
<tr><th></th><th>2014 Bridge UGAAP</th><th>2015 Test MIFRS</th></tr>
<tr><td>Opening PP&E NBV</td><td>No Change</td><td>~~2,434.4~~
2,435.1</td></tr>
<tr><td>Opening PP&E NBV Adjusted</td><td>No Change</td><td>~~2,858.1~~
2,858.8</td></tr>
<tr><td>Closing PP&E NBV</td><td>~~2,454.2~~
2,454.8</td><td>~~3,274.7~~
3,282.8</td></tr>
<tr><td>Average PP&E NBV</td><td>~~2,405.1~~
2,405.4</td><td>~~3,066.4~~
3,070.8</td></tr>
<tr><td>Working Capital Allowance</td><td>~~369.7~~
369.5</td><td>~~235.9~~
241.7</td></tr>
<tr><td>Rate Base</td><td>~~2,774.8~~
2,774.9</td><td>3,302.3
3,312.4</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 2A (Rate Base), Tab 1, Schedule 1 (Appendix 2-BA Fixed Asset Continuity Schedules), pp. 4-7 [Excel version has been filed].</td><td>Revised 2014 and 2015 forecasts to align with updates to various programs in the Distribution System Plan (Exhibit 2B), as described below.</td><td>The difference cannot be summarized for the purposes of this table. Please refer to the updated schedules.</td></tr>
<tr><td>Exhibit 2A (Rate Base), Tab 2, Schedule 2 (Property Plant & Equipment by Function), pp. 1-2.</td><td>Revised 2014 and 2015 forecasts of gross assets by function to align with updates to various programs in the Distribution System Plan (Exhibit 2B), as described below.</td><td>PP&E By Function ($ Millions)
<table>
<tr><th></th><th>2014 MIFRS</th><th>2015 MIFRS</th></tr>
<tr><td>Distribution Plant</td><td><s>4,646.5</s>
4,645.1</td><td><s>5,467.5</s>
5,485.9</td></tr>
<tr><td>General Plant</td><td><s>855.6</s>
858.2</td><td><s>996.4</s>
986.8</td></tr>
<tr><td>Capital Contributions</td><td>No Change</td><td><s>(371.0)</s>
(372.5)</td></tr>
<tr><td>Total Before CWIP</td><td><s>5,147.9</s>
5,149.0</td><td><s>6,092.9</s>
6,100.2</td></tr>
<tr><td>CWIP</td><td><s>505.4</s>
509.1</td><td><s>389.1</s>
395.1</td></tr>
<tr><td>Total Including CWIP</td><td><s>5,653.3</s>
5,658.2</td><td><s>6,482.0</s>
6,495.2</td></tr>
</table>
Gross Assets by Major Plant Account Summary ($ Millions)
<table>
<tr><th></th><th>2014 MIFRS</th><th>2015 MIFRS</th></tr>
<tr><td>Land and Buildings</td><td><s>69.0</s>
68.7</td><td><s>130.3</s>
143.4</td></tr>
<tr><td>TS Primary Above 50</td><td>No Change</td><td><s>29.5</s>
29.7</td></tr>
<tr><td>Distribution System</td><td><s>243.7</s>
244.2</td><td><s>309.2</s>
309.8</td></tr>
<tr><td>Poles and Wires</td><td><s>3,253.5</s>
3,252.0</td><td><s>3,822.0</s>
3,826.8</td></tr>
<tr><td>Services and Meters</td><td>No Change</td><td><s>349.2</s>
349</td></tr>
<tr><td>General Plant</td><td>No Change</td><td><s>165.3</s>
158.9</td></tr>
<tr><td>Equipment</td><td>No Change</td><td><s>199.3</s>
198.0</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><td>Other Distribution Assets</td><td>~~402.3~~
404.9</td><td>~~524.2~~
522.3</td></tr>
<tr><td>Contributions and Grants</td><td>No Change</td><td>~~(371.0)~~
(372.5)</td></tr>
<tr><td>Gross Assets</td><td>~~5,147.9~~
5,149.0</td><td>~~6,092.9~~
6,100.2</td></tr>
</table>
</td></tr>
<tr><td>Exhibit 2A (Rate Base), Tab 2, Schedule 2, Appendix A (Gross Assets by Major Plant Account).</td><td>Revised 2014 and 2015 forecasts of gross assets by major plant account to align with updates to various programs in the Distribution System Plan (Exhibit 2B), as described below.</td><td>Due to the size of the information, the differences cannot be summarized for the purposes of this table. Please refer to the updated schedule.</td></tr>
<tr><td>Exhibit 2A (Rate Base), Tab 3 (Working Capital Allowance).</td><td>Revised inputs to the calculation of working capital to reflect updated 2015 financial data.</td><td>Working Capital Calculations ($ Millions)
<table>
<tr><td></td><td>2015 Expenses ($ millions)</td><td>Working Capital Factor</td><td></td><td>Expenses * Working Capital Factor ($ millions)</td></tr>
<tr><td>Cost of Power</td><td>~~2,681.5~~
2,751.9</td><td>No Change</td><td></td><td>~~162.8~~
167.0</td></tr>
<tr><td>OM&A</td><td>~~270.6~~
269.5</td><td>No Change</td><td></td><td>~~15.7~~
15.6</td></tr>
<tr><td>Interest on Long Term Debt</td><td>~~82.0~~
81.8</td><td>No Change</td><td></td><td>No change</td></tr>
<tr><td>Income and Capital Taxes</td><td>~~22.7~~
24.4</td><td>No Change</td><td></td><td>~~6.4~~
6.9</td></tr>
<tr><td>DRC</td><td>No change</td><td>No Change</td><td></td><td>No change</td></tr>
<tr><td>Sub-Total Working Capital Requirement</td><td></td><td></td><td></td><td>~~197.0~~
201.8</td></tr>
<tr><td>HST at 13%</td><td></td><td>Net Lag Days</td><td>Expenses * Net Lag Days/365 * 13% HST</td><td></td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><td>Revenue</td><td>~~3,332.6~~
3,403.1</td><td>No change</td><td>~~-6.5~~
-6.6</td><td></td></tr>
<tr><td>Cost of Power</td><td>~~2,681.5~~
2,751.9</td><td>No change</td><td>~~43.9~~
45.0</td><td></td></tr>
<tr><td>OM&A Expenses</td><td>~~103.6~~
103.2</td><td>No change</td><td>No change</td><td></td></tr>
<tr><td>HST Working Capital Requirement</td><td></td><td></td><td></td><td>~~38.9~~
39.9</td></tr>
<tr><td>Total Working Capital</td><td></td><td></td><td></td><td>~~235.9~~
241.7</td></tr>
<tr><td colspan="3">Working Capital as % of Cost of Power and Controllable Expenses</td><td></td><td>~~7.99%~~
8.00%</td></tr>
</table>
</td></tr>
<tr><td>Exhibit 2A (Rate Base), Tab 5, Schedule 1 (Street Lighting Transfer), pp. 1-3, 5-6, 8-9, 13, 19, 24-25.</td><td>An explanation of the post filing assessment that was conducted by Toronto Hydro with respect to the assumptions and methodology underlying the transfer.

A revised description of detailed analysis which was undertaken to arrive at the revised transfer value of the former street lighting assets.

Corrected the PILs values for the calculation of the revenue requirement associated with the former street lighting assets. Revised forecast of the revenue offset from contract revenue.</td><td>Revenue Requirement from Street Lighting Assets ($ Millions)
<table>
<tr><td>PILS</td><td>~~0.1~~
0.3</td></tr>
<tr><td>Service Revenue Requirement</td><td>7.~~8~~
8.1</td></tr>
<tr><td>Revenue Offset – Contract Revenue</td><td>~~7.8~~
8.1</td></tr>
</table>
</td></tr>
</table>

Original Evidence (Filed July 31, 2014)	Revised Evidence (Filed September 23, 2014)	Numerical Differences
	Exhibit 2A (Rate Base), Tab 5, Schedule 2, Appendix A (PWC Addendum Letter): An addendum to the original report dated July 28, 2014 and filed July 31, 2014, consistent with the revisions to the evidence noted above.	N/A
Exhibit 2A (Rate Base), Tab 6, Schedule 2 (OEB Appendix 2-AA Capital Projects).	Revised table to align with updates to various programs in the Distribution System Plan (Exhibit 2B), as described below.	Please refer to the following descriptions below: x Exhibit 2B, Sec E5.1, pp. (Metering Program) x Exhibit 2B (Distribution System Plan), Sec E5.5 (Generation Protection, Monitoring and Control Program) x Exhibit 2B (Distribution System Plan), Sec E7.6 (Polymer SMD-20 Switch Renewal Program) x Exhibit 2B (Distribution System Plan), Sec E7.9 (Stations Expansion Program) x Exhibit 2B (Distribution System Plan), Sec E8.2 (Facilities Management & Security Program)
Exhibit 2A (Rate Base), Tab 6, Schedule 3 (OEB Appendix 2-AB Capital Expenditures Summary) [Excel version has been filed].	Revised table to align with updates to various programs in the Distribution System Plan (Exhibit 2B), as described below.	Please refer to the Forecasted Capital Investments by Category, below (Exhibit 2B, Section 00).

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 2A (Rate Base), Tab 8, Schedule 1 (Eligible Investments for Qualifying Facilities / Renewable Generation Facilities), pp. 4-5.

Exhibit 2A (Rate Base), Tab 8, Schedule 2 (OEB Appendix 2-FA).

Exhibit 2A (Rate Base), Tab 8, Schedule 3 (OEB Appendix 2-FB).</td><td>Revised 2015 to 2019 cost forecasts and associated provincial rate protection amounts, to align with updates to the Generation Protection Monitoring and Control Program (Exhibit 2B, Section E5.5), as described below.</td><td>Renewable Enabling Improvements (R EI) from 2015 to 2019 ($ Millions)

<table>
<tr><th>Capital Program</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th></tr>
<tr><td>Generation Protection Control and Monitoring</td><td><s>4.7</s>
6.12</td><td><s>4.7</s>
5.19</td><td><s>2.7</s>
3.26</td><td><s>1.8</s>
2.10</td><td><s>1.6</s>
2.02</td></tr>
<tr><td>Energy Storage</td><td><s>0.5</s>
0.54</td><td><s>1.1</s>
1.09</td><td><s>2.2</s>
2.16</td><td><s>3.2</s>
3.24</td><td><s>3.8</s>
3.78</td></tr>
<tr><td>Totals</td><td><s>5.2</s>
6.66</td><td><s>5.8</s>
6.27</td><td><s>4.9</s>
5.43</td><td><s>5</s>
5.34</td><td><s>5.4</s>
5.79</td></tr>
</table>

Provincial Rate Protection Amounts from 2015 to 2019 ($ Millions)

<table>
<tr><th>Year</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th></tr>
<tr><td>Provincial Rate Protection</td><td><s>0.2</s>
0.31</td><td><s>0.8</s>
1.00</td><td><s>1.5</s>
1.69</td><td><s>2.0</s>
2.31</td><td><s>2.6</s>
2.93</td></tr>
</table></td></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section 00 (Executive Summary), pp. 6, 15-17, 26-27 and 34-36.

Exhibit 2B (Distribution System Plan), Section E1 (Capital Expenditure Plan Summary), pp. 4-6.</td><td>Revised forecasted capital investments to reflect updates to various capital programs, as described below.</td><td>Forecasted Capital Investments by Category ($ Millions)

<table>
<tr><th>Investment Category</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th></tr>
<tr><td>System Access</td><td><s>76.73</s>
76.01</td><td><s>83.32</s>
86.13</td><td><s>92.30</s>
93.54</td><td><s>99.61</s>
100.93</td><td><s>89.45</s>
90.41</td><td><s>84.38</s>
85.47</td></tr>
<tr><td>System Service</td><td><s>104.91</s>
104.06</td><td><s>84.35</s>
86.84</td><td>No Change</td><td>No Change</td><td>No Change</td><td>No Change</td></tr>
<tr><td>General Plant</td><td><s>106.34</s>
109.47</td><td><s>93.89</s>
104.63</td><td><s>98.05</s>
99.44</td><td><s>32.29</s>
28.93</td><td>No Change</td><td>No Change</td></tr>
<tr><td>Other CAPEX</td><td><s>11.16</s>
13.30</td><td><s>10.34</s>
10.28</td><td><s>19.85</s>
19.75</td><td><s>28.80</s>
28.65</td><td><s>38.25</s>
37.89</td><td><s>49.86</s>
49.37</td></tr>
<tr><td>Total</td><td><s>585.51</s>
589.21</td><td><s>523.64</s>
539.61</td><td><s>501.71</s>
504.24</td><td><s>469.56</s>
467.36</td><td><s>469.45</s>
470.05</td><td><s>501.56</s>
502.16</td></tr>
</table>

Please refer to the Executive Summary updates above, for differences re forecasted capital investments by trigger driver.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E2 (CAPEX Planning Process Overview), pp. 4-7, 10, 18-21, and 27.</td><td>Updated the figures illustrating alternative system investment strategies to reflect changes to the capital programs, as described below.</td><td>Percent changes to the values in the illustrative “pacing” figures are minor (i.e. in the range of 1%). The estimated year for reaching ‘steady state’ by following the “paced” execution strategy remains unchanged. For numerical revisions to the 2015-2019 Capital Expenditure Plan, please refer to the Forecasted Capital Investments by Category table above.</td></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E4 (Capital Expenditure Summary), pp. 1, 3, 7, and 9-11.</td><td>Revised forecasted capital investments to reflect updates to various capital programs, as described below.</td><td>Please refer to the following updates above:
x Capital Investments by Trigger Driver (Exhibit 1A, Tab 2, Schedule 1); and
x Forecasted Capital Investments by Category (Exhibit 2B, Section 00).</td></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E5 (System Access Investments Introduction), p. 3.</td><td>Revised 2015-2019 total cost forecasts for System Access programs, reflecting updates to the capital programs in the right column, which are described below.</td><td>System Access Program Forecas t Revisions ($ Millions)
<table><tr><th>Program Name</th><th>Total Cost (5 yrs)</th></tr><tr><td>E5.1 Metering</td><td><s>$77.3 M</s>
$81.5 M</td></tr><tr><td>E5.5 Generation Protection, Monitoring & Control</td><td><s>$15.4 M</s>
$18.7 M</td></tr></table></td></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E5.1 (Metering Program), pp. 4-5. 7-11, 13-15, 28 and 42.</td><td>Revised 2014 to 2019 cost forecasts to account for (1) forecasted carry-over amounts from 2014 and (2) inclusion of integrated program costs that were omitted due to administrative error.</td><td>Metering Program ($ Millions)
<table><tr><th>Year</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th></tr><tr><td>CAPEX ($M)</td><td><s>$14.7</s>
$14.0</td><td><s>$23.3</s>
$24.7</td><td><s>$15.9</s>
$16.6</td><td><s>$14.0</s>
$14.7</td><td><s>$11.1</s>
$11.7</td><td><s>$13.0</s>
$13.7</td></tr></table></td></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E5.5 (Generation Protection, Monitoring and Control Program), pp. 3, 6, 27-28, 31, and 33-39.</td><td>Revised 2015 to 2019 cost forecasts re Monitoring and Control systems for renewable energy generation facilities.</td><td>Generation Protection Control and Monitoring Program ($ Millions)
<table><tr><th>Year</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th></tr><tr><td>CAPEX ($M)</td><td><s>$4.71</s>
$6.12</td><td><s>$4.67</s>
$5.19</td><td><s>$2.63</s>
$3.26</td><td><s>$1.80</s>
$2.10</td><td><s>$1.58</s>
$2.02</td></tr></table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E7 (System Service Investments), p. 3.</td><td>Revised total 2015-2019 cost forecasts for System Service programs, reflecting updates to the capital programs in the right column, which are described below.</td><td>System Service Program Forecast Revisions

<table><tr><th>Program Name</th><th>Total Cost (5 yrs)</th></tr><tr><td>E7.6 Polymer SMD-20 Switch Renewal</td><td><s>$5.52 M</s>
$4.84 M</td></tr><tr><td>E7.9 Stations Expansion</td><td><s>$182 M</s>
$185 M</td></tr></table></td></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E7.6 (Polymer SMD-20 Switch Renewal Program), pp. 2-5, 9, 13, and 17-19.</td><td>Revised 2015 to 2019 cost forecasts based on new information from the field indicating a lower number of remaining SMD-20s requiring replacement.</td><td>Polymer SMD-20 Switch Renewal Program ($ Millions)

<table><tr><td>Year</td><td>2015</td></tr><tr><td>CAPEX ($M)</td><td><s>$5.52</s>
$4.84</td></tr></table></td></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E7.9 (Stations Expansion Program), pp. 4-5, 27, and 40-41.</td><td>Revised 2014 and 2015 cost forecasts re Copeland TS Phase 1 project.</td><td>Stations Expansion ($ Millions)

<table><tr><td>Year</td><td>2014</td><td>2015</td></tr><tr><td>CAPEX ($M)</td><td><s>$83.0</s>
$82.2</td><td><s>$51.0</s>
$54.2</td></tr></table></td></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E8 (General Plant Investments), p. 2.</td><td>Revised total 2015-2019 cost forecasts for General Plant programs, reflecting updates to the capital programs in the right column, which are described below.</td><td>General Plant Program Forecast Revisions

<table><tr><th>Program Name</th><th>Total Cost (5 yrs)</th></tr><tr><td>E8.2 Facilities Management & Security</td><td><s>$75.3 M</s> [1]
$31.8 M</td></tr><tr><td>E8.3 Operating Centres Consolidation Program</td><td><s>$46.3 M</s>
$52.2 M</td></tr></table>
Note 1: the original Facilities Management & Security program total cost was entered incorrectly as $75.3 M due to administrative error. This value should have been $29 M.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E8.2 (Facilities Management & Security Program), pp. 4-5, 11, 16-17, 32, 36 and 41.</td><td>Revised 2012-2013 historical and 2014-2015 cost forecasts to account for (1) addition of projects that had been misallocated to the Operating Centres Consolidation Program due to administrative error and (2) addition of required 2015 project.</td><td>Facilities Management & Security Program ($ Millions)
<table><tr><td>Year</td><td>2012</td><td>2013</td><td>2014</td><td>2015</td></tr><tr><td>CAPEX ($M)</td><td><s>$5.4</s>
$6.6</td><td><s>$5.9</s>
$6.8</td><td><s>$5.0</s>
$7.5</td><td><s>$13.7</s>
$16.5</td></tr></table></td></tr>
<tr><td>Exhibit 2B (Distribution System Plan), Section E8.3 (Operating Centres Consolidation Program), pp. 2-3, 10, 13-15, 17, 30, and Appendix A and B [The appendices have been filed confidentially].</td><td>Revised 2013 historical and 2014-15 cost forecasts to account for IT investments that were correctly allocated to the OCCP program but that were not accurately expressed in this schedule due to administrative error.</td><td>Operating Centres Consolid ation Program ($ Millions)
<table><tr><td>Year</td><td>2013</td><td>2014</td><td>2015</td></tr><tr><td>CAPEX ($M)</td><td><s>$4.9</s>
$7.7</td><td><s>$69.0</s>
$82.7</td><td><s>$36.4</s>
$37.4</td></tr></table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 3 (Operating Revenue), Tab 1, Schedule 1 (Loads and Customer Forecast), pp. 1-3 and 11-14; Appendices A-1, A-2, B-1, B-2, B-3, D, E-1, E-2, E-3, F-2 [Excel version of Appendix A-1 has been filed].</td><td>Revised Load Forecast to reflect updated CDM estimates.</td><td>Load Forecast
<table>
<tr><th colspan="2">YEAR</th><th>Total Normalized GWh</th><th>Total Normalized MVA</th><th>Total Distribution Revenue ($M)</th></tr>
<tr><td>2009</td><td>Actual</td><td><s>25,573.7</s>
25,572.8</td><td><s>42,758.3</s>
42,754.7</td><td>No change</td></tr>
<tr><td>2010</td><td>Actual</td><td><s>25,607.4</s>
25,607.2</td><td><s>43,272.5</s>
43,273.3</td><td>No change</td></tr>
<tr><td>2011</td><td>Actual</td><td><s>25,418.4</s>
25,419.0</td><td><s>43,018.8</s>
43,020.2</td><td>No change</td></tr>
<tr><td>2012</td><td>Actual</td><td><s>25,640.8</s>
25,639.2</td><td><s>43,544.6</s>
43,544.5</td><td>No change</td></tr>
<tr><td>2013</td><td>Actual</td><td><s>25,212.6</s>
25,213.2</td><td><s>42,658.5</s>
42,658.7</td><td>No change</td></tr>
<tr><td>2014</td><td>Bridge</td><td><s>24,999.5</s>
25,018.5</td><td><s>43,344.8</s>
42,712.7</td><td><s>$542.3</s>
$539.4</td></tr>
<tr><td>2015</td><td>Test</td><td><s>24,357.2</s>
24,993.3</td><td><s>43,501.9</s>
42,697.2</td><td><s>$671.6</s>
$662.2</td></tr>
<tr><td>2016</td><td>Test</td><td><s>24,048.2</s>
25,027.4</td><td><s>43,819.9</s>
42,806.2</td><td><s>$712.7</s>
$697.9</td></tr>
<tr><td>2017</td><td>Test</td><td><s>24,135.2</s>
24,841.6</td><td><s>43,897.6</s>
42,631.3</td><td><s>$776.6</s>
$755.1</td></tr>
<tr><td>2018</td><td>Test</td><td><s>24,273.5</s>
24,696.9</td><td><s>44,115.5</s>
42,584.4</td><td><s>$839.6</s>
$811.3</td></tr>
<tr><td>2019</td><td>Test</td><td><s>24,472.5</s>
24,611.4</td><td><s>44,317.1</s>
42,529.2</td><td><s>$893.4</s>
$858.7</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 3 (Operating Revenue), Tab 2, Schedule 1 (Revenue Offsets), pp 1-2, 4 and 6.</td><td>Revised forecast of street lighting asset transfer offset revenue, 2014 and 2015 merchandising and jobbing, and 2014 gain on sale of properties.</td><td>Merchandise and Jobbing Revenue and Expenses ($000s)

<table><tr><td>Expenses</td><td>2014 Bridge Year</td><td>2015 Test Year</td></tr><tr><td>Customer Services</td><td>~~(3,308.0)~~
(2,894.0)</td><td>~~(2,683.5)~~
(2,269.5)</td></tr><tr><td>Net Revenue</td><td></td><td></td></tr><tr><td>Customer Services</td><td>~~150.1~~
564.1</td><td>~~233.6~~
647.7</td></tr></table>
Revenue Offset Summary ($000s)

<table><tr><td></td><td>2014 Bridge Year</td><td>2015 Test Year</td></tr><tr><td>Street-lighting Transfer Revenue Offsets</td><td>No Change</td><td>~~7,765.2~~
8,084.9</td></tr><tr><td>Merchandise and Jobbing Costs</td><td>~~14,766.0~~
14,351.98</td><td>~~13,122.5~~
12,708.53</td></tr><tr><td>Gain on Sale of Properties</td><td>~~0.0~~

453.5</td><td>No Change</td></tr><tr><td>Total Revenue Offsets</td><td>~~25,570.5~~
26,438.0</td><td>~~44,397.9~~
45,131.6</td></tr></table></td></tr>
<tr><td>Exhibit 3 (Operating Revenue), Tab 2, Schedule 1 (OEB Appendix 2-H: Other Operating Revenue).</td><td>Revised OEB Appendix 2H to align with the above noted changes to revenue offsets.</td><td>Please refer to the row above.</td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 1, Schedule 1 (OM&A Overview), pp. 2-5.</td><td>Revised narrative to align with updates to various OM&A programs, as described below.</td><td>Summary tables updated to reflect the 2014 and 2015 cost forecast changes which are described in more detail below.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 1, Schedule 2 (OEB Appendix 2-JA: Summary of Recoverable OM&A Expenses).</td><td>Revised schedule to align with the updates to various OM&A programs, as described below.</td><td>Summary of Recoverable OM &A Expenses ($ Millions)
<table><tr><th>Reporting Basis</th><th>2014 Bridge Year</th><th>2015 Test Year</th></tr><tr><td>Operations</td><td>~~60.2~~
58.5</td><td>~~70.2~~
70.3</td></tr><tr><td>Maintenance</td><td>No Change</td><td>~~60.8~~
61.2</td></tr><tr><td>Administrative and General</td><td>~~83.0~~
81.2</td><td>~~88.4~~
86.5</td></tr><tr><td>Taxes Other Than Income Taxes</td><td>No Change</td><td>~~6.6~~
6.5</td></tr><tr><td>Total</td><td>~~250.2~~
246.6</td><td>~~271.1~~
269.5</td></tr></table></td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 1, Schedule 3 (OEB Appendix 2-JB: Recoverable OM&A Cost Driver Table).</td><td>Revised schedule to align with the updates to various OM&A programs, as described below.</td><td>OM&A Cost Drivers ($ Millions)
<table><tr><th>Updated Cost Drivers</th><th>2012 Actuals</th><th>2014 Bridge Year</th><th>2015 Test Year</th></tr><tr><td>Opening Balance</td><td>No Change</td><td>No Change</td><td>~~250.2~~
246.6</td></tr><tr><td>Emergency Maintenance - Other</td><td>No Change</td><td>No Change</td><td>~~2.0~~
2.5</td></tr><tr><td>Planning</td><td>No Change</td><td>~~(2.5)~~
(4.6)</td><td>~~1.1~~
3.0</td></tr><tr><td>Refundable and Non-Refundable Tax Credits (ITC)</td><td>No Change</td><td>No Change</td><td>~~0~~
(1.3)</td></tr><tr><td>Building & Stations Maintenance</td><td>No Change</td><td>No Change</td><td>~~0.7~~
0.5</td></tr><tr><td>Property Taxes</td><td>No Change</td><td>No Change</td><td>~~(0.0)~~
(0.2)</td></tr><tr><td>Utilities & Communications</td><td>No Change</td><td>No Change</td><td>~~0.2~~
(0.1)</td></tr><tr><td>Control Centre Operations</td><td>~~0.4~~
(1.4)</td><td>No Change</td><td>No Change</td></tr><tr><td>Disaster Preparedness Management</td><td>~~(0.9)~~
0.9</td><td>No Change</td><td>No Change</td></tr></table></td></tr>
</table>

Original Evidence (Filed July 31, 2014)	Revised Evidence (Filed September 23, 2014)	Numerical Differences

Regulatory Costs	No Change	~~(0.5)~~ (2.3)	~~0.4~~ 1.9
Allocations and Recoveries	No Change	~~0.2~~ 0.6	No Change
Subtotal Updated Cost Drivers	No Change	~~(4.6)~~ (8.1)	~~6.3~~ 8.2
Closing Balance	No Change	~~250.2~~ 246.6	~~271.1~~ 269.5

Recoverable Cost Drive Table (App. 2-JB) ($ Millions)

Updated Cost Drivers	2012 Actuals	2014 Bridge	2015 Test
Opening Balance	No Change	No Change	~~250.2~~ 246.6
Emergency Maintenance - Other	No Change	No Change	~~2.0~~ 2.5
Planning	No Change	~~(2.5)~~ (4.6)	~~1.1~~ 3.0
Refundable and Non-Refundable Tax Credits (ITC)	No Change	No Change	~~0~~ (1.3)
Building & Stations Maintenance	No Change	No Change	~~0.7~~ 0.5
Property Taxes	No Change	No Change	~~(0.0)~~ (0.2)
Utilities & Communications	No Change	No Change	~~0.2~~ (0.1)
Control Centre Operations	~~0.4~~ (1.4)	No Change	No Change
Disaster Preparedness Management	~~(0.9)~~ 0.9	No Change	No Change
Regulatory Costs	No Change	~~(0.5)~~ (2.3)	~~0.4~~ 1.9
Allocations and Recoveries	No Change	~~0.2~~ 0.6	No Change
Subtotal Updated Cost Drivers	5.1	~~(4.6)~~ (8.1)	~~6.3~~ 8.2
Closing Balance	215.8	~~250.2~~ 246.6	~~271.1~~ 269.5

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 1, Schedule 4 (OEB Appendix 2-JC: OM&A Programs).</td><td>Revised schedule to align with the updates to various OM&A programs, as described below.</td><td>Revised OM&A Forecasts ($ Millions)
<table><tr><th>Updated Programs</th><th>2014 Bridge Year</th><th>2015 Test Year</th></tr><tr><td>Emergency Response</td><td>No Change</td><td>~~14.8~~
15.3</td></tr><tr><td>Operations Support - Planning</td><td>~~12.4~~
10.3</td><td>~~13.2~~
12.9</td></tr><tr><td>Facilities Management</td><td>No Change</td><td>~~28.1~~
27.5</td></tr><tr><td>Rates & Regulatory Affairs</td><td>~~8.3~~
9.9</td><td>~~8.7~~
10.1</td></tr><tr><td>Common Costs and Adjustments</td><td>No Change</td><td>~~2.3~~
1.0</td></tr><tr><td>Allocations and Recoveries</td><td>~~(20.3)~~
(19.9)</td><td>~~(20.62)~~
(20.2)19.8</td></tr><tr><td>Revised OM&A Total</td><td>~~$250.1~~
$246.6</td><td>~~$271.1~~
$269.5</td></tr></table></td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 1, Schedule 5 (OEB Appendix 2-L: Recoverable OM&A Cost per Customer and per FTE).</td><td>Revised schedule to align with updated 2014 and 2015 OM&A cost forecasts.</td><td>Recoverable OM&A Cost per Cust omer and per FTE ($ Millions)
<table><tr><th></th><th>2014 Bridge Year</th><th>2015 Test Year</th></tr><tr><td>Total Recoverable OM&A from Appendix 2-JB</td><td>~~$250.1~~
$246.6</td><td>~~$271.1~~
$269.5</td></tr><tr><td>OM&A cost per customer</td><td>~~$339.50~~
$334.68</td><td>~~$361.62~~
$359.51</td></tr><tr><td>OM&A Cost per FTE</td><td>~~162,828.79~~
160,517.12</td><td>~~173,393.03~~
172,378.66</td></tr></table></td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 2, Schedule 1 (Preventative and Predictive Maintenance Program), pp. 34-35, 59-60, 63, 72, 75,80,84,88, and 95.</td><td>Minor numerical and grammatical/stylistic corrections.</td><td>Missing decimal point added to Table 5, minor updates based on revised asset counts, and a correction of a calculation error in the discussion of year-over-year variance.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 2, Schedule 3 (Emergency Response Program), pp. 1, 3, and 14-15.</td><td>Revised 2015 cost forecasts in relation to the Grid Response segment.</td><td>Emergency Response Program ($ Millions)

<table><tr><th>2015 Test Year</th></tr><tr><td><s>14.8</s>
15.3</td></tr></table></td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 2, Schedule 7 (Operations Support – Planning Program), pp. 1, 3 and 7.</td><td>Revised 2015 cost forecast to reflect the capitalization of lease payments for the use of Hydro One Networks Inc (HONI) idle transmission lines.</td><td>Operations Support – Planning Program ($ Millions)

<table><tr><th>2014 Bridge Year</th><th>2015 Test Year</th></tr><tr><td><s>12.4</s>
10.3</td><td><s>13.2</s>
12.9</td></tr></table></td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 2, Schedule 11 (Facilities Management Program), pp. 1, 3-4, 7-8 and 12-15.</td><td>Revised 2015 cost forecasts in relation to maintenance expenditures for the Copeland Transformer Station, and to reflect cost savings associated with the Operations Center Consolidation Program (Exhibit 2B, Section E8.3).</td><td>Facilities Management Program ($ Millions)

<table><tr><th>2015 Test Year</th></tr><tr><td><s>28.1</s>
27.5</td></tr></table></td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 2, Schedule 17 (Rates and Regulatory Affairs Program), pp. 1, 3, and 6-10.</td><td>Revisions based on updated information and calculation corrections.</td><td>Rate and Regulatory Affairs Program ($ Millions)

<table><tr><th></th><th>2014 Bridge Year</th><th>2015 Test Year</th></tr><tr><td>Total Cost</td><td><s>8.3</s>
9.9</td><td><s>8.7</s>
10.1</td></tr><tr><td>2015 Revenue Requirement Amount</td><td></td><td>8.4</td></tr></table></td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 2, Schedule 17, Appendix A (OEB Appendix 2-M: Regulatory Costs)</td><td>Minor table reference correction.</td><td>N/A</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 2, Schedule 19 (LEAP Charitable Donations), p. 1.</td><td>Revised 2015 forecast of non-rate recoverable charitable donations.</td><td>Charitable Donations ($ 000s)
<table><tr><th>Category</th><th>2015 Test Year</th></tr><tr><td>Non-Rate Recoverable</td><td>~~50~~
250</td></tr><tr><td>Revised Total</td><td>~~900~~
1100</td></tr></table></td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 2, Schedule 20 (Common Costs and Adjustments), pp. 1-2.</td><td>Revised 2015 cost forecast to exclude refundable Input Tax Credits (ITCs) which have been reclassified to PILs (Exhibit 4B, Tab 2), as described below.</td><td>Common Costs and Adju stments ($ Millions)
<table><tr><th>Cost/Adjustment Type</th><th>2015 Test Year</th></tr><tr><td>Ongoing or Recurring</td><td>~~2.3~~
1.0</td></tr><tr><td>Revised Total</td><td>~~2.3~~
1.0</td></tr></table></td></tr>
<tr><td>Exhibit 4A (Operating Costs – OM&A), Tab 2, Schedule 21 (Allocations and Recoveries), pp. 1 and 4.</td><td>Revised 2014 and 2015 cost forecasts for Other Allocated costs.</td><td>Allocations and Recoveries to OM&A ($ Millions)
<table><tr><th>Allocations & Recoveries</th><th>2014 Bridge Year</th><th>2015 Test Year</th></tr><tr><td>Other Allocated Costs</td><td>~~0.4~~
0.0</td><td>~~0.4~~
0.0</td></tr><tr><td>Revised Total</td><td>~~(20.3)~~
(19.9)</td><td>~~(20.62)~~
19.8(20.2)</td></tr></table></td></tr>
<tr><td>Exhibit 4B (Operating Costs – Depreciation and PILS), Tab 1, Schedule 1, Appendix A (Summary of Depreciation Expense).</td><td>Revised table to align with updates to various program in the Distribution System Plan (Exhibit 2B), as described above.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 4B (Operating Costs – Depreciation and PILS), Tab 2, Schedule 1 (PILs Narrative), pp. 1 and 4-6.</td><td>Revised 2014 and 2015 PILs Models to align with updates to various programs in the Distribution System Plan (Exhibit 2B), as described above, and updates relating to Investment Tax Credits (ITC) allocation.</td><td>Summary of PILs ($ Millions)

<table><tr><th></th><th>2014 Bridge Year</th><th>2015 Test Year</th></tr><tr><td>Income Tax</td><td><s>5.7</s>
9.43</td><td><s>22.68</s>
24.45</td></tr><tr><td>Revised Total</td><td><s>5.7</s>
9.43</td><td><s>20.2</s>
19.824.45</td></tr></table></td></tr>
<tr><td>Exhibit 4B (Operating Costs – Depreciation and PILS), Tab 2, Schedule 2 (PILs Model), pp. 2-3, 5, 12, 16-21, and 24-27 [Excel model has been filed].</td><td>Revised 2014 and 2015 PILs Models to align with updates to various programs in the Distribution System Plan (Exhibit 2B), as described above, and updates relating to Investment Tax Credits (ITC) allocation.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated model.</td></tr>
<tr><td>Exhibit 5 (Cost of Capital), Tab 1, Schedule 1 (Capital Structure Narrative), pp. 3-4.</td><td>Revised the Long Term Debt table to include a recent debt issuance on September 16, 2016.</td><td>Long Term Debt

<table><tr><th>Description</th><th>Maturity</th><th>Outstanding Principal</th><th>Rate</th></tr><tr><td>$200M Prom Note</td><td>Sep. 16, 2044</td><td>$200,000,000</td><td>4.13%</td></tr></table></td></tr>
<tr><td>Exhibit 5 (Cost of Capital), Tab 1, Schedule 2 (OEB Appendix 2OA Capital Structure and Cost of Capital), p. 2.</td><td>Revised 2015 table to (1) align with the recent debt issuance on September 16, 2014 (see above), (2) correct the rate for the series 6 note, and include debt amortization costs which had been omitted due to an administrative error.</td><td>2015 Cost of Capital

<table><tr><th>Debt</th><th>Cost Rate</th></tr><tr><td>Long-term Debt</td><td><s>4.34%</s>
4.31%</td></tr><tr><td>Total Debt</td><td><s>4.14%</s>
4.11%</td></tr><tr><td>Total</td><td><s>6.21%</s>
6.19%</td></tr></table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 5 (Cost of Capital), Tab 1, Schedule 3 (OEB Appendix 2-OB: Debt Instruments).</td><td>Revised Debt Instruments to (1) align with the recent debt issuance on September 16, 2014 (see above), (2) correct the rate for the series 6 note, and include debt amortization costs which had been omitted due to an administrative error.</td><td>2015 Debt Instruments

<table>
<tr><th>Row</th><th>Description</th><th>Start Date</th><th>Term (years)</th><th>Principal ($)</th><th>Rate (%)</th><th>Interest ($) (Note 1)</th></tr>
<tr><td>3</td><td>2010 Series 6</td><td>20-May-10</td><td>30</td><td>$200,000,000</td><td><s>5.6%</s>
5.59%</td><td><s>$11,200,000</s>
$11,180,000</td></tr>
<tr><td>9</td><td>2014 Series 10</td><td><s>31-Aug-14</s>
16-Sep-14</td><td>30</td><td>$200,000,000</td><td><s>4.74%</s>
4.13%</td><td><s>$9,480,000</s>
$8,260,000</td></tr>
<tr><td>13</td><td>Amortization</td><td></td><td></td><td></td><td></td><td>$788,552</td></tr>
<tr><td>Total</td><td></td><td></td><td></td><td><s>$ 2,000,115,478</s>
$1,852,170,272</td><td><s>4,33%</s>
4.31%</td><td><s>$86,518,624</s>
$79,897,861</td></tr>
</table>

Please refer to the updated schedules for changes to 2011-2014 Debt Instruments.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 6 (Revenue Requirement), Tab 1, Schedule 1 (Narrative), pp. 1, and 3-4.

Exhibit 6 (Revenue Requirement), Tab 1, Schedule 2 (RRWF) [Excel version of the model has been filed].</td><td>Revised 2015 revenue requirement calculations consistent with the financial updates described above.</td><td>2015 Revenue Requirement ($ Millions)

<table>
<tr><th></th><th>2015 Test Year</th></tr>
<tr><td>OM&A Expenses</td><td><s>264.5</s>
265.1</td></tr>
<tr><td>Amortization/Depreciation</td><td><s>208.8</s>
208.2</td></tr>
<tr><td>Property Taxes</td><td><s>6.6</s>
6.5</td></tr>
<tr><td>Income Taxes (Grossed up)</td><td><s>22.7</s>
22.4</td></tr>
<tr><td>Deemed Interest Expense</td><td><s>82.1</s>
81.8</td></tr>
<tr><td>Return on Deemed Equity</td><td><s>122.8</s>
123.3</td></tr>
<tr><td>Service Revenue Requirement</td><td><s>707.6</s>
707.3</td></tr>
<tr><td>Revenue Offsets</td><td><s>35.3</s>
45.1</td></tr>
<tr><td>Base Revenue Requirement</td><td><s>672.3</s>
662.2</td></tr>
</table>

Revenue Deficiency ($ Millions)
<table>
<tr><th></th><th>2015 Test Year</th></tr>
<tr><td>2015 Revenue at Current (2014 approved) Rates</td><td><s>589.8</s>
599.9</td></tr>
<tr><td>2015 Service Revenue Requirement</td><td><s>707.6</s>
707.3</td></tr>
<tr><td>Gross Revenue Deficiency</td><td><s>(117.7)</s>
(107.4)</td></tr>
</table>
</td></tr>
<tr><td>Exhibit 7 (Cost Allocation), Tab 1, Schedule 1 (Narrative), pp. 1, 5 and 7.</td><td>Revised consistent with financial updates and Load Forecast updates described above.</td><td>Please refer to the Revenue to Cost Ratio updates described below.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td></td><td>Exhibit 7 (Cost Allocation), Tab 1, Schedule 1, Appendix A (Scenarios Shifting CSMUR Customers to GS 50-999kW Class) – new evidence filed in response to OEB Directive in EB-2010-0142, Decision and Order On Suite Metering (February 22, 2012 and as corrected March 9, 2012).</td><td>N/A</td></tr>
<tr><td>Exhibit 7 (Cost Allocation), Tab 1, Schedule 2 (Model), Sheets I6, I8, O1 and O2 [Excel version of the model has been filed].</td><td>Revised consistent with financial updates and Load Forecast updates described above.</td><td>Due to the size of the information, the differences cannot be summarized for the purposes of this table. Please refer to the updated schedule.</td></tr>
<tr><td>Exhibit 7 (Cost Allocation), Tab 2, Schedule 1 (OEB Appendix 2-P: Cost Allocation).</td><td>Revised consistent with financial updates and Load Forecast updates described above.</td><td>Revenue to Cost Ratios
<table>
<tr><th rowspan="2">Rate Class</th><th colspan="2">2015</th></tr>
<tr><th>Model</th><th>Proposed</th></tr>
<tr><td>Residential</td><td><s>92</s>
93</td><td><s>93</s>
94</td></tr>
<tr><td>Competitive Sector Multi-Unit Residential</td><td><s>111</s>
107</td><td>No change</td></tr>
<tr><td>General Service <50kW</td><td><s>85</s>
90</td><td><s>87</s>
91</td></tr>
<tr><td>General Service 50-999kW</td><td><s>120</s>
118</td><td><s>120</s>
118</td></tr>
<tr><td>Intermediate 1000-4999kW</td><td><s>104</s>
101</td><td><s>103</s>
101</td></tr>
<tr><td>Large Use</td><td><s>103</s>
95</td><td><s>102</s>
96</td></tr>
<tr><td>Streetlighting</td><td><s>111</s>
105</td><td><s>99</s>
93</td></tr>
<tr><td>Unmetered Scattered Load</td><td>No change</td><td>No change</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 8 (Rate Design), Tab 1, Schedule 1 (Overview), pp. 2, 4-6.</td><td>Revised consistent with financial updates and Load Forecast updates described above.</td><td>For a summary of the bill impacts please refer to the Executive Summary (Exhibit 1A, Tab 2, Schedule 1) updates, above.</td></tr>
<tr><td>Exhibit 8 (Rate Design), Tab 1, Schedule 2 (Fixed and Variable Rates).</td><td>Revised consistent with financial updates and Load Forecast updates described above.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to the updated schedule.</td></tr>
<tr><td>Exhibit 8 (Rate Design), Tab 3, Schedule 2 (Red Line Tariff) and Schedule 3 (Proposed Tariff). [Redacted and confidential versions have been filed].</td><td>Revised consistent with financial updates and Load Forecast updates described above.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to the updated Tariff Sheets.</td></tr>
<tr><td>Exhibit 8 (Rate Design), Tab 4, Schedule 1 (OEB Appendix 2V: Revenue Reconciliation).</td><td>Revised consistent with financial updates and Load Forecast updates described above.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to the updated schedule.</td></tr>
<tr><td>Exhibit 8 (Rate Design), Tab 7, Schedule 1 (OEB Appendix 2W: Bill Impacts).</td><td>Revised consistent with financial updates and Load Forecast updates described above.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to the updated schedule. For a summary of the bill impacts please refer to the Executive Summary (Exhibit 1A, Tab 2, Schedule 1) updates, above.</td></tr>
<tr><td>Exhibit 9 (Deferral and Variance Accounts), Tab 1, Schedule 1 (Overview), pp.14, 16 and 23.</td><td>Revised LRAMVA and IFRS 1575 balances. LRAMVA balances were revised to reflect updated CDM estimates and IFRS Balances were corrected to include return component.</td><td>Balance ($ Millions) for Clearance as at April 30, 2015 Including Carrying Charges
<table><tr><td>LRAMVA (1568</td><td><s>3.0</s>
3.6</td></tr><tr><td>IFRS-CGAAP Transitional PP&E Amounts</td><td><s>25.8</s>
30.5</td></tr></table></td></tr>
</table>

<table>
<tr><th>Original Evidence
(Filed July 31, 2014)</th><th>Revised Evidence
(Filed September 23, 2014)</th><th>Numerical Differences</th></tr>
<tr><td>Exhibit 9 (Deferral and Variance Accounts), Tab 2, Schedule 1 (Continuity Schedules) [Excel version has been filed].</td><td>Revised LRAMVA and IFRS 1575 balances. LRAMVA balances were revised to reflect updated CDM estimates and IFRS Balances were corrected to include return component.</td><td>Updated Continuity schedule reflects updated balances noted above. Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to the updated schedule.</td></tr>
<tr><td>Exhibit 9 (Deferral and Variance Accounts), Tab 2, Schedule 4 (OEB Appendix 2EC: Account 1575).
.</td><td>IFRS 1575 balances were corrected to include a return component.</td><td>IFRS 1575 Balances
<table><tr><td></td><td>2014 Transition Year</td><td></td><td></td></tr><tr><td>Closing Balance in deferral account</td><td>No change</td><td>WACC</td><td>~~Nil~~
6.19%</td></tr><tr><td>Return on Rate Base Associated with deferred PP&E balance at WACC</td><td>~~Nil~~
4,724,102</td><td># of years of Rate Rider disposition</td><td>~~Nil~~
4</td></tr><tr><td>Amount Included in DVA Rate Rider Calculation</td><td>~~25,782,326~~
30,506,428</td><td></td><td></td></tr></table></td></tr>
<tr><td>Exhibit 9 (Deferral and Variance Accounts), Tab 2, Schedule 5 (LRAM), p. 1 and 4-7, and Appendix A.</td><td>LRAMVA balances were revised to reflect updated CDM estimates.</td><td>LRAMVA Balances
<table><tr><td></td><td colspan="2">2011-2013 CDM Savings</td><td>Total LRAMVA</td></tr><tr><td></td><td>MWh</td><td>MVA</td><td>($)</td></tr><tr><td>Residential</td><td>~~65,371~~
64,629</td><td></td><td>~~-$153,630~~
-$161,870</td></tr><tr><td>Competitive Sector Multi-Unit Residential (CSMUR)</td><td>~~224~~
459</td><td></td><td>~~$1,582~~
$2,976</td></tr></table></td></tr>
</table>

Original Evidence (Filed July 31, 2014)	Revised Evidence (Filed September 23, 2014)	Numerical Differences			
		General Service <50 kW	~~182,188~~ 120,802		~~$2,386,864~~ $967,980
		General Service 50 - 999 kW		~~160.8~~ 500.9	~~$925,271~~ $2,881,653
		General Service 1000 - 4999 kW		~~160.1~~ 181.7	~~-$126,311~~ -$37,559
		Large Use		~~157.3~~ 152.3	~~-$77,499~~ -$100,807
		Total	~~247,784~~ 185,889	~~478.2~~ 834.9	~~$2,956,277~~ $3,552,374
Exhibit 9 (Deferral and Variance Accounts), Tab 2, Schedule 5, Appendix B (Q4 2013 OPA CDM Status Report).	Replaced the OPA Q4 2013 Preliminary Results Update Report with the OPA Draft 2013 Verified Results Report.	Please refer to the updated schedule.			
Exhibit 9 (Deferral and Variance Accounts), Tab 3, Schedule 1 (Rate Riders) [Redacted and confidential versions have been filed].	Revised consistent with updated corrected DVA balances (described above) and updated Load Forecast, as described above.	Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to the updated schedule.			

Appendix A: Table of Revisions (January 15, 2015), Toronto Hydro 2015-2019 Custom IR Application, OEB File No. EB-2014-0116

Original Evidence (as originally filed or subsequently updated)	Revised Evidence (Filed January 15, 2015)	Numerical Differences
Executive Summary (Exhibit 1A, Tab 2, Schedule 1)	Section 3.3.1: Updated to clarify Innovative Group's customer engagement work. Section 3.3.2: Updated to include a brief summary of storm related operational changes and investments that have been undertaken or that are planned to be undertaken over the CIR period. Section 4.4 . Updated the Bill Impacts Summary Table, to correspond with the updated Revenue Requirement (Exhibit 6) and Cost Allocation Model (Exhibit 7). Section 4.9 Updated the total net DVA balances proposed for disposal from $60.4M to $53.7M to reflect the removal and addition of DVA riders as described below (Exhibit 9, Tab 1, Schedule 1).	Due to the size of the Bill Impacts table, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.
Administrative Information (Exhibit 1A, Tab 3, Schedule 1)	Updated section 8 to refer to evidence (namely Exhibit 8, Tab 5, Schedule 1 and Exhibit 9, Tab 1, Schedule 1) regarding Toronto Hydro's previous undertaking to evaluate options to measure or estimate actual line losses and the impacts on Account 1588 balances.	N/A

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed January 15, 2015)</th><th>Numerical Differences</th></tr>
<tr><td>Rate Framework
(Exhibit 1B, Tab 2, Schedule 3)</td><td>Updated the custom Price Cap Index components to correspond with the updated 2015 Revenue Requirement (Exhibit 6).</td><td>
<table>
<tr><th></th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th></tr>
<tr><td>C_n</td><td><s>4.10</s>
4.11</td><td><s>4.10</s>
4.11</td><td><s>7.56</s>
7.57</td><td><s>6.67</s>
6.68</td><td><s>5.01</s>
5.01</td></tr>
<tr><td>S_{cap}</td><td><s>67.1</s>
66.2</td><td><s>67.1</s>
67.2</td><td><s>69.2</s>
69.3</td><td><s>70.8</s>
70.9</td><td><s>71.0</s>
72.0</td></tr>
<tr><td>Custom PCI</td><td></td><td><s>4.56</s>
4.57</td><td><s>7.99</s>
8.00</td><td><s>7.08</s>
7.09</td><td><s>5.40</s>
5.41</td></tr>
</table>
</td></tr>
<tr><td>Annual Reporting
(Exhibit 1B, Tab 2, Schedule 5)</td><td>Updated section 1.2 to provide additional information about the proposed manner of annual reporting of performance metrics, consistent with Exhibit 2B, Section C1.1.1</td><td>N/A</td></tr>
<tr><td>Customer Engagement
(Exhibit 1B, Tab 2, Schedule 7)</td><td>Updated section 1.3 to provide additional information about the Key Accounts Management process. Provided a sample of a key account presentation made during the development of the Application (Appendix C).</td><td>N/A</td></tr>
<tr><td>Performance Measurement (Exhibit 2B, Section C)</td><td>Updated section C1.1.1 to provide additional information about the proposed manner of annual reporting of performance metrics.</td><td>N/A</td></tr>
<tr><td>Asset Management Process (Exhibit 2B, Section D1)</td><td>Updated section D1.2.2 to provide additional information about internal cost estimation process.</td><td>N/A</td></tr>
</table>

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed January 15, 2015)</th><th>Numerical Differences</th></tr>
<tr><td>Load and Customer Forecasts, Narrative for Forecasts (Exhibit 3, Tab 1, Schedule 1)</td><td>Updated Table 1 (Total Distribution Revenues) consistent with updates to the Base Revenue Requirement (Exhibit 6) and the custom Price Cap Index components (Exhibit 1B, Tab 2, Sch 3).</td><td>
<table>
<tr><th colspan="2">YEAR</th><th>Total Distribution Revenue ($M)</th></tr>
<tr><td>2015</td><td>Test</td><td><s>$662.2</s>
$661.2</td></tr>
<tr><td>2016</td><td>Test</td><td><s>$697.9</s>
$696.8</td></tr>
<tr><td>2017</td><td>Test</td><td><s>$755.1</s>
$753.9</td></tr>
<tr><td>2018</td><td>Test</td><td><s>$811.3</s>
$809.9</td></tr>
<tr><td>2019</td><td>Test</td><td><s>$858.7</s>
$857.2</td></tr>
</table>
</td></tr>
<tr><td>Load and Customer Forecasts, Revenues (Exhibit 3, Tab 1, Schedule 1, Appendice E-1, E-2 and E-3)</td><td>Updated revenues to correspond with updates to the Base Revenue Requirement (Exhibit 6) and the custom Price Cap Index components (Exhibit 1B, Tab 2, Sch 3).</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
<tr><td>Revenue Requirement (Exhibit 6, Tab 1, Schedule 1); Revenue Requirement Workform (Exhibit 6, Tab 1, Schedule 2)</td><td>Updated tables to reflect the corrections to Revenue Offsets identified through the discovery process and filed on November 14, 2014.</td><td>
<table>
<tr><th></th><th>2015</th></tr>
<tr><td>Revenue Offsets</td><td><s>45.1</s>
46.1</td></tr>
<tr><td>Base Revenue Requirement</td><td><s>662.2</s>
661.2</td></tr>
<tr><td>2015 Revenue at Current (2014 approved) Rates</td><td><s>599.9</s>
600.9</td></tr>
<tr><td>Gross Revenue Deficiency</td><td><s>107.4</s>
106.4</td></tr>
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<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed January 15, 2015)</th><th>Numerical Differences</th></tr>
<tr><td>Cost Allocation Narrative (Exhibit 7, Tab 1, Schedule 1);
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OEB Appendix 2-P Cost Allocation (Exhibit 7, Tab 2, Schedule 1)</td><td>Updated tables to reflect corrections to the Cost Allocation Model and to Revenue Offsets identified through the discovery process and filed on November 14, 2014.</td><td>
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<tr><th>Rate Class</th><th>2011 OEB Approved</th><th>2015 Model</th><th>2015 Proposed</th></tr>
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89</td><td><s>93</s>
94</td><td><s>94</s>
95</td></tr>
<tr><td>General Service <50kW</td><td>n/a</td><td>n/a</td><td><s>87</s>
92</td></tr>
<tr><td>General Service 50-999kW</td><td><s>117</s>
118</td><td>n/a</td><td>n/a</td></tr>
<tr><td>Large Use</td><td><s>116</s>
115</td><td>n/a</td><td>n/a</td></tr>
<tr><td>Streetlighting</td><td>n/a</td><td><s>111</s>
92</td><td><s>99</s>
82</td></tr>
<tr><td>Unmetered Scattered Load</td><td>n/a</td><td><s>90</s>
87</td><td><s>91</s>
89</td></tr>
</table>
</td></tr>
<tr><td>Rate Design Overview (Exhibit 8, Tab 1, Schedule 1);
Fixed/Variable Allocation (Exhibit 8, Tab 1, Schedule 2)</td><td>Updated to summarize request/rationale for continuance of approved loss factor. Updated Bill Impact and Fixed Monthly Charge tables to reflect updates to Revenue Requirement (Exhibit 6) and the Cost Allocation Model (Exhibit 7), as noted above.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
<tr><td>Red Line Tariff (Exhibit 8, Tab 3, Schedule 2);
OEB Appendix 2-Z Proposed Tariff (Exhibit 8, Tab 3, Schedule 3);
OEB Appendix 2-V Revenue Reconciliation (Exhibit 8, Tab 4, Schedule 1)</td><td>Updated distribution rates to reflect updates to Revenue Requirement (Exhibit 6) and the Cost Allocation Model (Exhibit 7), as noted above. Addition and removal of various rate riders, as summarized below (Exhibit 9, Tab 3, Schedule 1).</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
</table>

<table>
<tr><th>Original Evidence
(as originally filed or subsequently updated)</th><th>Revised Evidence
(Filed January 15, 2015)</th><th>Numerical Differences</th></tr>
<tr><td>Loss Adjustment (Exhibit 8, Tab 5, Schedule 1)</td><td>Updated to include request/rationale for the continuance of the current OEB approved loss factor.</td><td>N/A</td></tr>
<tr><td>OEB Appendix 2-W Bill Impacts (Exhibit 8, Tab 7, Schedule 1)</td><td>Updated the Bill Impact Tables to reflect updates to Revenue Requirement (Exhibit 6) and the Cost Allocation Model (Exhibit 7), as noted above, as well as the addition and removal of various rate riders, as summarized below (Exhibit 9, Tab 3, Schedule 1).</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
<tr><td>Deferral and Variance Accounts Overview (Exhibit 9, Tab 1, Schedule 1)</td><td>Updated to include request to defer the clearance of the RSVA accounts. Provided a copy of a letter from OEB Audit Staff to the OEB re: Deferral of RSVA Clearance (Appendix C). Updated to include clearance of an additional DVA account (SME Charge), as noted in IR 9-OEBStaff-93.</td><td>Table 1: Summary of Proposed Disposition ($ millions)
<table>
<tr><th></th><th>Principal Balance as at December 31, 2013</th><th>Carrying Charges till April 30, 2015</th><th>Balance for Clearance as at April 30, 2015 Including Carrying Charges</th></tr>
<tr><td>Total DVA Amount Requested for Disposition</td><td><s>18.1</s>
12.3</td><td><s>1.8</s>
0.9</td><td><s>60.4</s>
53.7</td></tr>
</table></td></tr>
<tr><td>DVA Continuity Schedules (Exhibit 9, Tab 2, Schedule 1)</td><td>Updated to include clearance of an additional DVA account (SME Charge), as noted in IR 9-OEBStaff-93.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
<tr><td>Rate Riders (Exhibit 9, Tab 3, Schedule 1)</td><td>Updated to reflect removal of RSVA rate riders and addition of SME rate riders, consistent with the updates noted above.</td><td>Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.</td></tr>
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1. FOREWORD AND INTRODUCTION

This custom incentive rate application covers the next five years (2015-2019) for Toronto Hydro-Electric System Limited ("Toronto Hydro"), and touches on all aspects of what the utility needs in order to serve its customers effectively and efficiently, and ensure a safe and reliable source of electricity for the dynamic and complex urban environment that is the City of Toronto.

This application represents a five-year commitment by the utility at a crucial period in its history. Investments are required now in order to address aging infrastructure, ensure a safe and reliable source of electricity and acceptable customer service levels – during the next five years and in the future.

In Toronto Hydro's last Incremental Capital Module ("ICM") rate application, the Ontario Energy Board ("OEB") approved funding for a substantial capital work program, and the method of performing that work program.[1] This application builds on that foundation. Toronto Hydro has identified the system requirements based on prevailing engineering and utility practice, and has developed detailed and coordinated plans to deliver the program.

The proposals within this application are interdependent. They are the result of a planning approach in which the utility considered, among other things, operational and system needs, customer preferences, productivity, value-for-money and rate impacts.

[1] EB-2012-0064, Partial Decision and Order (April 2, 2013).

Much of Toronto Hydro ¶ proposed work has been reviewed and validated by external experts. Toronto Hydro has filed over a dozen third party reports in this application.

Toronto Hydro has also reached out to its customers in an unprecedented manner. The utility surveyed its customers on its plans. It learned that the majority of those customers accept the need for timely renewal of the distribution system, while acknowledging that this will mean an increase in their monthly bills.

And while Toronto Hydro ¶ engineers consider that an overall program larger than that represented in this application is optimal, the utility has chosen to restrain and constrain its work to achieve the pace and rate impacts that fall within a tolerable range.

Toronto Hydro has been an efficient organization. Through this application, it will continue that history of productivity, and share those benefits with ratepayers.

Finally, this application has been prepared in a manner that is consistent with the OEB ¶ guidance as expressed in its Renewed Regulatory Framework for Electricity Distributors policy (³RRFE ´).

In this Executive Summary, Toronto Hydro sets out the context in which it operates, its approach to this application, and a summary of key application details. References to evidence in the application where further details can be located are provided throughout.

2. ABOUT TORONTO HYDRO FACTS AND CONTEXT

Toronto Hydro is an electricity distributor licensed by the OEB to provide electricity to the City of Toronto, in accordance with its Distribution Licence.[2] In 2013, Toronto Hydro distributed 24.4 terawatt-hours of electricity representing approximately 18 percent of the electricity consumed in the province of Ontario, and served a peak demand of 4,914 megawatts. Toronto Hydro distributes electricity at voltages up to 27.6kV, and the utility ¶ asset base includes approximately 175,000 poles, 60,600 distribution transformers, 15,000 kilometres of overhead wires, 11,200 kilometres of underground wires, 16,000 primary switches and 167 municipal substations.

For more information about Toronto Hydro ¶ distribution system, please refer to Exhibit 1C, Tab 1, Schedules 1 and 2; and Exhibit 2B, Section D2.

Toronto Hydro is the successor to the six former hydro-electric commissions of the municipalities which amalgamated on January 1, 1998 to form the City of Toronto. The utility is a wholly-owned subsidiary of Toronto Hydro Corporation (THC), whose sole shareholder is the City of Toronto.

To learn more about Toronto Hydro ¶ Corporate Structure and Governance, please refer to Exhibit 1C, Tab 2, Schedule 1.

[2] ED-2002-0497.

2.1 Toronto Hydro ¶s Customers

Toronto Hydro serves approximately 730,000 customer accounts, ranging from individual residential consumers up to large industrial and commercial businesses. In addition, Toronto is home to the country ¶ largest banks, stock exchanges and other large customers that are sensitive to service interruptions. The utility powers non-residential customers from a wide variety of sectors, including: approximately 360 hospitals and healthcare facility accounts, 690 school accounts, 140 colleges and universities accounts, plus data centers as well as large industrial and manufacturing facilities. Toronto Hydro also supplies electricity to Ontario ¶ Provincial Legislature and Ministries, as well as Toronto ¶ municipal government. The utility also has over 2,900 high-rise multi-residential condominium and apartment buildings accounts, many of which are bulk-metered. Taking these behind-the-meter customers into account, Toronto Hydro ¶ effective customer base exceeds one million customers.

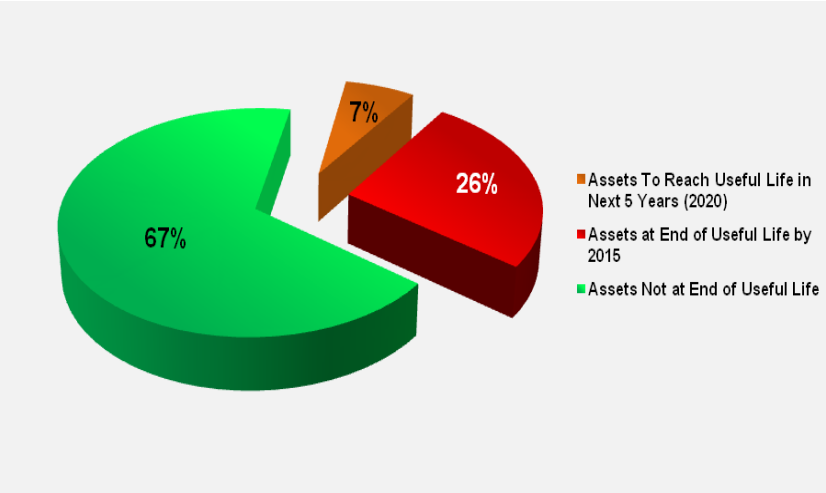
To learn more about the breadth and diversity of Toronto Hydro ¶ customer base, please refer to Exhibit 1B, Tab 2, Schedule 7.

2.2 Challenges Faced by the Utility

Toronto Hydro operates in a mature, congested urban environment. In undertaking its capital and maintenance work, the utility must contend with complexities including the intensification of development (like condominium complexes, the Pan-Am Games, and waterfront redevelopment), limited space for utility equipment installation, over a century of previous construction by various agencies often with missing or inaccurate historical records, and coordination with other City and utility reconstruction programs. Toronto ¶ densely populated downtown core, served by a complex arrangement of equipment

including a secondary network system, is unique in its span and configuration in Ontario ¶ distribution sector.

Toronto Hydro ¶ distribution system includes a large and growing backlog of assets that are operating beyond their expected useful lives ± an estimated 26% by 2015. If the utility were to invest in a minimal and reactive way (i.e., run-to-failure), this number is forecast to reach 32% by 2020 and reliability would likely deteriorate.[3] Toronto Hydro ¶ system also faces pressures from economic (system load) growth and capacity constraints. This results in part from large-scale projects in Toronto such as transit projects, and increased proliferation of distributed generation. Changes in climate and extreme weather also put additional strain on the distribution system.



In addition, approximately 50% of Toronto Hydro ¶ workforce is projected to retire over the next decade, and 25% during the next five years. Of that 25%,



[3] Toronto Hydro projects that a run-to-failure approach would result in SAIFI (System Average Interruption Frequency Index) worsening by approximately 30% and SAIDI (System Average Interruption Duration Index) worsening by approximately 24% from 2015-2019.

approximately half are from key segments (certified and skilled trades, designated and technical professionals, and supervisory positions). These personnel are critical to maintaining and operating the distribution system in a safe and efficient manner, and new personnel for these positions take up to six years to train.

These are among several of the realities that drive Toronto Hydro ¶s costs. To learn more about these challenges and other cost drivers, please refer to Exhibit 1B, Tab 2, Schedules 3-5; Exhibit 2B, and Exhibit 4A.

2.3 Toronto Hydro ¶s Corporate Strategy

The utility ¶s strategic vision is to continuously maximize customers ¶and stakeholders ¶ satisfaction by operating in a safe, reliable and environmentally responsible manner at optimal costs. To realize this vision, Toronto Hydro employs a framework consisting of four strategic pillars:

1. ***Customer Service***: deliver value-for-money to Toronto Hydro ¶s customers, including making it easier for them to work with the utility, helping them conserve energy and providing them with tools and technology;
2. ***Operations***: improve reliability through optimal and sustainable system management, including keeping the system safe, building a grid that supports a modern city and maintaining productivity;
3. ***People***: fully-engaged, safe and healthy workforce, that meets the changing business environment; and
4. ***Financial Strength***: meet financial objectives including obtaining a fair return.

These strategic pillars guide the establishment of the utility ¶ goals and business plans, and focus the organization. Toronto Hydro uses a comprehensive framework of Key Performance Indicators (³KPIs ´) and a balanced scorecard approach to track the implementation and execution of its plans against its strategic goals.



These pillars, and Toronto Hydro ¶ approach to business planning, execution and performance measurement, are well-aligned with the OEB ¶ performance outcomes described in the RRFE: Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance (together the ³RRFE Outcomes ´).

For more information, please refer to Exhibit 1C, Tab 3, Schedules 1 and 2.

3. APPROACH TO THIS APPLICATION

3.1 Planning for the Next Five years

Toronto Hydro ¶ approach to the planning that underlies this application entailed: (a) developing a proposed capital program that balances the needs of the distribution system with a level of rate increases that customers accept; and (b) building an Operations, Maintenance & Administration (³OM&A ´) plan that, following rebasing, requires the utility to operate with funding that is less than inflation for non-capital expenditures.

Consistent with its Strategic Pillars and the RRFE Outcomes, Toronto Hydro ¶ proposals and plans were informed by a number of operational needs such as asset investment requirements, maintenance requirements, staffing requirements and legislative and regulatory obligations. The plans are also informed by other important considerations such as customer needs and preferences (including service levels and consumption-management tools), rate impacts, value-for-money, productivity, and maintaining the financial health and viability of the utility.

To this end, for both capital and OM&A expenditures, Toronto Hydro did not put forward all possible and reasonable funding requests that would represent what the utility may believe is operationally optimal or required. For example, while Toronto Hydro views that a capital investment approach well above $500 million per year over the 2015-2019 period is optimal from an assets-needs perspective, in light of rate impacts and execution logistics, it has constrained its actual plan (and corresponding funding request to the OEB) to approximately $500 million per year over the 2015-2019 period. Toronto Hydro believes that a capital plan of this magnitude fairly balances system requirements with the needs of current and future customers.

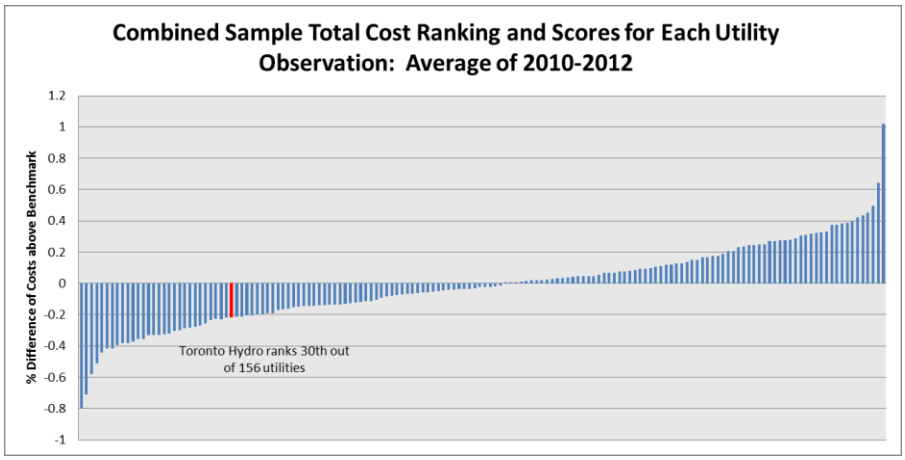
To learn more about the details of Toronto Hydro ¶ approach to business and financial planning, as well as its specific approaches to building the capital and OM&A proposals contained within this application, please see Exhibit 1B, Tab 2, Schedule 3; Exhibit 1B, Tab 2, Schedule7; Exhibit 1C, Tab 3, Schedule 2; Exhibit 2B; and Exhibit 4A.

3.2 Productivity And Performance

Toronto Hydro ¶ commitment to productivity and performance is embodied within its strategic pillars. Toronto Hydro has a long-standing productivity culture which has evolved over time in line with operating challenges, changes in government policy, and expectations that underlie the regulatory regimes that govern the utility ¶ operations. Toronto Hydro assesses that since amalgamation in 1998, its productivity efforts have resulted in significant savings for ratepayers.

The utility ¶ commitment to productivity and performance are embedded throughout its plans and proposals in this application. For example, Toronto Hydro has developed a ratemaking framework for this application, which by its nature provides incentives for the utility to seek out further productivity and efficiency improvements over the 2015-2019 timeframe and beyond. This framework also requires the utility to *share the benefits* of these improvements with its customers. Further, and in addition to the OEB Scorecard to measure performance, the utility has proposed a framework of capital performance metrics to facilitate the continuous improvement in the efficiency of capital planning and execution. Finally, the plans and proposals that Toronto Hydro has put forward in this application focus on delivering value-for-money to its customers.

Among other reasons, Toronto Hydro ¶ commitment to productivity and performance makes it a strong cost performer in comparison to other utilities. A third party total cost econometric benchmarking report concludes that the utility is below expected reasonable costs, and ranks Toronto Hydro ¶ total cost performance in the top quartile ±30th out of 156 Ontario and U.S. utilities.



To learn more about Toronto Hydro ¶ commitment and approach to productivity and performance, please refer to Exhibit 1B, Tab 2, Schedule 5 (including Appendixes A and B); Exhibit 2B, Section C; and Exhibit 4A.

3.3 Customers

Toronto Hydro ¶ commitment to its customers is embodied within its strategic pillars. On average, Toronto Hydro receives approximately 100,000 written enquiries and nearly 600,000 telephone calls a year. Toronto Hydro seeks to provide customer satisfaction and improve the customer experience: overall, the utility performs well against the OEB ¶ customer service quality indicators. Further, the utility consistently seeks opportunities to meaningfully engage with its customers, expand the range and quality of service that it provides, and integrate new technological tools and solutions to improve service levels and find efficiencies.

3.3.1 Engagement on Capital Plans

Toronto Hydro serves a broad and diverse customer base, with which it engages on a regular basis through ordinary-course interactions. In addition to these ordinary-course interactions, it reached out to its most populous rate classes, the residential and small general service customers, through Innovative Research Group, regarding the utility's capital plans for 2015-2019 (Exhibit 1B, Tab 2, Schedule 7, Appendix B). The results of this exercise provided Toronto Hydro valuable insight into these customers' perceptions of the utility's priorities. Among other things, Toronto Hydro learned that customers' preferences align with the central pillars of the utility's capital plan. And while these customers reasonably expect that the utility will make prudent investment decisions, the majority accept the need for timely renewal of the distribution system, while acknowledging that this will mean an increase in their monthly bills.

/C

3.3.2 Emergency and Extreme Weather Response

Recent extreme weather events such as the July 2013 flood and the December 2013 ice storm have had significant effects on Toronto Hydro's customers, and drive Toronto Hydro to continue to emphasize plans and programs that facilitate and improve its system resiliency, and ability to respond to these events.

At the core of the utility's emergency operations framework lies the Emergency Response Program, which provides an around-the-clock response to any urgent and

/C

unplanned events in Toronto's dense urban environment 365 days a year.[4] Moreover, to enhance the utility's operations during sustained and large-scale emergency events, Toronto Hydro is proposing a new Disaster Preparedness Management program (Exhibit 4A, Tab 2, Schedule 4) that aims to establish industry best practices for the planning, communication and coordination of work prior to, during and after major events across the utility and in relation to customers and key stakeholders.[5] Beyond the introduction of new communication and decision-making frameworks, the proposed program seeks to expand emergency training for Toronto Hydro's employees and facilitate the negotiation of Mutual Aid agreements with utilities that operate systems similar to Toronto's.

Toronto Hydro has also received valuable feedback from its customers regarding their experiences of communicating with the utility during the 2013 ice storm, and has implemented a number of key enhancements to its emergency communications systems. These include:

- An expanded Interactive Voice Response (IVR) capability to ensure that Toronto Hydro customers can successfully reach the utility to report an outage during emergencies when call volumes significantly exceed the typical levels.

- A new mobile-friendly website OutageTO.com, available in eight languages. The website consolidates all outage-related content in a single location, including detailed and frequent alerts through a variety of platforms, safety tips for customers without power, and a capability for customers to report new outages.

/C

[4] Exhibit 4A, Tab 2, Schedule 3
[5] Exhibit 4A, Tab 2, Schedule 4

- Planned enhancements to the 311 Toronto website and customer contact centre, to simplify customers' ability to reach the utility through the 311 platform to report outages and obtain relevant information.

In addition to recently implemented and planned operational enhancements, Toronto Hydro's application includes a number of capital investments and maintenance activities that can be expected to improve system performance against extreme weather, in addition to addressing their respective primary drivers. These include:

- Overhead Infrastructure Relocation (Trigger Driver – Functional Obsolescence);[6]
- Rear Lot Conversion (Trigger Driver – Functional Obsolescence);[7]
- Box Construction Conversion (Trigger Driver – Functional Obsolescence);[8]
- Feeder Automation (Trigger Driver – System Efficiency);[9]
- Contingency Enhancement (Trigger Driver – Reliability);[10]
- Downtown Contingency (Trigger Driver – Reliability);[11]
- Design Enhancement (Trigger Driver: Reliability); and[12]
- Vegetation Management (Trigger Driver – Reliability).[13]

Over the 2015-2019 timeframe, the utility anticipates taking further steps to enhance its storm-related operational practices and capabilities, including an upgrade of its Outage Management System, enhancements to the damage assessment activities and outage

[6] Exhibit 2B, E6.5
[7] Exhibit 2B, E6.6
[8] Exhibit 2B, E6.7
[9] Exhibit 2B, E7.3
[10] Exhibit 2B, E7.1
[11] Exhibit 2B, E7.7
[12] Exhibit 2B, E7.2
[13] Exhibit 4A, Tab 2, Schedule 1, pp.26-34

restoration time estimation practices, and other improvements recommended by the report of the independent panel that reviewed Toronto Hydro's performance during the 2013 ice storm.[14] /C

To learn more about Toronto Hydro's customer focus, engagement, and relevant plans and proposals, please see Exhibit 1B, Tab 2, Schedule 7; Exhibit 2B; and Exhibit 4A.

3.4 Consideration of OEB Guidance and Rate Setting

Toronto Hydro approached this application from the perspective of alignment with policy guidance provided by the OEB. This includes the form of the rate-setting mechanism, the RRFE Outcomes, as well as the scope and nature of the evidence the utility filed regarding productivity, capital planning, customer engagement and operational expenditures. In addition to aligning with policy direction, Toronto Hydro believes that its approach aids in the utility's application being more accessible to the OEB, intervenors and the public.

Toronto Hydro has proposed a rate-setting framework that constrains operational funding increases to less than inflation after rebasing. This approach reconciles the utility's need for significant multi-year capital investment with a level of rate increases that its customers are willing to accept. The framework is based on a forward test year for 2015, and a custom Price Cap Index ("PCI") for 2016 through 2019.

To learn more about how Toronto Hydro's application aligns with the OEB policy guidance and the utility's approach to rate making, please refer to Exhibit 1B, Tab 2, Schedules 2 and 3.

[14] Exhibit 4A, Tab 2, Schedule 4, Appendix A.

4.SUMMARY OF KEY DETAILS OF THE APPLICATION

4.1 Capital Expenditures And Rate Base

4.1.1Capital Expenditures

The nature and amount of capital spending in this application builds on the foundation that the OEB accepted in Toronto Hydro's 2012-2014 ICM application.[15] The majority of the capital programs are continuations of the work programs the OEB approved in the ICM application. New programs are driven by public policy responsiveness, additional system renewal needs, evolving system conditions, and enhancing customer value. Toronto Hydro's proposed capital plan has been validated by a third party expert,[16] and its pillars are accepted by the utility's customers.

Toronto Hydro's requested Capital Expenditures for the period 2015-2019 are approximately $500 million per year, which is comparable to the average annual spending since the utility's last rebasing in 2011 (approximately $440 million per year). Forecasted capital expenditures for the 2015 test year are approximately $ 531.1 million, which represents an increase of approximately $152.3

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/C

[15] EB-2012-0064, Partial Decision and Order (April 2, 2013).
[16] Exhibit 1B, Tab 2, Schedule 4, Appendix B.

million, or 40.2 percent, from the utility's last rebasing application in 2011.[17] For 2016 to 2019, Toronto Hydro is proposing capital expenditures as summarized below. /C

Table 1: 2016 – 2019 Requested Capital Expenditures ($ Millions)

	2016	2017	2018	2019
Capital Expenditures	518.8	467.4	470.0	502.2

/C

To learn more about Toronto Hydro's proposed multi-year capital funding needs, please refer to Exhibit 1B, Tab 2, Schedule 4, and Exhibit 2B.

Capital Investment Drivers

The "trigger" investment drivers of Toronto Hydro's DSP are summarized below. Trigger drivers are the primary reason that a program must be carried out. Most DSP programs also have secondary drivers that may be more consequential than the trigger driver. For example, although Safety and Reliability are trigger drivers for relatively few programs, these important drivers are the most common, relating to 32 and 23 programs respectively.

[17] EB-2010-0142

1 **Table 2: Trigger Drivers for Capital Investments from 2015 to 2019 ($ Millions)**

Trigger Driver	2015	2016	2017	2018	2019
Failure Risk	156.9	130.3	134.9	151.4	156.8
Functional Obsolescence	80.6	105.5	78.3	75.1	74.5
Customer Service Requests / Third Party Requests	55.3	71.7	82.9	76.6	69.8
System Maintenance & Capital Investment Support	80.3	52.1	28.9	32.1	27.9
Capacity Constraints	44.0	44.0	37.1	22.5	44.4
Failure	31.9	32.7	33.1	33.6	34.2
Other[18]	10.3	19.8	28.7	37.9	49.4
Mandated Service Obligations	30.8	21.8	18.0	13.8	15.7
Reliability	11.0	9.4	13.8	13.8	17.4
System Efficiency	11.7	16.2	11.6	13.2	12.2
Safety	16.5	13.7	0.0	0.0	0.0
Total Capital Expenditures	**539.6**	**504.2**	**467.4**	**470.1**	**502.2**

/C

[18] "Other" capital includes expenditures that do not fit in a discrete capital program, such as Historic Road Cut Repairs and inflation for the capital program. For more details, see Exhibit 2B, Section E4.

Costs Associated with REG Connections

Toronto Hydro's proposed Capital Expenditures over the 2015 to 2019 period include the following costs associated with renewable energy generation ("REG") connections:[9]

Table 3: Renewable Enabling Improvements (REI) from 2015 to 2019 ($ Millions)

Program	2015	2016	2017	2018	2019
Generation Protection Control and Monitoring[10]	6.12	5.19	3.26	2.10	2.02
Energy Storage[11]	0.54	1.09	2.16	3.24	3.78
Total REG Costs	**6.66**	**6.27**	**5.43**	**5.34**	**5.79**

/C

The total amount that Toronto Hydro seeks to recover from provincial ratepayers, pursuant to Ontario Regulation 330/09, is summarized below in Table 4.

Table 4: Provincial Rate Protection Amounts from 2015 to 2019 ($Millions)

	2015	2016	2017	2018	2019
Provincial Rate Protection	0.31	1.00	1.69	2.31	2.93

/C

[9] For more information please see Exhibit 2A, Tab 8, Schedule 1.
[10] Exhibit 2B, E5.05.
[11] Exhibit 2B, E7.11.

Smart Grid Costs

Toronto Hydro's proposed Capital Expenditures over the 2015 to 2019 period include the following costs associated with smart grid investments:[12]

Table 5: Smart Grid Related Costs from 2015 to 2019 ($Millions)

Program	2015	2016	2017	2018	2019
Metering (Exhibit 2B, E5.1)	24.7	16.6	14.7	11.7	13.7
Network Unit Renewal (Exhibit 2B, E6.10)	5.2	7.4	7.3	7.3	7.3
Stations Control & Monitoring (Exhibit 2B, E6.16)	0.1	0.9	1.1	1.5	1.4
Distribution System Communication Infrastructure (Exhibit 2B, E6.22)	6.1	6.0	4.0	0.0	0.0
Feeder Automation (E7.3)	11.1	15.1	9.4	10.0	8.5
Overhead Momentary Reduction (Exhibit 2B, E7.4)	0.0	0.0	0.6	0.6	0.6
Local Demand Response (Exhibit 2B, E7.10)	0.2	2.4	0.6	0.5	0.3
Total Smart Grid Costs	**47.4**	**48.4**	**37.7**	**31.6**	**31.8**

/C

/C

[12] Exhibit 2B, E1.3.2

In addition to the programs listed above, Toronto Hydro's Overhead Circuit Renewal program[23] includes costs for standardizing SCADAMATE related communications technology in areas currently using an obsolete radio communication system.

Regional Planning Investments

Toronto Hydro's proposed Capital Expenditures over the 2015 to 2019 period include the following costs associated with regional planning investments:

Table 6: Regional Planning Investments from 2015 to 2019 ($ Millions)

Program	2015	2016	2017	2018	2019
Generation Protection, Monitoring and Control (Exhibit 2B, E5.5)	6.12	5.19	3.26	2.10	2.02
Stations Expansion (Exhibit 2B, E7.9)	43.8	41.6	36.5	22.0	44.0
Local Demand Response (Exhibit 2B, E7.10)	0.17	2.4	0.60	0.50	0.35

/C

[23] Exhibit 2B, E6.4.

4.1.2 Rate Base

Toronto Hydro's requested rate base for the 2015 Test Year is $3,247.6 million, which represents an increase of approximately $949.4 million, or 41.3%, from the rate base amount of $2,298.2 million approved by the OEB in the utility's last rebasing application in 2011.[24] /C /C

The change in rate base is driven by an increase of approximately $1,003.5 million in the average net book value ("NBV") of property, plant and equipment ("PP&E"), which is offset by a decrease of approximately $55 million in the working capital allowance ("WCA") component of rate base due to an updated WCA rate, as per Toronto Hydro's updated Lead Lag study. The growth in PP&E includes investments Toronto Hydro has made under the ICM framework during the 2012-14 period, as well as the addition of street lighting assets into rate base. /C

For more information about Toronto Hydro's rate base, please refer to Exhibit 2A.

[24] EB-2010-0142.

4.2 Operations, Maintenance And Administrative (OM&A)

Toronto Hydro's plan is intended to efficiently maintain functional requirements such as safe and reliable grid operations and system performance, service levels, as well as legal and regulatory compliance. New or materially-expanded OM&A activities since the utility's last rebasing in 2011 include: disaster preparedness and increased preventative and predictive maintenance.

Toronto Hydro's OM&A expense for the test year is $269.5 million, which represents an increase of $31.5 million, or 13.2%, from the utility's last rebasing in 2011. This translates into an average annual increase of approximately 3.3% over the 2011-2015 timeframe.

/C

4.2.1 Cost Drivers

Table 7 below provides a summary of the overall drivers and cost trends for operating expenditures:

Table 7: OM&A 2015-2019 Cost Drivers[15]

OM&A	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge	2015 Test
Reporting Basis	CGAAP	USGAAP	USGAAP	USGAAP	MIFRS
Opening Balance	**$238.0**	**$238.6**	**$215.8**	**$246.4**	**$246.6**
Workforce Compensation (net)		($12.0)	$3.0	$14.5	$1.4
Distribution Operations Programs[16]	-	$4.7	$5.8	($13.6)	$13.4
Customer Service and Communications	$0.7	($1.3)	$1.5	$1.6	$3.7
Human Resources	-	($0.6)	$1.0	($0.5)	$0.6
Information Technology Services	-	($1.1)	$1.9	$2.2	$0.8
Common Corporate Costs	-	($11.4)	$10.0	($0.3)	($1.3)
Facilities Maintenance	-	($0.3)	$0.9	$3.3	$0.2
Other Various	($0.1)	($0.8)	$6.6	($7.0)	$4.0
Closing Balance	**$238.6**	**$215.8**	**$246.4**	**$246.6**	**$269.5**
Restructuring Costs[17]		$27.7			
Closing Balance - Including Restructuring Costs	**$238.6**	**$243.5**	**$246.4**	**$246.6**	**$269.5**

[15] For a more detailed presentation of Toronto Hydro's 2011-2015 OM&A cost drivers, please see Exhibit 4A, Tab 1, Schedule 2, (OEB Appendix 2-JB).
[16] Includes storm restoration expenditures such as Hurricane Sandy, the December 2013 ice storm, and others.
[17] OEB Account 6310 - Extraordinary Deduction

4.2.2 Inflation Rates and Economic Assumptions

Toronto Hydro used both general and specific cost and economic assumptions in its 2015 forecast for operating costs. For further details, please see section 4.5 below.

4.2.3 Compensation

Toronto Hydro's forecasted total compensation cost for the 2015 test year are approximately $225.3 million, which represents a *decrease* of approximately 9.3 million, or 4.0%, from 2011 actuals. Because Toronto Hydro's last rebasing application was settled on an envelope basis, the utility is unable to detail the OEB-approved compensation costs for 2011.[28]

4.3 Revenue Requirement

For the 2015 test year, Toronto Hydro requests a base revenue requirement of $655.0 million, which represents an increase of $132.9 million, or 25.5%, from the base revenue requirement previously approved by the OEB in the utility's last rebasing application. **/C** **/C**

The main drivers of the increase in base revenue requirement for the 2015 test year are the additions to rate base due to Toronto Hydro's significant capital program over the 2012-15 period, and an increase in OM&A expenses.

To learn more about Toronto Hydro's revenue requirement and related drivers, please see Exhibit 6, Tab 1, Schedule 1.

[28] EB-2010-0142, Partial Decision and Order (July 7, 2011), at Appendix C, s. 3.4 of the Settlement Agreement.

4.4 Bill Impacts

On average, for each of the next five years, Toronto Hydro calculates that the bill impacts associated with its application (including all of the proposed rate riders) are approximately $ $3.26 per month for the residential customer, or less than a 3% increase to the overall bill.[29] **/C**

Table 8 below provides a summary of total bill impacts (before taxes and the Ontario Clean Energy Benefit) for typical customers in all classes.

[29] Calculation of approximate percentage increase to bill resulting from Toronto Hydro's application is based on other bill components being what they are today.

Table 8: Summary of Total Bill Impacts by Rate Class

Rate Class	Change in Bill	2015 Proposed	2016 Proposed	2017 Proposed	2018 Proposed	2019 Proposed
Residential	$/30 days	$3.28	$2.64	$3.36	$5.30	$1.71
	%	2.5%	1.9%	2.4%	3.7%	1.2%
Competitive Sector Multir Unit Residential	$/30 days	$0.52	$1.72	$2.60	$3.21	$1.10
	%	0.8%	2.5%	3.6%	4.3%	1.4%
General Service <50kW	$/30 days	$8.76	$4.47	$2.30	$10.90	$4.95
	%	2.7%	1.3%	0.7%	3.2%	1.4%
General Service 50r999 kW	$/30 days	$299.67	$146.69	$227.87	$341.13	$178.95
	%	1.4%	0.7%	1.0%	1.5%	0.8%
General Service 1,000r4,999 kW	$/30 days	$899.33	$749.79	$948.94	$1,292.46	$688.28
	%	0.8%	0.7%	0.8%	1.1%	0.6%
Large Use	$/30 days	$5,225.61	$4,375.61	$5,301.20	$7,166.52	$3,845.26
	%	0.8%	0.7%	0.8%	1.1%	0.6%
Street Lighting	$/30 days	-$0.56	$0.45	$0.56	$0.83	$0.41
	%	-4.1%	3.5%	4.2%	5.9%	2.8%
Unmetered Scattered Load	$/30 days	$4.50	$2.07	$3.17	$4.16	$2.30
	%	6.4%	2.8%	4.1%	5.2%	2.7%

/C

4.5 Budgeting and Accounting Assumptions

Toronto Hydro used both general inflation and specific cost assumptions in its 2015 forecast of operating costs. Labour costs have been adjusted to reflect the annual rate adjustment that the utility is required to pay under its collective agreements. The labour cost forecast was also adjusted to reflect market-competitive increases for non-unionized employees.

An inflation rate of 1.7% was applied to the test year operational expenditure forecasts, consistent with the OEB ¶ current inflation factor. An inflation factor of 2.07% was applied to the utility ¶ capital expenditures over the 2016 to 2019 rate period, consistent with Statistics Canada Consumer Price Index (³CPI ´) for the City of Toronto.

To learn more about Toronto Hydro ¶ budgeting and accounting assumptions, please see Exhibit 1B, Tab 2, Schedule 3; Exhibit 1C, Tab 3, Schedule 2; Exhibit 2A, Tab 6, Schedule 1; Exhibit 4A, Tab 1, Schedule 1; and Exhibit 4A, Tab 4, Schedule 5.

4.6 Load Forecast Summary

Toronto Hydro ¶ load forecast was developed using multivariate regression models by customer class to derive loads based on input variables for economic activity, weather and other drivers of energy consumption. The forecast explicitly accounts for conservation and demand management (³CDM ´) impacts on load.

Toronto Hydro ¶ customer forecast was developed using extrapolation models for each rate class.

The following table summarizes the total historic and load and customer values for 2011-2019.

Table 9: Total Load and Total Customers for 2011-2019

Year	Total Load (GWh)	Total Customers
2011	25,419	705,756
2012	25,639	713,093
2013	25,213	724,144
2014	25,018	736,974
2015	24,993	749,679
2016	24,027	763,091
2017	24,842	773,850
2018	24,697	785,107
2019	24,611	796,865

/C

To learn more about Toronto Hydro's forecast of loads and customers, please see Exhibit 3, Tab 1, Schedule 1.

4.7 Cost Of Capital

Toronto Hydro calculated its Cost of Capital based on the OEB's Cost of Capital guidelines. For the purpose of 2015 revenue requirement, Toronto Hydro used a Return on Equity ("ROE") forecast rate of 9.30% based on the latest forecasts of inputs into the OEB's ROE formula. The utility will update this value once the OEB has determined the applicable ROE for 2015. Debt costs were forecast based on Toronto Hydro's embedded and new debt costs.

To learn more about Toronto Hydro's approach to Cost of Capital, please refer to Exhibit 5, Tab 1, Schedule 1.

4.8 Cost Allocation And Rate Design

The 2015 base revenue requirement has been allocated to the company ¶ eight rate classes using the OEB ¶ cost allocation model. The resulting revenue to cost ratios for all classes are within the OEB ¶ guidelines as established in EB-2010-0219.

Toronto Hydro proposes fixed and variable rates for all rate classes based on the current split of revenue generated through each of these components. The OEB has initiated a process to review rate design for the Residential and GS<50 kW rate classes. If the OEB issues directions to distributors as a result of that process, Toronto Hydro anticipates incorporating those directions at that time.

4.8.1 Rate Year Synchronization

Toronto Hydro ¶ fiscal year is January 1 to December 31. As a public debt issuer, Toronto Hydro is required to produce public financial statements on a fiscal year basis, and to regularly explain these statements to financial markets (i.e., bond holders, credit rating agencies, short-term creditors), and to the utility ¶ shareholder. When revenues received by the utility are not aligned with the costs, presentation of this material can become more complex and less transparent.

Toronto Hydro is accordingly seeking approval in this application to align its rate year with its fiscal year effective January 1, 2016. Rates for 2015, the utility ¶ rebasing year, are proposed to be effective May 1, 2015. Rates for the first year under the proposed Price Cap Index (³PCI ´) would be effective January 1, 2016.

To learn more about Toronto Hydro's approach and proposals regarding cost allocation and rate year synchronization, please refer to Exhibit 7, Tab 1, Schedule 1, and Exhibit 8, Tab 1, Schedule 1, respectively.

4.9 Deferral and Variance Accounts

Toronto Hydro proposes new rate riders to clear a number of Deferral and Variance Accounts ("DVAs") balances. Toronto Hydro also seeks approval to clear to customers amounts related to Gains on Sale of properties associated with the Operational Centers Consolidation Plan ("OCCP"), tax refunds related to past tax reassessments, and lost revenue amounts related to the operation of the IRM mechanism over the 2012-14 period.

The total net DVA balances proposed for disposal are $53.7 million. The proposed disposition periods vary from one to five years. **/C**

Toronto Hydro seeks approval of three new deferral and variance accounts: 1) a variance account in respect of externally-initiated plant relocations and expansions; 2) a variance account in respect of de-recognition losses; and 3) a variance account to record the difference between the actual costs of approved eligible investments and the revenue received from the IESO relating to Provincial Rate Protection amounts.

For more information about DVA accounts, and amounts proposed for clearance, please refer to Exhibit 8, Tab 1, Schedule 1, and Exhibit 9, Tab 1, Schedule 1.

ADMINISTRATIVE INFORMATION

In accordance with the 2 (% ¶FWing Requirements (July 17, 2013), this schedule provides information about the following subjects:

1. Notice of Application, including:
    - a) a statement as to who will be affected by this application,
    - b) publication information; and
    - c) a summary of the bill impacts.
2. Concordance with the Filing Requirements;
3. 7 R U R Q W R aterial y Rnf¶ Vholl P;
4. Accounting treatment of non-utility business;
5. Existing accounting orders and departures from USoA;
6. Changes to methodologies used on previous applications;
7. Accounting Standard
8. Previous OEB Directives and Undertakings;
9. Conditions of Service; and
10. Internet address for viewing the application;

1. NOTICE OF APPLICATION

a) Affected Customers

Toronto Hydro has approximately 730,000 distribution customers across its service areas that will be affected by this Application. For more information D E R X W 7 R U R Q W R + \ G U F customer base, refer to the Executive Summary in Exhibit 1A, Tab 2, Schedule 1, and the Customer Engagement evidence at Exhibit 1B, Tab 2, Schedule 7.

b) Publication Information

Toronto Hydro proposes to publish a notice of this application to appear in the Toronto Star and L ¶Express newspapers, both of which are paid publications, as well as on the Company ¶ website www.torontohydro.com. L ¶Express is a weekly French language newspaper serving Toronto and the Greater Toronto Area, which has a circulation of approximately 22,000 readers per week. The Toronto Star is a daily newspaper serving Toronto and the surrounding area, has a total average daily circulation of approximately 360,000 readers. Toronto Hydro proposes to publish the notice of its application in these publications because they are the most-widely circulated newspapers in the City of Toronto in Canada ¶ official languages.

c) Summary of Bill Impacts

Table 1 below provides a summary of the distribution-only bill impacts (per sub-total A of Appendix 2-W, which is filed at Exhibit 8, Tab 7) to be used for the notice of application for a typical residential customer using 800 kWh per month and for a General Service <50kW customer using 2000 kWh per month.

Table 1: Summary of Bill Impacts (Distribution Only) for Notice of Application

Residential (800 kWh)					
Distribution Bill	**2015**	**2016**	**2017**	**2018**	**2019**
Subtotal A $	$ 4.05	$ 2.97	$ 3.29	$ 5.47	$ 2.56
Subtotal A %	12.29%	8.01%	8.22%	12.64%	5.24%
GS < 50 kW (2000 kWh)					
Distribution Bill	**2015**	**2016**	**2017**	**2018**	**2019**
Subtotal A $	$ 12.33	$ 3.80	$ 2.17	$ 11.51	$ 5.89
Subtotal A %	14.87%	3.99%	2.19%	11.37%	5.23%

2. MATERIALITY THRESHOLD

In accordance with section 3.2.2.2 of the Filing Requirements, Toronto Hydro ¶ materiality threshold is $1 million because its distribution revenue requirement exceeds $200 million. Unless otherwise noted, Toronto Hydro has generally applied this threshold throughout the application.

3. ACCOUNTING TREATMENT OF NON-UTILITY BUSINESS

Toronto Hydro confirms that it has segregated the activities of its non-utility business from rate regulated activities.

4. EXISTING ACCOUNTING ORDERS AND DEPARTURES FROM USOA

Toronto Hydro confirms that it has complied with the Uniform System of Accounts (³USoA ´) as set out in the 2 (% ¶ Accounting Procedures Handbook (³APH ´), and with the following utility-specific accounting orders:

- Impact for USGAAP Deferral Account, effective January 1, 2012, to record the financial impacts resulting from the transition to and implementation of USGAAP;[1]
- Sub-Accounts to Account 1508 ±Other Regulatory Assets, effective June 1, 2013, relating to Incremental Capital Module (³ICM ´) amounts;[2] and
- Sub-Accounts to Account 1508 ±Other Regulatory Assets, to record the costs and revenues associated with wireless pole attachments.[3]

5. CONCORDANCE WITH THE FILING REQUIREMENTS

Toronto Hydro is filing a Custom Incentive Rate-setting (³Custom IR ´) Application. In preparing this A S S O L F D W L R Q 7 R U R Q W R + \ G U R K D V F R Q V L G H U H G Filing Requirements for Electricity Distribution Rate Applications issued July 17, 2013

[1] EB-2012-0079, Decision and Order (June 7, 2012).
[2] EB-2012-0064, Rate Order (May 9, 2013).
[3] EB-2012-0234, Decision and Accounting Order (June 5, 2014).

(the "Filing Requirements") issued on December 20, 2013. Departures from the Filing Requirements are noted in the Checklist filed at Exhibit 1A, Tab 3, Schedule 2. [4]

6. METHODOLOGY CHANGES

Since its last rebasing application in 2011 (EB-2010-0142), Toronto Hydro has made the following methodology changes:

- Accounting Standard changes, as discussed in section 7 below; and
- Working Capital Allowance rate changes, as outlined in Exhibit 2A, Tab 03.

7. ACCOUNTING STANDARD

Toronto Hydro plans to adopt International Financial Reporting Standards ("IFRS") for financial reporting purposes in the year beginning on January 1, 2015. Under IFRS 1, Toronto Hydro is required to present one year of comparative information under IFRS in its first set of IFRS financial statements. The first day of the comparative year is referred to as the "IFRS transition date". The utility has chosen to early adopt IFRS in accordance with the APH. For Toronto Hydro, the transition date is January 1, 2014, and the changeover date is January 1, 2015.

Article 510 *Transitional Issues Relating to the Adoption of IFRS* of the APH directs distributors to use modified IFRS ("mIFRS") as of the changeover date and requires distributors to compare the balances as determined under previous GAAP on December 31, 2014 to the corresponding balances at December 31, 2014 determined in accordance with mIFRS. Toronto Hydro has recorded the differences to opening Plant Property & Equipment ("PP&E") balances in Account 1575. For more information, refer to Exhibit 9, Tab 1, Schedule 1.

The adoption of IFRS 1 and compliance to APH 510 resulted in the following material impact to the 2015 test year revenue requirement in comparison to the revenue requirement under previous GAAP: [5]

- **Derecognition**: $33.9 million increase to depreciation expense;
- **Borrowing Costs**: $0.8 million increase to allowance for borrowed costs applied to fund construction work in progress ("CWIP"); and
- **Asset Retirement Obligations ("ARO"):** $0.9 million decrease in depreciation expense

For more information, please refer to Exhibit 2A, Tab 7, Schedule 1 and Exhibit 4B, Tab 1, Schedule 1.

8. PREVIOUS OEB DIRECTIVES AND UNDERTAKINGS

The summary below identifies previous OEB directives and undertakings and how these are being addressed in the current Application:

- File a cost allocation model that will disaggregate meter reading costs appropriately into Account 5310.[6] All USofA amounts used in the Cost Allocation model have been reviewed. The full Cost Allocation model is filed at Exhibit 7, Tab 1, Schedule 2, in printed and excel format.
- Review each of the assumptions set out in the Decision and Order when its cost allocation study is refreshed for its next cost of service application.[7] Please refer to Exhibit 7, Tab 1, Schedule 1 for an explanation of the inputs to the Cost Allocation model.

[5] Toronto Hydro expects that there would also be an impact to Payments in Lieu of Taxes (PILs), but has not quantified this impact for the purpose of the Application.
[6] EB-2010-0142, Decision on Draft Order Regarding Suite Metering Issues (April 17, 2012) at page 4.
[7] EB-2010-0142, Decision and Order On Suite Metering (February 22, 2012 and as corrected March 9, 2012) at page 29.

- Provide external evidence related to productivity and capital planning in the next cost of service application.[8] For external evidence relating to productivity, please refer to the Power System Engineering Report, which has been filed as Appendix B to Exhibit 1B, Tab 2, Schedule 5. For external evidence relating to capital planning, please refer to the Navigant Report which is filed as Appendix B to Exhibit 1B, Tab 2, Schedule 4.
- Provide seminar on FIM to Intervenors before filing 2015 application.[9] A seminar was provided at the second stakeholdering session on July 3, 2014. For more information, please refer to the evidence at Exhibit 1B, Tab 2, Schedule 8.
- Use best efforts to track any assets taken out of service before the end of their useful lives associated with the completion of ICM work segments approved in Phase 2 of this proceeding.[10] Toronto Hydro proposes to defer ICM true-up to a separate proceeding (Exhibit 2A, Tab 9), and intends to comply with this directive, as part of that proceeding.
- Evaluate options to measure or estimate actual line losses and the impacts on Account 1588 balances in accordance with the Accounting Procedures Handbook. File the results in its application for 2015 rates. Please refer to Exhibit 8, Tab 5, Schedule 1 for an update on this particular item. **/C**

9. CONDITIONS OF SERVICE

Toronto Hydro's current Conditions of Service can be found at the following link: http://www.torontohydro.com/sites/electricsystem/business/ConditionsofService/Pages/default.aspx. At this time, Toronto Hydro does not expect any of the approvals in this Application to result in a substantive change to its Conditions of Service.

[8] EB-2011-0144, Decision With Reasons and Order on the Preliminary Issue (January 5, 2012) at page 24.
[9] EB-2012-0064, Settlement Agreement (December 18, 2013) at page 7.
[10] EB-2012-0064, Decision and Order (December 18, 2013) at page 8.

10. INTERNET ADDRESS FOR VIEWING THE APPLICATION

The application can be viewed at: http://www.torontohydro.com/sites/electricsystem/Pages/2015CIR.aspx

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

EB-2014-0116

Date:July 22, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
GENERAL			
Ch 1 p4	Confidential Information - Practice Direction has been followed	**Yes**	
2	In advance of scheduled application - meet threshold established in Board letter (April 20, 2010)	**N/A**	
2	Align rate year with fiscal year - rationale for proposed alignment	**Yes**	Exhibit 8, Tab 1, Schedule 1
3	Text searchable and bookmarked PDF documents	**Yes**	
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS			
7	Overall business strategy including narrative of how the four RRFE outcomes are supported	**Yes**	Exhibit 1A, Tab 2, Schedule 1
7	Revenue Requirement - service RR, increase from previously approved, main drivers	**Yes**	Exhibit 1A, Tab 2, Schedule 1
7	Budgeting Assumptions - economic overview	**Yes**	Exhibit 1A, Tab 2, Schedule 1
7	Load Forecast Summary - load and customer growth, change in kWh and customer numbers, methodology description	**Yes**	Exhibit 1A, Tab 2, Schedule 1
7	Rate Base and Capital Plan - major drivers of DSP, rate base for test year, change from last approved, capex for test year, change from last approved, costs for any REG	**Yes**	Exhibit 1A, Tab 2, Schedule 1
8	OM&A for test year and change from last approved, summary of drivers, inflation assumed, total compensation for test year and change from last approved.	**Yes**	Exhibit 1A, Tab 2, Schedule 1
8	Statement regarding use of Board's cost of capital parameters; summary of any deviations	**Yes**	Exhibit 1A, Tab 2, Schedule 1
8	Cost Allocation & Rate Design - summary of any deviations from Board methodologies and significant changes	**Yes**	Exhibit 1A, Tab 2, Schedule 1
8	Deferral and Variance Account - total disposition (RPP and non-RPP), disposition period, new accounts requested	**Yes**	Exhibit 1A, Tab 2, Schedule 1
8	Bill Impact - total impacts ($ and %)for all classes for typical customers	**Yes**	Exhibit 1A, Tab 2, Schedule 1
8	Overview of customer engagement activities; description of engagement, how customer needs are reflected in application. Explanation if no customer engagement	**Yes**	Exhibit 1B, Tab 2, Schedule 7
9 & 34	Audited Financial Statements for 2 most recent historical years (i.e. 3 years of historical actuals)	**Yes**	Exhibit 1C, Tab 4, Schedule 2
9	Detailed reconciliation of AFS with regulatory financial results filed in the application	**Yes**	Exhibit 1C, Tab 4, Schedule 3
9	Annual Report and MD&A for most recent year of parent company	**Yes**	Exhibit 1C, Tab 4, Schedule 4 and 5
9	Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances	**Yes**	Exhibit 1C, Tab 4, Schedule 6 and 7
10	Materiality threshold; additional details beyond the threshold if necessary	**Yes**	Exhibi 1A, Tab 3, Schedule 1
Ch 1 p2	Certification that evidence is accurate, consistent and complete	**Yes**	Exhibit 1A, Tab 5, Schedule 1
10	Table of Contents	**Yes**	Exhibit 1A, Tab 1, Schedule 1
10	Statement of who will be affected by application	**Yes**	Exhibit 1A, Tab 3, Schedule 1
10	Publication information (paid, readership, circulation)	**Yes**	Exhibit 1A, Tab 3, Schedule 1
10	Applicant's internet address for viewing of application	**Yes**	Exhibit 1A, Tab 3, Schedule 1
10	Primary contact information (name, address, phone, fax, email)	**Yes**	Exhibit 1A, Tab 3, Schedule 1
10	Identification of legal (or other) representation	**Yes**	Exhibit 1B, Tab 1, Schedule 1, Appendix A
10	Requested effective date	**Yes**	Exhibit 1B, Tab 1, Schedule 1
10	Bill impacts - distribution only impacts for 800 kWh residential and 2000 kWh GS<50 (sub-total A of Appendix 2-W)	**Yes**	Exhibit 1A, Tab 2, Schedule 1
11	Form of hearing requested and why	**Yes**	Exhibit 1B, Tab 1, Schedule 1
11	List of approvals requested (and relevant section of legislation), including accounting orders	**Yes**	Exhibit 1B, Tab 1, Schedule 1

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

EB-2014-0116

Date:July 22, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
11	Change in tax status	N/A	No change in tax status.
11	Existing accounting orders and departures from USoA including references to the accounting orders	Yes	Exhibit 1A, Tab 3, Schedule 1
11	Description of Operating Environment (including map, list of neighbouring utilities)	Yes	Exhibit 1C, Tab 1, Schedule 1
11	Identification of embedded and/or host distributors	N/A	Applicant does not have any embedded/host distributors; see Exhibit 1C, Tab 1, Schedule 1
11	Corporate and Utility Organizational Structure, planned changes, corporate entities relationship chart, reporting relationships between LDC and parent	Yes	Exhibit 1C, Tab 2, Schedule 1
12 & 13	Corporate Governance: Number of Directors on Board, number of independent directors, how independent judgement is facilitated - Board Mandate; Schedule of Board Meetings - Orientation and Continuing Education for directors - Ethical Business Conduct - written code where available - Process for Nomination of Directors - Committees - function and charter for each committee - Audit Committee - number of independent members, whether members are financially literate	Yes	Exhibit 1C, Tab 2, Schedule 1
13	Statement regarding any transmission assets previously deemed distribution and whether LDC seeks deeming in current application	Yes	Exhibit 1C, Tab 1, Schedule 1
5, 6 & 13 Appendices	Accounting Standard used and when it was adopted. - MIFRS - Adoption of IFRS effective Jan 1-15, Jan 1-14 or earlier - CGAAP - must implement regulatory accounting changes for depreciation and capitalization by Jan 1-13 - USGAAP or ASPE - evidence of eligibility, authorization, benefits. Must implement regulatory accounting changes for depreciation and capitalization by Jan 1-13 Summary of changes to accounting policies and quantification of revenue requirement impact. LDC may choose to file Appendix 2-YA (MIFRS) or 2-YB (CGAAP or ASPE).	Yes	Exhibit 1A, Tab 3, Schedule 1; Applicant has not filed Appendix 2-YA at this time.
13	Statement identifying all deviations from Filing Requirements	Yes	Exhibi 1A, Tab 3, Schedule 1
13	Statement identifying and describing any changes to methodologies used vs previous applications	Yes	Exhibi 1A, Tab 3, Schedule 1
13	Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities	Yes	Exhibi 1A, Tab 3, Schedule 1
13	Identification of Board Directives from previous Board Decisions, and how addressed	Yes	Exhibi 1A, Tab 3, Schedule 1
13	Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service as a result of application	Yes	Exhibi 1A, Tab 3, Schedule 1
EXHIBIT 2 - RATE BASE			
14 & 15	Completed Appendix 2-BA1 or 2-BA2 (application material and Excel)	Yes	Exhibit 2A, Tab 1, Schedule 2
14	Opening and Closing balances, average of opening and closing balances for gross assets and accumulated depreciation; working capital allowance (historical actual, bridge and test year forecast)	Yes	Exhibit 2A, Tab 1
14	Continuity statements (year end balance, including interest during construction and overheads). Year over year variance analysis; explanation where variance greater than materiality Hist. Brd-Approved vs Hist. Actual Hist. Act. Vs previous Hist. Act. Bridge vs. Test	Yes	Exhibit 2A, Tab 1

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

EB-2014-0116

Date:July 22, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
14 & 15	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (eg. WIP, ARO, smart meter balances). Reconciliation must be between YE 2013 and YE 2014 net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Yes	Exhibit 2A, Tab 1
15	Gross Assets Breakdown by Function and by major plant account; description of major plant items for test year	Yes	Exhibit 2A, Tab 2, Schedule 1
15	Summary of any ICM adjustment from IRM	Yes	Exhibit 2A, Tab 1, Schedule 1; Exhibit 2A, Tab 9, Schedule 1
15 & 32	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Yes	Exhibit 2A, Tab 1, Schedule 1; Exhibit 4B, Tab 1, Schedule 1
15	Working Capital - 13% allowance or Lead/Lag Study or Previous Board Direction	Yes	Lead Lag Study - Exhibit 2A, Tab 3
16	Cost of Power must be determined by split between RPP and non-RPP customers based on actual data, use most current RPP price, use current UTR. Should include SME charge.	Yes	Exhibit 2A, Tab 3, Schedule 1
16	Lead/Lag Study - leads and lags measured in days, dollar-weighted	Yes	Exhibit 2A, Tab 4
17 & 18	Stranded Meters - if not previously addressed by the Board, proposed treatment for recovery that conforms to Board approach: NBV of stranded meters at YE 2013, proposed stranded meter rate riders for applicable customer classes. Explanation for approaches that are not the Board approach Completed Appendix 2-S.	Yes	Exhibit 2A, Tab 4
19	DSP filed as a stand-alone document	Yes	Exhibit 2B
Ch 5 p9	Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table	Yes	Exhibit 2B, Section A0 (see also Exhibit 1B , Tab 2, Schedule 4)
Ch 5 p9-10	Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies	Yes	Exhibit 2B, Sections and D
Ch 5 p10-11	Coordinated Planning with 3rd parties - description of consultations - deliverables of the Regional Planning Process, or status of deliverables - OPA letter in relation to REG investments (Ch 5 p8&9) and Dx response letter	Yes	Exhibit 2B, Section B
Ch 5 p11	Performance Measurement - identify and define methods and measures used to monitor DSP performance - summary of performance and trends over historical period. Must include SAIFI, SAIDI and CAIDI for all interruptions and all interruptions excluding loss of supply - explain how information has affected DSP	Yes	Exhibit 2B, Section C
Ch5 p12	Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments	Yes	Exhibit 2B, Section D, Schedule D1
Ch5 p12	Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	Yes	Exhibit 2B, Section D, Schedule D1
Ch 5 p13	Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP), - description of system configuration - service profile and condition by asset type (tables and/or figures) - date data compiled - assessment of degree the capacity of system assets is utilized	Yes	Exhibit 2B, Section D, Schedule D2
Ch 5 p13-14	Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions - description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation	Yes	Exhibit 2B, Section D, Schedule D3

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

EB-2014-0116

Date:July 22, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
Ch 5 p14-15	Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category - list, description and total capital cost of material capital expenditures sorted by category (table recommended) - information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate) - description of customer engagement - Dx expectations of system development over next 5 years - list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended)	**Yes**	Exhibit 2B, Section E, Schedule E1
Ch 5 p15	Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritise REG investments	**Yes**	Exhibit 2B, Section E, Schedule E2
Ch 5 p16	System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints	**Yes**	Exhibit 2B, Section E, Schedule E3
Ch 5 p16-18 **Ch 2 p19**	Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB	**Yes**	Exhibit 2B, Section E, Schedule E4; Exhibit 2A, Tab 6, Schedule 3
Ch5 p19	Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment	**Yes**	Exhibit 2B, Section E, Schedules E1 and E4
Ch 5 p19-25	Material Investments - For each project that meets materiality threshold set in Ch 2 p10 - general information - total capital, customer attachments, dates, risks, variances, REG investments - evaluation criteria - may include: efficiency, customer value, reliability, etc. - category specific requirements for each project - system access, system renewal, system service, general plant (as applicable)	**Yes**	Exhibit 2B, Section E, Schedules E5 - E8 (see also Exhibit 1B, Tab 2, Schedule 4)
19	Capital Expenditures - completed Appendix 2-AA showing capex on a project specific basis for 5 historical years, bridge and test; explanation of variances, accounting treatment for projects with life cycle greater than one year	**Yes**	Exhibit 2A, Tab 6
19	Non-distribution activities - capital expenditures and reconciliation to total capital budget	**Yes**	Exhibit 2A, Tab 6, Schedule 1
5 & 19-20	Capitalization policy, changes to capitalization since previous rebasing - explanations must be provided. The changes must be identified (eg. capitalization of indirect costs, etc) and the causes of the changes must also be identified.	**Yes**	Exhibit 2A, Tab 7, Schedule 1
20	Capitalization of overhead - Completed Appendix 2-DA (MIFRS) or 2-DB (CGAAP or ASPE) Burden rates must be identified; changes from last rebasing must be identified; LDC must identify burden rates prior to and after the change	**N/A**	Exhibit 2A, Tab 7, Schedule 2; Applicant has not made any changes to capitalized overhead since the last rebasing (EB-2010-0142).
20	For Eligible Investments - proposal to divide costs per O.Reg. 330/09	**Yes**	Exhibit 2A, Tab 8, Schedule 1
21	Appendices 2-FA through 2-FC must be filed identifying eligible investments	**Yes**	Exhibit 2A, Tab 8, Schedules 2 to 4
21	Distributor with approved ICM - schedule of ICM amounts, variances and explanation	**N/A** **N/A**	Proposal to defer ICM true up to seperate application; see Exhibit 2A, Tab 9, Schedule 1.

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

EB-2014-0116

Date:July 22, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
21	Balances in 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue	N/A	Proposal to defer ICM true up to seperate application; see Exhibit 2A, Tab 9, Schedule 1.
22	5 historical years of ESQRs, explanation for any under-performance and actions taken	Yes	Exhibit 2A, Tab 10, Schedule 1
22	5 historical years of SAIDI and SAIFI - for all interruptions and all interruptions excluding loss of supply, explanation for any under-performance and actions taken	Yes	Exhibit 2A, Tab 10, Schedule 2
22	Completed Appendix 2-G	Yes	Exhibit 2A, Tab 10, Schedule 3
EXHIBIT 3 - OPERATING REVENUE			
22 & 25	Customer, volume and revenue forecast	Yes	Exhibit 3, Tab 1
22	Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for load and customer forecast	Yes	Exhibit 3, Tab 1
23 & 24	Regression Model - rationale for choice, regression statistics, explanation for any unintuitive relationships, explanation of modeling approaches and alternative models tested, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, explanation of any constructed variables; data used in load forecast must be provided in Excel format, including derivation of constructed variables	Yes	Exhibit 3, Tab 1
24	NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including licence conditions, discussion of weather normalization considerations	Yes	Exhibit 3, Tab 1
24 & 25	CDM Adjustment - 2013 and 2014 CDM reductions must take into account 2011 and 2012 CDM program results reported by OPA. CDM adjustment should take into account historical CDM results factored into base load forecast before CDM adjustment	Yes	Exhibit 3, Tab 1
25	CDM savings for 2014 LRAMVA balance and adjustment to 2014 load forecast; data by customer class	Yes	Exhibit 3, Tab 1
25	Completed Appendix 2-I, or alternative with explanation	Yes	Exhibit 3, Tab 1
22 & 25	Schedule of volumes, revenues, customer/connection count by class and total system load: 5 years historical, Board approved, 5 years historical weather normalized, bridge year and test year.	Yes	Exhibit 3, Tab 1
25	Customer count increases or decreases for test year - explanation by class; confirmation of year end or average format	Yes	Exhibit 3, Tab 1
25	Explanation for any changes in definition or composition of class	Yes	Exhibit 3, Tab 1
25	Weather normalized average consumption per customer for historical 5 years, bridge and test	Yes	Exhibit 3, Tab 1
25	Explanation of net change in average consumption from last Board approved, and actual historical, bridge and test - for each rate class	Yes	Exhibit 3, Tab 1
25	Details of development of billing kW	Yes	Exhibit 3, Tab 1
26	Revenues on existing and proposed rates	Yes	Exhibit 3, Tab 1
26	Variance analysis of volumes, revenues, customer/connection count and total system load: Historical Board approved vs Historical Actual (and Historical Actual weather normalized) Year over year historical weather normalized variance, weather normalized bridge, test year	Yes	Exhibit 3, Tab 1
24 & 26	Data used to determine forecast should be filed as Excel	Yes	Exhibit 3, Tab 1
26	Breakdown of other distribution revenue accounts; completed Appendix 2-H	Yes	Exhibit 3, Tab 2
26	Variance analysis - year over year, historical, bridge and test	Yes	Exhibit 3, Tab 2
26	Any new proposed specific service charges	Yes	Exhibit 3, Tab 2; Exhibit 8A, Tab 2
26 & 30	Revenue from affiliate transactions, shared services, corporate cost allocation	Yes	Exhibit 3, Tab 2

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

EB-2014-0116

Filing Requirement Page # Reference

Date:July 22, 2014

		Yes/No/N/A	Evidence Reference, Notes
EXHIBIT 4 - OPERATING COSTS			
27	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes	**Yes**	Exhibit 4A, Tab 1 and Tab 2.
28	Summary of recoverable OM&A expenses; Appendix 2-JA	**Yes**	Exhibit 4A, Tab 1
28	OM&A cost drivers; Appendix 2-JB	**Yes**	Exhibit 4A, Tab 1
28	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	**Yes**	Exhibit 4A, Tab 1
28	Identification of change in OM&A in test year in relation to change in capitalized overhead.	**N/A**	Applicant has not made any changes to capitalized overhead since last rebasing (see Exhibit 2A, Tab 7, Schedule 2)
28	OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-DA or 2-DB	**Yes**	For variance analysis see Exhibit 4A, Tab 2; Re Appendix 2-DA: Applicant has not made any changes to capitalized overhead since last rebasing (see Exhibit 2A, Tab 7, Schedule 2)
28	Completed Appendix 2-JC OM&A Programs Table - by program or major functions; include variance analysis between test year and last Board approved and most recent actual	**Yes**	Exhibit 4A, Tab 1 and Tab 2.
28	Employee Compensation - complete Appendix 2-K	**Yes**	Exhibit 4A, Tab 4, Schedule 2
29	Description of compensation strategy	**Yes**	Exhibit 4A, Tab 4, Schedule 5
29	Explanation for material changes to head count and compensation: year over year variances, inflation, plans for new employees, details on collective agreements, basis for performance pay, filing of any relevant studies	**Yes**	Exhibit 4A, Tab 4, Schedules 3 and 5
29	Details of employee benefit programs including pensions for last Board approved, historical, bridge and test; must agree with tax section	**Yes**	Exhibit 4A, Tab 4, Schedule 5
29	Most recent actuary report	**Yes**	Ehxibit 4A, Tab 4, Schedule 7
30	Identification of all shared services among affiliates	**Yes**	Exhibit 4A, Tab 5
30	Allocation methodology for corporate and shared services, list of costs and allocators, including any third party review	**Yes**	Exhibit 4A, Tab 5
26 & 30	Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue	**Yes**	Exhibit 4A, Tab 5, Schedule 2
30	Identification of any Board of Director costs for affiliates included in LDC costs	**Yes**	Exhibit 4A, Tab 5, Schedule 2
30	Shared Service and Corporate Cost Variance analysis - test year vs last Board approved and most recent actual	**Yes**	Exhibit 4A, Tab 5, Schedule 1
30	Purchased Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance)	**Yes**	Exhibit 4A, Tab 3, Schedule 2
30 & 31	Explanation for procurements above materiality threshold without competitive tender	**Yes**	Exhibit 4A, Tab 3, Schedule 1
31	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years)	**Yes**	Exhibit 4A, Tab 2, Schedule 20.
31	Regulatory costs - breakdown of actual and forecast, supporting information related to CoS application, proposed recovery (ie amortized?). Completed Appendix 2-M	**Yes**	Exhibit 4A, Tab 2, Schedule 17
31	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes	**Yes**	Exhibit 4A, Tab 2, Schedule 19
32	Statement whether test year revenue requirement includes legacy programs. If yes, identify programs	**Yes**	Test year revenue reuqirement does not inlcude legacy programs; see Exhibit 4A, Tab 2, Schedule 19
32	Charitable Donations - amounts paid from last Board approved up to test year	**Yes**	Exhibit 4A, Tab 2, Schedule 19
32	Detailed information for any proposal to recover charitable donations (outside of assistance for payment of electricity bills)	**N/A**	Applicant does not propose to recover any charitable donationations.
32	Any non-recoverable contributions identified and removed from revenue requirement. Confirm that no political contributions have been included for recovery	**Yes**	Exhibit 4A, Tab 2, Schedule 19

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

EB-2014-0116

Date:July 22, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
15 & 32	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must tie back to accumulated depreciation balances in continuity schedule under rate base. Ensure that significant parts of each item of PP&E are depreciated separately	Yes	Exhibit 4B, Tab 1, Schedule 1
32	Identify any Asset Retirement Obligations and associated depreciation	Yes	Exhibit 4B, Tab 1, Schedule 1
32	Historical depreciation practice and proposal for test year. Variances from the half year rule must be documented with supporting rationale	Yes	Exhibit 4B, Tab 1, Schedule 1
33	Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Yes	Exhibit 4B, Tab 1, Schedule 1
33	Regulatory Accounting changes for depreciation and capitalization - use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA, detail and explain differences in TUL from Kinectrics - Appendix 2-BB - recalculation to determine average remaining service life of opening balance on date of making depreciation changes	N/A	Applicant has not made any material changes to depreciation and capitalization since its last rebasing application (EB-2010-0142); see Exhibit 2A, Tab 7, Schedule 1 and Exhibit 4B, Tab 1, Schedule 1.
33 Appendices	Filing under MIFRS - applicable depreciation appendices (Appendix 2-CA to 2-CM)	N/A	Applicant has not made any material changes to depreciation and capitalization since its last rebasing application (EB-2010-0142); see Exhibit 2A, Tab 7, Schedule 1 and Exhibit 4B, Tab 1, Schedule 1.
33 Appendices	Filing under CGAAP,ASPE,USGAAP - applicable depreciation appendices (CGAAP or ASPE Appendix 2-CN to 2-CU, USGAAP Appendix 2-CV); details of TUL whether Kinectrics or other, impacts and justification for change	N/A	Applicant has not made any material changes to depreciation and capitalization since its last rebasing application (EB-2010-0142); see Exhibit 2A, Tab 7, Schedule 1 and Exhibit 4B, Tab 1, Schedule 1.
33	Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test	Yes	Applicant filed completed PILs model for the bridge and test year; see Exhibit 4B, Tab 2, Schedule 2.
33	Supporting schedules and calculations identifying reconciling items	Yes	Exhibit 4B, Tab 2, Schedules 1 and 2
34	Most recent federal and provincial tax returns	Yes	Exhibit 4B, Tab 2, Schedule 3
9 & 34	Financial Statements included with tax returns if different from those filed with application	N/A	Financial statements included with tax returns are not different from those filed at Exhibit 1C, Tab 4, Schedule 2.
34	Calculation of Tax Credits	Yes	Exhibit 4B, Tab 2, Schedules 1 and 2
34	Supporting schedules, calculations and explanations for other additions and deductions	Yes	Exhibit 4B, Tab 2, Schedule 2
34	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Yes	Exhibit 4B, Tab 2, Schedule 1
34 & 35	Completion of Integrity checks listed on p34-35; statement confirming completion	Yes	Exhibit 4B, Tab 2, Schedule 1
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE			
36	Statement that LDC adopting Board's guidelines for cost of capital and confirming updates will be done. Alternatively - utility specific cost of capital with supporting evidence	Yes	Exhibit 5, Tab 1, Schedule 1
3 & 36 Appendices	Completed Appendix 2-OA for last Board approved and test year; total capitalization (debt and equity) must equate to total rate base	Yes	Exhibit 5, Tab 1, Schedule 2
36	Completed Appendix 2-OB for historical, bridge and test year	Yes	Exhibit 5, Tab 1, Schedule 3
37	Explanation for any changes in capital structure	N/A	Applicant has not made any changes in capital structure
37	Calculation of cost for each capital component	Yes	Exhibit 5, Tab 1
37	Profit or loss on redemption of debt	N/A	Not applicable
37	Copies of promissory notes or other debt arrangements with affiliates	Yes	Exhibit 1C, Tab 4, Schedule 6
37	Explanation of debt rate for each existing debt instrument	Yes	Exhibit 5, Tab 1, Schedule 1
37	Forecast of new debt in bridge and test year - details including estimate of rate	Yes	Exhibit 5, Tab 1, Schedule 1

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

EB-2014-0116

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Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
37	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	N/A	
EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY			
37 & 38	Calculation of Delivery-Related Revenue Deficiency/Sufficiency: net utility income, rate base, actual return on rate base, indicated rate of return, requested rate of return, def/sufficiency, gross def/sufficiency. Def/sufficiency must be net of other costs (eg. electricity price).	Yes	Exhibit 6, Tab 1
38	Summary of drivers for test year def/sufficiency, how much each driver contributes; references in evidence mapped to drivers	Yes	Exhibit 6, Tab 1
38	Impacts of any changes in methodologies to def/sufficiency	N/A	Applicant has not made any changes in methodologies.
38	RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Yes	Exhibit 6, Tab 1, Schedule 2
EXHIBIT 7 - COST ALLOCATION			
39	Completed cost allocation study reflecting future loads and costs. Excel version of 2014 cost allocation model (updated load profiles or scaled version of HONI CAIF)	Yes	Exhibit 7, Tab 1
39	Description of weighting factors, and rationale for use of default values (if applicable)	Yes	Exhibit 7, Tab 1
39	Hard copy of sheets I-6, I-8, O-1 and O-2 (first page)	Yes	
39 &40	Host Dx - evidence of consultation with embedded Dx - Statement regarding embedded Dx support for approach to allocation of costs - If embedded Dx is separate class - class in cost allocation study and Appendix 2-P - If new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and Appendix 2-P - If embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. LDC may choose to file Appendix 2-Q.	N/A	Applicant is not a host Dx (see Exhibit 1C, Tab 1, Schedule 1).
40	New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS	N/A	
41	Completed Appendix 2-P; supporting information for any proposal to re-balance rates	Yes	Exhibit 7, Tab 2
41	Proposal to re-balance to bring R:C ratio into Board policy range; any proposal to re-balance beyond test year.	Yes	Exhibit 7, Tab 2
42	If Cost Allocation Model other than Board model used - exclude LV, exclude DVA such as smart meters	N/A	
EXHIBIT 8 - RATE DESIGN			
42	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places	Yes	Exhibit 8, Tab 1
42	Current and Proposed F/V proportion with explanation for any changes	Yes	Exhibit 8, Tab 1
42 & 43	Table comparing current and proposed fixed charge with floor and ceiling from cost allocation study. Explanation for MFC that exceed the ceiling; analysis must be net of adders and riders	Yes	Exhibit 8, Tab 1
43	Retail Transmission Service Rate Work Form - PDF and Excel	Yes	Exhibit 8, Tab 6
16 & 43	RTSR information must be consistent with working capital allowance calculation	No	RTSR (Exhibit 8, Tab 6, Schedule 1) are based on current UTR, as required by model. The Cost of Power forecast used for working capital allowance (Exhibit 2a, Tab 3, Schedule 1) includes a forecast of UTR to better reflect expected transmission charges in 2015.
43	If proposing changes to Retail Service Charge - evidence of consultation and notice	N/A	
44	Wholesale Market Service Rate - reflect $0.0056 in application or justify otherwise	Yes	Rate is $.0057 for 2015; Exhibit 8, Tab 1
44	Smart Metering Charge - reflect $0.79 in application for Residential and GS<50	Yes	Exhibit 8, Tab 1
44	Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges	Yes	Exhibit 8, Tab 2

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

EB-2014-0116

Date:July 22, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
44	Identify any rates and charges in Conditions of Service that do not appear on tariff sheet Explain nature of costs, schedule outlining revenues 2009-2012, bridge and test Whether these charges are included on tariff sheet	Yes	Exhibit 8, Tab 2; Exhibit 3, Tab 2.
45	Ensure revenue from SSC corresponds with Operating Revenue evidence	Yes	Exhibit 8, Tab 2; Exhibit 3, Tab 2.
45	Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes	N/A	
45	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	N/A	
45	Allocation of LV cost to customer classes (typically proportional to Tx connection revenue)	N/A	
45	Proposed LV rates by customer class	N/A	
45	Proposed SFLF and Total Loss Factor for test year	Yes	Exhibit 8, Tab 1, Schedule 1
45	Statement as to whether LDC is embedded	N/A	Applicant is not embedded
45	Study of losses if required by previous decision	N/A	Not required by decision
45	3-5 years of historical loss factor data - Completed Appendix 2-R	N/A	As noted in Exhibit 8, Tab 1, Schedule 1, a review of loss factors is currently underway, and will be filed as an update to the Applicaiton.
46	Explanation of losses >5%	N/A	Current approved losses <5%
46	If proposed loss factor >5%, action plan to reduce losses going forward	N/A	Current approved losses <5%
46	Explanation of SFLF if not standard	N/A	Standard applied
46	Current Tariff of Rates and Charges	Yes	Exhibit 8, Tab 3, Schedule 1
46	Track Changes version of current tariff showing proposed changes	Yes	Exhibit 8, Tab 3, Schedule 2
46	Proposed Tariff of Rates - Appendix 2-Z	Yes	Exhibit 8, Tab 3, Schedule 3
46	Explanation of changes to terms and conditions of service if changes affect application of rates	N/A	No changes affecting application of rates
46	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement	Yes	Exhibit 8, Tab 1, Schedule 2
46	Completed Appendix 2-V (Revenue Reconciliation)	Yes	Exhibit 8, Tab 4
46 & 47	Bill Impacts - completed Appendix 2-W for all classes for representative samples of end-users. Must provide residential 800 kWh and GS<50 2,000 kWh. Commodity and regulatory charges held constant	Yes	Exhibit 8, Tab 7
47 & 48	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation	N/A	Total bill increase is not > 10% for any customer class.
48	Rate Harmonization Plans, if applicable - including impact analysis	Yes	Exhibit 8, Tab 1, Schedule 1
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS			
48	List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH	Yes	Exhibit 9, Tab 1; no deviation from APH.
48 & 49	Completed DVA continuity schedule for period following last disposition to present - Excel format	Yes	Exhibit 9, Tab 2, Schedule 1
49	Interest rates applied to calculate carrying charges (month or quarter)	Yes	Exhibit 9, Tab 2, Schedule 2
49 & 55	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	Yes	No deviation from AFS; Exhibit 9, Tab 2, Schedule 1.
49	Identification of Group 2 accounts that will continue/discontinue going forward, with explanation	Yes	Exhibit 9, Tab 1, Schedule 1
49	Proposed allocators for DVA for which Board has not established approved allocator	Yes	Exhibit 9, Tab 1, Schedule 1; Exhibit 9, Tab 3, Schedule 1
48 & 49	Statement as to any new accounts, and justification.	Yes	Exhibit 9, Tab 1, Schedule 1
49	Statement whether any adjustments made to DVA balances previously approved by Board on final basis; explanation and amount of adjustment	N/A	No adjustments to DVA
49	Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped to USoA. Provide explanation if making a profit or loss on commodity.	Yes	Exhibit 9, Tab 2, Schedule 2
49	Statement confirming that IESO GA charge is pro-rated into RPP and non-RPP; provide explanation if not pro-rated.	Yes	Exhibit 9, Tab 2, Schedules 1 and 2
50	If not addressed previously, disposition of Account 1592 - Completed Appendix 2-TA	Yes	Exhibit 9, Tab 2, Schedule 3

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

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Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
50	If not addressed previously, disposition of Account 1592 sub-account HST/OVAT ITC - analysis that supports conformity with Dec 2010 APH FAQ (particularly #4) - completed Appendix 2-TB Applicant must state the period that the account covers (i.e. Jul 1-2010 up to start of new rate year (year of rebasing))	Yes	Exhibit 9, Tab 1, Schedule 1.
50 & 51	Assuming 2014 CoS filed under MIFRS: One time IFRS transition costs - If IFRS transition costs in rates, file for disposition of balance in IFRS variance account; - completed Appendix 2-U - statement whether any one time IFRS transition costs are embedded in 2014 revenue requirement where it is embedded - explanation for each category of cost recorded in 1508 sub-account - explanation for material variances - statement that no capital costs, ongoing IFRS compliance costs are recorded in 1508 sub-account; provide explanation if this is not the case	N/A	Applicant is not seeking to recover IFRS transitions costs in this Application.
51 & 52	Assuming 2014 CoS filed under MIFRS - 1575 IFRS-CGAAP PP&E account - breakdown of balance, Appendix 2-EA, 2-EB or 2-EC - listing and quantification of drivers - a breakdown for quantification of any accounting changes arising from IFRS in relation to PP&E - volumetric rate rider to clear 1575; explain basis for disposition period - rate of return component is to be applied to 1575 but not recorded in 1575 - statement confirming no carrying charges applied to 1575 - show the balance in DVA continuity schedule	Yes	Exhibit 9, Tab 1 and 3
53 & 54	Assuming 2014 CoS filed under CGAAP or ASPE, or 2014 CoS under MIFRS with changes to depreciation and capitalization in 2012 or 2013 - 1576 IFRS-CGAAP PP&E account - Appendix 2-BA1 or 2-BA2 must not be adjusted for 1576 - breakdown of balance related to 1576, Appendix 2-ED or 2-EE - volumetric rate rider to clear 1576; explain basis for disposition period - rate of return component is to be applied to 1576 but not recorded in 1576 - statement confirming no carrying charges applied to 1576 - show the balance in DVA continuity schedule	N/A	
54	Retail Service Charges - material balance in 1518 or 1548 - confirm variances are incremental costs of providing retail services - identify drivers - provide schedule identifying all revenues and expenses listed by USoA for 2012, bridge and test years - state whether Article 490 of APH has been followed; explanation if not followed	Yes	Exhibit 9, Tab 2, Schedule 1
54	Retail Service Charges - zero balance in 1518 or 1548 - state whether Article 490 of APH has been followed; explanation if not followed	No	Exhibit 9, Tab 2, Schedule 1; did not follow Article 490 of the APH due to immateriality; included in revenue offset Exhibit 3, Tab 2.
4 & 55	Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why Proposal for disposition of deferral accounts for renewable generation connection and smart grid as set out in FR "Distribution System Plans - Filing Under Deemed Conditions of Licence"	Yes	Exhibit 9, Tab 2, Schedule 1
55	Proposed rate riders (Separate rate rider for RSVA GA for non-RPP customers). Default disposition period of 1 year and provide explanation for deviations from default period. Show calculations - allocation of each account, billing determinants and length of disposition period	Yes	Exhibit 9, Tab 1, Schedule 1; Exhibit 9, Tab 3, Schedule 1
49 & 55	Statement whether DVA balances before forecasted interest match the last AFS	Yes	Yes DVA balances before forecasted interest match the AFS.

Filing Requirements Checklist

Toronto Hydro-Electric System Limited ("Toronto Hydro")

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Date:July 22, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
55	Provide an explanation of variance > 5% between amounts proposed for disposition and amounts reported in RRR for each account. Provide explanations even if such variances are < 5% threshold if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior Board decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings	Yes	Exhibit 9, Tab 1, Schedule 1.
55	New DVA - must meet causation, materiality, prudence criteria; include draft accounting order	Yes	Exhibit 9, Tab 1, Schedule 1
56	LRAMVA - disposition of balance - statement indicating use of most recent input assumptions when calculating lost revenue -statement indicating reliance on most recent CDM evaluation report from OPA; copy of report - Tables for each rate class showing lost revenue by year - lost revenue calculations - energy savings by class and Board approved variable charge - statement that indicates if carrying charges are requested - Third party report for any Board-approved programs	Yes	Exhibit 9, Tab 2, Schedule 5
57	Smart Meters - if applying for final disposition, completed smart meter model (excel) must be filed. Refer to G-2011-0001 regarding proposal to dispose of balances. Any previous approval should be documented.	N/A	Smart meter disposition approved by OEB in EB-2013-0287.
	TOTAL "NO"	**2**	

RESPONSE TO THE LETTERS OF COMMENT

In the course of Toronto Hydro's 2015-2019 Custom IR application, the Ontario Energy Board ("OEB") received three letters of comment from Toronto Hydro's customers, namely from Messrs. Norm Hann, Ron Dash, Sr., and Richard Cassel. Toronto Hydro appreciates its customers sharing their observations and provides the following response.

While each author raised a number of points, the above-noted letters generally addressed three major areas, including Toronto Hydro's variable compensation structure, efficiencies/savings available within Toronto Hydro's budget and the electricity sector more generally, as well as Toronto Hydro's system planning and response procedures associated with major storms. Toronto Hydro will address each of these topics in order.

Incentive/Variable Compensation

In his commentary, Mr. Cassel requests that the OEB give consideration to mandating that Management employee's variable compensation structures be based on multiple criteria (including maintenance standards, safety record, profit and customer satisfaction and be determined by an independent third party).

As discussed in Exhibit 4A, Tab 4 Schedule 5 of Toronto Hydro's application the utility's "variable performance pay rewards employees for their contribution to the achievement of business goals and objectives tied to the utility's pillars in combination with the successfully demonstrated corporate competencies."[1] In other words, each eligible employee's variable compensation pay depends on their performance relative to specific objectives outlined in their annual performance contracts, and their contribution to a set of departmental and corporate measures, known as the Key Performance Indicators, relating to customer service, operating activities, financial performance and employee

[1] Exhibit 4A, Tab 4 Schedule 5, p.7

health and safety. More information regarding Toronto Hydro's corporate Key Performance Indicators can be found in Toronto Hydro's response to interrogatory 1B-SIA-2.

With respect to Mr. Cassel's suggestions regarding the third-party evaluation of variable compensation amounts for Toronto Hydro's management, the utility notes that it has filed in this proceeding an independent third-party study which benchmarks its compensation and benefits program relative to other energy sector entities, as well as general industry organizations. This study, prepared by Towers Watson, can be found at Exhibit 4A, Tab 4, Schedule 6.

To summarize, Toronto Hydro's variable pay structure is based in part on the individuals' contribution to a broad range of corporate objectives, and is subject to a third-party assessment as part of an overall compensation and benefits benchmarking exercise.

Available Savings and Efficiencies

Toronto Hydro is not in a position to comment on Mr. Dabor's observations regarding Ontario Power Generation (OPG) and its operations. However, the utility notes that in the current application, it has provided a significant amount of evidence regarding efficiency and productivity. This evidence is located at Exhibit 1B, Tab 2, Schedule 5 and includes:

- an econometric total cost benchmarking study prepared by Power System Engineering Inc. that evaluates Toronto Hydro's historical and projected total cost levels against the model-derived efficient cost levels for a utility with Toronto Hydro's business characteristics,
- a past productivity study that details the significant productivity/efficiency efforts undertaken by the utility from the time of Toronto's municipal amalgamation to 201, and

- evidence discussing Toronto Hydro's corporate approach to productivity and performance measurement which contains multiple examples of current and planned initiatives underlying the utility's culture of continuous improvement.

Finally, Toronto Hydro notes that its application is underlined by a custom Price Cap Index formula, which is designed to incent the utility to continuously seek operating efficiencies throughout the remainder of its 2015-2019 plan.

To summarize, Toronto Hydro has advanced a substantive and comprehensive account of its productivity and efficiency accomplishments to date, the reasonableness of its cost forecasts and the key tenets of the utility's productivity and continuous improvement culture.

Storm-Related Investments

In his letter, Mr. Hann raises a number of technical issues pertaining to Toronto Hydro's storm-related system design parameters and operating practices, as well as the specific circumstances surrounding the utility's response to the December 2013 Ice Storm.

Toronto Hydro notes that these issues surrounding major event preparedness and response have been thoroughly canvassed in the Report of the Independent Review Panel filed at Exhibit 4A, Tab 2, Schedule 4, Appendix A.

As stated in the Executive Summary [Exhibit 1A, Tab 2, Schedule 1], over the 2015-2019 timeframe, Toronto Hydro's plans supporting its funding requests include taking a number of steps to enhance its storm-related operational practices and capabilities, including an upgrade of its Outage Management System, enhancements to the damage

assessment activities, outage restoration time estimation practices, and other improvements recommended by the Panel's Report.[2]

In addition, Toronto Hydro's application contains a number of proposed capital investments and maintenance activities that can be expected to improve system performance against extreme weather, as well as to address their respective primary drivers. Among these programs are:

- Overhead Infrastructure Relocation;
- Rear Lot Conversion;
- Box Construction Conversion;
- Feeder Automation;
- Contingency Enhancement;
- Downtown Contingency;
- Design Enhancement; and
- Vegetation Management.

Toronto Hydro assesses that undertaking the above-referenced investments, activities and operating enhancements, and leveraging the practical experience and insights gained from the 2013 December Ice Storm will enable the utility to increase its service levels in future emergency situations.

[2] Exhibit 1A, Tab 2, Schedule 1, pp. 13A-14.

Toronto Hydro 2015-2019 Custom IR Application Roadmap

(Evidence citations are not exhaustive)

RRFE Outcomes View

Worst Performing Feeders (2B,E6.2.1)

Feeder Automation (2B,E7.3)

Customer Focus

Public Policy Responsiveness

Generation Protection, Monitoring & Control (2B, E5.5)

Stakeholdering & Customer Engagement (1B,T2,S7 & 8)

Local Demand Response (2B,E7.10)

Productivity (1B,T02,S05)

RRFE (1B,T2,S2)

Rate Making (1B,T2,S3)

Operational Effectiveness

Financial Performance

Revenue Requirement (E6,T1)

OM&A Planning (4A,T1,S1)

Capital Structure (E5,T1)

ERP (E2B,E3.6)

Program Specific Initiatives (4A, T2)

Evidence Structure View

Rate Calculation View

Cost of Capital

Rate Base

Operating Expenses

Operating Revenue

Revenue Requirement

Cost Allocation & Rate Design

OFFICER'S CERTIFICATE

As the Executive Vice President, Chief Regulatory Officer and General Counsel of Toronto Hydro-Electric System Limited ("Toronto Hydro"), I hereby certify that the evidence submitted in support of Toronto Hydro's 2015-2019 Custom Incentive Rate-setting Application (EB-2014-0116) as filed with the Ontario Energy Board is accurate, consistent and complete to the best of my knowledge.

This certificate is given pursuant to the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (revised July 17, 2013).

DATED this 31st day of July, 2014.

Paul Sommerville
Executive Vice President, Chief Regulatory Officer and General Counsel

Glossary

"Affiliate Relationships Code" or "ARC" refers to the OEB's Affiliate Relationships Code for Electricity Distributors and Transmitters.

"AFUDC" refers to Allowance For Funds Used During Construction.

"AWG" refers to aluminum conductor steel reinforced assets.

"ACM" refers to Asbestos Containing Material.

"ACA" refers to Toronto Hydro's asset condition assessment.

"AFS" refers to Toronto Hydro's audited financial statements

"APH" refers to the OEB's Accounting Procedures Handbook.

"ARO" refer to Asset Retirement Obligation.

"ATS" refers to Automatic Transfer Switches.

"BAS" refers to Building Automation Systems.

"BCE" refers to business case evaluation.

"CAIDI" refers to the Customer Average Interruption Duration Index and is a measure (in hours) of the average duration of interruptions experienced by customers, not including MED. CAIDI represents the quotient obtained by dividing SAIDI by SAIFI.

"Capital Expenditures" or "Capex" refers to expenditures relating to property, plant and equipment and intangible assets.

"Catastrophic Failure" refers to a mode of failure of an electrical distribution component in which incidental damage to other equipment and/or injury to a person

occurs or could occur, in addition to the loss of the electrical distribution function of the component itself. Arc flashes, fires, falling poles, and structural collapse are examples of catastrophic failure. Catastrophic failure is distinguished from failure-by-design and simple failure modes in which a component, such as a fuse, performs according to design to interrupt the flow of electricity.

"CC&B" refers to the Customer Care & Billing system, Toronto Hydro's main customer care interface used for billing and customer information.

"CDM" refers to conservation and demand management.

"CDP" refer to Toronto Hydro's corporate disaster preparedness framework.

"CDS" refers to Cogeco Data Services.

"CEA" refers to the Canadian Electricity Association.

"CEMLC" refers to Commercial Energy Management & Load Control,

"CGAAP" refer to Canadian Generally Accepted Accounting Principles,

"CHI" refers to Customer Hours Interrupted,

"CI" refers to Customer Interruptions.

"CIS" refers to customer information system. Toronto Hydro's current CIS is the CC&B.

"City" refers to the City of Toronto.

"C&I" refers to Commercial and Institutional customers.

"CO" refers to Carbon Monoxide

"CPCP" refers to a Certified Power Cable Person.

"CPLP" refers to a Certified Power Line Person

"CRD" refers to Compact Radial Design assets.

"CWDM" refers to Coarse Wavelength Division Multiplexing.

"CUPE One" or "CUPE" refers to the Canadian Union of Public Employees, Local One

"CWIP" refers to Construction Work In Progress

"DOS" refers to Days Of Service.

"Distribution System Code" or "DSC" refers to the OEB's Distribution System Code.

"DMS" refer to Toronto Hydro's Distribution Management System.

"DRH" refers to the OEB's Electricity Distribution Rate Handbook..

"DST" refers to the Distribution System Technologist.

"DVA" refers to Deferral and Variance Accounts.

"EHS" refers to Environment, Health and Safety.

"EHSMS" refer to the Environmental, Health and Safety Management System.

"Electricity Act" refers to the Electricity Act, 1998, S.O. 1998, c. 15, Sched. A (Ontario), as amended.

"EUSR" refers to the Electrical Utilities Safety Rules.

"ERM" refers to Enterprise Risk Management.

"ERP" refers to an Enterprise Resource Planning system.

"ESQR" refers to Electricity Service Quality Requirements as mandated by the OEB's Distribution System Code.

"FCI" refers to a Faulted Circuit Indicator.

"FESI" refers to Feeders Experiencing Sustained Interruptions.

"Filing Requirements" refers to Chapters 2 and 5 of the OEB Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013).

"FIM" refers to Toronto Hydro's Feeder Investment Model.

"GIS" refers to the Geographical Information System.

"GEAR" refers to the Geospatially Enabled Asset Registry, a geospatial information system used by Toronto Hydro that provides a graphic representation of distribution assets and their relationship to other assets within Toronto Hydro's network.

"GEA" or "Green Energy Act" refers to the Green Energy and Green Economy Act, 2009, S.O. 2009, C. 12 (Ontario), as amended.

"GWh" refers to a gigawatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One GWh is the amount of electricity consumed by one million kWh.

"HST" refer to Harmonized Sales Tax.

"HVAC" refers to Heating, Ventilation, and Air-Conditioning.

"Hydro One" or "HONI" refers to Hydro One Networks Inc.

"IAS" refers to International Accounting Standards.

"IED" refers to an Intelligent Electronic Device.

"IEEE" refers to the Institute of Electrical and Electronic Engineers Inc.

"IESO" refers to the Independent Electricity System Operator.

"IFRS" refers to the International Financial Reporting Standards.

"IHD" refers to an In-Home Display.

"IRRP" refers to the Integrated Regional Resource Plan.

"ISA" refers to an in-service addition of assets to the utility's rate base.

"IT" refers to Information Technology.

"IVR" refer to the Interactive Voice Response technology that assists customers with their account management enquiries by providing updated account balances, payment option information, bill amount predictors and other related tools.

"KPI" refers to Key Performance Indicators.

"kW" refers to a kilowatt, a common measure of electrical power equal to 1,000 Watts.

"kWh" refers to a kilowatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by ten 100 Watt light bulbs burning for one hour.

"LEAP" refers to the financial assistance portion of the OEB's Low-Income Energy Assistance Program.

"LCA" refers to a Life Cycle Analysis.

"LRAM" refers to the Lost Revenue Adjustment Mechanism.

"LRAMVA" refers to the Lost Revenue Adjustment Mechanism Variance Account.

"MED" refers to major event days as defined by Institute of Electrical & Electronic Engineers Inc. specification 1366.

"MCR" refers to the City of Toronto's Municipal Consent Requirements for the Installation of Plant Within City of Toronto Streets.

"mIFRS" or "MIFRS" refers to Modified IFRS.

"MAIFI" refers to the Momentary Average Interruption Frequency Index.

"MW" refers to megawatt, a common measure of electrical power equal to one million watts.

"NBV" refers to Net Book Value.

"NPV" refers to Net Present Value.

"NERC" refers to the North American Electric Reliability Corporation.

"OCCP" refer to the Operational Orders Consolidation Program.

"OEB" refers to the Ontario Energy Board.

"OEM" refers to the Original Equipment Manufacturer.

"OHSA" refers to the Occupational Health and Safety Act, R.S.O. 1990, c. O.1.

"OMERS" refers to the Ontario Municipal Employees Retirement System, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario.

"OMS" refers to Toronto Hydro's Outage Management System.

"OPA" refers to the Ontario Power Authority.

"OSC" refer to the Ontario Securities Commission.

"OTO" refers to Orders to Operate.

"PCT" refers to a Programmable Communicating Thermostat.

"PFA" refers to police, fire and ambulance emergency calls.

"PILs" refers to the Payment In Lieu of Corporate Taxes.

"PILC" refers to Paper-Insulated Lead Cable.

"PPE" refers to Personal Protective Equipment.

"PP&E" refer to Property, Plant and Equipment.

"PSC" refers to a Power System Controller.

"PSE" refers to Power System Engineering Inc.

"RPB" refers to Reverse Power Breakers.

"REG" refers to Renewable Energy Generation.

"RRFE" refers to the OEB's policy for a Renewed Regulatory Framework for Electricity Distributors.

"RRR" refers to the OEB's Reporting & Record Keeping Requirements.

"RSC" refers to the OEB's Retail Settlement Code.

"RTU" refers to a Remote Terminal Unit.

"SAIDI" refers to the System Average Interruption Duration Index and is a measure (in hours) of the annual system average interruption duration for customers served, not

including MED. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

"SAIFI" refers to the System Average Interruption Frequency Index and is a measure of the frequency of service interruptions for customers served, not including MED. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

"SCADA" refers to Supervisory Control and Data Acquisition.

"Smart Meter" refers to a metering device capable of recording and transmitting hourly consumption information of a residential or general service customer.\

"SSS" refers to the OEB Standard Supply Service Code for Electricity Distributors.

"Toronto Hydro" refers to Toronto Hydro-Electric System Limited.

"TOU" refer to Time of Use billing practices

"Transmission System Code" or "TSC" refers to the OEB's Transmission System Code.

"TRC" refers to Total Resource Cost.

"TSSA" refers to the Technical Standards and Safety Authority.

"URD" refers to Underground Residential Distribution.

"USGAAP" refers to United States Generally Accepted Accounting Principles.

"USL" refer to the Unmetered Scattered Load rate class.

"USofA" refers to the Uniform System of Accounts set out in the Accounting Procedures Handbook.

“WCA” refers to the Working Capital Allowance.

“Watt” or “W” refers to a common measure of electrical power. One Watt equals the power used when one ampere of current flows through an electrical circuit with a potential of one volt.

“WMS” refer to the Warehouse Management System.

“WSIB” refers to the Workplace Safety and Insurance Board.

DISCLAIMER

The information in these materials is provided to the OEB for the purpose of presenting the OEB with Toronto Hydro's electricity distribution rates application pursuant to the OEB's Custom Incentive Rate-Setting framework (the "Application"). Toronto Hydro does not warrant the accuracy, reliability, completeness or timeliness of the information and undertakes no obligation to revise or update these materials, except as required for purposes of providing new information that represents a material change to the evidentiary record in the Application before the OEB. Toronto Hydro (including its directors, officers, employees, agents and subcontractors) hereby waives any and all liability for damages of whatever kind and nature which may occur or be suffered as a result of the use of these materials or reliance on the information therein.

These materials may also contain forward-looking information within the meaning of applicable securities laws in Canada ("Forward-Looking Information"). The purpose of the Forward-Looking Information is to provide Toronto Hydro's expectations and future requirements for 2015 through 2019, and may not be appropriate for other purposes. All Forward-Looking Information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "aims", "anticipates", "believes", "budgets", "committed", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "strives", "will", "would" and similar expressions are often intended to identify Forward-Looking Information, although not all Forward-Looking Information contains these identifying words.

The Forward-Looking Information reflects the current beliefs of, and is based on information currently available to, Toronto Hydro's management. The Forward-Looking Information in these materials includes, but is not limited to, statements regarding Toronto Hydro's future results and performance, as well as expected nature, timing and cost of capital and operational programs. The statements that make up the Forward-Looking Information are based on assumptions that include, but are not limited to, expected load and customer growth, externally driven plant relocation requests, estimated project costs, receipt of applicable regulatory approvals and requested rate orders. The Forward-Looking Information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the Forward-Looking Information. The factors which could cause results or events to differ from current expectations include, but are not limited to, the rate of deterioration of Toronto Hydro's assets, weather and environmental factors, unexpected increases or decreases in load and customer growth, differences between estimated and actual project costs, project delay due to factors beyond the control of Toronto Hydro's management, and legislative, judicial or regulatory developments that could affect Toronto Hydro's ability to meet the goals set out in this application. Toronto Hydro cautions that this list of factors is not exclusive.

All Forward-Looking Information in these materials is qualified in its entirety by the above cautionary statements, except as required by law, or by the OEB for the purposes of the Application. Toronto Hydro undertakes no obligation to revise or update any Forward-Looking Information as a result of new information, future events or otherwise after the date hereof, except as required under securities laws, or by the OEB for the purposes of the Application.

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, Schedule B to the *Energy Competition Act, 1998*, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Toronto Hydro-Electric System Limited for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2015 to December 31, 2019.

The Applicant, Toronto Hydro-Electric System Limited (referred to in this application as the "Applicant, "Toronto Hydro", "THESL", the "Company" or the "Utility"), is a corporation incorporated under the *Business Corporations Act*, (Ontario), and is licensed by the Ontario Energy Board (the "OEB") under licence number ED-2002-0497 to distribute electricity in the City of Toronto.

Toronto Hydro hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") as amended, for approval of its proposed

1) electricity distribution rates and other charges effective May 1, 2015; and
2) custom Price Cap Index ("Custom PCI") framework to set distribution rates effective for the period January 1, 2016 to December 31, 2019, and the rates and charges resulting from it.

This application is prepared in accordance with the following OEB documents:

1) Filing Requirements for Electricity Distribution Rate Applications issued by the OEB on November 14, 2006 under file number EB-2006-0170, and updated on July 17, 2013 (the "Filing Requirements"); and

2) Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance - Based Approach, issued by the OEB on October 18, 2012 under file numbers EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004 (the "RRFE Report").

This application is supported by pre-filed written evidence, which may be amended from time to time, prior to the OEB's final decision on this application.

I. FORM OF HEARING REQUESTED

Toronto Hydro requests that this application be disposed of by way of an oral hearing.

II. PROPOSED EFFECTIVE DATE

The applicant requests that the OEB make its Rate Order effective May 1, 2015, notwithstanding that the OEB's Decision with Reasons approving or fixing these rates and other charges may not be delivered until after that date. In the alternative, the Applicant requests an interim Order making the Applicant's current distribution rates and charges effective on an interim basis as of May 1, 2015 and establishing an account to recover any differences between the interim rates and the actual rates effective May 1, 2015 based on the OEB's Decision and Order.

III. PROPOSED DISTRIBUTION RATES AND OTHER CHARGES

The Tariff of Rates and Charges proposed in this application is identified in Exhibit 8, Tab 3, Schedule 3. In addition to the evidence in support of those rates and charges for 2015 test year, Toronto Hydro also files with this application evidence in support of its Custom Incentive Rate-Setting ("Custom IR" or "CIR") framework and the rates resulting from it.

IV. PROPOSED DISTRIBUTION RATES ARE JUST AND REASONABLE

For all the reason set out in this application. Toronto Hydro submits that the proposed distribution rates and other charges are just and reasonable.

V. SPECIFIC RELIEF REQUESTED

With this application, Toronto Hydro requests:

1) Approval of 2015 base revenue requirement as proposed in Exhibit 6, Tab 1. For greater clarity, this includes:

a) cost of capital and debt to fund rate base, as set out in Exhibit 2A;
b) revenue offset forecasts, as set out in Exhibit 3, Tab 2; and
c) operations, maintenance and administration expenses, as set out in Exhibit 4A,
d) a depreciation expense, as set out in Exhibit 4B, Tab 1; and
e) payments in lieu of taxes, as set out in Exhibit 4B, Tab 2;

2) Approval of 2015 electricity distribution rates and charges as proposed in Exhibit 8, including a number of credits to customers. In particular:

a) base distribution rates as set out in Exhibit 8, Tab 1, Schedule 1;
b) rate riders as set out in Exhibit 9, Tab 3, Schedule 1; and
c) Specific Service Charges as set out in Exhibit 8, Tab 2, Schedule 1.

3) Approvals related to deferral and variance accounts as proposed in Exhibit 9. In particular:

a) to dispose of balances in existing deferral and variance accounts as at December 31, 2013 as detailed in Exhibit 9, Tab 1, Schedule 1;

b) approval of the continuation of existing deferral and variance accounts, as set out in Exhibit 9, Tab 1, Schedule 1;

c) relief from having to record amounts to Retailer Cost Variance Accounts as set out in Exhibit 9, Tab 1, Schedule 1; and

d) approval of four new deferral and variance accounts as proposed in Exhibit 9, Tab 1, Schedule 1: /C

   i) a variance account in respect of externally-initiated plant relocations and expansions;

   ii) a variance account in respect of derecognition losses;

   iii) a variance account to record the difference between the actual costs of approved eligible investments and the revenue received from the IESO relating to Provincial Rate Protection amounts; and

   iv) a deferral account in respect of costs and savings related to the mandatory transitioning of certain customers to monthly billing. /C

4) Approval of the rate-setting formula and related elements, as proposed in Exhibit 1B, Tab 2, Schedule 3.

5) Approval to implement rate year synchronization effective January 1, 2016, as proposed in Exhibit 8, Tab 1, Schedule 1.

6) Approval of annual reporting as proposed in Exhibit 1B, Tab 2, Schedule 6;

7) Deferral of the Incremental Capital Module true-up from EB-2012-0064, and approval to bring forward a separate application in 2015 as proposed in Exhibit 2A, Tab 9, Schedule 1.

8) Other items or amounts that may be requested by the Applicant in the course of the proceeding, and such other relief or entitlements as the OEB may grant.

DATED at Toronto, Ontario, this 13 day of February, 2015. **/C**

Applicant: **TORONTO HYDRO-ELECTRIC SYSTEM LIMITED** ("Toronto Hydro")

14 Carlton Street
Toronto, Ontario
M5B 1K5

Signed by:

Daliana Coban, Lead Regulatory Counsel **/C**

- Appendix to Legal Application -

Title of Proceeding:	An Application by TORONTO HYDRO-ELECTRIC SYSTEM LIMITED for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2015 to December 31, 2019.
Applicant's Name:	Toronto Hydro-Electric System Limited ("THESL")
Application Address:	14 Carlton Street Toronto, Ontario M5B 1K5
Applicant's Counsels:	Charles Keizer, Torys LLP, LSUC# 34135D Crawford Smith, Torys LLP, LSUC# 42131S Daliana Coban, THESL, LSUC# 62139A
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2015 – 2019 CUSTOM IR FRAMEWORK INTRODUCTION

The purpose of this schedule is to provide a brief overview of the documents contained in the Exhibit 1B, Tab 2, which describe the key elements of Toronto Hydro's Custom Incentive Rate-Setting (Custom IR) application. The evidence sets out Toronto Hydro's proposal for and justification of the Custom IR framework underlying this application, and provides references to other supporting evidence throughout the Application.

Exhibit 1B, Tab 2 consists of eight schedules:

1) Schedule 1, Introduction (this document)
2) Schedule 2, Alignment with OEB Guidance: Describes how Toronto Hydro's Custom IR application aligns with the OEB's guidance in the Renewed Regulatory Framework for Electricity (RRFE) report and Chapters 2 and 5 of the Filing Requirements for Electricity Distribution Rate applications.
3) Schedule 3, Rate Framework: Details Toronto Hydro's proposed rate-setting framework , including the custom Price Cap Index approach to setting rates for the 2016-2019 period, following the establishment of 2015 base rates through a traditional test year approach.
4) Schedule 4, Capital Investment (and Appendices): Provides an overview of Toronto Hydro's Distribution System Plan (DSP), the utility's approach to capital planning, and Toronto Hydro's operating environment, which presents certain planning and work execution challenges. This schedule also includes a third-party review of Toronto Hydro's DSP, performed by Navigant Consulting Inc. (Navigant).
5) Schedule 5, Efficiency, Productivity and Continuous Improvement (and Appendices): Centralizes Toronto Hydro's evidence in support of the adequacy of its past and future productivity levels, describes Toronto Hydro's approaches to performance measurement and continuous improvements, and provides references

to other parts of the application where productivity and efficiency initiatives are described in more detail. This schedule also includes a third-party econometric benchmarking study of Toronto Hydro's total costs and reliability conducted by Power System Engineering Inc. (PSE).

6) Schedule 6, Annual Reporting: Provides information about the scope and manner of the annual reporting activities that Toronto Hydro proposes to undertake over the 2015-2019 Custom IR period.
7) Schedule 7, Customer Engagement (and Appendices): Details the utility's approach to customer engagement both in the ordinary course of its operations, as well as for this application, particularly relating to the DSP.
8) Schedule 8, Stakeholder Consultation (and Appendices): Describes Toronto Hydro's approach to, and results of, the stakeholdering activities undertaken in preparing this application.

ALIGNMENT WITH OEB GUIDANCE

1. OVERVIEW

The purpose of this schedule is to describe how Toronto Hydro's 2015-2019 Custom Incentive Rate-Setting ("Custom IR" or "CIR") application aligns with the Ontario Energy Board's ("OEB") guidance contained within the Renewed Regulatory Framework for Electricity Distributors, and the Filing Requirements (together, "OEB Guidance").

Specifically, in preparing this application, Toronto Hydro has considered the tenets of the Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" issued October 18, 2012 (the "RRFE Report"), as well as Chapters 2 and 5 of the OEB's Filing Requirements for Electricity Distribution Rate applications issued July 17, 2013 (the "Filing Requirements").

Toronto Hydro has applied this approach understanding that aside from Chapter 5 of the Filing Requirements, there are no specific filing requirements for the CIR applicants. However, and as discussed in more detail below, Toronto Hydro's view is that the RRFE Report clearly conveys a number of key policy and mechanistic/administrative components of the OEB's expectations for CIR applications. These include the form of the rate-setting mechanism, areas of focus for the enquiry, and the scope and nature of evidence filed in support of the applications.

Toronto Hydro's view is that, in addition to substantive reasons to follow OEB Guidance, doing so also aids in the utility's application being accessible and digestible to the OEB, intervenors and the public. In particular, Toronto Hydro's Custom IR application aligns with OEB Guidance as follows:

1) The mechanism of the CIR Rate-Setting Framework;
2) The scope and nature of productivity evidence, including benchmarking;

3) Capital planning and implementation performance measures;
4) Evidence of customer engagement on the proposed capital investments;
5) A Distribution System Plan ("DSP") that conforms to Chapter 5 of Filing Requirements;
6) A program-based presentation of the Capital, Maintenance & Administration ("OM&A") expenditures; and
7) General adherence to Chapter 2 of the Filing Requirements.

Table 1 below provides a brief overview of these seven aspects.

Table 1: OEB Guidance Addressed in Toronto Hydro's 2015-2019 CIR Application

	OEB Guidance	Toronto Hydro's 2015-2019 CIR Application	Evidence Reference
1	A Custom Index rate-setting model, incorporating benefit-sharing through a Productivity Factor and a Stretch Factor, using the OEB's Inflation and Productivity analysis.[3]	OEB Guidance Addressed. The Application is based on a Custom Index rate-setting approach, incorporating the elements of the OEB's PCI framework, and the results of the OEB's inflation and productivity analysis.	Exhibit 1B, Tab 2, Schedule 3. Exhibit 1B, Tab 2, Schedule 5.
2	CIR productivity evidence should enable a sufficiently rigorous assessment of adequacy of the past and future productivity levels.[4] CIR applicants are expected to provide benchmarking evidence in support of reasonableness of their cost forecasts.[5]	OEB Guidance Addressed. The application includes a review of the utility's past productivity achievements, a Custom Total Cost and Reliability Econometric Benchmarking study, along with specific examples of current and anticipated productivity/efficiency initiatives and the utility's	Exhibit 1B, Tab 2, Schedule 5, and Appendices.

[3] RRFE Report at page 13.
[4] RRFE Report at page 70.
[5] RRFE Report at page 13, Table 1.

	OEB Guidance	Toronto Hydro's 2015-2019 CIR Application	Evidence Reference
		corporate culture of productivity.	
3	DSP filings must be supported by Performance Measures covering Customer-Oriented Performance, Cost Efficiency / Effectiveness of Planning and Implementation, and Asset / System Performance.[6]	OEB Guidance Addressed. Toronto Hydro's DSP includes 12 capital performance measures that the utility proposes to track and report on over the CIR timeframe. The measures address all three specific OEB-mandated categories.	Exhibit 2B, Section C.
4	Applications must showcase the applicants' efforts to engage their customers on their capital plans and planning processes.[7]	OEB Guidance Addressed. Toronto Hydro's application details the steps taken by the utility to engage its customers on the proposed DSP, along with the results of these engagements.	Exhibit 1B, Tab 2 Schedule 7
5	CIR applicants are required to file a DSP as specified in Chapter 5 of the OEB's Filing Requirements.[8]	OEB Guidance Addressed. Toronto Hydro's DSP has been prepared according to the Chapter 5 requirements.	Exhibit 2B and Appendices.
6	Applicants should showcase their year over year variance analyses based on their OM&A programs.[9]	OEB Guidance Addressed. Toronto Hydro Historical, Bridge and Test Year OM&A expenditures are presented on a	Exhibit 4A.

[6] Filing Requirements, Chapter 5 at page 11, section 5.2.3.
[7] Filing Requirements, Chapter 5 at page 15, section 5.4.2.
[8] Filing Requirements, Chapter 5 at page 7, section 5.1.3.
[9] Filing Requirements, Chapter 2 at page 27, section 2.7.

	OEB Guidance	Toronto Hydro's 2015-2019 CIR Application	Evidence Reference
		program basis.	
7	The Cost of Service Filing Requirements are relevant for Custom IR filers.[10]	OEB Guidance Addressed. Toronto Hydro's application for the 2015 Test Year is sufficiently compliant with the Chapter 2 Filing Requirements.	Exhibit 1A, Tab 3, Schedule 2 All Exhibits.

The remainder of this schedule discusses each of the above-noted elements of the RRFE guidance and the manner in which Toronto Hydro's 2015-2019 CIR application reflects this guidance in more detail. Toronto Hydro's evidence for the 2015-2019 CIR application addresses each of the above-noted OEB expectations.

2. CIR RATE-SETTING FRAMEWORK

2.1. OEB Expectations

In the RRFE Report, the OEB notes its expectation that the form of the CIR applications is to be that of a "Custom Index", covering Capital and OM&A expenditures, supplemented with a Productivity Factor, and a benefit-sharing mechanism in the form of a Stretch Factor or another construct determined on a case-by-case basis.[12]

The RRFE Report also notes that a distributor's rate trend will be set on the basis of a combination of:

- A distributor's cost, inflation and productivity forecasts;
- The OEB's productivity analysis; and
- Benchmarking to assess the reasonableness of a distributor's forecasts.

[10] RRFE Report at page 70.
[12] RRFE Report at page 13.

2.2. Toronto Hydro's Approach

As detailed in Exhibit 1B, Tab 2, Schedule 3 and 4, Toronto Hydro's proposed rate-setting model for the 2015-2019 CIR application addresses each of the above-noted OEB expectations. In particular, the utility's rate-setting model entails:

- (a) a forward test year rebasing approach to establish the 2015 Revenue Requirement and base rates; and
- (b) a Custom Index proposal for rate adjustments over the 2016-2019 period.

The Custom Index incorporates the OEB's long-standing Price Cap Index ("PCI") approach for the escalation of the OM&A portion of the 2015 Revenue Requirement over the out-years, augmented by a Custom Capital Factor ("CCF" or "C-factor") to account for the costs of forecasted capital additions over the 2016-2019 years.

The proposed Custom Index rate adjustment mechanism covers both OM&A and capital expenditures, and provides for sharing of benefits of efficiency and productivity improvements incented through the PCI framework with Toronto Hydro's customers. The values for the Inflation and Productivity Factors in the proposed Custom Index will be set on the basis of the OEB's analysis contemplated under the 4th Generation IR rate adjustment framework. Toronto Hydro proposes a custom stretch factor that will apply the OEB's methodology, but will be set on the basis of benchmarking evidence that Toronto Hydro has filed at Exhibit 1B, Tab 2, Schedule 5 in support of the reasonableness of its cost forecasts.

Toronto Hydro submits that the proposed rate-setting framework meets the OEB's expectations as to the form, function and outcomes of the CIR rate-setting framework.

3. PRODUCTIVITY EVIDENCE AND BENCHMARKING

3.1. OEB Expectations

The RRFE Report indicates the OEB's expectation that Custom IR applications will enable "an assessment of the adequacy of past and future productivity levels."[13] Elsewhere in the RRFE Report, the OEB states that it expects to use benchmarking evidence "to assess the reasonableness of the distributor's forecasts."[14]

3.2. Toronto Hydro's Approach

As detailed in Exhibit 1B, Tab 2, Schedule 5 and the associated Appendices, Toronto Hydro's evidence for the 2015-2019 CIR application addresses each of the above-noted OEB expectations. In particular, Toronto Hydro's evidence contains a detailed description of the utility's past and future productivity levels, as well as the reasonableness of the utility's 2015-2019 cost forecasts. The evidence also outlines the features of the proposed CIR rate-setting framework and its supporting elements, which in Toronto Hydro's submission, provide sufficient incentives for the utility to seek further productivity and efficiency improvements over the CIR timeframe, and to share the benefits of these improvements with its customers.

In support of the adequacy of Toronto Hydro's past and future productivity levels are: (i) a Review of Past Productivity Initiatives that recaps and quantifies, at a high level, the utility's productivity improvements since the time of Toronto Hydro's amalgamation; and (ii) a comprehensive Total Cost Econometric Benchmarking Study, evaluating the efficiency of Toronto Hydro's past and forecasted expenditures against a large sample of electric utilities in Ontario and the United States.

[13] RRFE Report at page 70.
[14] RRFE Report at page 13, Table 1.

In addition, Toronto Hydro's DSP (Exhibit 2B, Section C) contains a framework of capital performance metrics that the utility proposes to track over the CIR timeframe, consistent with section 5.1.3 in the Chapter 5 Filing Requirements. By monitoring its performance, Toronto Hydro expects to facilitate continuous improvement in the efficiency of execution in respect of capital additions and related costs.

Finally, Toronto Hydro's productivity and efficiency evidence provides specific examples of initiatives that utility is in the process of implementing, or expects to introduce over the CIR rate period.

4. PERFORMANCE MEASURES AND METRICS

4.1. OEB Expectations

Section 5.2.3 in Chapter 5 of the Filing Requirements notes the OEB's expectation for utilities to identify qualitative and quantitative measures and metrics to assess the performance of their capital planning and implementation practices as a part of their DSP filing. The Chapter 5 Filing Requirements specifically break down the measures that the utilities are expected to provide into three categories, namely:

- Customer-Oriented Performance;
- Cost Efficiency of Planning Quality and Implementation; and
- Asset / System Operation Performance.[15]

More generally, Performance Measurement and Continuous Improvement section of the RRFE Report, the OEB notes the expectation that,

> Under the renewed regulatory framework, a distributor will be expected to continuously improve its understanding of the needs and expectations of its

[15] Filing Requirements, Chapter 5 at page 11, section 5.2.3.

customers and its delivery of services, which in turn can lead to reduced costs for customers.[16]

4.2. Toronto Hydro's Approach

Exhibit 1B, Tab 2, Schedule 5 addresses each of the above-noted OEB expectations. In Toronto Hydro's assessment, the objectives of understanding customer needs and improving service delivery processes are best supported by quantitative performance measurement tools and processes. In evidence, Toronto Hydro accordingly showcases a number of activity-specific performance measures that the utility has put in place or plans to develop and refine over the 2015-2019 timeframe.

More specifically, in accordance with the section 5.2.3 in the Chapter 5 Filing Requirements, Section C of Toronto Hydro's DSP provides a framework of 12 performance measures related specifically to capital performance. Along with the Efficiency/Productivity measures discussed in the previous section, the proposed performance measurement framework includes measures of Customer-Oriented Performance and Asset and System Operational Performance, thereby addressing all three measure categories outlined in the Chapter 5 Filing Requirements. The proposed measures include advanced reliability measures such as Momentary Average Interruption Frequency Index ("MAIFI"), and Feeders Experiencing Sustained Interruptions ("FESI").

[16] RRFE Report at page 55.

5. CUSTOMER ENGAGEMENT ON PROPOSED CAPITAL INVESTMENTS

5.1. OEB Expectations

Section 5.4.2 in the Chapter 5 Filing Requirements expresses the OEB's expectations that the applicants' DSP submissions be supported by information related to the distributors' efforts to engage their customers on various facets of their capital planning processes. In particular, the OEB states that distributors should provide details regarding the approach they use "to engage customers for the purpose of identifying their needs, priorities and preferences", and "the aspects of the DSP that have been particularly affected by consideration of that information."[17]

5.2. Toronto Hydro's Approach

Exhibit 1B, Tab 2 Schedule 7 of Toronto Hydro's evidence for the 2015-2019 CIR application addresses each of the above-noted OEB expectations. To facilitate customer dialogue and input, the utility developed a series of comprehensive workbooks containing customer-friendly explanations of the components of Toronto Hydro's distribution system, key issues facing its asset base, and draft plans as to how to address these issues. The workbooks were tailored specifically towards different subsets of the utility's customers (e.g., residential and commercial), and contain a range of customer class-specific specific questions seeking feedback on the information presented in the workbook. Toronto Hydro posted its workbooks on its website and advertised them through a number of channels.

In addition to generating and seeking online feedback on its workbook, Toronto Hydro (with the assistance of its external consultant) undertook a series of focus group sessions with representatives of different customer classes, supplementing these activities with an

[17] Filing Requirements, Chapter 5 at page 15, section 5.4.2.

on-line questionnaire and a tele-survey. The evidence at Exhibit 1B, Tab 2, Schedule 7 discusses the results of these and other related customer engagement activities, and explains how the insights gained through this work relate to the utility's planned work program.

6. CAPITAL AND DISTRIBUTION SYSTEM PLAN

6.1. OEB Expectations

The RRFE Report clearly states that the OEB's expectations with respect to the nature and content of a distributor's DSP and applicable supporting materials are set out in Chapter 5 of the Filing Requirements.[19] Among other things, the Chapter 5 Filing Requirements oblige a distributor to outline its capital planning objectives; the criteria used for planning; processes used to identify and implement alternatives; and tools and processes used to identify, select, prioritize and pace the proposed expenditures.

6.2. Toronto Hydro's Approach

Toronto Hydro's DSP, filed at Exhibit 2B of this application, addresses the above-noted OEB expectations. Each proposed capital program identified in the DSP is supported by a detailed Business Case justification that provides the following information:

- A description of the proposed capital program and its purpose;
- Primary and secondary drivers for the investments (consistent with the guidance in the Chapter 5 Filing Requirements);
- Asset lifecycle information and failure impacts (where applicable);
- Approach to the timing and pacing of investments;
- Description of program benefits, including customer value;
- Program execution approach and mitigation of associated risks; and
- Other pertinent information.

[19] RRFE Report at page 52.

For all of the applicable distribution plant programs, the DSP also includes a benefit calculation of undertaking the investments performed by the utility's Feeder Investment Model ("FIM"). The FIM received a positive review from the OEB in Toronto Hydro's Incremental Capital Module ("ICM") application[20]:

> The Board finds that the FIM is a useful tool to compare the financial consequences of failure of aging assets to the benefits of delaying the work and to assess capital spending associated with replacement by extending service life as long as possible.

A comprehensive discussion of Toronto Hydro's approach to asset management, capital planning and execution, that is responsive to specific requirements previously mentioned, supports the individual Business Cases in the DSP. Toronto Hydro submits that the scope and level of detail contained within the DSP provides the OEB valuable insight into the utility's capital planning and execution processes. Toronto Hydro's DSP also provides empirical support as to the need of proposed capital investments, along with information of the customer-oriented, utility-specific, and public policy outcomes underlying each proposed capital program.

7. OM&A EVIDENCE

7.1. OEB Expectations

As discussed in Chapter 2 of the Filing Requirements, the OEB is moving towards a program-focused review of the applicants' OM&A expenditures,[21] and expects applicants to present their OM&A variance analyses and other related information in a program-based format to facilitate this transition.

[20] EB-2012-0064, Partial Decision and Order (April 2, 2013) at page 21.
[21] Filing Requirements, Chapter 2 at page 27, section 2.7.

7.2. Toronto Hydro's Approach

Toronto Hydro's OM&A evidence at Exhibit 4, Tab 2 addresses each of the above-noted OEB expectations. Specifically, the evidence provides a program-based view of the utility's historical and forecast OM&A expenditures, describes each program and its main objectives, justifies the Historical, Bridge, and Test Year expenditures, and discusses notable improvements in the areas of productivity, efficiency and service delivery. Toronto Hydro's general approach in preparing the OM&A evidence was to thoroughly explain the activities and functions comprising each program, and highlight their value to customers and the utility.

8. OEB FILING REQUIREMENTS

8.1. OEB Expectations

The RRFE Report conveys the OEB's expectation that "much of the material in Cost of Service Filing Requirements will be relevant for Custom IR filers."[22] Elsewhere in the RRFE Report, the OEB mentions that it sees merit in receiving the evidence of third-party experts while reviewing the applications under the RRFE, particularly in the area of distribution system planning.[23]

8.2. Toronto Hydro's Approach

In preparing this application, Toronto Hydro followed the Filing Requirements (where practicable and possible), in order to provide the OEB visibility into the utility's rate application in a familiar format that aids accessibility and provides the OEB a detailed view of the utility's operations and plans. Specifically, to support its evidence, Toronto Hydro has completed all the relevant Excel-based OEB appendices. Beyond the 2015 Test Year, Toronto Hydro's CIR application provides the OEB with insight into the

[22] RRFE Report at page 70.
[23] RRFE Report at page 37.

utility's proposed 2016-2019 capital expenditures to enable the determination of need and other relevant considerations, and to support the calculation of the Custom Capital Factor as proposed in the Exhibit 1B, Tab 2, Schedules 3 and 4.

Toronto Hydro's DSP is supported by a third-party review of the proposed investments and overall capital planning approaches and tools. This review was performed by Navigant and a copy of the report is filed as an Appendix to Exhibit 1B, Tab 2, Schedule 4. In addition to the Navigant Report, this application contains a number of other third-party assessments and evaluations of Toronto Hydro's operations and proposed plans.

RATE FRAMEWORK

This schedule describes the rate framework that Toronto Hydro proposes to apply for the 2015 to 2019 period.

Toronto Hydro submits that the proposed rate framework is:

- Concordant with OEB policy, and in particular with the objectives and guidance set out in the Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" issued on October 8, 2012 (the "RRFE Report");
- Based on sound ratemaking principles; and,
- Expected to provide funding that:
  - Reconciles Toronto Hydro's significant, multi-year investment needs; and,
  - Constrains operational funding increases going forward at less than the rate of inflation.

1. SUMMARY

To better conform to the OEB's Guidance for CIR applicants, Toronto Hydro is proposing a rate framework that is a modification of the standard 4th Generation IR approach.

Year 1 is a traditional rebasing year, with costs allocated and rates set on the basis of a forecast Test Year.

Distribution rates in Years 2 through 5 are adjusted annually by a custom Price Cap Index ("PCI"):

$$PCI = I - X + C$$

Where,

- "**I**" is the OEB's inflation factor, determined annually **/C**
- "**X**" is the sum of:
  - The Board's productivity factor.
  - Toronto Hydro's custom stretch factor.
- "**C**" provides funds incremental to "I – X" that are necessary to reconcile Toronto Hydro's capital need within a PCI framework.

Toronto Hydro submits that the proposed framework is concordant with OEB policy in the following respects:

- The proposed rate framework is comprehensive.
- The proposed rate framework is informed by Toronto Hydro's forecasts.
- The proposed rate framework is informed by the OEB's inflation and productivity analyses.
- The proposed rate framework is informed by benchmarking to assess the reasonableness of the Toronto Hydro's forecasts.
- The proposed rate framework includes a productivity and stretch factor.
- The proposed rate framework covers the entirety of the application's five year term.

In this way, Toronto Hydro is proposing a rate framework that differs from previous CIR filers.

2. YEAR 1: STANDARD REBASING

The first year of the proposed rate application is a standard rebasing year, consistent with the OEB's 4th Generation Incentive Rate-Setting ("4th Generation IR") approach.

Toronto Hydro developed and submitted in this application a forecast of its base revenue requirement for 2015. The utility developed forecasts of its costs based on its capital and operational plans for 2015. The Distribution System Plan ("DSP") and Operations, Maintenance & Administration ("OM&A") evidence contained in Exhibits 2B and 4A, respectively, provides the details supporting these projected costs. The calculated revenue requirement resulting from these projections is detailed in the Revenue Requirement evidence filed at Exhibit 6.

Similarly, Toronto Hydro employed the OEB's Cost Allocation model to allocate the revenue requirement to its eight rate classes and developed base distribution rates for each class. The standard rebasing approach maintains revenue-to-cost ratios for each class within the boundaries set out in the OEB's 2011 Review of Electricity Cost Allocation Policy.[1] For more information about Cost Allocation and Rate Design, please refer to Exhibits 7 and 8, respectively.

In addition to the base distribution rates, Toronto Hydro is applying to clear a number of Deferral and Variance accounts. Based on the values Toronto Hydro proposed for clearance, a number of new rate riders are proposed. These rate riders are proposed to be implemented beginning in 2015, and have various clearance time-frames. For more information about these rate riders, please refer to Exhibit 9, Tab 3.

3. YEARS 2 TO 5: CUSTOM PCI

Under 4th Generation IR, the years following a rebasing year constitute a period where distribution rates are subject to an incentive rate mechanism ("IRM"). The IRM is a formulaic approach to rate making under which distribution rates are adjusted annually using a two-component PCI:

[1] EB-2010-0219

$$PCI = I - X$$

The I-factor is intended to reflect changes to the input prices faced by the industry (i.e., inflation), while the X-factor is intended to capture changes in the productivity of the Ontario electricity distribution industry as a whole, and differences between utilities within it.

In the RRFE Report, the OEB offers alternative forms of rate making "to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant."[2] The OEB notes that the CIR option in particular "will be most appropriate for distributors with significant large multi-year… investment commitments that exceed historical levels," whereas 4th Generation IR is more suitable for utilities with "some" incremental needs.[3] The evidence at Exhibit 1B, Tab 2, Schedule 4 and the Distribution System Plan at Exhibit 2B discuss Toronto Hydro's capital investment needs and, by extension, the appropriateness of the CIR option in greater detail.

A challenge for CIR applicants like Toronto Hydro is to reconcile their significantly large, multi-year investment commitments with a framework that concords with RRFE guidance. To this end, Toronto Hydro proposes that these needs be reconciled within a custom PCI framework that entrenches the OEB's inflation and productivity factors within a formulaic approach to adjusting distribution rates.

The following subsections discuss the retention of the inflation and productivity factors and the inclusion of the customized elements of the proposed PCI formula.

[2] RRFE Report at page 9.
[3] RRFE Report at page 14.

3.1. Inflation and Productivity Factors

In 2013, the OEB updated its standard rate adjustment parameters following a consultation process that explicitly considered:[5]

1) The development of a more Ontario-specific inflation factor;
2) The estimation of long-run Ontario electricity distribution total factor productivity ("TFP"); and,
3) The development and implementation of total cost benchmarking.

The OEB decided on a new methodology for the I-factor. The I-factor is based on a 30/70 weighting of labour and non-labour sub-indices and is updated annually. The labour sub-index is determined by changes in the average weekly earnings of Ontario workers, and the non-labour sub-index is determined by changes in the Canada Gross Domestic Product Implicit Price Index for final domestic demand.

Toronto Hydro proposes to use the OEB's I-factor in its custom PCI. As the value for the I-factor is updated annually, Toronto Hydro will incorporate the value into its custom PCI to appropriately adjust base distribution rates for the following year.

The productivity factor, one of the two X-factor components, was also updated. The productivity factor is intended to estimate the overall trend in the productivity of the electricity distribution industry in Ontario by measuring changes in TFP, defined by Pacific Economics Group as a "comprehensive measure of the extent to which firms convert inputs into outputs."[7] TFP can change over time for a number of reasons, such as change in technology, achievement in economies of scale and overall improvements in efficiency.

[5] EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario Electricity Distributors (December 20, 2013) [the "OEB Rate Setting Parameters Report"].
[7] Pacific Economics Group (2013), Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario, (corrected January 24, 2014) at page 12 [the "PEG Report"].

In its report, PEG used an indexing method to estimate TFP for the Ontario distribution sector based on data from the 2002 to 2012 period.[9] This sample excluded the experience of both Toronto Hydro and Hydro One because, as a result of their large size relative to the rest of the industry, PEG determined that they were exerting a disproportionate impact on industry TFP.[10] Toronto Hydro presumes that this principle would have held if one or both had outperformed the sector on TFP.

The result of PEG's analysis that excluded both utilities suggested that industry TFP over that period grew at an average annual rate of -0.33%. That is, TFP for sector actually declined over that period. As PEG noted, not only are negative productivity factors a "theoretical possibility", it cited multiple examples of negative productivity factors in other western democracies. The Australian experience in the early 2000s is of particular interest given that negative productivity factors occurred at a time when utilities "were undertaking extensive capital investment programs," which is the state that Toronto Hydro is currently operating in.

In alignment with PEG's recommendation, the OEB ultimately adopted a zero productivity factor as a matter of policy. In Toronto Hydro's view, any departure from the value produced by the methodology chosen to produce the productivity factor represents an implicit "stretch" to the sector. In this case, the sector is expected to achieve an additional 0.33 percentage points of productivity gains relative to the sector's overall trend in TFP. This is not an immaterial amount, particularly for a utility with the capital requirements of Toronto Hydro.

Nevertheless, Toronto Hydro notes that the OEB is very clear in its guidance to applicants that its productivity factor be part of a CIR rate framework. Accordingly,

[9] PEG suggests that a 10-year horizon is the minimum required for TFP Indexing.
[10] PEG Report, supra note 5 at page 4.

Toronto Hydro proposes to embed the OEB's productivity with its implicit incremental stretch factor unchanged within the proposed custom PCI. /C

3.2. Custom Stretch Factor

The second component of the X-factor is an explicit stretch factor. According to the OEB, "Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend."[8] Under the current methodology, which was updated most recently in 2013, utilities are assigned one of five stretch factors. This occurs on the basis of a comparison of the utility's total costs relative to their predicted total costs. The predicted total costs are determined using a total cost econometric model developed by PEG.[9]

As part of this application, Toronto Hydro is submitting alternative total cost benchmarking, the details of which can be found in the Power System Engineering's Econometric Benchmarking Report, at Exhibit 1B, Tab 2, Schedule 5 (the "PSE Report"). The alternative total cost benchmarking model prepared by PSE for Toronto Hydro is econometric in nature (similar to PEG's model) and includes an expanded data set. The results are statistically significant and relevant to the OEB's consideration of Toronto Hydro's performance.

Accordingly, Toronto Hydro submits that this is an appropriate basis for setting its stretch factor. As noted in the PSE Report, Toronto Hydro's forecasts of its total costs are within ten percent of its predicted total costs. Utilities within this demarcation point are assigned to Group III of the OEB's benchmarking cohorts, implying a stretch factor of 0.30%. Toronto Hydro therefore proposes that the stretch factor in the proposed custom PCI framework be set at 0.30%.

[8] OEB Rate Setting Parameters Report, *supra* note 3 at page 18.
[9] OEB Rate Setting Parameters Report, *supra* note 3 at page 19.

3.3. Custom Capital Factor

The premise of the inclusion of a custom capital factor ("CCF" or "C-factor") is to reconcile the OEB's guidance that the CIR framework is best suited for utilities with significant, multi-year capital investment requirements as it is clear that the standard 4th Generation IR framework is not.

The proposed C-factor is designed as an adjustment mechanism that is directly proportional to the degree of capital investment required by Toronto Hydro, as detailed in its DSP (Exhibit 2B). It is comprised of two sub-components that serve two primary functions:

- Reconcile Toronto Hydro's capital investment need in a price cap framework; and,
- Return to ratepayers the funding advantage provided for capital through the standard "I – X" increase.

The first sub-component, termed "C_n", is determined as the percent change in total revenue requirement that is attributable to changes in capital-related revenue requirement – that is, depreciation, return on equity, interest and PILs/taxes. Changes in capital-related revenue requirement are based on forecast changes in average annual rate base, associated depreciation and taxes. Tax rates and the cost of capital are maintained at their 2015 levels, consistent with the standard 4th Generation IR treatment.

For Toronto Hydro, C_n in 2016 would be determined on the following basis:

Table 1: Calculation of C_n ($ Millions)

Revenue Requirement Component	2015	2016
Interest	80.2	89.5
ROE	120.9	135.0
Depreciation	206.5	221.6
PILs/Taxes	24.0	14.7
Capital-related RR	**431.6**	**460.9**
OM&A	269.5	
Revenue Offsets	(46.1)	
Total RR	**655.0**	

/C

The change in forecast capital related revenue requirement from 2015 to 2016 is $29.3 million ($460.9 million minus $431.6 million). The total revenue requirement in 2015 is $655.0. C_n for 2016 is therefore:

/C

$$C_n = (460.9 – 431.6) / 655.0 = \mathbf{4.47\%}.$$

Calculating C_n for years beyond 2016 requires a forecast of total revenue requirement. Capital-related revenue requirement, as noted, is determined on a forecast basis. By contrast, OM&A and Revenue Offsets are assumed to increase by "I – X". A more detailed discussion of why this is the case can be found towards the end of this schedule.

Applying this method results in values for C_n that are summarized in Table 2 based on inputs summarized in Table 3. These values represent the amount by which base rates would need to be increased to fund Toronto Hydro's capital needs over the course of the rate term.

Table 2: Values of C_n for 2016 to 2019 (in percent)

	2016	2017	2018	2019
C_n	4.47	8.25	6.68	5.01

/C

Table 3: Inputs for the determination of C_n for 2016 to 2019

Revenue Requirement Component	2015	2016	2017	2018	2019
Interest	80.2	89.5	98.4	103.9	109.2
ROE	120.9	135.0	148.3	156.6	164.6
Depreciation	206.5	221.6	248.3	266.8	287.4
PILs/Taxes	24.0	14.7	22.6	40.3	46.5
Capital-related RR	**431.6**	**460.9**	**517.6**	**567.5**	**607.6**
OM&A	269.5	273.3	277.1	281.0	284.9
Revenue Offsets	(46.1)	(46.8)	(47.4)	(48.0)	(48.7)
Total RR	**665.0**	**687.5**	**747.4**	**800.5**	843.8

/C

With the inclusion of C_n in the custom PCI, Toronto Hydro would receive sufficient funding for its capital needs as presented in the DSP. However, the "I – X" increase retained in the custom PCI from the standard 4th Generation IR framework does provide some degree of incremental funding. Absent additional constraints, the custom PCI formula would risk over-funding relative to Toronto Hydro's capital need because a portion of the "I – X" increase could be committed to capital expenditures. Toronto Hydro proposes to remove this risk through an automatic distribution rate reduction captured in the C-factor to constrain the impact of C_n.

An efficient and principled approach is to reduce the C-factor by a capital-related proportion of "I – X". Toronto Hydro proposes that this "scaling" factor be determined

by the proportion of the total revenue requirement that is capital-related. Termed S_{cap}, this scaling factor is calculated in the following fashion:

$$S_{cap} = \text{(capital-related revenue requirement)} / \text{(total revenue requirement)}$$

Table 4 provides the information necessary for calculating S_{cap} for 2015.[10]

Table 4: Revenue Requirement Components for Determining S_{cap}

Revenue Requirement Component	2015
Interest	80.2
ROE	120.9
Depreciation	206.5
PILs/Taxes	24.0
Capital-related RR	**431.6**
OM&A	269.5
Revenue Offsets	(46.1)
Total RR	**655.0**

/C

In 2015, the capital-related revenue requirement is forecast to be $431.6 million and the total revenue requirement $655.0 million. S_{cap} for 2015 would therefore be:

/C

$$S_{cap} = 431.6 / 655.0 = 0.659 \ (65.9\%)$$

The same methodology for calculating S_{cap} is proposed for all years from 2016 to 2019.

[10] This particular example is for illustrative purposes only as the custom PCI, for which the term is required, does not apply until 2016. S_{cap} values for 2016 cannot be calculated at this time because S_{cap} is sensitive to changes in the inflation factor as determined annually by the OEB. Toronto Hydro proposes, for the purpose of determining its annual rates, to calculate S_{cap} using this methodology once the value of the inflation factor for the following year is determined by the OEB.

The above discussion sets out the variables that constitute Toronto Hydro's proposed custom PCI. The resulting PCI value for a given year would, in keeping with IRM principles, be applied to all distribution rates from the previous year to determine the following year's distribution rates.

To summarize, the custom PCI is determined in the following fashion:

$$PCI = I - X + C, \text{ or}$$

$$PCI = I - X + C_n - S_{cap} * (I - X)$$

Where,

- "I" is the OEB's inflation factor, determined annually
- "X" is the sum of:
  - The OEB's productivity factor of 0.0%
  - Toronto Hydro's custom stretch factor, set applying the OEB's methodology to Toronto Hydro's alternative benchmarking model
- "C" is difference of:
  - C_n, a reflection of Toronto Hydro's capital investment need
  - $S_{cap} * (I - X)$, an offsetting adjustment required to ensure that the C-factor provides funding only in excess of what is already provided for capital through "I – X"

While the custom PCI cannot be calculated until the OEB determines its inflation factor for a given year, it is possible to develop scenarios using the methodology detailed in this schedule and an assumed value for the I-factor.

Table 5 shows the components of the custom PCI based on an assumed I-factor of 1.7%, its value at the time of writing, and the corresponding value of the custom PCI. This is

the same I-factor that is used to calculate bill impacts, which can be found in Exhibit 8, Tab 7, Schedule 1. Again, this is for illustrative purposes only.

Table 5: Custom PCI Values Assuming An Inflation Factor Of 1.7% For Each Year

CUSTOM PCI COMPONENT (%)	2016	2017	2018	2019
I	1.7	1.7	1.7	1.7
X - productivity	0.0	0.0	0.0	0.0
X - custom stretch	-0.3	-0.3	-0.3	-0.3
C_n	4.47	8.25	6.68	5.01
S_{cap}	67.1	69.3	70.9	72.0
Custom PCI	**4.94**	**8.68**	**7.09**	**5.41**

/C

4. CONCLUSION

4.1. Policy Concordance

The manner in which the rate framework submitted as part of this CIR application concords with the OEB's guidance in the RRFE Report is fundamental to Toronto Hydro's development of this application. Toronto Hydro has deliberately chosen a framework that includes a standard rebasing year followed by four years of a custom PCI framework as the mechanism by which to have its distribution rates set over the course of the term. It has done so because, in Toronto Hydro's view, this represents an approach that is appropriately concordant with RRFE guidance. Where this proposed rate framework does not explicitly conform to that guidance, it is Toronto Hydro's view that its approach is reasonable and appropriate. One such example is the explicit inclusion of the OEB's inflation and productivity factors into the custom PCI formula, which goes further than the OEB's guidance to be "informed" by those analyses.

In considering its custom approach, Toronto Hydro was particularly concerned with the contents of Table 1 in the RRFE Report.[14] This table provides some of the clearest indications of the OEB's expectations for prospective applicants.

The remainder of this sub-section outlines how Toronto Hydro's proposed rate framework concords with the guidance provided in that table.

The proposed rate framework is comprehensive. Toronto Hydro proposes that the rate framework commence with a standard rebasing year to determine base distribution rates, followed by four years where a custom PCI governs incremental changes to those base rates. Base rates are determined by a base revenue requirement that relates to both capital and operating costs.

The proposed rate framework is informed by Toronto Hydro's forecasts. The rebasing year offers the opportunity to test capital and operating expenditures. The C-factor in the custom PCI is calculated based on a forecast of Toronto Hydro's capital-related revenue requirement during the remainder of the term, which can also be tested. This incorporates expectations of inflation for its capital costs, as set out in Exhibit 2A, Tab 6, Schedule 1.

The proposed rate framework is informed by the OEB's inflation and productivity analyses. The proposed rate framework is not only informed by, but firmly entrenches the OEB's productivity analyses through the inclusion of its inflation and productivity factors within the custom PCI formula. While not a requirement, Toronto Hydro believes this is to be a distinctive element of its proposed rate framework.

[14] RRFE Report at page 13.

The proposed rate framework is informed by benchmarking to assess the reasonableness of the distributor's forecasts. The custom PCI incorporates a custom stretch factor that applies the OEB's methodology of assigning stretch factors but that uses Toronto Hydro's alternative total cost benchmarking model, as set out in Exhibit 1B, Tab 2, Schedule 5.

The proposed rate framework includes a productivity and stretch factor. In Toronto Hydro's view, the inclusion of the OEB's productivity factor and a custom stretch factor into the custom PCI meets the OEB's expectations for the sharing of (financial) benefits.

The proposed rate framework covers the entirety of the application's five year term.

4.2. Implications for OM&A and Revenue Offsets

An intended implication of this custom PCI framework is the amount of funding that is as a matter of consequence provided for OM&A and Revenue Offsets. Tested in the standard rebasing fashion in 2015, the custom PCI provides incremental funding for OM&A and Revenue Offsets in the amount of only "I – X". Consider the entire custom PCI formula, with the C-factor in its constituent parts: **/C**

$$CPI = I - X + C_n - S_{cap}*(I - X)$$

By design, C_n reconciles Toronto Hydro's capital investment need, leaving the remaining terms to fund increases in OM&A and Revenue Offset. In simplified terms, that amount is:

$$(1 - S_{cap}) * (I - X)$$

This can be restated in another fashion, using S_{OMA} and S_{RO} to respectively represent the ratio of OM&A and Revenue Offsets to the total revenue requirement (recall this is identical to how S_{cap} was determined). Given that capital costs, OM&A and Revenue Offsets are the only three components of the total revenue requirement, the above formula can be restated as follows:

$$(1 - S_{cap}) * (I - X) =$$
$$(S_{OMA} + S_{RO}) * (I - X) =$$
$$S_{OMA} * (I - X) + S_{RO} * (I - X)$$

In other words, the custom PCI proposed by Toronto Hydro embeds the expectation that the components of rates attributable to OM&A and Revenue Offsets will continue to increase by only "I – X". If actual OM&A was to increase at a rate greater than this, or if Revenue Offsets were to stagnate, Toronto Hydro is at risk for under-recovery through the 2015 to 2019 period. Toronto Hydro is aware of this risk and, in response to the incentives created by its proposed custom PCI, expects to continue to seek efficiency and productivity improvements throughout the rate term.

5. OFF-RAMPS

Toronto Hydro proposes to apply the OEB's existing policy with respect to off-ramps. The RRFE Report indicates that each rate setting method includes a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points, at which point a regulatory review may be initiated.

6. SPECIFIC Z-FACTOR

One of the incremental challenges inherent in a five-year rates plan is the need to contend with prudent, material unexpected costs. As part of this application, and as explained in further detail throughout this application,[15] Toronto Hydro has proposed restrained/constrained OM&A and capital funding requests. The funding that Toronto Hydro seeks in this application is expected to enable the utility to carry out the work that it has detailed in these programs. That funding, by definition, is not sufficient to address the prudent costs of material events that occur outside the control of the utility and which have not been forecasted. Accordingly, Toronto Hydro proposes to incorporate within its rate framework the availability of Z-factor relief, which Toronto Hydro understands is available to CIR filers as part of the RRFE framework.

As detailed below, while Toronto Hydro expects that a request for relief would be exceptional, the utility has prepared a list of possible categories of specific events which it believes could occur, and where they occur, may necessitate additional funding during the term of the plan. The criteria that would apply to the consideration of any of these events would be the standard Z-factor criteria, most recently articulated by the OEB in its Decision on Enbridge Gas Distribution Inc.'s 2014 to 2018 Rate application.[16] To the extent the OEB has concerns with respect to the possible availability of Z-factor treatment in relation to any of the items set out below, Toronto Hydro asks the OEB to identify these concerns as part of this application.

6.1. Events with a one-time impact

One-time events that Toronto Hydro anticipates may give rise to a Z-factor application include:

- Extreme weather events such as storms;

[15] See for instance the Financial Planning Process (Exhibit 1C, Tab 3, Schedule 2), Overview of OM&A Expenditures (Exhibit 4A, Tab 1, Schedule 1) and Capital Expenditures Planning Process Overview (Exhibit 2B, Section E2).
[16] EB-2012-0459, Decision with Reasons (July 17, 2014) at pages 18-21.

- One-time investments made at the behest of government direction and outside of management's control, such as:
  - Smart Meter implementation;
  - Conservation and Demand Management;
  - Regional Planning; and,
- Any other one-time events that meet the Z-factor criteria.

6.2. Events with an ongoing impact

Material ongoing events that Toronto Hydro anticipates may give rise to a Z-factor application include:

- Changes to IESO market rules;
- Changes to OEB codes or policies, such as distributor rate design;
- Changes to income tax rates or laws;
- Changes to accounting frameworks or technical standards;
- Changes resulting from new or amended government legislation, regulation or policy, such as environmental laws;
- Ongoing investments made at the behest of government direction and outside of management's control; and,
- Any other ongoing events that meet the z-factor criteria.

In the interest of regulatory efficiency, Toronto Hydro proposes that any application for this treatment would compartmentalize the material impacts of the event, as opposed to undergoing a full regulatory review of the rate framework. For one-time events, Toronto Hydro would propose a targeted rate rider. For events with an ongoing impact, Toronto Hydro would propose an adjustment to the base revenue requirement if one was to occur in 2015, or else to the custom PCI.

CAPITAL INVESTMENT

1. INTRODUCTION

As described in Exhibit 1B, Tab 2, Schedule 3, Toronto Hydro has filed this rate-setting application under the Custom Incentive Rate-setting ("Custom IR" or "CIR") framework primarily due to the significant multi-year investment needs of Toronto's electrical distribution system. Toronto Hydro's 2015-2019 Distribution System Plan ("DSP")[1] captures, in detail, the capital requirements of the system. These investment commitments exceed historical levels, as demonstrated in the DSP and as further indicated in the Navigant Report (Appendix B to this Schedule).

Toronto Hydro's DSP reflects the utility's need for a sustained period of capital investment to replace and expand the City's aging distribution infrastructure. Toronto Hydro's infrastructure investment plans over the five year forecast period (2015-2019) are aligned to the longer-term objective of reaching a "steady-state" of annual investment that is intended to (1) enhance value for money over the service life of all distribution assets and (2), through a restrained and prudent approach to achieving "steady-state", provide greater predictability in customer bill impacts in the short and long-term. The steady-state concept is further explained in Section 2 of this schedule.

Toronto Hydro's proposed capital program:

I. represents a minimum level of appropriate investment given the distribution system's needs;
II. reflects customers' preferences;
III. will be delivered productively and efficiently; and
IV. ultimately delivers long-term value for ratepayers.

[1] Exhibit 2B

Each of these aspects of the evidence is summarized in Section 2 of this schedule, with reference to other, more detailed sections of the application where appropriate.

Section 3 of this schedule describes Toronto Hydro's presentation of its capital evidence in the form of the 2015-2019 DSP and the compliance of the DSP with the Chapter 5 Filing Requirements[2].

2. 2015-2019 CAPITAL PLAN OVERVIEW

I. Responding to System Needs

Toronto Hydro's most recent rate setting application was the 2012-2014 Incremental Capital Module ("ICM") application (EB-2012-0064), which was approved the by Ontario Energy Board ("OEB") and covered the years immediately preceding the 2015-2019 Custom IR application. Toronto Hydro identified its proposed capital programs in the DSP based on feedback from customers and by leveraging the same asset management tools and processes authorized by the OEB in EB-2012-0064[3]. Toronto Hydro's Asset Management Process – including its various components, decision tools and inputs and outputs – is discussed in detail in Section D3 of the DSP.

Continuity With Respect to the 2012-2014 IRM/ICM Application

With reference to the previous application, Toronto Hydro's proposed 2015-2019 DSP capital programs can be classified according to two general categories:

1) capital programs that are a direct continuation of activities described in one of the OEB-approved ICM segments, and
2) capital programs that are incremental to the ICM segments approved by the OEB.

[2] Filing Requirements for Electricity Distribution Rate applications (July 17, 2013) [the "Filing Requirements"].
[3] EB-2012-0064, Partial Decision and Order (April 2, 2013) at page 21.

The following tables summarize the proposed capital programs in the 2015-2019 DSP and their relationship to activities that were described in the 2012-2014 ICM application. The DSP programs listed in Table 1 are direct continuations of the activities featured in the ICM segments listed in the left column. The forecasted expenditures for the programs listed in Table 1 are comparable to those in the ICM period, with some programs tapering off or coming to an end within the 2015-2019 period, and other programs increasing marginally to address greater investment needs in the 2015-2019 period.

Table 1: DSP Capital Programs that are Continuations of OEB-Approved ICM Segments

Approved ICM Segment	DSP Program
B1 Underground Infrastructure	E6.1 Underground Circuit Renewal
B2 PILC Piece-outs and Leakers	E6.2 PILC Piece-outs and Leakers
B3 Handwell Replacement	E7.5 Handwell Upgrades
B4 Overhead Infrastructure	E6.4 Overhead Circuit Renewal
B5 Box Construction	E6.7 Box Construction Conversion
B6 Rear Lot	E6.6 Rear Lot Conversion
B7 Polymer SMD-20 Switches	E7.6 Polymer SMD-20 Switch Renewal
B8 SCADA-Mate R1 Switches	E6.8 SCADA-Mate R1 Switch Renewal
B9 Network Vaults and Roofs	E6.9 Network Vault Renewal
B10 Fibertop Network Units	E6.10 Network Unit Renewal[4]
B11 ATS and RPB	E6.11 Legacy Network Equipment Renewal
B12 Station Power Transformers	E6.14 Stations Power Transformer Renewal
B13-1 Municipal Substation Switchgear Replacement	E6.13 Stations Switchgear Renewal
B13-2 Transformer Station Switchgear Replacement	E6.13 Stations Switchgear Renewal

[4] E6.10 Network Unit Renewal includes fibertop units as well as an additional network unit type in need of renewal.

Approved ICM Segment		DSP Program
B14 Stations Circuit Breakers		E6.15 Circuit Breaker Renewal
B17 Copeland TS		E7.9 Stations Expansion[5]
B18 HONI Capital Contributions		E6.13 Stations Switchgear Renewal
		E7.9 Stations Expansion
B20 Metering		E5.1 Metering
B21 Externally Initiated Plant Relocations and Expansions		E5.3 Externally Initiated Plant Relocations and Expansions
C1 Operations Portfolio Capital	Customer Connections Capital	E5.2 Customer Connections
	Mitigating System Operating Constraints	E5.4 Load Demand
	Critical Stations Work	E6.17 Stations Ancillary Systems
		E6.18 Station Building Infrastructure
		E6.19 Stations DC Battery Renewal
	Reactive Capital	E6.20 Reactive Capital
	Worst Performing Feeder Capital	E6.21 Worst Performing Feeders
C2 Information Technology Capital		E8.4 IT Hardware Refresh
		E8.5 IT Software
C3 Fleet Capital		E8.1 Fleet and Equipment Services
C4 Buildings and Facilities Capital		E8.2 Facilities Management and Security

/C

The proposed capital programs in Table 2 are incremental to the approved OEB segments from the ICM application. Toronto Hydro added these programs to the 2015-2019 capital plan to accomplish one of three overarching objectives:

1) maintain responsiveness to public policy objectives and fulfil mandated service obligations (e.g., Generation Protection, Monitoring and Control);
2) address system and non-system renewal needs identified in the course of the utility's long-term planning review process (e.g., Underground Legacy

[5] Segment B17 was narrowly focused on the first phase of Copeland TS; E7.9 Stations Expansion includes carryover expenditures from Copeland TS Phase 1, new Copeland TS Phase 2 investments and other capacity expansion investments at the station level over the five year forecast period. /C

Infrastructure; Distribution System Communications Infrastructure; Voice Radio System Upgrade; ERP Implementation); or

3) achieve targeted system and operational objectives in light of evolving system conditions (e.g., Local Demand Response; Design Enhancement; Program Support) and opportunities to enhance customer value (e.g., Feeder Automation, Operating Centers Consolidation)

Table 2: Proposed DSP Capital Programs that are Incremental to the OEB Approved ICM Segments

Proposed DSP Program
E5.5 Generation Protection, Monitoring and Control
E6.3 Underground Legacy Infrastructure
E6.12 Network Circuit Reconfiguration
E6.16 Stations Control & Monitoring
E6.22 Distribution System Communications Infrastructure
E7.1 Contingency Enhancement
E7.2 Design Enhancement
E7.3 Feeder Automation
E7.4 Overhead Momentary Reduction
E7.7 Downtown Contingency
E7.8 Customer Owned Station Protection
E7.10 Local Demand Response
E7.11 Energy Storage Systems
E8.3 Operating Centers Consolidation
E8.6 ERP Implementation
E8.7 Voice Radio System Upgrade
E8.8 Program Support

Proposed Level of Spending

Figure 1 shows (i) the historical level of capital spending from 2006 to 2011, (ii) the

average of actual and forecasted spending over the three-year ICM period (2012-2014), and (iii) the proposed level of capital spending for each of the five years in the planning horizon.

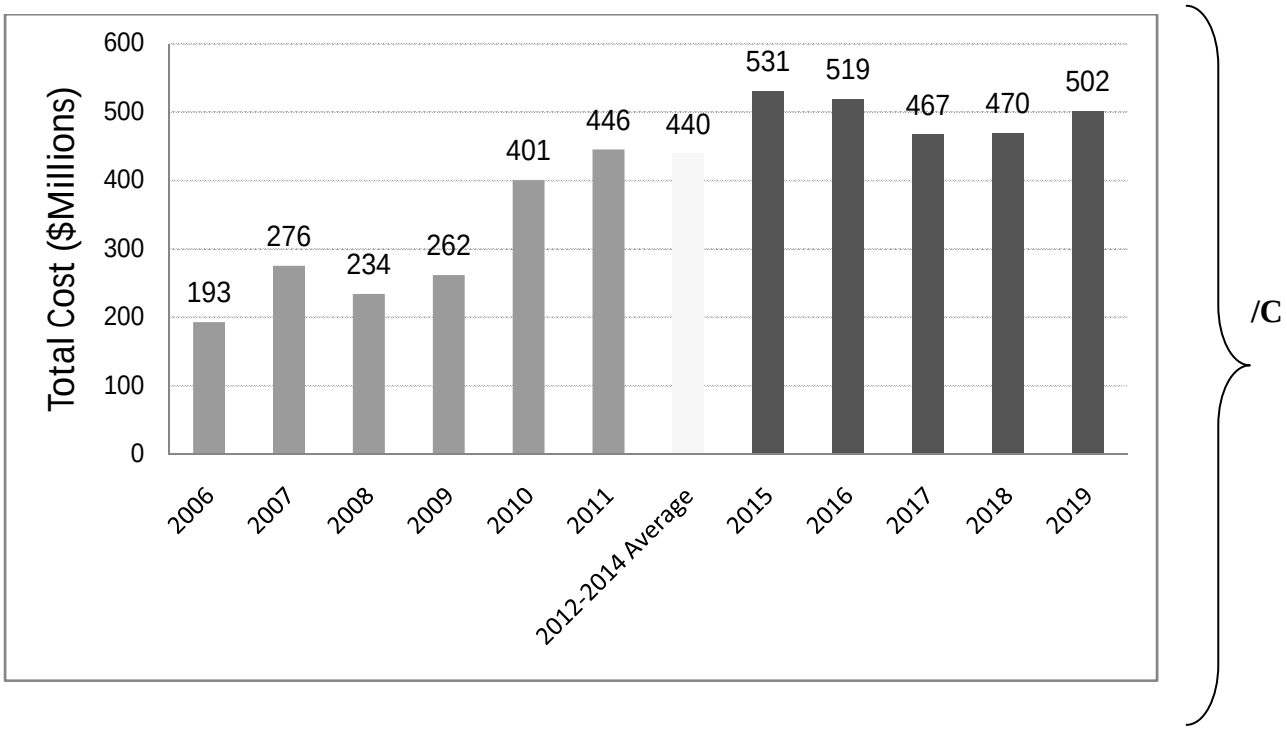


Figure 1: Historical and Forecast Capital Spending (2006 – 2019) ($Millions)

As shown above, the average annual level of investment for the proposed capital program is comparable to the level of spending during the utility's 2012-2014 IRM/ICM period. This level of investment is required primarily to address the large and growing backlog of end-of-life and obsolete assets, while also addressing critical system challenges and operational needs at a pace and in a manner that moderates rate increases and is consistent with customer preferences. As demonstrated in the DSP, and as validated in the Navigant Report (Appendix B of this Schedule), this level of spending is the minimum level of investment that is appropriate during the 2015-2019 period given the distribution system's needs. While the optimal level of capital investment exceeds the

work proposed in Toronto Hydro's DSP, the level of capital investment in this application balances the needs of the distribution system against a level of rate increases that customers accept.[6]

Distribution System Pressures

Toronto's distribution system faces a number of significant and evolving challenges that necessitate the proposed level of investment. These challenges include the following.

- Aging and Obsolete Assets: The foremost pressure driving distribution system investment commitments is the large and growing backlog of in-service assets that are operating beyond their expected useful lives. An estimated 26% of Toronto Hydro's existing distribution system asset base will be operating beyond end-of-life as of 2015. Assuming a run-to-failure approach (i.e., executing a capital expenditure plan with minimal proactive asset replacement), Toronto Hydro expects an additional 7% of the existing asset base to reach end-of-life by 2020. Without a sufficient proactive renewal program, the utility anticipates that reliability will deteriorate over the five-year CIR period, and the growing backlog of end-of-life assets will become more difficult to manage beyond 2019 without potentially unacceptable rate increases and execution challenges due limited resource availability.

  With respect to system renewal, Toronto Hydro's long-term asset management policy objective is to eventually arrive at an optimal percentage of assets operating beyond end-of-life in order to minimize the overall lifecycle costs of operating the system over time. This concept is discussed in Section IV of this schedule.

[6] For further discussion of Toronto Hydro's customer engagement program, please refer to the evidence at Exhibit 1B, Tab 2, Schedule 7 and the 2015-2019 DSP (Exhibit 2B).

The forecasted improvement in reliability associated with Toronto Hydro's proposed capital plan[7] is due in part to the ongoing renewal of aging and defective assets, but is also an expected outcome of a small number of targeted, high-value programs such as Feeder Automation[8] and Design Enhancement[9], which are incremental to the OEB-approved ICM segments and are expected to deliver significant improvements in system performance and operational efficiency for a level of annual investment that is relatively small compared to the typical renewal program. These cost-effective interventions allow Toronto Hydro to enhance customer value through system reliability and efficiency improvements while executing core renewal programs at a moderate pace.

x Economic Growth and Capacity Constraints: Toronto's distribution system continues to face utilization pressures related to economic growth and evolving system use. These pressures include existing and emerging capacity constraints in several areas throughout the system due to load and customer growth; an anticipated increase in large externally initiated plant relocation projects (e.g., Metrolinx light rail transit projects); and the expectation that connected distributed generation ("DG") capacity will more than triple over current levels during the five-year CIR period.

As explained in Exhibit 9, Tab 1, Toronto Hydro is requesting a minimal, below-forecast baseline amount of rates funding for externally initiated plant relocations work as part of the DSP, representing less than the utility's forecast annual spending on externally initiated projects. This below-forecast amount is accompanied by a variance account to capture annual differences from this base amount. The utility's expectation is that this approach will allow it to fund

[7] Exhibit 2B, Section E2.
[8] Exhibit 2B, Section E7.3.
[9] Exhibit 2B, Section E7.2.

necessary, non-discretionary work while, at the same time, holding ratepayers harmless from the potential that a material amount of the forecast third party work does not materialize, due to the unpredictable nature, costs, and timing of such projects.

- Critical Issues: Toronto Hydro also plans to address a number of critical distribution system issues that go beyond core renewal and capacity/utilization concerns. These include potential safety issues, system design deficiencies and reliability issues.

- Climate Change: An AECOM-Toronto Hydro report entitled Future Impacts of Climate Change on Toronto Hydro's Distribution System[10] concludes that weather and climate change can be expected to impact the reliability of the distribution system going forward, and that Toronto Hydro will be required to manage assets that may not have been designed for future climate conditions. Climate change forecasts anticipate worsening pressures such as increases in extreme maximum temperatures and increased intensity of rainfall events. A number of Toronto Hydro's planned capital programs are expected to enhance system performance and operational efficiency during major storm events and other adverse weather conditions.

- Utility Operations Needs: Toronto Hydro must also continue to maintain and enhance its non-distribution system assets to ensure the efficient and effective execution of the proposed capital program, maintenance activities and other business functions. In addition to the fleet, facilities and Information Technology ("IT") asset renewal investments, Toronto Hydro has identified several additional, one-time capital projects that are required during the forecast

[10] Exhibit 2B, E8.8, Appendix A.

period, including replacement of the obsolete enterprise resource planning ("ERP") system and the voice radio system.

Toronto Hydro's asset management process and the resulting 2015-2019 DSP balance these various system needs in a manner intended to maximize customer value while mitigating bill impacts during the forecast period and ensuring prudent and efficient progress toward the achievement of a more stable, predictable and balanced system state in the long-term.

Complete details and justification for all of the programs that address the aforementioned system and non-system investment needs are available in the DSP, Exhibit 2B, Sections E5 through E8. A discussion of the pacing of investment and its alignment to longer-term objectives is provided in part IV of this section.

II. Customer preferences and the DSP

As part of preparation for this rate filing, and to achieve alignment with the RRFE Report and associated specifications set-out in its Filing Requirements, Toronto Hydro set out to gather customer preferences with respect to the proposed 2015-2019 capital expenditure plan and its associated outcomes and bill impacts. Toronto Hydro worked with Innovative Research Group ("Innovative") – a firm known for their expertise in meaningful customer engagement in the energy and utilities sector – to identify customer preferences in all customer classes up to, but not including, the utility's very large user class. Toronto Hydro relied on its standard, year-round key account management programs for the largest users, as these customers generally have more complex and specific needs and concerns with respect to electricity distribution. A comprehensive discussion of these processes, how they were designed, and the results gathered can be found at Exhibit 1B, Tab 2, Schedule 7, including Innovative's final report. For a

detailed discussion of the alignment of Toronto Hydro's proposed DSP to the needs and preferences gathered through customer engagement, please refer to Exhibit 2B, Section E2.4.

In general, Toronto Hydro has taken a customer focused approach at every stage of preparing its DSP. The foremost example of this is Toronto Hydro's asset management process,[11] which relies extensively on outputs from the Feeder Investment Model ("FIM"). The FIM tool uses quantified customer interruption costs ("CICs") as one of several inputs when calculating the optimal replacement or maintenance time for an asset. This approach ensures that engineering investment decisions are inherently sensitive to customer value.

In terms of the overall capital expenditure plan, Toronto Hydro has also considered customer and regulator expectations with respect to acceptable bill impacts over the 2015-2019 period. The capital "ask" has been deliberately reduced to reflect these expectations. Alignment to these expectations was demonstrated through the Innovative customer engagement process, the results of which suggests that most customers (between 48% and 58%, depending on the class) are accepting of the rate increase based largely on the belief that Toronto Hydro's proposed capital plan is necessary to maintain the grid to a reasonable standard.

The level of restraint that Toronto Hydro's proposed plan represents versus actual system needs is discussed in part IV of this section.

III. The proposed capital program will be delivered productively and efficiently.

Toronto Hydro is committed to providing the OEB and customers with a transparent, meaningful view of the ways in which the utility works toward maximizing the efficiency and productivity of its capital work.

[11] Exhibit 2B, Section D.

Toronto Hydro has a long-standing productivity culture which has evolved over time in line with emerging operating challenges, changes in government policy and expectations underlying the regulatory regimes that govern the utility's operations. Toronto Hydro's framework of current and planned productivity processes and initiatives emphasize increasingly sophisticated performance measurement tools, a bottom-up approach to identifying new efficiency opportunities, and streamlining labour-intensive processes through technological improvements and rationalization of supporting infrastructure. For a comprehensive overview of the evidence that Toronto Hydro has filed this application to enable the OEB to evaluate the utility's ongoing efforts regarding efficiency and productivity improvements, please refer to Exhibit 1B, Tab 2, Schedule 5.

Performance Measurement in the DSP

With specific reference to the OEB's Chapter 5 Filing Requirements, Toronto Hydro has proposed a series of measures for monitoring and encouraging continuous improvement with respect to the execution of 2015-2019 capital expenditure plan in the DSP. These metrics are listed in Table 3 below.

The measures cover several dimensions of the utility's capital planning and implementation processes or pertain directly to the outcomes of such processes, motivated by customer needs, regulatory compliance obligations, or corporate efficiency objectives. Several of these measures are already in a mature state and will be tracked during the five-year planning horizon; others are in a relatively nascent state, to be developed and refined over the course of the CIR term as part of Toronto Hydro's commitment to productivity and continuous improvement.

Table 3: Proposed Performance Measures Framework[12]

Customer-Oriented Performance	Cost Efficiency/ Effectiveness of Planning and Implementation	Asset/System Operation Performance
1. System Average Interruption Duration Index (SAIDI) 2. System Average Interruption Frequency Index (SAIFI) 3. Customer Average Interruption Duration Index (CAIDI) 4. Feeders Experiencing Sustained Interruptions (FESI) 5. Momentary Average Interruption Frequency Index (MAIFI)	1. Distribution System Plan Implementation Progress 2. Planning Efficiency: Engineering, Design and Support Costs 3. Supply Chain Efficiency: Materials Handling On-Cost 4. Construction Efficiency: Internal vs. Contractor Cost Benchmarking 5. Construction Efficiency: Standard Asset Assembly Labour Input	1. Outages caused by defective equipment 2. Stations capacity availability

Execution Considerations and the Need for Flexible Capital Funding

Toronto Hydro expects that flexibility in project scheduling across the five-year term of this application will be a source of efficiency as the utility executes the proposed capital work in the DSP. This ability to shift projects between years and to increase or decrease the amount of spending in a program in any given year allows Toronto Hydro to execute the overall capital expenditure plan outlined in the DSP in the most cost-effective manner

[12] For more information, please refer to Exhibit 2B, Section C.

possible.

Due to a number of factors, executing capital work in Toronto is necessarily a complex and dynamic process. While executing a planned work program, external factors, such as work permit timing, weather, re-prioritization of jobs due to system needs, etc., will inevitably arise. In many of these situations, good utility practice and prudent work planning is best served by (a) specific projects within a capital program being substituted, on a like-for-like basis, with other projects; and (b) specific projects being added to, or deferred from, a given program. These numerous externalities mean that Toronto Hydro cannot plan with certainty of execution timing or costs in advance, and attempting to do so would actually be an imprudent use of time and ratepayer funds. Toronto Hydro has prepared a detailed overview of the practical execution challenges that the utility often faces during development and execution of its capital program. This overview can be found in Appendix A to this schedule ("Execution Challenges").

Despite its best efforts to anticipate and plan around these challenges, Toronto Hydro must be prepared to respond to circumstances "on the ground" in order to make the most efficient use of resources and ultimately deliver the best value for its customers. From a planning perspective, this means that the utility must be able to substitute, defer and add projects in the annual work program in a given year, to accommodate the operational realities that it encounters in the course of executing its work program.

Toronto Hydro's planning process attempts to mitigate these issues in various ways, but ultimately the execution of any given project can be changed by various external forces that cannot be predicted with certainty. Over time, these issues can generally be mitigated – some work can be advanced if not work must be delayed – but the forecast work for any given year may change depending on circumstances, and as a result the aggregate work in service in a given year may change.

While specific projects may change in scope, cost and timing during the CIR period, the utility has confidence that, over the course of the five-year planning horizon, the overall work program presented in the DSP can be executed as described. Prudence dictates that Toronto Hydro must retain the flexibility to execute an optimal mix of work in each given year. It is not possible to predict the specific work that will comprise Toronto Hydro's execution work program in 2019, but the utility can be certain that, over the five years of the application, this level of work, as set out in the DSP programs, is required.

IV. The proposed capital program ultimately delivers long-term value for customers

As discussed in part I of this section, the pace of investment during the 2015-2019 period is driven by system needs. The underlying need and establishment of pacing is described in detail in Toronto Hydro's asset management policy and processes[13] and in the capital expenditure plan.[14] At a high level, the long-term objective of Toronto Hydro's asset management policy is to achieve an optimal "steady-state", in which the number of assets that are past their economic end-of-life (explained below) is minimized. When the system is in that theoretical steady state, the total operating (or lifecycle) costs associated with the broader in-service asset population are minimized, meaning that customer value is maximized.

The concept of a steady state is based on Toronto Hydro's risk-based optimization approach to investment planning, which relies largely on use of the utility's Feeder Investment Model ("FIM") and other age and condition based information. Using these tools, Toronto Hydro determines the optimal asset renewal timing based on the economic end-of-life criteria for each asset. An asset reaches its economic end-of-life when the risk cost of continuing to operate the asset, which increases over time, becomes equal to or

[13] Exhibit 2B, Section D.
[14] Exhibit 2B, Section E.

greater than the cost of replacing the asset, which decreases over time. An asset management policy that strives to replace the broader population of assets at this "optimal intervention time" ensures that, on average, Toronto Hydro is minimizing the total costs of operating the system, thereby maximizing customer and utility value derived from the assets.

Theoretically, Toronto Hydro's risk based model defines the ideal "steady state" as the scenario where, on a system level, no assets are allowed to operate beyond their optimal intervention time, and all assets are replaced at exactly the optimal intervention time and no earlier (except those that inevitably fail prematurely). (Practically speaking, Toronto Hydro must group asset replacements into efficiently executable projects; therefore, the actual "steady state" will necessarily involve replacing a small percentage of assets before end-of-life and allowing a small percentage of assets to operate beyond end-of-life.)

As discussed in part I of this section, Toronto's distribution system currently features a high percentage of assets operating beyond end-of-life. Clearing this backlog and achieving "steady state" as quickly as possible is ideal for the utility and customers to the extent that it will minimize the duration that the distribution system is operating in an unbalanced state with higher than necessary aggregate lifecycle costs. However, in reality, clearing this backlog in one year (i.e., the economically ideal approach), or even over the duration of the five-year CIR period, would not be feasible as it would feature levels of investment that do not immediately align to Toronto Hydro's current resources and system constraints. For these reasons, Toronto Hydro's DSP is based on a paced execution strategy, which represents the minimum level of investment appropriate given system needs during the 2015-2019 period.

If Toronto Hydro were to continue at the proposed annual average pace of investment beyond 2019, the system is forecasted to reach steady state by approximately 2037. This paced approach has the advantage of moderate and predictable bill increases during the 2015-2019 period and alignment with Toronto Hydro's immediate execution capacity. The paced strategy also helps to ensure more predictable bill impacts and system performance beyond the achievement of steady-state, due to the more gradual or dispersed approach to clearing the backlog of end-of-life assets.

3. STRUCTURE AND COMPLIANCE OF TORONTO HYDRO'S DSP

Toronto Hydro has organized its 2015-2019 Distribution System Plan ("DSP")[15] in a manner consistent with Chapter 5 of the Filing Requirements. Toronto Hydro has worked to provide DSP content that aligns with the spirit of the RRFE Report, as expressed through the Chapter 5 Filing Requirements, and that allows the OEB to evaluate all aspects of the utility's detailed and integrated five-year capital plan within the context of this Customer IR application. Key features of the DSP include the following.

- The five major sections of Toronto Hydro's DSP adhere to the organizational structure outlined in sections 5.2 and 5.3 of Chapter 5. This includes:
  - Section A: DSP Overview
  - Section B: Coordinated Planning with Third Parties
  - Section C: Performance Measurement for Continuous Improvement
  - Section D: Asset Management (AM) Process
  - Section E: Capital Expenditure Plan

[15] Exhibit 2B.

- The contents of these chapters are substantial compliance with the various filing requirements listed throughout the applicable sections of Chapter 5.

- Toronto Hydro has organized its capital investments in accordance with the OEB's prescribed investment categories (System Access, System Service, System Renewal and General Plant) and has provided figures and analysis for historical and forecasted expenditures in these categories as well as for System Operating & Maintenance ("System O&M") expenditures.

- To address the OEB's incremental filing requirements for "Material Investments"[16], Toronto Hydro has further grouped investment activities within the investment categories into 46 capital programs, which are analogous, and in many cases identical, to the "segments" filed in the utility's 2012-2014 ICM application. Programs consist of investment activities or groups of discrete projects that are similar in nature and purpose and that share similar justifications and business case elements.

- Each capital program is further defined by a single 'trigger' driver and a number of secondary drivers. These drivers generally align to the example drivers provided by the OEB in Chapter 5.17 The trigger driver indicates the primary reason that a particular program must be carried out. However, in some cases, secondary drivers may be as or more consequential than the trigger driver (e.g., safety as a secondary driver).

- Each capital program contains detailed information that can be used to assess Toronto Hydro's investment plans in light of the OEB's specific evaluation criteria (i.e., Customer Value, Reliability, Efficiency, Safety, etc.). To aide in this

[16] Filing Requirements, Chapter 5 at section 5.4.5.2.
[17] Filing Requirements, Chapter 5 at section 5.1.1, Table 1.

evaluation, Toronto Hydro has provided summary tables of anticipated program benefits in the description of each program.

x Toronto Hydro has complied with specific requirements in Chapter 5 that are meant to promote integrated planning, including, for example:
  - a complete analysis of regional planning considerations and their effect on the DSP;
  - a system capability assessment for renewable energy generation;
  - details on System O&M expenditures and their relationship to capital investments;
  - forecasted smart grid development; and
  - identified sources of cost savings during the forecast period.

APPENDIX A: EXECUTION CHALLENGES

When executing its capital program Toronto Hydro must be prepared to respond to circumstances “on the ground” in order to make the most efficient use of resources and ultimately deliver the best value for its customers. From a planning point of view, this means that the utility must be able to substitute, defer and add projects in the annual work program in any given year to accommodate the operational realities that it experiences in the course of its work program.

This appendix describes aspects of Toronto Hydro’s service territory that add complexity to the execution of large capital projects.

1. WEATHER AND THE NATURAL ENVIRONMENT

A number of unpredictable work execution challenges arise due to severe weather and conditions that exist in the natural environment. These challenges are difficult to assess in advance of undertaking projects and planned work.

1.1. Weather

Unpredictable weather events have the potential to impact work execution in two ways. One is that extreme weather (e.g., very cold or very hot temperatures) over a prolonged period can cause projects to be delayed or cost. Second, severe weather such as extreme wind, ice, and rain events can cause wide-spread damage to Toronto Hydro’s distribution system and necessitate the redirection of crews from planned work to emergency storm restoration activities.

An example of a prolonged weather pattern that impacted Toronto Hydro’s ability to execute planned work was the cold experienced during the 2013-2014 winter. Due to

frost, snow, and ice, utilities are generally challenged to conduct civil and pole installation work during winter months. To manage this reality, Toronto Hydro conducts significant amounts of civil work in the lead up to winter and then does not schedule much civil work until winter conditions subside. Given that the 2013-2014 winter was particularly long and cold, resulting in frost settling deep into the ground, civil work was substantially delayed in 2014. The long winter not only impacted capital projects but also maintenance programs such as insulator washing that cannot be conducted in cold temperatures.

Examples of severe weather events causing damage to Toronto Hydro's distribution system occurred on October 29, 2013 (i.e., Hurricane Sandy) and December 21, 2014 (i.e., the 2013 Ice Storm). In response to the damage caused by these severe weather events, Toronto Hydro redirected all available crews, including crews working on planned projects and programs, to emergency storm restoration activities. In any given year, the amount of time and delay caused by severe weather can vary but can equate to weeks of construction time across all projects as evidenced in 2013, where planned work was delayed due to flooding in July, strong winds in August and October, and the ice storm in December. Some of the delays were overcome by working overtime at an increased cost to individual projects.

1.2. The Natural Environment

The natural environment can create challenges due to issues that may involve soil conditions, ground water, and vegetation. Prior to work execution, Toronto Hydro attempts to plan for the natural environment and mitigate associated risks. However, it is not uncommon for even the most prudently planned projects to be delayed due to challenges associated with the natural environment.

One set of challenges that are encountered are related to the soil conditions found on sites

where planned projects are being conducted. For example, it is not uncommon for Toronto Hydro to encounter shale while installing poles. When identified, shale must be removed using a jackhammer causing delays and increased costs. Toronto Hydro tries to mitigate the risk of unexpected shale using test pits prior to commencing work. These test pits require additional site visits and are costly. As a result, it is prudent for Toronto Hydro to only undertake such costs if there is a reason to believe that soil conditions are abnormal.

Another risk related to soil conditions is soil contamination. The removal and disposal of contaminated soil can be particularly costly and can delay projects if identified during work execution. An example of a where this occurred is the Strachan TS Civil Egress project. This project was required to construct cable chambers and underground conduits from Hydro One's Strachan TS to Manitoba Drive. When construction commenced, contaminated soil was discovered and the additional cost for soil testing, removal, and disposal was approximately $400,000.

A second set of challenges associated with the natural environment is excessive ground water. Although de-watering needs are anticipated for many projects including those that are undertaken close to Lake Ontario, these needs can significantly exceed estimates and contingencies. In some cases, de-watering specialists need to be called in during work execution as excessive and unanticipated water levels delay the project and increase costs. Further complications can arise if soil is contaminated and de-watering is required. Finally, Toronto Hydro may need to obtain a permit from the City of Toronto to pump water out and to release it in the City's sewer system. An example of excessive de-watering needs occurred during the civil construction work associated with the Copeland TS project. Some of the conduits and cable chambers being built as part of this project resulted in approximately $375,000 in additional costs for excessive de-watering.

Beyond the de-watering challenges described above, complications can also arise with de-watering that is required following heavy rains. For example, the heavy rain on July 9, 2013 and the flooding that ensued caused work at a number of Toronto Hydro's construction sites across the City to stop until de-watering could be completed. Project schedules as a result were generally delayed for approximately four days each.

A third set of challenges associated with the natural environment is related to vegetation, specifically trees. Many of Toronto Hydro's overhead and underground construction projects have the potential to negatively impact trees and as part of the design and estimating process, Toronto Hydro takes into consideration precautions to protect trees. These precautions are often conditions of obtaining permits and approvals from the City of Toronto. These conditions are enforced by City inspectors that may visit sites during construction. In many cases, precautions must be expanded upon or altered during work execution based on conditions that are identified at the time. For example, Toronto Hydro may need to dig deeper, alter trench routes, or construct unplanned tree tunnels during work execution to avoid damaging a tree. These requirements can and do result in delays and additional costs.

2. EXTERNAL STAKEHOLDERS

Work execution challenges often arise as a result of external stakeholder needs, preferences, requests, and actions. External stakeholders include the City of Toronto, Toronto Hydro's customers, Hydro One, and a wide variety of other organizations and individuals that have an interest in the work that Toronto Hydro undertakes. Challenges that are related to external stakeholders can greatly impact project and program schedules and costs as illustrated by the examples that follow.

2.1. The City of Toronto

A significant stakeholder in all work that Toronto Hydro undertakes is the City of Toronto. The vast majority of Toronto Hydro's assets are located on City road allowances and co-exist with City (e.g., water and sewer systems, roads, sidewalks) and other utility (e.g., telecommunications, gas lines) and non-utility (e.g., transit) infrastructure. To enable the efficient management of road allowances, the City has implemented a number of co-ordination, permitting, and approval processes that have the potential to influence work execution, schedules, and budgets.

An example of how the City's processes can impact work execution is road moratoria that are implemented following City road improvement projects.[1] Depending on the type of road (e.g., road, curb, sidewalk) improvement that the City undertakes, utilities such as Toronto Hydro will not be granted permits to conduct subsequent construction work for a period of three to ten years.

In situations where the City advances or provides short notice for road improvements, Toronto Hydro must re-prioritize work to ensure that projects that are planned in the short and medium terms are completed before a moratorium goes into place. A specific example of this is work that Toronto Hydro planned in the Hogg's Hollow area of Toronto. Plans were to initially execute the work in five sequential phases. When the City announced that it was moving forward with road improvement work, Toronto Hydro brought forward the execution of the fifth phase to avoid a road moratorium after 2013. Re-prioritizing projects in this manner can force the deferral of another project and has the potential to increase costs depending on whether the project must be undertaken by a different contractor or resource group.

[1] Moratoria are implemented by the City's Municipal Consent Requirements for the Installation of Plant Within City of Toronto Streets, pursuant to the City's authority over highways (public roads) under sections 32 and 33 of the City of Toronto Act, 2006, S.O. 2006, C. 11, Sched. A.

Another example is work that Toronto Hydro had to conduct as a result of a series of City projects (e.g., granite sidewalk retrofit; water main replacement) in the vicinity of Bay and Bloor Streets. During one project, Toronto Hydro was given only three months to complete its work and during another project, Toronto Hydro had to rebuild an overhead pole line during the Christmas season. Typically, work in this area is constrained as restrictions to only work certain hours of the day, to only occupy a certain length of street at a time, to minimize disruption to local business, and to eliminate work during rush hour are in place. Given the tight timelines imposed, Toronto Hydro had to obtain noise exemptions from City and crews had to work overtime resulting in costs that would not otherwise have been required. Another project on Asquith Avenue in the same vicinity needed to be delayed entirely and was only completed in 2014 as a result of City work in the area.

On many occasions, challenges that arise as a result of City requests do not result in delays or additional costs, but instead result in a need to advance costs from one year to the preceding year. One example is a voltage conversion project south of Bloor Street. Initially, Toronto Hydro had planned to finish the project by May 1, 2014 when the City asked for the project to be completed by March 31, 2014 due to a planned water main and sewer replacement project. To accommodate the City's request, Toronto Hydro started construction in the last quarter of 2013 and advanced more than $200,000 of expenditures into 2013. Another example is a project to place direct buried cable on Starview Lane and Rockbank Crescent in the Weston Road and Sheppard Avenue area. To avoid a scheduling conflict with other City's water main and sewer work, Toronto Hydro advanced an additional $250,000 into 2013.

2.2. Customers

A second set of stakeholders that can introduce unexpected challenges during work execution are customers and members of the public. Although Toronto Hydro undertakes

significant customer engagement activities (e.g., informational letters, town hall meetings, responses to requests for accommodation) before and during planned work, and although the vast majority of Toronto Hydro's customers are supportive and very reasonable when work is being undertaken in proximity to their homes and businesses, incidents and challenges do arise.

One example is the aforementioned set of projects at Bay and Bloor Streets in downtown Toronto. During one project, pedestrian control in the area became so challenging that Toronto Hydro had to increase the budgeted number of paid duty police officers from one to two. In addition, one of the buildings along the project route started renovations at the same time that Toronto Hydro's project was to be executed. The building's contractors installed scaffolds outside the building for two months and this prevented Toronto Hydro from commencing its project during this time.

2.3. Hydro One Networks

Toronto Hydro is supplied by Hydro One Networks Inc. ("HONI") and owns equipment at 34 transformer station sites that are owned by HONI. The equipment at station sites is tightly integrated and the two companies must closely coordinate planned work. At times, even the best efforts and plans cannot fully mitigate the risk that challenges will arise and delays will occur.

3. OPERATING ENVIRONMENT

Work execution challenges that are brought by the Operating Environment relate to issues that arise as a result of working within congested underground utility corridors that are shared with other service providers such as the City of Toronto's Water Division, natural gas and telecom companies. This includes past tenants or users of the space that now makes up the corridors. These challenges, as illustrated below, can greatly influence

Toronto Hydro's ability to execute work on schedule and on budget.

3.1. Aging Infrastructure

Challenges often arise due to the need to work around aging infrastructure that is often owned by third parties (or Toronto Hydro). One example of this is water and sewage lines. Around these lines, Toronto Hydro utilizes specialized excavation techniques such as vac-truck digging to mitigate the risk of damage. However, aging lines have at times broken open despite the use of these techniques and have caused water or sewage spills that delay projects and increase costs.

A particular example of the unexpected failure of water and sewage lines during the execution of a Toronto Hydro project occurred on Laird Drive in East York. As illustrated in Figure 1, a sewer line was uncovered during the project, the line began to leak as a result of a defective fitting. The fitting needed to be replaced and the line needed to be supported during the construction of the duct bank.

Figure 1: Sewage Line Uncovered During Duct Bank Construction

As part of the same project, a water line was also uncovered while constructing a new cable chamber. This water line began to leak and water migrated into the chamber as shown in Figure 2. These two issues caused several weeks of delays in the construction schedule of the Laird Drive project.

Figure 2: Water Line Leak Flooding Cable Chamber During Construction

Another particular example occurred where Toronto Hydro needed to construct a duct structure well below an old existing water main. This main can be seen at the bottom of the trench in Figure 3. During excavation, the water main broke. (Water can be seen running in the trench in Figure 3.) The main had to be repaired and supported by chains, which caused delays and additional costs in the project.

Figure 3: Water Main Leak at the Bottom of a Trench

Beyond aging water and sewer infrastructure, challenges also arise during work execution in the vicinity of telecommunication infrastructure and even Toronto Hydro's own infrastructure. For example, older telecom cables were buried directly into the ground without concrete encasings as found during a recent project on Toresdale Avenue in North York. Precautions to mitigate the risk of damage to in-service cables during the Toresdale Avenue project added to costs and, if damage had occurred, would have resulted in delays. Precautions must also be taken with Toronto Hydro's own infrastructure, which often must be supported and maintained in functional condition throughout a project. The following figures illustrate live cables being supported during construction projects.

Figure 4: In-Service cable being supported as a large cable chamber was re-constructed in the aforementioned Laird Drive project.

Figure 5: In-Service cables being supported during a vault re-build at Wellington and Emily Streets in downtown Toronto.

Figure 6: In-Service cables being supported during a vault re-build at 390 Bay Street in downtown Toronto.

The complexity of some of these work sites and the necessity to support at times aging and deteriorated assets can lead to issues, risks, delays in work schedules, and increased costs.

3.2. Undocumented Sites and Infrastructure

During work execution, it is not uncommon for Toronto Hydro to encounter sites and infrastructure that are not documented or difficult to anticipate. Some of these discoveries can be accommodated within the scope of a project. However, some are particularly unique and result in unavoidable delays and costs. Discoveries often cause

projects to be placed on hold as they necessitate investigations, project redesigns, and new permits.

One example of a unique discovery during work execution is an unregistered archaeological site that was found on Scenic Hill Court in Scarborough. The discovery was made during an underground duct construction project and resulted in a four-month delay in the project.

A second example of a unique discovery is an old undocumented gas pipe that was found during a system expansion project to supply new customer load. The project was replacing an overhead single circuit steel pole line with a new double circuit wood pole line. When an old cast iron pipe was discovered, pole installation was halted and a subsequent investigation revealed that the pipe was an abandoned gas main (see Figures 6 and 7 below). Enbridge was contacted and approval to break out the abandoned gas main at the proposed new wood pole locations obtained. The impact of the abandoned pipe, which included breaking out the pipe at 28 pole locations, resulted in approximately $120,000 of additional expenditures and a three-week delay.

Figure 7: Abandoned Gas Main Found During Pole Placement

Figure 8: Pole Placed in Vicinity of Abandoned Gas Main

INDEPENDENT ASSESSMENT OF TORONTO HYDRO'S DISTRIBUTION SYSTEM PLAN AND BUSINESS CASES

Review of Proposed Projects and Programs to be Filed before the Ontario Energy Board for the 2015 through 2019 Rate Period

The star design is a trade mark of Toronto Hydro Corporation used under licence.
'Toronto Hydro' means Toronto Hydro Electric System Limited.

JULY 29, 2014

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EXECUTIVE SUMMARY

Navigant Consulting Ltd. (Navigant) was retained by Toronto Hydro-Electric System Limited (THESL) to conduct an independent review of THESL's Distribution System Plan (DSP), prepared to support distribution projects and programs that THESL plans to submit for approval under the OEB's Chapter 5 requirements for electricity transmission and distribution applications. The specific investment categories and business case segments that Navigant reviewed are listed in Table 1.

Table 1: DSP Capital Investments Reviewed by Navigant

Based on our review of THESL's DSP and the business cases it prepared to support its five-year spending plan (for simplicity, "the proposed investments"), Navigant has concluded the following:

1. THESL's DSP supports the OEB's four performance outcomes; customer focus, operational effectiveness, public policy responsiveness and financial performance as outlined in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (Chapter 5). Further, THESL's DSP addresses specific provisions set forth in applicable subsections of Chapter 5.
   - Where applicable, the proposed project plans provide information on customer engagement to identify customer preferences. THESL has taken steps to ensure that customer inputs were taken into consideration, and to ultimately provide economic efficiency, superior performance and cost-effectiveness for its customers.
   - THESL has provided descriptions of how its proposed assessment, management strategy and capital expenditure plans best maximize the opportunities for operational effectiveness and continual improvements for productivity and cost performance.

- Proposed projects are explained and rationalized as to how the capital expenditure plan is integrated with public policies (government mandates) where applicable.
- Each of the projects proposed offer justification for prudent capital expenditure and show they can be executed with financial viability and operational effectiveness. Furthermore, the project plans provide details of how these efficiencies can be sustained over the long term.

2. The proposed projects in each investment category of THESL's DSP are required and justified based on methods and criterion that reflect Chapter 5 objectives.
   - The DSP provides a clear and concise approach to asset management and planning, including the data bases and decision tools it used to prioritize and select capital projects that appear in its five year investment plan.
   - Business cases consistently apply methods outlined in DSP asset management processes, and the results of THESL's evaluation confirm that the solutions it proposes are the preferred alternative based on performance and economic criteria.
   - The proposed investments are consistent with solutions other similar utilities have or propose to implement; for example, utilities throughout North America are replacing obsolete air blast magnetic breakers, transformers and communications and control systems.
   - Several of the proposed projects reflect the intent of relevant sections of OEB Chapter 5, the Ontario Distribution System Code and Electrical Safety Authority (ESA) rules and regulations with respect to power system safety and reliability.

3. THESL's DSP and proposed projects prudently address key drivers such as condition, safety and growth in a responsible and efficient manner, and are consistent with other utility practices.
   - Each of the projects proposed in the four investment categories addresses important reliability, safety, and performance issues. Deferring these projects will degrade service reliability and quality of service to THESL customers.
   - Several of the safety related upgrades, including breaker and switchgear replacements, are issues that many other utilities have encountered and have proactively addressed or are addressing.
   - Many of the deficiencies THESL has identified and proposes to address were identified in Asset Condition Assessment (ACA) procedures and DSC mandated inspections, and should be addressed without unreasonable delay.

4. THESL's decision tools, planning criteria and design practices underpinning the business cases in the DSP are consistent with industry best practices.

   - THESL planning criteria with respect to equipment loading and distribution feeder design are consistent with other utilities, except in the downtown Toronto core, where feeder back-up is provided by intra-station ties instead of inter-station feeder ties.
   - Where differences in standards exist, they typically are due to constraints associated with operating energy delivery facilities in a major urban center, or because of unique equipment requirements due to higher operating voltages or subject to higher fault current levels.
   - The decision tools and processes cited above have been consistently applied in THESL's business cases, where projects are selected based on a thorough evaluation of reliability, safety, economic, environmental and other factors applicable to each investment category.

5. The methods and tools employed by THESL to evaluate and select the proposed projects are appropriate, and meet or exceed those employed by electric utilities in Ontario and other provinces. The business cases provide ample evidence that the projects are not only required, but have been thoroughly evaluated.

   - THESL has conducted extensive technical evaluation of the condition of the assets it proposes to upgrade or replace. The underlying reasons as to why the equipment or facilities proposed for renewal are deficient are clearly evident from the analyses THESL engineers and support staff have performed and documented in the business cases.
   - Proposed upgrades are based on rigorous and thorough condition assessment methods, using modern tools and methods. For example, power transformer and breaker replacements were selected, in large part, based on physical data from DGA records that confirms declining performance or potential for failure.
   - Project need and the evaluation of alternatives are based on similar asset management best practices and principles that leading utilities now employ, including optimizing the timing of renewal investments based on trade-off of cost and risk.

6. THESL's proposed projects are coordinated to ensure they will result in the maximum utilization and efficient use of equipment.

   - Project selection is based on sound asset management practices and principles that are consistent with those we have seen at other utilities that have adopted best practices and solutions. These include use of asset condition data and decision tools that ensure renewal investments optimize the timing of replacements or upgrades.
   - Several projects are complementary; that is, investments often are needed to ensure maximum efficiency and utilization of equipment, particularly those designed in consideration of area planning.

- Some assets are nearing maximum utilization and new facilities are needed to serve growing load and to ensure reliability is maintained. Downtown Toronto is one of the areas experiencing capacity constraints and increased risk of exposure to high impact events. For example, downtown station's capacity constraints will be addressed by a combination of new feeder ties, expanded station capacity and targeted CDM in the form of localized demand response.

- Some investments are needed to support City of Toronto initiatives, including major in-City roadway projects that will require major relocation of underground facilities and cables.

7. THESL's proposed aggregate capital spending of approximately $490 million annually over the five year period is reasonable and justified based on the information and analyses provided in THESL's DSP. There are potential undesirable consequences to system reliability, safety and performance if THESL does not proceed with the proposed projects.

   - THESL's proposed spending is the minimum needed to complete the continuation of ICM programs in 2015 and to maintain a reasonable balance between risks and costs over the five year rate period. The level of spending is higher than the prior five years, but is the minimum required to reduce the backlog of end-of-life asset replacement by 2037 and meet OEB Chapter 5 requirements.

   - The technical and economic analyses THESL has developed to support capital is rigorous and consistent with Chapter 5 guidelines for each of the four major spending categories.

   - Data and analyses presented in the business cases demonstrate that key distribution equipment and facilities are increasingly at risk of failure or are inadequate to reliably serve current and future load. System reliability and customer satisfaction are expected to decline in the absence of proposed investments as these risk factors increase and equipment performance declines.

   - THESL is proposing to responsibly address known safety and performance deficiencies that company personnel have identified, including structures, devices and facilities that place public and crew safety at risk. Similarly, the known deficiencies associated with primary distribution equipment should be addressed to reduce safety risk to THESL crews and minimize the potential for interruptions or longer restoration times for customers.

   - Without the proposed investments, THESL customers would likely see higher costs in the form of increased O&M, longer restoration time, and greater likelihood of collateral damage due to catastrophic equipment failures.

   - Timely completion of key major projects is needed to complement Hydro One renewal programs, and vice-versa, with sub-optimal performance and higher costs if these are not installed as THESL and Hydro One have proposed.

In summary, each of the proposed investment categories and business cases in THESL's DSP that Navigant reviewed is consistent with those currently or previously undertaken by many other urban utilities in Canada and the United States that Navigant has evaluated. Notably, we did not identify any projects or measures that are inconsistent in scope or need with programs implemented elsewhere. In Navigant's view, because of these reasons and the review and analysis presented in subsequent sections of our report, the proposed projects in THESL's DSP are reasonable and justified.

INTRODUCTION AND BACKGROUND

Background

Chapter 5 of the OEB's Filing Requirements for Electricity Transmission and Distribution Applications sets forth guidelines and objectives applicants must follow to support proposed capital investments.

THESL has prepared a Distribution System Plan (DSP) to support proposed investments for the years 2015 through 2019 based on requirements in Chapter 5. The DSP includes detailed business cases for each major project or program under which THESL seeks OEB approval.

Navigant's Scope of Work

Navigant was retained by THESL to conduct an independent review of its Distribution System Plan (DSP) and business cases that it prepared to support proposed capital investments from 2015 through 2019, inclusive.

Specifically, Navigant was asked to answer the following questions in its review:

1. Is THESL's Distribution System Plan (DSP) consistent with the guidelines, objectives and criteria set forth in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (Chapter 5)?
2. Does THESL's DSP and proposed investment plan satisfy the objectives set forth in Chapter 5?
3. Are the business cases that THESL presents in its DSP consistent with the requirements of Chapter 5?
4. Does each of THESL's business cases apply the methods, tools and criterion outlined in its DSP, and has THESL provided sufficient evidence to justify the proposed investments?
5. Are THESL's design and planning practices consistent with utility best practices?
6. Are the methods and tools employed by THESL to select proposed projects appropriate and sufficient to justify the investment?

Navigant conducted its independent review and assessment based solely on information and findings obtained from documents THESL prepared under five DSP document categories listed below. Navigant did not request nor did THESL advise as to content or suggest modifications to any of the findings or conclusions contained in this report.

1. Section A: Distribution System Plan Overview

2. Section B: Coordinated Planning with Third Parties

3. Section C: Performance Measures for Continuous Improvement

4. Section D: Asset Management Process

5. Section E: Capital Expenditure Plan (including Business Cases)

Section E includes detailed business plans based on the methods, criteria, and evaluation framework set forth in Sections A through D. These business cases are grouped according to four categories outlined in Chapter 5. Navigant's review includes a detailed assessment and evaluation of over 30 specific business cases, grouped according to the four OEB investment categories listed in Table 2.

Table 2: THESL Capital Investments Reviewed by Navigant

Navigant's Approach

For each investment category, Navigant reviewed the overall robustness of the business cases in terms of establishing that the projects are required and sufficiently justified to support each of the proposed investments. The criteria considered by Navigant in its review included, among other factors, the following:

1. Comprehensiveness of impact analysis including underlying logic, quantification of benefits wherever possible, and linkage back to a robust, systematic capital planning approach used by THESL.
2. Prioritization within the cases, as appropriate (e.g., why do the recommended units need to be replaced or upgraded?) and rationale for such prioritization.
3. Clarity regarding impact of the proposed investment relative to other capital investments or expenses (e.g., maintenance, do nothing, capitalized maintenance).

4. Robustness of analytical methods and technical support for establishing need and the impact on reliability and performance if the projects are not funded and implemented by THESL.
5. Identification of options considered and robust analysis of these options clearly showing the advantage of the preferred options.
6. Comparison with industry practices and standards as appropriate (e.g., asset economic end of life schedules).

Navigant also reviewed THESL's Feeder Investment Model (FIM) methodology and how it was applied to support each of the business cases in terms of consistency with industry practice and sound logical underpinning.

In the sections that follow, Navigant answers the six questions set out at the beginning of this section.

DISTRIBUTION SYSTEM PLAN OVERVIEW

In this section, Navigant addresses THESL's Distribution System Plan ("DSP" or the "Plan") with respect to consistency and compliance with the guidelines and objectives set out by the OEB. Specifically, our review of the DSP is intended to address the following question:

Is THESL's Distribution System Plan (DSP) consistent with the guidelines, objectives and criteria set forth in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (Chapter 5)?

Distribution System Plan Framework

Our review of THESL's DSP, including relevant chapters and sections contained in Sections A through E, confirms that the Plan meets each of the requirements set forth in Chapter 5. Navigant reviewed in detail THESL's DSP framework presented in Section A through D, and specific business cases in Section E, and has determined that THESL has developed a DSP with sufficient rigour and supporting analysis to justify the proposed levels of spending throughout the rate period. Additionally, Navigant has determined that the methods, tools, and system that THESL used to evaluate and justify proposed capital spending in its DSP meets or exceeds current utility practices. Our determination is based on comparable reviews Navigant has conducted in Ontario, the United Kingdom, the United States, and other provinces in Canada.

The basis for our conclusions and opinions regarding THESL's DSP is supported by the detailed review and assessment in sections that follow.

Overview

The following presents Navigant's general findings and opinions on the processes, tools and methods THESL developed and applied to support proposed capital spending throughout the five year rate period. Navigant's findings with respect to the above are based largely on the DSP overview and framework presented in Sections A through D, and application thereof to individual business cases in Section E. Our independent assessment seeks to make a determination as to the whether THESL's DSP is consistent with Chapter 5 guidelines and objectives, and to identify potential opportunities where new data or information could be incorporated into THESL's planning for greater optimization of proposed investments during the five year rate period.

Asset Management Plan

Section D of THESL's Application provides a concise overview of the processes, systems and methods it uses to manage its capital assets, and to meet an overarching objective of optimizing spending over the rate period to meet customer and performance objectives at acceptable cost and rates. THESL's AM objectives are set forth in the following excerpt, which

appears in Sections A.1.2 and D.1.1 of its filing documents. Navigant believes these objectives are consistent with the OEB's general requirements set forth in Chapter 5.

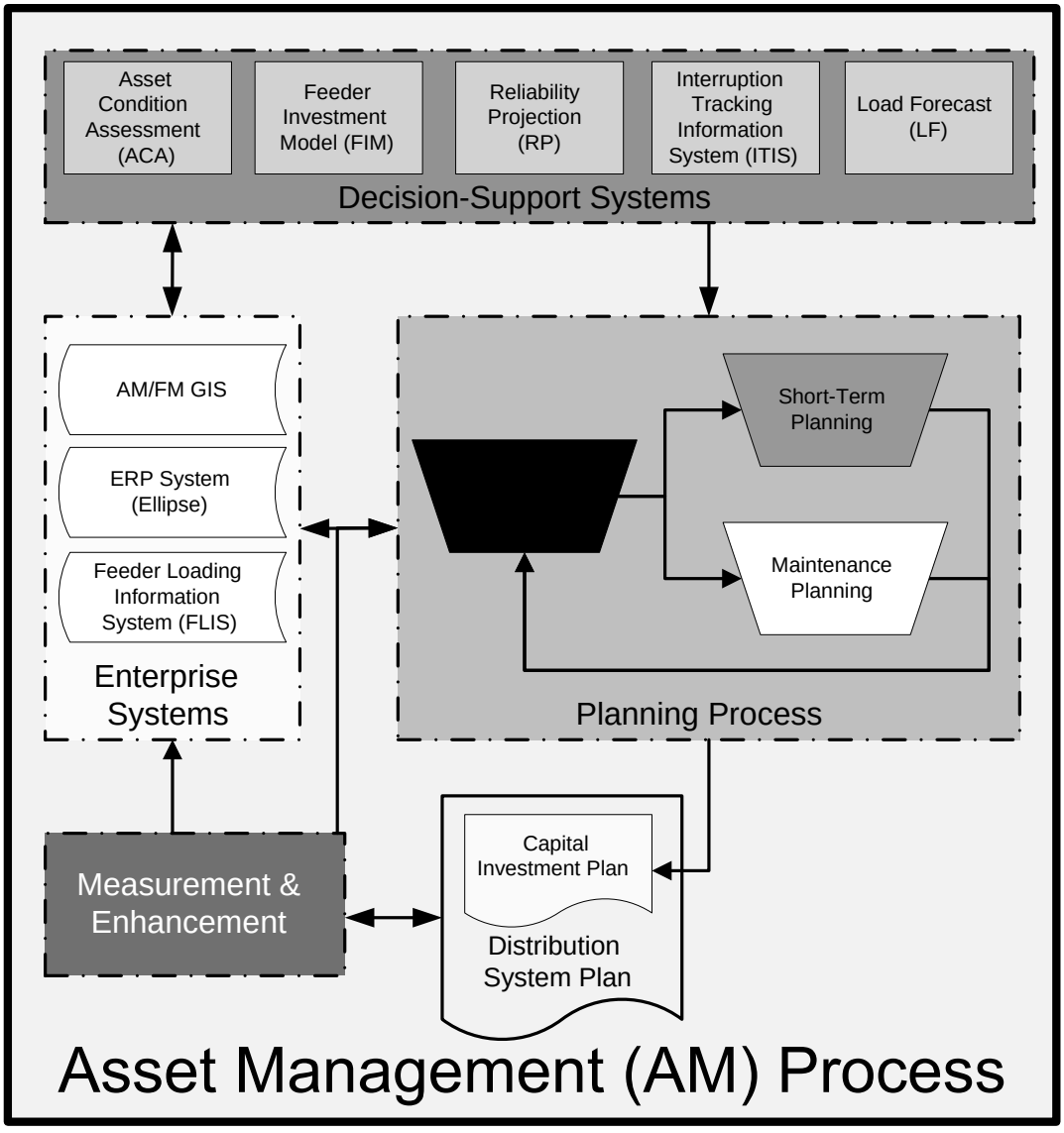
> Toronto Hydro's asset management objectives proactively identify, manage and mitigate deficiencies and risks to the electrical distribution system in order to (i) maximize value to the utility's customers, (ii) minimize or eliminate safety risks, and (iii) strike an optimal balance between required capital investment and risk costs associated with asset failure (Toronto Hydro refers to this balance as "steady state").

To maintain a desired balance in spending – THESL seeks to achieve spending equilibrium (i.e. "steady state" as described above) in a "paced" manner such that funds are spent at relatively consistent levels – the AM Plan outlines the approach THESL used to evaluate asset needs over the short-, mid-, and long-term to derive a level of spending that balances risk versus cost, consistent with Chapter 5 guidelines prescribed in Section 5.3.1. Figure 1 is a high-level process diagram THESL prepared to illustrate foundational elements of its AM plan, each of which Navigant has reviewed and analysed in forming its opinion on THESL's AM strategy, approach, and proposed spending plan.

Based on our prior review of THESL's previous ICM application and the current DSP, Navigant is able to confirm that THESL has developed a comprehensive Asset Management (AM) strategy that is based on key principles outlined in Chapter 5, and consistent with leading industry practices such as those outlined in British Publicly Available Standard (PAS) 55[1]. The strategies THESL's DSP has adopted are designed to identify renewal program requirements based on quantifiable data that accurately describe asset condition and risk. Our review indicates the information contained in the business cases include significant condition data based on measurements and root cause analysis, such as those performed for station transformers and overhead switches. THESL's DSP also highlights the associated risks if the investments are not undertaken. The EIM is one of the primary AM tools used to incorporate project economic value based on asset condition, risk factors and customer impacts.

[1] PAS 55 recently migrated to ISO 55001 & 2, which expands upon and incorporates most elements of PAS 55, but includes greater standardization requirements for auditing and certification; and separate segments on requirements and guidelines for application of asset management systems. The new standard has been adopted in the U.S., UK and Canada, among other nations.

Figure 1. THESL Asset Management Planning Process



Source: THESL Application, Section D: Figure D1.2.2 Asset Management Planning Process Overview

Decision Support Systems

Figure 1 includes five decision support systems or tools THESL relies on to evaluate project need and investment alternatives. Each of these systems links to AM databases to support the planning processes for selection of investments and formulation of the DSP. Our assessment of each of these systems and related processes follows.

Asset Condition Assessment (ACA)

The ACA is a critical element of THESL's AM processes for evaluating capital investment options, as it relies heavily on ACA data to support spending for asset renewal. The renewal

of assets that have deteriorated or are otherwise obsolete is based largely on application of ACA metrics for virtually all major equipment categories. THESL's use of ACA to determine the condition of distribution asset extends to the past decade, when it created asset records and a methodology to categorize the condition of its assets based on consistently applied testing, measurement and evaluation techniques. The results of a recent ACA audit indicate that many assets have deteriorated to a state where replacement, recondition or upgrade is warranted. To maintain spending at desired levels, THESL prioritized renewal projects by applying economic methods that incorporate risk and criticality; thereby enabling the selection of assets that demonstrate the highest level of need and justification.

In June 2014, THESL updated an ACA audit originally completed in 2007 and revised in 2012 by its independent consultant, Kinectrics, to include one new asset category (Network Protectors), and a series of other enhancements. The ACA processes and health indices now incorporate updated asset condition and failure data, enhanced equipment testing and inspection, and larger sample sizes.[2] The 2014 audit report presents asset condition data for 21 asset categories ranked by health indices on a scale of 1 through 5. The report also provides reasoning on how ACA data can be used for asset prioritization and ranking. It lists seven recommendations to further improve ACA processes, many of which THESL applied in this application, including data entered into Ellipse and used in BI (Business Intelligence) tool calculations[3]. THESL has provided information in its DSP that confirms it has or proposes to implement these recommendations.

The Kinectrics report confirmed a series of enhancements THESL has implemented since the prior audit, including changes in asset sample size and condition for each of the 21 categories included in the ACA. Results indicate relatively minor changes in asset condition for some of the 21 categories, but increased deterioration in others, such as station transformers and switchgear; Navigant views each of these as critical assets in terms of reliability, safety and customer satisfaction.

Navigant views the level of rigor and use of ACA data that THESL applies in its asset renewal selection process as consistent with industry best practices, supported by condition data and assessment methods that have evolved and continuously refined over time. In support of its DSP, THESL's ACA audit highlights those assets whose condition has remained relatively stable versus those that are experiencing accelerated deterioration. This information provides key input into decision tools, that THESL's distribution planners use to prioritize proposed renewal spending to assets that demonstrate greatest justification and need. It also indicates where asset upgrades or capitalized maintenance may be a more cost effective choice. In addition, THESL's incorporation of continuous improvement and monitoring of equipment performance, ACA data, and evaluation methods indicates it intends to update or revise

[2] Toronto Hydro Electric System Limited, 2014 Asset Condition Assessment Audit, Kinectrics Inc. Report No: K-418649-RA-R00, June 20, 2014.

[3] Specific recommendations appear in the Kinectrics report.

specific business case investments during the 2015 through 2019 rate period using the most current information available at the time of implementation of the investment. Navigant views THESL's approach as reasonable, as it will produce the greatest value to its customers for a given level of investment over the life of the asset.

Feeder Investment Model (FIM)

THESL uses a Feeder Investment Model (FIM) to evaluate the economic value of asset renewal capital investments options. FIM is a series of distribution simulation and analytical tools designed to predict asset performance and equipment loading under a range of operating conditions. The FIM incorporates key risk factors and life cycle economics to evaluate and justify project need and value, summarized in the following excerpts from Section D.3 – Asset Lifecycle Optimization Policies & Practices, which states that FIM is

> ". . . used as part of the Long-Term System Review Process to determine the asset renewal investment timing based upon the economic end of life criteria for each asset. It is through this approach that Toronto Hydro plans to eventually achieve a 'steady state" at the system level through the execution of its capital investment plan."

Where,

> ". . . 'steady state' represents an optimal balance between required capital investment and aggregate risk costs associated with the existing asset base, such that the total lifecycle cost of the broader asset population is minimized."

From the above statements and DSP process descriptions, THESL demonstrates that it has incorporated least-cost planning criteria and methods to support its investment strategy and proposed spending levels, which Navigant finds is consistent with OEB Chapter 5. Navigant also finds that FIM includes the capability to identify optimal investments for an appropriate range of performance, safety, operating efficiency and cost and performance factors. . . .

One of the key inputs is Value of Service (VOS), applied to net reliability gains achieved over the life of an asset or investment strategy to quantify a primary value driver for the investment. The use of VOS is consistent with Chapter 5 guidelines and practices that utilities in North America, the UK and elsewhere have applied. The assumptions for VOS components also are consistent with values applied by comparable utilities. THESL's predictive reliability impact analysis data, described below, is a key input for renewal and other project categories where VOS is a driver. The FIM model is applied to most renewal investments, in addition to other projects with a range of performance and cost trade-offs. The FIM model is used to determine the optimal timing of investments based on criteria that establish when an asset has reached end of life (in economic terms).[4] . . .

[4] Assets not evaluated using FIM are targeted for replacement based on estimates of useful remaining life.

THESL has consistently applied EIM to proposed renewal investments, which should result in least cost investment choices based on end of life economic evaluation criteria. The EIM results, coupled with other critical replacements THESL has identified, indicates up to a $2.5 billion backlog of assets exists for 2015 with another $1.55 billion for the remaining four years for a total of about $4 billion that is justified based on DSP economic end of life criterion. However, proposed spending for asset replacement over the five year rate period is much less, reflecting a desire to balance risk and cost via paced spending.[5] The validity of the levelized approach is supported by THESL's reliability metric projections, which indicate proposed spending will maintain or improve system performance up to 2019.

Reliability Projections (RP)

The RP is an important process and set of analyses THESL uses to predict the reliability benefits associated with proposed upgrades and renewal replacements, including the impact on reliability for reinforcement and replacement options.[6] This capability is important, as the accuracy of the RP is contingent upon ACA data and predictive methods that quantify reliability impacts over time, including accelerated degradation for "do nothing" or "run to failure" strategies.

Databases

THESL relies on several data bases, collectively referred to as its Enterprise system, for use in its planning process and decision support tools described above. It includes asset records and condition data contained in THESL's Ellipse data base, a system commonly used by utilities for tracking and recording of maintenance and performance data. Similarly, the AM/FM GIS contains diagrams and feeder attribute data needed for planning, design and construction of the distribution system. It also provides requisite links or inputs to GEAR, and plant record keeping systems. The reliability data base provides failure history and cause code information needed to assess risk factors and the extent to which candidate solutions will impact reliability, safety and performance. As noted in our ACA review, THESL reports that the accuracy and quantity of data stored has risen over the past several years, commensurate with increases in sample size and quantity of information collected.

Feeder loadings are continually read and downloaded from the SCADA system and captured in a Feeder Loading Information System (FLIS) to provide information distribution planners use to conduct short , and long term capacity studies. The data also ensure distribution simulation studies of feeder performance and operation are based on accurate loading data. This process is similar to those applied by most utilities to evaluate capacity alternatives and proposed spending.

[5] Replacement spending of up to $4 billion over five years also would create disproportionate and unacceptable rate increases.

[6] In the absence of proposed spending programs, reliability would degrade to a SAIFI of 1.99 and SAIDI of 1.50.

THESL's reliance on and accuracy of systems such as Ellipse, AM/FM/GIS, FLIS and reliability history is consistent with leading industry practices, as each provides critical input to decision and planning tools that the company relies on to determine assets that present the greatest risk and economic impact. The data also is used to prioritize and select investments among candidate options. The data also support processes such as current state analysis (CSA) for determination of such conditions as distribution reliability, performance history and remaining life of key equipment. Importantly, THESL has established processes to ensure data quality is maintained and used properly in its suites of tools and systems. Navigant views THESL suite of Enterprise data bases, type of data collected, and quality assurance processes to be consistent with current industry practices.[7]

Other Key Asset Management Metrics

Navigant also finds that THESL has appropriately used other key AM metrics to justify and support investments included in its AM plan and business cases. These additional AM metrics include distribution system attributes such as urban versus rural, underground versus overhead, temperate versus extreme weather and fast versus slow economic growth areas.

Capital Planning Process

THESL's capital planning process is designed to consider investments across three broadly defined investment categories, each reflecting a range of business drivers and planning horizons. Figure 2 presents these three categories, which includes two sub-categories for AM investments based on risk based versus useful life economic justification methods. Each investment category includes evaluation processes that determine when intervention is required to achieve an optimal balance of spending versus risk.

Figure 2.

Section E.2.1: Capex Planning Approach

[7] Navigant's review focused on the systems, procedures and application of Enterprise system data. However, Navigant did not conduct a review of data accuracy.

THESL's planning process includes recognition of DG interconnection and integration requirements. Specific upgrades and mitigation strategies are proposed to relieve constraints that currently limit the amount of DG that can be installed in various sections of Toronto.

Key Business Drivers

Table 3 presents the key value drivers THESL prepared and presented in Section 2A.2.1.1 Navigant reviewed these drivers and the analyses THESL presents in specific business cases and supporting sections and has determined that these drivers are consistent with Chapter 5 requirements and guidelines. THESL's asset management based approach to developing its DSP and proposed investment incorporates inputs and data for each relevant driver. The business cases prepared by THESL and reviewed by Navigant demonstrate that drivers listed in Table 3 also are consistently and appropriately evaluated to support proposed investments.

Table 3. Key Business Drivers by Asset Category

A key outcome of THESL's capital investment program is improved distribution system reliability performance (as measured by system reliability metrics). By 2019, THESL expects reliability as measured by outage (interruption) frequency and duration will improve:

- SAIFI (system average interruption frequency index): Reduce from 1.53 to 1.13
- SAIDI (system average interruption duration index): Reduce from 1.21 to 0.97

The above reductions represent a significant improvement in reliability. Although THESL seeks to balance investments over the five year rate period to balance costs versus risks, it also has instituted a reliability improvement program designed to lower (i.e. improve) these two metrics at low cost. In addition to targeted renewal programs that optimize spending based on reliability performance, THESL's reliability improvement program also includes low cost, smart grid investments such as feeder automation and equipment monitoring to achieve these gains. This strategy is consistent with leading practices utilities have implemented elsewhere in Canada, the UK and North America.

Load Forecast

THESL projects increases in peak demand at each of the 35 station busses serving 13kV and 27kV load. The forecast is based on known changes in building construction and population forecasts, which are continuously monitored for changes, including proposed load transfers that make best use of available station bus or transformation capacity among adjacent stations; particularly important at downtown stations where capacity upgrades are most costly. The forecast also incorporates CDM measures in the forecast, including targeted demand response to reduce peak demand in the relatively few peak load hours. These practices are consistent with or exceed industry practices, particularly with respect to incorporation of CDM in localized forecasts.

CDM and Distributed Generation

THESL's planning methodology includes "non wires" options as candidate solutions to meet capacity shortages caused by growing demand. Key among these is targeted CDM, designed to defer capacity additions on a cost effective basis. Programs THESL proposes are comparable to other programs Navigant has encountered or supported, such as Consolidated Edison Company of New York's Targeted T&D DSM program. Non wires solutions also are included in the Central Toronto Integrated Regional Resource Plan (IRRP), currently underway.

These measures include a comprehensive Demand Response program designed to reduce distribution peak demand in Section E.7.10 (Local Demand Response). The DR program THESL proposes is consistent with Chapter 5 guidelines that recommend applicants consider load control and efficiency as a means to defer distribution capacity investments at the station level, where the value of capacity upgrade deferrals often is high due to the complexity of design and high cost of major equipment components. Because of long lead times for planning and design of both station and local DR programs, THESL's targeted program is suitable for deferring station capacity over the mid to long term. For this application, the downtown Cecil station is targeted for deferral, as the cost of upgrades and criticality of the station makes it an ideal candidate for localized DR. THESL and its consultant, IDF, conducted a series of economic studies of both capacity and DR options under a range of tests using an external model (e.g., total resource costs, ratepayer, as opposed to Avoided Risk Cost

(ARC) or Cost of Ownership (COO) under its Business Case Evaluation (BCE), and the DR program produces favorable results in terms of cost effectiveness. The use of a set of tests other than BCE is appropriate given the nature and timing of DR programs, which are comparable to energy efficiency programs where use of such tests are common. Accordingly, Navigant finds that THESL's DR program meets this objective on a cost effective basis, as it will defer up to 9 MW of capacity by 2019.

Although limited to Cecil for this application, almost half of THESL's 35 major stations will require capacity upgrades by 2025. Navigant concludes that Localized DR programs ultimately will result in cost effective deferral of future capacity upgrades. Although not cited as a primary objective, Navigant notes that the Local DR program also relies on smart technology and communications, consistent with Chapter 5 smart grid objectives.

THESL's current projection of DG capacity additions by 2019 is 626 MW, about 200 of which is renewable energy sources. Table 1 summarizes these additions by type and year.

Table 4. DG Capacity Additions

Past and current studies reveal DG capacity is constrained at the transmission and distribution level. A major limiting factor is station equipment, typically breakers, that is not rated to accept the additional fault current contribution from DG. Reverse power flow on DESN power transformers is an additional constraint.

Because these constraints are evident at both the transmission and distribution level, HONI and THESL each have proposed several mitigation options to relieve these constraints. HONI expects to complete major equipment upgrades at Manby and Leaside (also referenced in THESL's 2012 ICM filing) in 2015 while THESL will implement upgrades coincident with DG capacity projections in Table 4.

Other THESL upgrades designed to relieve constraints include enhanced protection, real-time monitoring and control, and bus tie arrangements. The use of advanced monitoring and controls is needed to safely and reliably integrate large quantities of DG. These real-time systems rely on smart technology and communications, consistent with Chapter 5 objectives. These strategies are reviewed in greater detail in several of the business cases we reviewed.

Performance Reporting

THESL proposes to enhance performance measurement processes and monitoring to ensure continuous improvement of processes, data and methods used to support investments, and assure accountability of results. The concepts THESL has outlined are consistent with Chapter 5 guidelines and approaches implemented by other utilities.

THESL's Investment Plan

THESL proposes to spend approximately $490 million annually over the five-year rate period. Figure 3 presents total annual spending for each of THESL's DSP investment categories. Notably, about one-half of proposed spending is for asset renewal, reflecting a level of spending designed to gradually reduce the backlog of assets that have reached economic end-of-life without compromising reliability, safety or performance. The investment strategy appears warranted, as an accelerated approach to decrease the backlog would increase annual capital spend by about 60 percent, with attendant undesirable rate impacts. It also reflects a minimum level of investment needed to maintain distribution system performance, reliability, safety and performance at a level consistent with customer expectations and OEB Chapter 5 requirements.

Based on our review of THESL's AM-based planning processes and individual business cases, Navigant finds that the proposed five-year investment plan is justified and consistent with OEB Chapter 5 requirements. Further, performance monitoring and measurement procedures will help ensure that appropriate adjustments and refinements to specific investment plans can be made based on new information received during the five-year rate period.

Additional details and rationale supporting this finding is providing in subsequent sections and business case reviews.

Figure 3. Proposed 5-Year Investment Plan

BUSINESS CASE REVIEW

In the following, Navigant opines on the benefits of the proposed investments, with emphasis on the likely outcomes and benefits that will accrue to THESL customers from DSP investments. Our review seeks to answer the following questions regarding consistency with THESL's DSP framework and Chapter 5 requirements.

Does each of THESL's business cases apply the methods, tools and criterion outlined in its DSP, and has THESL provided sufficient evidence to justify the proposed investments?

Concurrent with its review of Sections A through D, Navigant conducted an independent review and assessment of business cases THESL prepared in Section E of the DSP. Navigant's assessment of THESL business cases, summarized in Appendix A, includes two key objectives:

1. Develop a thorough understanding of the specific business cases THESL prepared for each the four OEB investment categories outlined in its Chapter 5 filing requirements.

2. Determine the extent to which THESL adopted the principles and methods set forth in Sections A through D to specific business cases and Chapter 5 requirements and guidelines for the four investment categories.

Given these objectives, our review of THESL's business cases seeks to answer the following question:

Are the business cases that THESL presents in its DSP consistent with the requirements of Chapter 5?

THESL has prepared detailed business cases that thoroughly address why the investment is needed and includes several alternatives and solutions, including "do nothing" and "run to failure" options. It has consistently applied the methods and principles outlined in its DSP, consistent with OEB Chapter 5, to support the level of investment for each business case. THESL also demonstrates that it has evaluated and selected alternatives within each business case based on life cycle economic criterion. THESL's business case analyses also confirm the investments will provide value to its customers over the five year rate period and beyond. For these reasons, Navigant concludes that the investments THESL proposes are supported and justified by the business cases it has prepared.

Navigant review of THESL's business cases is presented in Appendix A for each of the four OEB investment categories.

CONSISTENCY WITH UTILITY PRACTICES AND STANDARDS

In this section, Navigant addresses the degree to which THESL's practices and proposed projects are consistent with those used and implemented by comparable utilities. It includes an assessment as to whether THESL's practices meet or exceed those of other utilities, and reasons why differences exist in some segments of the distribution system. Specifically, this section sets out Navigant's response to the following question:

Are THESL's design and planning practices consistent with utility best practices?

To support its review, Navigant compared THESL's planning criterion, and design and construction practices to other comparable utilities in Ontario and other provinces. We also reviewed a June 2014 report prepared by Power System Engineering (PSE) that evaluated design standards and practices covering four areas.[8]

Design Practices

The PSE report confirms the adequacy of THESL's design standards, succinctly summarized in the following excerpts from the study.

> The SDP[9] document was found by PSE and LHB to be thorough, well documented and consistent with what is seen in the industry throughout North America as best practices.
>
> Overall, the standards and specifications contained in the SDP would not be perceived as insufficient or excessive.

Navigant agrees with PSE's overall assessment. Navigant's concurrence with these statements is based on our review of the PSE report and a prior independent review of THESL's design standards and practices that Navigant completed for its 2012 IRM filing. For the 2012 IRM, Navigant conducted a survey to support its findings relating to design standards and practices covering the following. Navigant considered these criteria, where applicable, in developing findings and conclusions herein.

- Distribution design and planning criteria
- Equipment selection criteria
- Station and distribution line loading criteria and practices
- Line relocation policies and practices

[8] Standards Review Study, Power System Engineering, Inc. LHB, Inc., January 14, 2014.

[9] The SDP refers to THESL's Standard Design Practices (SDP) document, which documents Company Standards as applied to the design of the electric distribution system.

- Equipment replacement (renewal) criteria
- Overhead and underground distribution design and protection
- Physical infrastructure and renewal programs
- Safety-related upgrades and replacements

Planning Criteria and Methodology

THESL's approach to planning recognizes differences in methods applied to assets where criticality requires short-term action versus assets where long-term planning methods are appropriate. The type of economic evaluation also differs for business case evaluation, where Avoided Risk Cost is applied to replacement of assets and Cost of Ownership for new or non-like-for-like interventions.

Long-Term Planning

Over the longer term, THESL's planning criteria and methods, outlined in various sections of its DSP, consider a range of options, including "non-wires" strategies such as CDM and localized Demand Response as alternatives to new lines and stations. THESL's long-term capacity planning also recognizes integration requirements associated with renewable energy generation (REG) and other forms of distributed generation (DG) such as CHP. THESL's planning processes thus must consider factors such as increased fault current contribution and two-way power flows on distribution assets. Operational considerations such as intertie transfer constraints, enhanced protection and the need to monitor third party generation become more apparent and critical as REG and other DG capacity increases.

THESL also must consider differences in the fundamental design of the distribution system. The mostly overhead 27kV system serving areas outside the downtown core has greater flexibility due to multiple feeder ties between stations; whereas the mostly underground 13kV system serving Toronto's downtown core has few feeder ties and limited station back-up at the transmission level. THESL has taken steps to proactively address these issues, including joint planning with HONI on development of east-west 115kV transmission tie lines and the construction of the Bremner station (renamed Copeland), each of which will provide greater flexibility and capacity serving critical downtown core load. In the DSP, THESL expands on this design philosophy via enhanced contingency plans for the downtown core, with increased feeder ties needed for load growth and reliability. It also is applying non-wires solutions in the form of localized DR for the Cecil station as a cost-effective alternative to new station capacity.

Short-Term Planning

THESL short-term planning focuses on assets where degradation, safety, municipal projects and relocations, and customer requests require near-term action. For assets that are rapidly degrading or where safety concerns are evident, THESL has taken steps to remedy deficiencies, which includes replacements from the 2012 IRM that will be completed in 2015

(also see Continuation of IRM projects in Business Case Review section). Strategies include enhanced maintenance, both corrective and preventative, as an alternative to replacement or upgrade. Key among these programs is THESL pole inspection and mitigation, where ACA data is used to identify poles in need of remediation or replacements. ACA data and current state assessment (CSA) results also provides information from which THESL can make cost-effective choices to address performance issues or known deficiencies. Each of these practices is consistent with practices Navigant has encountered at other comparable utilities that have adopted best practices for short term investment planning.

Based on the above and our review of documents that outline THESL's approach to planning its assets, supported by business case reviews, Navigant confirms that THESL has appropriately considered a diverse range of options and strategies, consistent with OEB Chapter 5. Further, the economic criteria and methods used to evaluate and rank options is consistent with leading utility practices.

Consistency with Industry Best Practices

As noted in prior sections, THESL's proposed projects are consistent with measures undertaken at other utilities with comparable service areas and electric system configurations. The methods that THESL has employed to determine need and sequencing of renewal upgrades also is consistent with current utility practices. This is particularly evident for high cost replacements such as power transformers and station switchgear, where THESL has undertaken a high level of rigour and significant analysis to determine where the need for renewal is greatest.

The replacement of obsolete equipment and facilities that are deteriorated and pose reliability or safety risks, such as non-arc resistant switchgear, is common among utilities, as are some of the more salient, and equally compelling needs to replace defective porcelain and change out of gang operated overhead switches – each of these programs are underway at many other utilities in Canada and the U.S.

The upgrade of communications and SCADA is also consistent with common utility practice, as sound and reliable communications provided via redundancy is now an essential component of utility monitoring and control systems. The increased sophistication of these systems and introduction of Generation Protection Monitoring and Control program is needed to enable increased penetration of distributed generation.

In summary, Navigant views THESL practices and proposed investment programs to be in line with those undertaken by other utilities that have adopted best practices for renewal programs. Such actions assure that THESL's energy delivery system will continue to operate safely and reliably. Further, the proposed investment schedule will assure that renewal programs are implemented in a scheduled and orderly manner, both during the 2015 – 2019 and thereafter, until the renewal backlog is fully addressed by 2037.

Overall Findings

From our in depth review of THESL's DSP, policies and practices, specific business cases, and planning methods and criteria, and prior experience evaluating similar utilities, Navigant finds that THESL's planning practices are consistent with those employed by other utilities and the requirements set forth in relevant sections of OEB Chapter 5. Significantly, business plans in THESL's DSP consider a diverse set of options and selects the least cost options based on life cycle economic criteria.

Based on our review of THESL documents and extensive work with other electric utilities in Ontario and other provinces, Navigant finds that THESL's design practices also are consistent with Chapter 5 guidelines and prudent utility planning practices. Where differences exist, such as limited downtown feeder ties, higher fault current rating of some station equipment, these are due to the unique challenges and requirements associated with a major urban system; many of which are discussed in THESL's DSP and business cases and that will be addressed through THESL's proposed projects.

CONFORMANCE WITH OEB DISTRIBUTION SYSTEM PLAN REQUIREMENTS

In this section, Navigant opines on the degree to which THESL's DSP conforms and complies with the major objectives and guidelines outlined in Chapter 5. Specifically, this section sets out Navigant's response to the following question:

Does THESL's DSP and proposed investment plan satisfy the objectives set forth in Chapter 5?

Following a careful review of Chapter 5, Navigant has concluded that THESL's DSP meets the general and specific requirements set forth therein. Our findings are based on the degree to which THESL processes outlined in the DSP comply with Chapter 5, and the consistency of THESL's business plans with OEB guidelines. Our conclusions are supported by findings contained in the sections that follow.

OEB Investment Categories

THESL's CAPEX plan has been developed in a manner generally consistent with OEB asset capital investment categories; however, certain asset classes and investments span more than one category. THESL prepared the diagram that is replicated in Figure 4 to facilitate external review of its application, and is referenced herein as an aid in our assessment. It highlights the asset categories that are designated as material investments outlined in Section 5.4.5.2 of Chapter 5.

Figure 4. Mapping of THESL Investments to OEB Categories

Integrated Planning

Planning for the safe and reliable operation of an electricity distribution system requires the integration of a range of primary and secondary drivers to ensure needs are met in a cost effective manner. Inherent in this process is the recognition of drivers outside of the utility's direct control, such as transportation infrastructure improvements. It also recognizes the drivers jointly affecting other utilities; most relevant to THESL is joint planning with HONI where investments are made as a result of the respective needs of each utility.

Navigant has found that, through the policies and practices outlined in Sections A through D, and the detailed business cases in Section E, integrated planning has been consistently undertaken by THESL and it has been incorporated in virtually all aspects of its system. Several examples of comprehensive and proactive integrated planning are presented in our review, with key examples highlighted below.

- Load forecasts that recognize CDM and localized demand response for capacity planning
- System upgrades designed to enable safe and reliable integration of DG, consistent with provincial policy and Green Energy and Economy Act mandates
- Contingency planning of critical downtown load recognizing HONI transmission design and constraints
- Recognition of major transportation infrastructure and city expansion to guide the development of new or upgraded facilities to meet these needs
- Safety and reliability improvements designed to meet customer expectations and needs
- Balancing of risk versus of cost in developing a five year investment plan

These factors support Navigant's conclusion that THESL's DSP recognizes and consistently applies integrated planning principles and practices to support formation of its proposed investment plan. It incorporates principles and requirements in Section 5.0.3.1 (Integrated Planning) specifically and Section 5.2 (Distribution System Plan) generally, thereby ensuring compliance with OEB DSP objectives. Our review of individual business cases supports this finding, as many projects and programs include elements of several of the above drivers.

Long-Term Planning

THESL clearly has taken a long term approach for each of the investment categories outlined in Chapter 5 and addressed herein. The use of ACA and EIM determines the optimal timing of renewal replacement based on economic end of life criteria; which for many assets has been partially deferred to ensure an appropriate balance of risk and cost. THESL's paced investment plan for reducing the backlog of economically justified renewal and replacement goes well beyond 2019, with the backlog fully addressed by 2037.

System Service investments, especially more costly station upgrades, are made with consideration given to "non-wires" alternatives and rebalancing and transfer of distribution loads to ensure station and line capacity is used in the most efficient manner, consistent with OEB Section 5.4.2(b) and other relevant sections in Section 5.2. These initiatives are projected to result in the deferral of costly upgrades at critical downtown stations such as Cecil. Navigant views the multitude of options THESL considered in its planning process and strategy to maintain a paced spending profile for renewal projects as entirely consistent with Chapter 5 objectives specifically, and common industry practices in general.

Regional Considerations and Third Party Planning

THESL, as an embedded LDC, does not interconnect to or provide distribution supply to other LDCs – all points of supply are from HONI networks via direct connection to the transmission system or HONI stations. Hence, most regional planning considerations focus on HONI and the OPA. Navigant's review of THESL's DSP and knowledge of regional planning for the Greater Toronto Area (GTA) confirms regional issues have been incorporated into the DSP.[10] Foremost among these is the extensive joint planning efforts to address reliability of supply for downtown Toronto.[11] The development and expansion of HONI's 115kV transmission to create a new east-west tie was the result of extensive joint planning, including supply to the Copeland station in the 2012 IRM and the Downtown Contingency Plan in the DSP. Additionally, THESL has coordinated its plans to mitigate constraints limiting DG and renewable sources with HONI, as conditions such as fault current limitations exist on both systems (e.g. Leaside and Manby on HONI's system).

THSEL also is actively supporting the Central Toronto Integrated Regional Resource Plan (IRRP) to address alternatives for ensuring reliable, low-cost supply to Toronto, including non-wires alternatives. For these reasons and evidence of joint planning for City infrastructure projects and downtown development, Navigant concludes that THESL has demonstrated that it has proactively addressed regional issues in its DSP, consistent with Chapter 5 requirements. Our conclusion is supported by the cost-effective alternatives THESL evaluated and proposed in business cases from Section E5 of the DSP that Navigant reviewed in preparing this report.

[10] Navigant's involvement in prior GTA regional issues include business case review of the Copeland station for the 2012 ICM; review and assessment of THESL's GEA Plan; market potential assessment of DG with the OPA, and an assessment for enabling greater amounts of DG in Toronto in concert with HONI proposed upgrades, among other engagements addressing supply.

[11] For example, THESL demonstrates that it has coordinated station expansion and upgrades with third parties, including HONI and the Ontario Power Authority for upgrades considered in the ongoing OPA led IRRP planning process.

Smart Grid Development and Implementation

Although THESL does not include a spend category labeled Smart Grid, our review of its planning processes and specific business cases indicates the five year spending plan include many smart grid components and systems. Many smart grid initiatives are effectively embedded within projects and programs, such as enhanced monitoring of distributed generation to enable higher levels to be installed. Other smart grid investments such as automated switching and transfer schemes are categorized as reliability improvements. The use of smart technologies is proving to be particularly effective as a low cost method to improve reliability, a foundational aspect of SmartGrid deployed throughout North America and worldwide. Further, the build out of communications system provides requisite infrastructure to support a range of smart grid investments, including those that will enable higher penetration of DG throughout the distribution system. Each address specific OEB guidelines set forth in Section 5.0.3.4, including the use of smart technologies to "facilitate the integration of distributed generation and complex loads."

Integration of Renewable Energy Generation to THESL's Network

THESL fully complies with Chapter 5 requirements set forth in Section 5.4.3 (a) through (e), (System Capability Assessment for Renewable Generation), which directs applicants to provide information on the capability of the distribution system to accommodate REG capacity and integration constraints. Section E.3 of THESL's DSP includes a projection of renewable and other DG technology capacity to 2019 (626 MW total), and specific solutions and mitigation strategies to address constraints it has identified on its and HONI's system. These upgrades are consistent with those outlined in THESL's 2012 Green Energy Act plan and related studies it prepared over the past several years that addressed DG market potential, DG capacity limits and solutions to address integration constraints. THESL is also proposing implementation of monitoring and controls via its Generation Protection Monitoring and Control program. Navigant believes this is a vital and necessary project that reduces the likelihood of DG disrupting distribution performance or operations, thereby increasing THESL's DG integration capability. In addition, as discussed previously, THESL is undertaking joint planning and coordination with HONI to identify solutions to facilitate integration of REG that are best addressed at the transmission level.

Reliability and Performance

Almost 50 percent of THESL's proposed spending over the five year rate period is for renewal programs. Because of the backlog in economically justified renewal replacements and other critical infrastructure projects, THESL has relied on a risk based process and economic model (FIM) to identify the most critical upgrades to ensure reliability and performance does not degrade. The processes and methods THESL used to select up to $250 million of renewal investments annually are consistent with Section 5.4.5 (Justifying Capital Expenditures) of Chapter 5. The validity of the levelized approach is underscored by THESL's reliability

projections, as the proposed spending program will maintain or improve system performance metrics by 2019.

Performance Monitoring

THESL presents a performance monitoring and continuous plan designed to ensure the investments it proposes over its five year rate period produces efficiency, performance and customers satisfaction gains outlined in its DSP and business plans. It includes 12 measures over three categories that THESL proposes to monitor throughout the rate period (Figure 5). Foremost among these is Customer Oriented Performance that THESL will track and measure using IEEE reliability and performance metrics.

Figure 5. THESL Performance Measures

THESL also proposes to track DSP progress via internal and external benchmarking for key supply, construction and design performance metrics. THESL will track operational performance via two metrics, outage from defective equipment and station capacity; charts in the DSP confirm increased utilization of station capacity. THESL also proposes to continue to track customer satisfaction through periodic surveys to gauge customer views on a series of performance and cost issues. These surveys also are used to provide guidance to THESL to ensure program spending, to the extent practicable, is directed to areas of greatest concern of interest to its customers. Based on THESL's proposed monitoring and tracking of key metrics, Navigant concludes the plan, consistently tracked, should yield continuous improvements in each performance category listed in Figure 5.

Customer Value

Customer value is repeatedly underscored throughout THESL's DSP by the significant emphasis on ensuring and improving reliability performance, taking numerous proactive steps to improve system safety, and realizing operational and investment efficiency synergies whenever possible. Utilizing ACA data and the FIM as tools for informing sensible and cost efficient system investments maximize customer value and represent best practice in investment planning. The implementation of tracking continuous improvement measures for reliability should enhance customer value throughout the rate period, which THESL will verify by periodic surveys. Consistent with Chapter 5 requirements, consideration of both current and future customer value is present in THESL's planned investments that in many cases may enable future modernization projects not yet directly contemplated in this plan (e.g. development and modernization of distribution communication infrastructure will support future smart grid opportunities).

SUMMARY ASSESSMENT

The section addresses the methods and tools THESL employed to evaluate projects, and the level of rigour applied to justify project need. Specifically, with respect to THESL's proposed projects, Navigant critically reviewed the approach THESL undertook to justify each project, summarized in the following question:

Are the methods and tools employed by THESL to select proposed projects appropriate and sufficient to justify the investment?

Technical Need

For all business cases Navigant reviewed, THESL provided factual or empirical evidence that amply demonstrate why the proposed projects are needed, consistent with guidelines set forth in Chapter 5. The methodology, engineering principles, assumptions, and level of rigour used by THESL are broadly consistent with those used by leading utilities. Foremost among these is the use of sophisticated tools and tests to determine the condition of equipment, and to predict the areas of the system at greatest risk. For example, the condition and need for replacement of station transformers is based on dissolved gas analysis (DGA) performed by reputable firms, coupled with the exposure to customers if such devices were to fail. Similarly, the replacement of station class breakers, switchgear and overhead, gang operated switches is based on thorough research and tests performed by THESL personnel that confirm that some of the devices installed on THESL's system are defective, with attendant reliability and safety exposure.

THESL uses a comprehensive series of distribution simulation and analytical tools to accurately predict asset performance and equipment loading under a range of operating conditions. These include the FIM for renewal spending, which incorporates risk factors and life cycle economics to evaluate project need and value. The upgrade of remote terminal units (RTU) also is critical as several devices are no longer capable of reliably providing continuous status data to system operators. Navigant has witnessed the degradation of RTU functionality at many other utilities, which have adopted similar replacement strategies.

Economic Value

Navigant has determined that the economic value of the five year investment plan to THESL customers is consistent with OEB Chapter 5 requirements and leading industry practices. This finding is supported by the rigour and application of economic methods THESL used to develop its capital spending plan. Navigant views THESL's proposed level of spending over the five year rate period as the minimum needed to ensure distribution reliability, safety and customer satisfaction. THESL has developed and implemented economic models designed to optimize investments based on risk versus cost trade offs. Although THESL does not propose spending levels that are supported by economic end of life criterion – this would result in capital spending at 60 percent above proposed levels it has developed a spending strategy to

meet Chapter 5 requirements at an acceptable level of risk. Navigant's review of THESL's methodology presented in its DSP, and its application of these methods to business cases we reviewed, confirm the projects and programs THESL proposed are justified based on life cycle economic value.

Smart Grid and Renewable Generation

THESL proposes a series of investments designed to reliably integrate up to 626 MW of DG capacity that it expects to be added to its distribution system through 2019, including over 200 MW of renewable generation. THESL prepared a DG capacity forecast, and includes in its DSP a series of investments to proactively address constraints and violations caused by the addition of DG resources. These include upgrades such as communications, monitoring and controls that Navigant believes are essential to reliably integrate large amounts of DG. THESL has also coordinated its investigation of impacts and mitigation options with HONI. Accordingly, we conclude that THESL's DSP meets or exceeds the requirements set forth in OEB Chapter 5 and are consistent with leading industry practices.

Environmental Factors

THESL proposes programs that address environmental factors at the system and distribution level. At the system level, THESL has proposed upgrades and system that will enable greater amounts of DG capacity, including environmentally favourable renewable generation. At the distribution level, THESL proposes replacement of critical infrastructure and equipment that pose local environmental hazards. Our review of the DSP and individual business plans indicates that the upgrades and replacements THESL proposes also will produce the value in terms of reasonable efforts to mitigate or reduce environmental impacts. Further, by focusing on assets with the highest risk, THESL has taken a responsible approach to addressing infrastructure and equipment with potential environmental impacts.

Overall Assessment of the THESL's DSP and Five-Year Capital Investment Plan

Our review and assessment of THESL's DSP indicates the methods it has applied to develop its capital investment program are consistent with other urban utilities in Canada and the United States where Navigant has conducted a similar evaluation. Notably, we did not identify any projects or measures that are inconsistent in scope or need prescribed in OEB Chapter 5. In Navigant's view, because of these reasons and the analysis presented in prior sections of our report, THESL's DSP, and the business cases and proposed projects therein, are reasonable and justified.

Further, THESL's proposed five year capital spending plan of approximately $490 million annually is justified based on Navigant's review of the evidence and facts THESL presents in its DSP that we relied upon to conduct our independent review and evaluation.

Our conclusion is based on the following key findings:

- THESL's proposed spending is the minimum needed to complete the continuation of IRM programs in 2015 and to maintain a reasonable balance between risks and costs over the five year rate period. The level of spending is higher than the prior five years, but is the minimum required to reduce the backlog of end of life asset replacement by 2037 and meet OEB Chapter 5 requirements.
- The technical and economic analyses THESL has undertaken to support the capital investment plan is rigorous and consistent with Chapter 5 guidelines for each of the four major spending categories.
- THESL's has consistently applied technical and economic evaluation methods to support individual business cases; and proposed spending for each business case is justified by the facts, evidence and analysis Navigant evaluated for its review.

APPENDIX A: BUSINESS CASE REVIEWS

Concurrent with its review of Sections A through D, Navigant conducted an independent review and assessment of business cases THESL prepared in Section E of the DSP. Navigant's review of these business cases is presented below.

System Access

2014 ICM Continuation Programs

Metering

THESL's investment in its metering program is designed to achieve mandatory service obligations as outlined by the IESO (for wholesale metering) and the Gas & Electricity Inspection Act (for revenue metering). THESL's DSP outlines the work involved in the program, including meter removal for verification testing; there is a further breakdown of assets proposed for replacement by customer class. THESL quotes the relevant OEB amendment to the Distribution System code (DSC) which impacts a portion of its metering upgrade program. For the suite metering segment of its business case, THESL cites the Energy Consumer Protection Act (ECPA) as a standard mandating these installations. The total capital required for the program is $77.3 million. Annual capital expenditures and unit replacement schedules are presented, with annual costs averaging $17 million with most spending concentrated at the beginning of the program.

Compliance with statutory provisions and regulatory requirements are the primary drivers for THESL's metering program. Asset management is governed by identified standards (specifically Sections 9, 11, and 12 of the Electricity and Gas Inspection Act) which are expanded upon extensively and summarized in Table 19.

The benefits of the metering program are highlighted in THESL's business case, primarily improvements to customer service. For example, large building operators' dependence on metering data to manage electrical plants is cited, as well as the number of customers (9,500) that will benefit from the replacements. THESL also states that interval metering upgrades will allow for more efficient outage verification and a reduction in SAIDI, consistent with customer benefits cited by other utilities.

The business case lists timelines for the program and the start dates of the sub programs. It also list factors contributing to year to year variances in spending, including data processing deferment and dependence on HONI for scheduling wholesale revenue metering changes. THESL also summarizes program risks, such as delays in HONI work and methods for mitigation (i.e. scheduling work closely with HONI for proper allocation of resources). THESL highlights the consequences of changing its current approach for meter reads; for example, manual reading of meters would require "immense resources" compared to upgrading

metering to smart synch meters. THESL's program is unique in that due to regulatory mandates, there are no alternatives for the majority of THESL's proposed work plan. Accordingly, this requirement obviates the need to perform economic feasibility analyses. THESL provides further justification in its business case by separately listing all of the individual standards and regulations that the program work must comply with in Table 19.

Customer Connections

THESL's customer connections program is driven by its obligation to connect to new buildings on its distribution lines or for an occupant that requests connection. The work includes installation of overhead or underground supply lines, service poles, cable chambers, transformers, commercial meters and other connection tasks. Expansion work is sometimes necessary, and may include upgrades such as new circuits or civil infrastructure enhancements. THESL's forecasted total cost forecast from 2015 to 2019 is $260 million, with $70 million offset by customer contributions.

THESL's business case indicates the primary justification and program benefit is customer value. THESL states that the investment will provide, and continue to maintain, distribution service to customers, particularly during a period of time of when it expects increasing numbers of high rise developments, consistent with growth projections in the City's GDP. THESL compares the rate of development of high rise buildings in Toronto to other large cities to support a view that connection work in Toronto is likely to be comparable to or exceed that of other large cities.

Regarding the pacing of its program, THESL cites the timelines of individual connection work mandated by the Electricity Act and CoS. THESL forecast connection requests through development of a historical baseline, and then incorporated economic growth factors, development factors, and large construction projects to augment the baseline. This method is typically used in developing load forecasts and is consistent with what has been provided by similar utilities. THESL describes cross program efficiency initiatives in prior connection projects, citing cases where expansion for future load was integrated into task work. Risks in program execution are highlighted, including variations in the forecasted demand impacting timelines.

Externally Initiated Plant Relocation & Expansion

Investment in this program is for government mandates that require Toronto Hydro to work in conjunction with public entities to facilitate public development projects. This includes like for like replacement of some assets during relocations or upgrade of service to provide safe and reliable service. Some requests are mandated by Public Service Works on Highways. THESL estimates it will be able to recover 30 percent of construction costs from projects associated with the road authority, while all other agencies cover 100 percent of THESL's relocation cost. An example of the latter is the ELRT, with program costs of about $220 million from 2015-2019, averaging about $40 million annually.

THESL's report thoroughly supports paced program spending, citing major projects between 2015-2019, such as the MTO Bridge Rehabilitation, GO Transit Electrification, Eglinton Light Rail Transit, and other Metrolinx LRT projects. THESL notes that since investments are highly dependent on external agencies, high variability in required funds is likely and largely beyond THESL's control. For this reason, Toronto Hydro requests OEB authorize funding for a base rate sufficient to fund the sub-forecasted base amount; a variance account is also requested to cover additional costs that are difficult to predict.

The report also identifies opportunities to upgrade system assets instead of like-for-like replacement for externally initiated relocations. THESL's DSP provides a description and review of how potential efficiencies in the upgrade process are evaluated. This review provides evidence that Toronto Hydro selects work plans to consider associated work when carrying out "non-discretionary capital projects" (i.e. to directly address EB-2012-0064, as discussed in the report).

Load Demand

THESL investment in the Load Demand program funds three activities on its 13.8kV and 27.6kV distribution system: load transfers, feeder upgrades and equipment upgrades. These upgrades and modifications will alleviate operational constraints associated with available connection capacity. THESL evaluated stations forecasted to be overloaded in the 2015 through 2019 late period, and proposes to proactively transfer load off of these station buses to reduce reactive work and resultant less efficient system configurations. THESL's program includes upgrades to 18 stations at a cost of $63.14 million. Average annual expenditures are approximately $15 million, with program costs increasing throughout the five-year investment period.

Program benefits include enhanced customer value, expressed as the difference in cost of ownership between existing and renewed assets for the first year of the program ($24.21 million), a common metric used as evidence to support the investment. This value, along with a positive first-year NPV ($12.31 million), indicates that the program is prudent investment. Additional qualitative benefits include enhanced reliability, safety, and efficiency (i.e. reduction in restoration time, reduction in asset failure risk, and increased operational freedom). The primary driver is customer service requests. THESL's interpretation of DSC 3.3.1, in which the distributor is obligated to plan and build the system for reasonable forecast load growth, and improve the system for relieving system capacity constraints" provides additional rationale to support proposed investments. Other drivers, such as reliability, also reference DSC operational mandates with regards to the planned program work.

The business case conveys sound underlying support for pacing program investments. For example, the number of proposed developments in the process of obtaining permits is a significant factor driving the need for increased investment in load transfers and station upgrades. THESL demonstrates that based on historical timelines, substantial connection work will be needed between 2015 and 2019. As evidence, THESL provides service territory maps

overlaid with proposed connected load to illustrate concentrated load requests necessitating specific station upgrades. The lower amount of spending in 2015 is due to the City's construction moratorium for the Pan Am games. Other program expenditures are based on individual project ranking criteria, including area capacity to connect new customers, the ability to continue operations under single contingency conditions, and area reliability; each are consistent with utility prioritization approaches for asset replacement or upgrade. Finally, THESL includes funding for temporary upgrades to ensuring system operability is maintained until future upgrades have been evaluated and completed.

The business case evaluates investment alternatives, including upgrading station capacity through expansion or the construction of new stations. These options were eliminated in favour of equipment upgrades due to long lead times, potentially exposing the system to degraded reliability until work is completed. THESL includes asset replacement for each sub-project.

Generation Protection, Monitoring and Control

THESL's Generation Protections, Monitoring and Control (GPMC) program aims to enhance and enable protection schemes, and increase visibility via the monitoring and control of distributed generation (DG). This program includes high speed protective relays at station buses with short circuit constraints, bus tie reactors that minimize the short circuit at station busses, and monitoring and control equipment to provide greater visibility and provide distribution operators with proactive controls to prevent risky conditions such as islanding. The program is expected to cost approximately $15.5 million over the next 5 years. The program also supports HONI's ongoing efforts to alleviate constraints at the transmission level, as protection systems will be installed at Leslie, Basin and Wiltshire TS with a bus tie reactor at Richview TS. Related program benefits associated with enabling greater DG capacity include greater customer value, reliability, safety, efficiency, and meeting public policy and environmental goals.

Given significant projected increases in DG capacity in its service territory, THESL's business case amply justifies the investment by citing field crew safety, reliability impacts and potential deterioration of distribution assets due to high fault currents. THESL forecasts that 626 MW of new DG capacity is likely to come on line over the next 5 years for FIT, CHP and other DG. Its staggered plan to install the advanced protection, monitoring and control devices is in line with expected DG capacity additions between 2015 and 2019. The program includes anti-islanding to reduce risk for field crews during restoration. Enhanced protection and monitoring capability also enables distribution operators to better manage thermal loads via load transfers. The NPV cost for the GPMC program is about $18 million

THESL evaluated alternatives such as major system upgrades and deemed these too expensive and largely dependent on HONI to perform the work with scheduled timeframes outside the five-year window. Navigant views THESL's GPMC program as less costly and providing tangible benefits within a desired timeframe. Tables and graphs THESL used to evaluate

program need and benefits support the business case, although details on the process THESL used to select technologies is limited – additional details on cost for selected technologies would further strengthen the business case.

System Renewal

2014 ICM Continuation Programs

THESL provided significant evidence in its 2012 ICM filing to justify and support proposed renewal expenditures for programs continuing into 2015. Navigant reviewed much of this evidence for its independent evaluation of the ICM filing. Navigant also reviewed the updated business cases THESL prepared for the DSP and the technical and economic methods used to justify these projects. Based on its review, Navigant finds that each of the renewal program investments continue to be justified based on need and life cycle economics. We did not see any major changes in assumptions, costs or economic results that would justify deferring or eliminating completion of these programs as part of the ICM filing.

Reactive Capital

Reactive capital is necessary to ensure THESL retains the ability to reliably serve its customers and quickly respond to service interruptions or hazardous system conditions. Exact budget requirements for a reactive capital program are difficult to predict. THESL justifies its business case based on past experience, inventory of asset condition (via a Defective Equipment Tracking System), and tracking corrective work request needs. THESL estimates reactive capital spending over the 2015 to 2019 late period at $165.5 million, a figure inclusive of the offset expected from planned non-reactive asset replacements.

The business case justifies the renewal program budget in light of THESL's to ongoing obligation to maintain system reliability, quickly correct hazardous system conditions, address imminent or likely asset failures, and restore service resulting from defective, failing assets and unplanned contingencies including natural disasters and foreign interference. Reactive capital also is required to facilitate planned modernization and system growth by ensuing resources needed to support planned operational investments are available for those activities. THESL expects reactive capital requirements to increase based on a growing trend of equipment reaching or exceeding EUL, with 26 percent of distribution system expected to be beyond their EUL by 2015. While the overall reactive budget is reasonable in light of expected increases in asset failure due to larger shares of system equipment exceeding EUL, among other factors, asset condition may be a more useful and clear metric than asset EUL and is described but not as clearly and quantitatively summarized as asset age in this business case.

Creating a reactive capital budget based on expected future asset failure and historical failure data is consistent with standard utility practice. The program is required to ensure the continued safe operation of the distribution system, maintaining crew and public safety, mitigation of environmental hazards, and proactive response to actual or potential

contingency events. Though financial analysis is not performed for alternative scenarios, including "do nothing" options, Navigant recognizes both the need and level of investment THESL presents in its business case.

Underground Legacy Infrastructure

THESL's Underground Legacy Infrastructure (UGL) renewal program is designed to upgrade system components that present challenges on multiple fronts including system maintenance, operational efficiency, crew and public safety, and delivery of customer value through reliable and efficient service. In its business case, THESL supports the replacement of several assets between 2015 and 2019 including:

1. Sachsenwerk switch and fuse units
2. Specific equipment in the Thorncliffe Park distribution area
3. Transclosures
4. Powerlite switches
5. Vault step transformers
6. Cable chamber covers (i.e. "manhole" covers)

The program is expected to cost $27.39 million over the five year rate period, and includes replacement of the above listed assets at various locations across THESL's service territory.

THESL's business case for replacement of these UGL assets covers a range of factors unique to individual assets, though primary drivers across all categories include obsolescence of equipment design and/or configuration, increased failure probability in light of equipment condition and age, and safety concerns for both the public and THESL crews resulting from failing and outdated equipment or equipment in poor condition. Navigant agrees that continued operation of aging and non-standard assets experiencing intermittent failures, particularly with regard to the Sachsenwerk switch and fuse units, Powerlite switches, and certain transclosures, presents operational challenges, safety hazards, and inefficiencies as reactive replacement or repair may require custom engineered solutions and workarounds that lead to longer customer outage times. Further, certain UGL assets (e.g. Powerlite switches) are no longer manufactured, making continued operation impractical without OEM support or an adequate supply of replacement parts. Others, such as in the case of Sachsenwerk switches, are of an outdated design prone to flash over hazards.

Potential safety hazards exist for other UGL assets as well. Traditional unsecured chamber covers present a danger to the public/THESL crews in the event of an underground explosion (24 incidents of dislodged covers have occurred in the past 17 years), and corroded transclosures beyond their EUL (representing the majority of the system) present hazards to THESL crews as transformers are degraded by the elements. Reliability of transclosure units following replacement also is enhanced, as THESL seeks to convert radially fed units to a

looped system with open ties. THESL also proposes to replace or decommission vault step transformers installed between the late 1950s through the early 1980s in a wide array of sizes (both in kVa and voltage). The program is justified, as THESL no longer provides multiple service voltages, and it no longer stocks replacement transformers due to the small number of installed units. Decommissioning will improve reliability by reducing the potential for equipment failure and by removing non-standard equipment no longer in stock and that is challenging to replace.

Navigant notes that THESL's plan to upgrade UG infrastructure in the Thorncliffe Park distribution area includes replacement of newer vintage assets (compared to other UGL assets); it includes the replacement of live and six-way SF6 switches installed by the former East York Hydro. These switches, permanently sealed after manufacture, have a rated EUL of only 20 years, and are deemed "effectively failed" after leaking sufficient levels of SF6 insulating gas. THESL does not stock replacements as these switches are no longer manufactured and are used in a small segment of its service territory. Replacement solves a series of challenges and brings greater uniformity to system design, avoids possible near-term failures (as experienced by other similar vintage SF6 switches), and reduces equipment exposure to flooding and corrosion by reconfiguring equipment to be pad-mounted. Notably, the Thorncliffe Park area has experienced flooded vaults resulting in damaged UG equipment despite THESL's use of sump pumps. This reduced automatic transfer switching (ATS) capability of SF6 switches, which have higher failure rates due to flooding and that require frequent maintenance.

Based on the quantification of these risks and constraints, THESL estimates the cost of ownership of existing legacy infrastructure (COE) is greater than the cost of ownership of new assets of a standard design (CON). Total CON, inclusive of additional quantifiable benefits, risks and program cost, is expected to yield a positive NPV of $1.46 million in the first year.

THESL's business case for replacing UGL assets is justified by a host of safety, reliability, and customer value concerns: improving system architecture and uniformity offers THESL greater flexibility for optimal network management, both by crews (via safe/efficient use of engineering resources) and remotely (i.e. smart grid); and replacement CRD/CLD and pad-mounted switches can be retrofitted to enable remote operability. THESL's ranking and prioritization of equipment replacements is clearly outlined, both in methodology and expected installation sequence. THESL's analysis evaluates asset condition, load served, upstream effects, and coordination with other program work balanced to ensure equipment replacements enhance customer value by delivering service reliably and efficiently.

Network Unit Renewal

Network units (NUs) are a critical element of THESL's downtown secondary distribution network. These devices contain several components including a network protector, a primary disconnect and grounding switch, and a network transformer. These units are essential, as they isolate faults from separate feeders within the network, which protects network

equipment, and provide uninterrupted service to downtown load. Many of THESL's NUs are beyond or approaching EUL, and, particularly for "fibertop" units, an outdated design that risk service disruption and increased risk of vault fires. All NUs scheduled for replacement are susceptible to damage and corrosion from flooding, and replacement with submersible units will mitigate these impacts. THESL estimates total program costs over the 2015 through 2019 rate period at $34.38 million. First year program cost versus avoided risk cost is $7.11 million NPV.

THESL's business case justifies the NU renewal program based on safety, reliability, and customer value. Further value is realized via the replacement of submersible equipment that will be less susceptible to corrosion and flood damage, and improved visibility of vault conditions through remote load monitoring (i.e. via use of smart grid technology). Existing network unit equipment includes "fibertop" and "semi-dust-type" units that are not water tight and in many cases experience significant corrosion and rust following years of exposure to flooding. Fibertop units have an outdated design that increases the risk of phase tracking, which can instigate costly and dangerous vault fires with attendant risk to the public and THESL crews. Some units also are connected to the secondary grid using asbestos-insulated, lead cables that also pose significant hazards in the event of a vault fire. THESL's proposed replacement of fibertops with submersible units virtually eliminates tracking risk, as use of a raised secondary busbar reduces accumulation of salts and debris. Some older units also may leak oil, which poses an environmental hazard and higher risk of failure.

THESL's proactive replacement of network units that are both of inadequate design, susceptible to flooding damage, and pose increasing risk of failure is consistent with industry practices. THESL has prioritized replacements by focusing on fibertop units most prone to failure, followed by replacement of units in the poor condition and those most likely to encounter flooding. Though not fully detailed in the business case, a feeder investment model (FIM) is used to balance asset condition and customer impact to determine optimal intervention time and replacement prioritization. Annual forecasted capital expenditures are provided with approximately 500 units replaced annually.

Distribution System Communication Infrastructure

THESL's existing communications infrastructure is becoming increasingly difficult to maintain and expand, with reliability bottlenecks that are inconsistent with current design practices. THESL's renewal program addresses key communication infrastructure constraints and deficiencies, several with synergies to other renewal programs. THESL's supervisory control and data acquisition (SCADA) system is critical for optimal distribution system (DS) management, as it enables controllers to respond quickly to changing system conditions and manage contingency events. Proposed communications and control infrastructure will significantly reduce outage times. THESL estimates outage time increases from 30 minutes to three hours without proper SCADA functionality. THESL estimates program costs of $16 million over the 2015 to 2019 rate period, with all work scheduled to be completed by the end of 2017. Placing and prioritization of the work is based on the dependency of individual

communication components as well as the dependency of other programs on the communication infrastructure.

Consistent with other renewal programs, THESL's business case justifies the investment based on improved reliability, operational efficiency, and enhanced customer value, achieved by limiting outage duration via optimized system control. The program includes three primary investments: 1) DS communication technology upgrade; 2) DS fiber optic plant replacement/expansion; and 3) SCADA wireless infrastructure. For its current DS communication technology, THESL relies on an outmoded 1980's vintage synchronous optical network (SONET) system that has produced 90 communication outages over the last five years. The system is no longer supported by the manufacturer, is compatible with only one remote terminal unit (RTU) system, and limits benefits achieved by other programs such as station control and monitoring, and station switchgear renewal. Navigant agrees that it is neither cost effective nor prudent to continue to investing in and utilizing the outdated SONET system, as this system is non-standard and incompatible with future expansion.

Fiber optic plant replacement and expansion, the second major investment category, creates reliability exposure and an expansion bottlenecks, both in design and ownership structure. Currently, 75 percent of all fiber optic cable is jointly owned by THESL and Cogeco Data Services (CDS). This arrangement limits THESL's ability to optimally route cables and eliminate single points of failure, resulting in potential SCADA outages. Targeting areas prone to failure, THESL plans to reduce dependency on CDS through gradual migration to a fully-diverse THESL owned fiber optic plant, while also expanding its reach.

Wireless SCADA infrastructure, the third primary investment area, is currently dependent on five separate wireless technologies, three of which are now functionally obsolete. Over 1,100 vault or overhead RTUs now rely on communications from this equipment, and system operations are further complicated by a lack of manufacturer support for outdated models. Also, THESL cites a potential cyber security risk by operating an outdated and unencrypted wireless communications system, one that will be minimized thorough investment in new equipment.

THESL's justification for proposed investment for the upgrade of this critical communications infrastructure is consistent with practices Navigant has encountered with other utilities. We also acknowledge that it is necessary to further enable smart grid management, and to fully realize benefits and opportunities presented by other planned system investments. In summary, THESL proposed investments will significantly modernize and improve the security of THESL's distribution communications network.

Station Building Infrastructure

THESL's proposed investment in its Station Building Infrastructure program is driven by the failing building components identified through a civil assessment on Toronto Hydro station buildings. The assessment included observations of water infiltration, moisture ingress,

structural integrity, rodent infestation, building security, and other hazards, each of which are targeted for upgrade. Failure to address structural degradation could negatively impact safety and reliability. For some buildings, maintenance is recommended instead of replacement to save cost and reduce lead time. Total proposed program cost from 2015 to 2019 is $11.25 million for 11 stations; on average, about $2.5 million annually.

The value of THESL's program is presented in terms of avoided estimated risk cost (ARC), estimated at $0.65 million. In maintenance based programs where assets are primarily repaired versus replaced, demonstrating positive ARC is typically sufficient evidence to demonstrate the investment is prudent, and in lieu of financial metrics such as difference in Cost of Ownership. The proactive nature of the maintenance work is justified through planning and labour management efficiencies that will be recognized through advanced notice. In addition, although standard maintenance is carried out, the level of investment that is recommended is such that standard maintenance can be performed without failure risk.

The civil assessment details several criteria required for station buildings to be deemed at risk including age, foundation deterioration, flood risk, and potential for high risk to customers under failure. These criteria imply a careful assessment of asset operability, beyond asset age, which provides convincing evidence for the proposed investment. Furthermore, THESL provides both the number of customers and the amount of load served by targeted stations serve to illustrate the impact of failures on continuity of service.

Navigant views THESL's approach to prioritize program work as sound. This finding is supported by our review of engineering notes and cost estimates from the civil assessment, the complexity of the proposed work, and sequence of stations proposed for upgrade. THESL also cites potential risks and challenges in scheduling the work, including Hydro One restrictions to THESL station work, extensive coordination for de-energization and load transfer, and potential permitting delays from the City of Toronto; each of which are factored into the program schedule.

Circuit Breaker Renewal

THESL's Circuit Breaker Renewal program is designed to replace aging oil circuit breakers that are nearing the end of or are currently beyond their useful service life, and that pose unnecessarily significant safety, reliability, and environmental risks in the event of failure. THESL intends to replace breakers in tandem with the replacement of similar vintage electromechanical (EM) feeder protection relays with modern microprocessor units to enable future feeder automation and other smart grid functionality. THESL's decision to simultaneously replace EM relays comes as a lesson learned after two outage events of previously replaced circuit breakers revealed end of life relays were defective that had to be replaced reactively at higher cost. This approach will reduce reliability risk, improve operational efficiencies, and result in lower cost compared to reactive replacement. Figure 16 presents the age profile of THESL's circuit breakers.

THESL's program is expected to cost $9.13 million over the 2015 to 2019 rate period. It includes the replacement of 135 oil circuit breakers with vacuum units equipped with microprocessor relays. In 2015, THESL expects 46 stand alone oil circuit breakers to remain in service, with 42 located at 27.6kV outdoor transformer stations across North York, and four in 13.8kV municipal substations in the Scarborough area.

Figure 6. Circuit Breaker Age Profile in 2015 (EUL = 45 Years)

The business case for the circuit breaker renewal program is well justified. Oil circuit breakers present both operational challenge and risk that can be mitigated at a very low cost relative to the total renewal budget and estimated risks. Operational challenges include the difficulty of finding suitable replacement parts and increased maintenance costs versus vacuum breakers. Further, safety and environmental concerns in the event of catastrophic failure are daunting. In the event of such a failure these units have the potential to cause significant/explosive fire, while emitting flying debris, and, in some cases, the release of PCBs at a concentration in excess of 50ppm. In contrast, vacuum units have fewer moving parts, require less maintenance, and do not contain oil that imposes additional risk. THESL proposes to systematically replace these circuit breakers over five years, and has prioritized renewal replacement schedules first by asset condition and age, and second by load and customers served.

Navigant views THESL's proposed replacement of oil based circuit breakers (OCBs) as an important investment in reliability, customer value, safety, and environmental protection. Navigant is aware that numerous other electric utilities also are replacing OCBs, and THESL has presented a logical sequence for upgrading these assets based on their likelihood to fail (age and condition), and the severity of impacts from a failure (customers affected and load served). THESL's business case includes a table and graphic that indicates the quantity of circuit breakers to be replaced annually and transformer stations where these replacements are scheduled.

OH Circuit Renewal

THESL's Overhead Circuit Renewal program is designed to replace assets that are nearing the end of their useful service lives or which have degraded to a stage where replacement is justified. Specific asset classes in the program include wood and concrete poles, single and gang operated overhead switches, CSP transformers, animal guards and porcelain insulators. The program will cost approximately $39 million over 5 years, which includes about $10 million in 2015 for SCADA Mate switch replacements that THESL included in its 2012 Incremental Capital Model (ICM) rate filing. Annual spending averages between $25 and $30 million. Most of these assets are located on THESL's 27kV overhead distribution lines outside the downtown core, but include lower voltage 4kV and 13kV connected to 27kV lines or unit substations.

THESL's business case justifies the renewal program based on a combination of factors, including obsolescence for certain manual overhead switches, crew safety for devices such as SCADA Mates switches, public safety for pole replacements, and reliability associated with each of the individual asset replacement categories. Tables that present historical reliability trends for each equipment type are included to support expected reliability benefits. The program also includes the conversion of 4kV and 13kV lines and equipment to operate at 13kV or 27kV, both to increase line capacity and to replace deteriorated equipment. Each of these programs and the justification used to support these investments is common for utilities in Ontario and throughout North America. An NPV analysis is performed for specific projects over 5 years and the first year avoided risk for the combined programs is about $39 million.

Each of the programs and the methods THESL used to justify the proposed investments is consistent with practices Navigant has applied and encountered with other electric utilities. The detailed list of individual project business cases, such as those presented for individual feeders, is beyond what some utilities use to support replacement programs covering a wide range of investments. The business case also describes the ranking and selection criteria for each equipment category. The replacement of critical assets such as wood poles whose condition has deteriorated beyond acceptable limits is an important component of renewal programs that regulatory bodies now require from electric utility distribution systems. We note that the business case does not include tables that summarize the quantity of equipment THESL proposes to replace versus the total population of each asset class. For example, utilities often will present pole replacements based on scheduled inspections, with test results, and condition. These additional summary tables would provide further support and justification.

Network Circuit Reconfiguration

THESL's Network Circuit Reconfiguration program is comprised of two initiatives: (1) enhance secondary network grid flexibility, and (2) expansion and upgrades of its 600V network distribution, which includes conversion of grid to spot networks. The first proposes increased power transfers from new high voltage station feeders and connecting transformers

(Figure 7 illustrates THESL's secondary network design). This portion of the work is also identified as a necessary prerequisite to the Downtown Contingency work described in the System Service section.

Figure 7. THESL Network Configuration

The second initiative is to introduce a 600Y/347V network to supplement existing lower voltage 4.33Y/250V and 2.16Y/125V network equipment. The higher voltage system will prevent functional obsolescence of the secondary distribution network, as 4.33Y/250V equipment is obsolete and difficult to acquire, while the 2.16Y/125V grid, while suitable for smaller buildings, is not preferable for use in all buildings due to internal voltage drop. Finally, some existing 600Y/347V network equipment has been identified as hazardous, and is also up for replacement.

The objective of THESL's program is to minimize customer interruption, improve planning and operational flexibility, enhance the ability of the network to operate under extreme events,

and prevent the secondary network distribution system from becoming functionally obsolete. To meet this objective, THESL proposes to replace four transformer and eight switchgear line ups, and add eight network underground transformers. The total cost of the program between 2015 and 2019 is estimated at $9.14 million. THESL expects the program to continue beyond 2019. The average cost of the program is about $2.3 million, which begins in 2016.

THESL indicates customer value is confirmed by an analysis that produces a positive first year NPV of $0.77 million, with a cost of ownership of $3.08 million. THESL also cites reliability, safety and efficiency benefits to further support the program. THESL's analysis includes a 66 percent reduction in load interruption during second contingency events, the elimination of hazardous Sachsenwerk switch/fuse units, and the elimination of special operation procedures associated with the new configuration. THESL states the primary program driver is functional obsolescence, supplemented by the necessity to expand or convert the secondary network to a mixed network configuration, with expansion of 600V connections for new large buildings and customers. THESL supports safety concerns with Sachsenwerk switches by describing failure events that have occurred. The replacement of these switches is further detailed in the UG Legacy Infrastructure business case.

THESL's pacing of the program is reasonably justified and in line with common utility practice. THESL plans to stagger rollout to ensure staff training and safe work procedures are developed. Furthermore, individual sites are planned based on operational restrictions that allow distribution operators to take feeders out of service in certain areas. THESL identifies the portions of the program that will be completed in the short, versus long, term. The risks associated with downtown underground work are listed along with mitigating options, such as scheduling construction work outside of the switching restrictions periods in the summer. The cost of ownership of the status quo system configuration is assessed and quantified in terms of the number of outage hours and associated avoided costs ($1.81 million) resulting from the proposed reconfiguration, for a net difference is shown to be $0.77 million.

Stations DC Battery Renewal

This program is designed to proactively replace station DC battery systems that control and operate station circuit breakers. THESL's proposed battery system replacements vary in capacity from 50Ah to 400Ah that will be installed between 2015 and 2019. The variation in battery sizes are due to the diverse requirements of the stations such as load requirement, different alarm systems, emergency lights, SCADA protection systems, and RTUs. THESL estimates total program cost at approximately $3.1 million, with annual spending of approximately $700K per year beginning in 2016. The proposed program aims to replace 67 battery systems at an average rate of 14 per year.

The useful life of existing DC battery systems is about ten years, and 27 percent of THESL's 194 battery systems are expected to be beyond their useful life by 2015, with an additional 33 percent expected to reach end of life by 2020. THESL's business case justifies the renewal program citing operational issues such as the increased potential for failed batteries to cause

lengthy outage and safety of workers when performing manual switching activities, and potential risk of exposure to acid and fumes from old batteries, and operational efficiency. In addition, the proposed program is consistent with Transmission System Code requirements.

Navigant views methods THESL used to justify the proposed investment to be consistent with industry practices. THESL conducted an extensive analysis of battery performance and presented graphs and tables summarizing the age of batteries that failed over 2011-2013 and the percentage of the battery population approaching end of life. It also includes a detailed assessment of the 167 battery systems that THESL identified for replacement. THESL is also considering the replacement of vented lead-acid (VLA) batteries with Valve-regulated lead-acid (VRLA) batteries that do not release chemical fumes to further reducing safety risk. THESL also evaluated run-to-failure versus planned replacement, with the latter yielding an avoided risk cost of $5.10 million for the year of 2015.

Station Ancillary Systems

Station ancillary systems ensure that THESL's stations function normally with minimal disruption to operations. THESL's program is designed to maintain the integrity of systems such as air compressors, fire alarms, heating and lighting, batteries and chargers, station service power supply, sump pumps, and fire barriers or fire suppression systems. The estimated investment for this program is approximately $2.29 million between 2015 and 2019. The assets that will be replaced under this program are listed in Table 5.

Table 5. Assets to be Replaced by Asset Class

Assets (units)	2015	2016	2017	2018	2019	Total
Air Compressors	4			2		6
Station Service Power Supply		1				1
Fire Alarm System			2	1	2	5
Fire Barrier/Suppression System	1	2				3

Assets targeted for upgrade are rated from 4.16kV and 13.8kV for air compressors to 230kV for fire barrier/suppression around transmission transformers.

THESL's business case is justified based on the criticality of the ancillary systems required for reliable distribution operations. THESL estimates over 100,000 customers are at risk of extended outages if the proposed station ancillary system program investment is not undertaken. Tables and graphs presented in the business case clearly illustrate the escalating number of repairs proportional to the increasing age profile of these assets. The primary driver for this program is the risk of failure resulting in extended customer outages and failure of station assets. The secondary drivers for this program are functional obsolescence and safety of crews and customers at or near the station. An NPV analysis performed for this program produces a net benefit of about $1.53 million.

The methods THESL used to justify the business case provide an objective view of each asset in THESL's ancillary systems. It includes an analysis of the current situation, and the prioritization and ranking of required upgrades by asset type. The business case provides analysis of alternative options with associated costs. The alternative option to replacing the ancillary services is the status quo option. Given the risk to customer outages and safety risks, THESL has decided the replacement of ancillary systems is the preferred option. The business case covers the overall program cost; additional details about individual asset replacement cost would provide further support and justification.

Worst Performing Feeder

THESL's worst performing feeder (WPF) renewal program is designed to improve the performance of feeders that, on average, experience the highest number of customer interruptions as measured by THESL reliability metrics. Asset replacements executed under the WPF program typically include replacement of legacy or worn components or outdated designs that pose a higher risk of service disruption or, in some cases, safety hazards. THESL uses a metric of seven interruptions per 12 month period (FESI-7[12] status) to classify and identify worst performing feeders, with plans to address feeders exceeding or trending toward FESI-7 status. Most feeders classified as worst performers are 27kV overhead lines outside the downtown core. Proposed spending is projected at $8.5 million between 2015 and 2019.

THESL's targeted investment for worst performing feeders is justified as it is expected to improve system reliability at low cost. Economic value and improved customer service is achieved by targeting equipment or conditions known to produce the highest level of interruptions. Many, if not most major utilities have implemented similar programs as they often produce very favourable NPV as measured by value of service (VOS) metrics. Typical components THESL proposes to replace or upgrade include uninsulated secondaries and services (replaced with insulated conductors to mitigate the impact of temporary faults), metal switch brackets (replaced with non-conductive brackets), defective glass/porcelain insulator (replaced with polymer insulators to reduce tracking or flashover risk), and certain underground assets such as transformers and cable segments with repeat failure histories. Proactive measures include insulator shielding to prevent animal contact, such as the installation of animal guards on transformer bushings and conductor leads, a common utility practice.

Targeting worst performing feeders is a standard practice that Navigant has recommended or encountered with numerous electric utilities. THESL's prioritization of feeders selected for mitigation is based on identifying those experiencing the highest number of sustained interruptions over a 12 month period, and that can be addressed at reasonable cost. Notably,

[12] THESL utilizes the acronym FESI-7 to refer to feeders experiencing sustained interruption seven or more times in a 12 month period.

1

1

THESL recalibrated its WPF program in 2012 to focus on short term mitigation options that yield immediate reliability benefits, with demonstrable success over the past few years.

1

System Service

Station Expansion

THESL proposes to upgrade several major stations during the five year period, many in the downtown area where building activity and growth are driving the need for increases in station capacity and connections capability. The other major driver is fault current constraints on station equipment that both THESL and HONI propose to address via breaker, switchgear and associated equipment replacement and upgrades. The relief of fault current constraints is a key requirement to enable greater DG capacity in the City of Toronto. THESL's station plan includes approximately $50 million in 2015 to complete the first phase of the Copeland station that is currently under construction and previously approved in THESL's 2012 IRM. Work at Copeland has been delayed to a combination of harsh winter weather and challenging site conditions associated with a high complex underground station. The need for Copeland was fully supported in THESL's 2013 IRM, in which Navigant provided evidence to justify need and proposed capital spending. Total program cost for stations over the five year late period is $182 million, with annual costs ranging from a low of $22 million in 2018 to a high of $51 million in 2015; the latter mostly to complete work at Copeland.

The methods THESL used to justify the proposed station project is consistent with leading practices Navigant has applied and encountered with other electric utilities. THESL's business cases emphasize use of CDM measures to permanently reduce peak demand enabling it to defer capacity upgrades, where possible. As noted in other business cases Navigant reviewed, CDM in the form of local demand response is proposed to defer capacity upgrades at Cecil. The business case also demonstrates station capacity is utilized to the extent practicable, accomplished via increased use of load transfer and greater use of feeder ties. Station upgrades in the downtown core are planned based on composite loadings and projected growth at several stations, recognizing the need to balance loadings to maximize the capability of each station to the extent possible.

THESL's business case clearly describes factors and assumptions supporting the ranking and selection process for each station project, including potential outcomes if proposed projects are not completed. These include new feeder positions such as the two needed at Bathurst to accommodate a large customer request. THESL also demonstrates that it has coordinated station expansion and upgrades with third parties, including HONI and the Ontario Power Authority for upgrades considered in the ongoing OPA led IRRP planning process. THESL is active in the IRRP working group committees, which issued a recommendation to increase transformation capacity and the Manby area. For the reasons cited above, Navigant finds that THESL's proposed station expansion plan is justified, as it has comprehensively considered

both expansion and non-expansion options and demonstrates that it has sought to maximize the utilization and capability of existing assets.

Station Control and Monitoring

Remote Terminal Units (RTUs), SCADA systems and pilot wire configurations are systems that THESL relies on to clear and manage faults. Due to aging hardware and lack of new communication capabilities, station relays many not be able to clear all faults and could be susceptible to cyber attacks. The Station Control and Monitoring program is designed to upgrade or replace station RTUs and pilot wire protection systems that have reached their end of useful life. The program is also designed to install SCADA at stations where none exists and that can utilize remote monitoring capabilities of RTU and pilot wire systems. The program is expected to cost approximately $5.05 million between 2015 and 2019. Average spending is $1 to $1.5 million per year starting in 2016 with very little upgrade planned for 2015. When the difference in cost of ownership is compared to the associated program costs, the Station Control & Monitoring program produces an NPV of $0.02 million.

THESL's business case justifies need by identifying RTU and pilot wire systems that are at the end of their useful lives. Given the capabilities of newer RTUs, communication systems and pilot wire systems, additional efficiencies and benefits are anticipated, particularly installing SCADA systems in stations where none exist. Supporting plots and tables indicate that customer hours interrupted (CHI) is nearly double for stations without SCADA capability. The primary driver for this program is functional obsolescence, with additional benefits focusing on labour and maintenance cost efficiency and a power distribution system with greater resilience from cyber attacks.

Each of THESL's program initiatives and methods used to justify spending are consistent with Navigant's experience with other utilities. THESL provides examples of prior outages caused by the failure of RTUs or pilot wire system to further justify the need and value. The business case also describes the ranking and prioritization criteria, which considers other system renewal programs in its evaluation. Since this program requires station outages for the work to be performed, THESL also considered program risks and appropriate mitigation measures to limit outage exposure. Like other business cases, THESL's evaluation of alternatives includes status quo (do nothing) versus the RTU, communication system and pilot wire upgrades it has proposed.

Feeder Automation

THESL's Feeder Automation (FA) program includes installation and refurbishment of SCADA switches with software upgrades to enable autonomous tie transfer for unaffected feeder segments during interruptions. THESL's directive for its Feeder Automation program is to reduce outage times through decreasing the resources and effort necessary to restore service following an interruption. The upgraded system will detect and automatically isolate faults, thereby reducing isolation times from between 30 minutes and 3 hours depending on the

existing setup. THESL is proposing feeder upgrades in both the Downtown and Horseshoe areas of its distribution system, where it will automate 640 switches on 130 feeders. The total cost of the program is projected to be $54.1 million from 2015-2019, with average annual cost of about $10 million.

THESL provides compelling evidence in terms of increased reliability to justify the FA program, citing improvements in outage metrics such as number of customer interruptions (CI), customer hours interrupted (CHI), and SAIDI/SAIFI. THESL compared current reliability metrics to the projected system state following automation, and determined that it can achieve an approximate 50 percent improvement in these metrics. Based on THESL's method of analyzing the number of feeder trunk lines that will benefit by automation, improved fault location and isolation times, and reductions in CI and CHI achieved by prior automation projects, THESL's DSP goals appear reasonable. The project produces a positive difference in the cost of ownership of $102.74M and NPV of $91.6M for the first year of the project.

THESL relies on past experience with feeder automation in the Horseshoe area and standardized utility practice to extend feeder automation to the Downtown system (first of its kind deployment in downtown area). The process THESL used to sub prioritize work appears justified, as it includes trunk outage data, and consultation with operations staff and systems planning approaches to identify the best opportunities given the loadings and geography of downtown lines. THESL also evaluated project risk, including potential for rapid load increases, integrity of the communication infrastructure, and premature asset failure. The report provides mitigating planning techniques which are reasonable, including monitoring load forecasts and connection requests, review of radio design, and reactive replacement of failed switching devices to enable the FA program.

THESL present program alternatives, including a status quo option, remote, manual switching control, along with the proposed option. The COO and NPV for these options are derived, and the proposed option offers significant benefit over other alternatives.

Contingency Enhancement

The Contingency Enhancement program includes several investments to improve response time during outages, achieved by re-routing power via feeder ties to restore affected customers. The program will improve customer service by reducing customer outage hours. Total program cost is $66.1 million from 2015 to 2019, excluding capital expenditures from previous years, as projects were undertaken as part of asset renewal or plant upgrades prior to 2015. Assets scheduled for replacement include primary cable, underground transformers, poles, overhead transformers, and overhead switches. Average annual spending is approximately $10 million, with the greatest spending occurring in the last year of the program.

THESL justifies the Contingency Enhancement by highlighting reliability, system efficiency, and safety improvements. THESL notes in its business case that fewer crews will be deployed

in outage scenarios to operate tie switches; as more tie transfer switches are installed, potentially dangerous manual switching also will be reduced. THESL determined that in the first year the program will produce a positive NPV of $49.82 million, with a difference in cost of ownership between existing and renewed assets of $59.19 million. The capacity of some conductors will be upgraded, as maximum peak loading during transfers on could exceed maximum ratings. THESL has structured the program pace to coincide with system renewal projects, so that replacement efficiencies are realized.

THESL's business case includes a description of each feeder tie project, along with costs, justification, and assets to be replaced in the sub projects. The Cost of Ownership in terms of asset risk and non asset risk is significant higher than program costs, and the NPV for the first year activities is much larger than the proposed net spend. Given these data, Navigant finds THESL's proposed contingency enhancements to be a cost effective approach to improving reliability and increasing operating flexibility.

Overhead Momentary Reduction

THESL's proposed overhead momentary reduction program is designed to reduce the number of customers impacted by momentary interruptions caused by temporary or permanent line faults. On longer feeders, the number of customers interrupted by permanent faults can be high, and these can be reduced via installation of line reclosers. Use of line reclosers is relatively new for THESL, and the primary focus of the program is to improve distribution performance and enhance customer satisfaction by reducing the quantity of customers impacted by momentary interruptions. THESL proposes to focus spending during the first two years to evaluate options and identify the best locations for installing line reclosers on its 13.8kV and 27.6kV distribution system. Thereafter, THESL proposes to install eight per year starting in 2017. The total cost of the program over five years is estimated at $1.92 million.

Customer service disruptions, even momentary, can be a major inconvenience to customers, and some result in material economic losses. Navigant's experience confirms that customers are increasingly impacted by momentary disruptions due to use of digital electronics susceptible to drop out. Momentary disruptions [13] account for 54 percent of interruptions on THESL's distribution system, and are of particular concern to customers that require uninterrupted supply for sensitive equipment. Installation of reclosers on main line sections can reduce the number of customers affected by momentary and sustained disruptions by eliminating station breaker operation that otherwise would occur absent the recloser. In addition to enhanced customer satisfaction, use of reclosers also improves THESL crew and general public safety. By isolating faults automatically quickly (through improved protection coordination), hazards can be isolated faster (e.g. high impedance faults such as overhead lines on roadway pavement). Manual switching by crews also is reduced as reclosers can be operated remotely by distribution operators via SCADA communications links. Operational

[13] Defined as an interruption with a duration of less than one minute.

efficiencies are also achieved by reducing the time required by field crews to patrol and isolate faults.

Navigant finds that THESL's proposed use of reclosers to reduce the number of customers impacted by momentary interruptions is justified, as use of these devices is a cost-effective approach to improve distribution reliability and performance, and it is common among utilities throughout North America. THESL's NPV estimate of $5.76 million demonstrates the program produces significant value for a relatively small investment, and that will enhance customer value by providing more reliable and efficient service.

Design Enhancement

THESL's design enhancement program focuses on two primary areas of improvement: (1) improved fuse protection and coordination and (2) installation of tree wire on 27.6kV overhead lines. These investments are proposed to improve distribution reliability via low cost enhancements. The total cost of the program is $7.3 million over the five-year rate period. THESL selected feeders for improved fusing based on known fusing deficiencies and where installation of fuses currently is limited by high fault current (i.e., exceeds 14ok maximum rating). In addition, THESL will install fuses where none currently exist, mostly on three-phase laterals integral to trunk lines.

THESL proposes to install tree wire or insulated overhead conductor in areas most susceptible to tree-related outages. Tree wire (insulated conductor) is most effective in areas where trees cause temporary interruptions; insulated wire will prevent line trips for self-clearing faults, and some permanent faults such as small branches lying on the line that are later removed by field crews. THESL will select distribution lines for fusing (install correct fuse sizes or improved coordination) or insulated conductor based on studies that are most susceptible to interruption due to fuse deficiencies or a high number of tree-related interruptions.

The primary benefits of these two initiatives is improved reliability, achieved by reducing the number of customer interrupted due to absence of fuses, undersized fuses or miscoordination; or by reducing the number of sustained faults via replacement of bare conductor with insulated conductor. The program NPV of $5.2 million is very favourable compared to the level of investment. Navigant finds THESL's proposed design enhancements to be prudent, as these are common reliability improvements it has seen elsewhere and demonstrate positive economic value.

Energy Storage Systems

The goal of THESL's Energy Storage Systems (ESS) program is to install 24 ESS's for a total installed capacity of 4.4MW and energy output of 10MWh. The program is designed to improve system efficiency, reliability, power quality, distributed generation enablement and electric vehicle enablement. The function of the ESS's is to provide load relief and shave peak load to reduce strain on system assets. THESL has divided the proposed investments into

centralized forms (Compressed Air Energy storage and Lithium ion batteries) and decentralized forms (solely lithium ion batteries) of ESS. The centralized devices can deliver 400 kW over 3 hours to municipal substations, whereas the decentralized devices can deliver 100-200kW of grid support/local support for 1-2.5 hours at strategic locations within the system. It is expected that the ESS program will cost $10.82 million from 2015-2019 with an average annual cost of about $2.0 million.

THESL scopes program benefits in terms of OEB goals, such as the enablement of DG and renewable generation. Expected reliability improvements are comparable to goals established by other utilities, such as increased voltage support, decreased harmonics, and uninterrupted service. The primary driver for the program is efficiency, as ESS is argued to increase the utility and lifespan of existing distribution assets while managing the variability of distribution system load, thus improving service and distribution capacity. The secondary drivers of improving reliability and power quality also contribute to the narrative of THESL targeting proactive improvement of its system assets.

The timing and pacing of the program is methodical, with planning work occurring in the first year, and a steady ramping of annual installations occurring for the remainder of the program. THESL's historical experience from ESS pilots that occurred in 2014 ensures that preferred sites (i.e. overloaded stations, feeders with reliability issues, areas with historical power quality complaints, areas with high DG penetration, etc.) are chosen for installation. The process outlined in THESL's execution plan is similar to utility practices for handling DG connection; with system evaluation, technology selection, site selection, design, procurement and commissioning playing large roles.

THESL addresses program risks, including limited technical expertise, load transfer constraints, and labour availability. Mitigation techniques appear reasonable, as THESL commits to advanced planning, training, and coordination between lines of business. THESL cites a third party study performed by Sandia National Laboratories to determine the cost of ownership for recommended ESS technologies. THESL's methodology for converting Sandia's findings to a quantitative first year benefit appears sound. THESL's justification of GSES work in 2015 is well outlined and complies with the OEB mandate of accommodating connection of DG to distribution systems.

Local Demand Response

The goal of THESL's Local Demand Response (Local DR) program is to encourage a shift in electricity consumption from peak to off peak periods, to delay system expansion until a permanent means to address load growth becomes financially prudent. THESL's program is designed to operate in conjunction with its Stations Expansion program, targeting load served by Cecil TS. Cecil TS is geographically confined so as to restrict physical expansion, and the load profile for the station transformers exhibits short duration peaks, which suggests DR as an alternative to capacity upgrades. THESL's program will cost $4.02M from 2015 to 2019, with an average cost of just under $1 million annually.

The primary driver for this program is relief of capacity constraints at Cecil TS, which THESL expects to be overloaded by 2020. Navigant views load growth projections as reasonable for this area of the city, and supported by the increasing trend in customer connections to Cecil TS. The business plan describes THESL's decision making process for mitigating capacity constraints; first, load transfer to adjacent buses is considered, and failing this, load transfer to surrounding stations. It is argued that load transfer may not feasible due to lack of station interties and existing station capacity limits. Physical expansion of Cecil TS is also considered. THESL's justification of switchgear additions as the only feasible expansion option to relieve capacity constraints is supported by evidence it presents. Even for switchgear replacement, extensive coordination with Hydro One would result in long lead times and lower short-term reliability in the short term.

THESL cites the positive results from the economic analysis performed for the project, operational issues associated with options for relieving capacity constraints at Cecil TS, and the ability to use proposed local DR for future work to justify the investment. THESL's selection of Cecil TS amongst other candidate stations is justified by a combination of factors, including year of required load relief, implementation time, physical restrictions, asset condition, cost of investment, and DR potential. THESL's business case provides an analysis of risks and alternatives, while an external consultant, ICF International, developed a financial model that incorporates cost-effectiveness tests to evaluate the potential financial impacts.

Customer-Owned Station Protection

Customer-owned substations are used by commercial and industrial customers of THESL that have significant power usage. These substations contain overhead steel structures and electrical assets like transformers that connect to THESL's larger distribution network. The Customer-Owned Substation Protection (COSP) program is designed to improve the protection mechanism at customer-owned substation and utility-owned protection mechanism installed upstream from the customer-owned substation. The program investment is estimated at $4.04 million over the 5-year period from 2015 to 2019. THESL estimates about 630 devices to be installed at 210 customer-owned substations on the overhead 13kV and 27kV in the Horseshoe and Downtown networks. The program cost and estimated devices are subject to change based on the outcome of the audit phase proposed in this program.

The business case for this program is justified given the primary driver is reliability and the failure of customer-owned equipment has caused nearly 17 interruptions per year. The failure of customer-owned substation is due to equipment not meeting the required standards or THESL-owned protection devices are absent altogether. The secondary drivers are safety of field crew that may have to perform work on rusted metal structures and poorly maintained transformers. The supporting details such as pictures, graphs and outage analysis in the business case exhibits a clear picture of the aged and under-maintained infrastructure that has caused service interruptions. The proposed protection mechanism is in line with the industry standards and good utility practice.

THESL has conducted an assessment of 10% of the total population (about 214 customer owned substations) and has found 21 of 185 visited customer owned substations in the Horseshoe area with equipment beyond its useful life and numerous substations with missing upstream protection devices. This type of analysis is consistent with utility operations that Navigant has seen. As required by such a program, THESL has proposed a two phase approach to executing this program. According to the business case THESL will conduct an audit phase followed by an implementation phase. Table 6 illustrates the outcome of the audit phase that is ongoing. Prioritization of the required work has been done based on priority for overhead lines susceptible to faults caused by trees and animals, number of interruptions, condition of equipment and protection coordination. THESL has considered the status quo option to perform system repairs and upgrades reactively which would result in considerable reliability concerns and has hence decided to adopt the proposed plan which is well justified.

Table 6. Customer-Owned Stations

Downtown Contingency

The Downtown Contingency program will install inter station feeder ties in the downtown 13.8 kV network in order to change the network configuration from a dual radial distribution design to an open loop design. (Figure 8)

Figure 8. Dual Radial Dx Design (current) & Inter-station Feeder-Ties Design (Proposed)

THESL is planning for 6 separate projects which will cost a total of $3.36 million from 2015, 2019. The business case quantifies the number of assets scheduled for replacement by this

work, which include underground switches, overhead switches, underground cable, and overhead conductor.

Customer Value is justified by THESL through quantifying the expected service restoration time during contingency events (8.2 hours currently, versus 1 hour after upgrades, on average). Reliability improvements are further quantified in Figure E7.7.8 which details downtown contingency outages from August 2003 to July 2013 (a 10 year window which covers the previous 5 years of system activity). This chart also summarizes CMO, CHI, CI, and outage duration, and forecasts the improvements in these metrics after system upgrades (consistent with other utilities' practices in quantifying outage data). Furthermore, the first year of activities of the program will represent a difference in cost of ownership of $3.07 million and an NPV of $2.33 million, which is in line with overall spending. THESL's pacing of the discussed project work is justified in the context of 3rd party utility constraints (HONI) and construction moratoriums (Pan Am Games), which demonstrates coordination with regional planning. Advanced planning with HONI is specified in the Program Risks section as a mitigating technique. Project prioritization is ranked first with respect to Historical Outage data, and second with respect to execution complexity, which is consistent with reviewed utility practice.

There is a thorough analysis of the alternatives to this program. The financial feasibility of the status quo alternative is compared against the proposed program, wherein the NPV of the proposal is found to be more financially prudent. However, although a third program alternative is provided, a financial analysis was not performed as a part of its assessment. When considering multiple alternatives, utilities generally attempt to discount the financial feasibility of each to strengthen the investment proposition.

General Plant

Information Technology

THESL's IT refresh programs are designed to replace and maintain assets relating to the software and hardware components to support ongoing operations. These components are required in order for THESL to efficiently execute required tasks such as preparing customer bills and dispatching crews to respond to outages. The IT Hardware Refresh program addresses the renewal and maintenance specifically for hardware assets. Software assets are specifically addressed in a separate business case (IT Software Upgrades, Enhancements and Analytics Program). Specific asset classes in this program include endpoint assets (such as desktops, laptops, tablets, printers and plotters) and core backend infrastructure assets (such as servers, disk arrays, network and telephony assets, and ancillary items). The IT Hardware Refresh program will cost approximately $37 million over 5 years, which includes $28 million of core backend infrastructure assets and $9 million of endpoint assets. Annual spending averages are expected to be approximately $7.4 million per year, with 2018 as the year with the highest spend at $10 million. This is primarily driven by the maintenance and capital investment required for disk and flash storage assets.

The primary driver for the program is system maintenance, which is justified by the necessity to periodically refresh IT infrastructure to mitigate risk associated with aging assets. If investment is not granted, the risks as outlined in the report may be:

1. Business continuity – obsolete hardware can result in core process interruption
2. Cyber security – security updates and patches could be impaired
3. Inability to pursue operational efficiency – obsolete hardware might act as a bottleneck for new program development
4. Lost opportunity cost – inability to plan for a uniform update can lead to system operation inefficiencies

Toronto Hydro also significantly details the stages of its IT asset lifecycle, and provides reasonable evidence for the benefits of constant failure rate operation. Navigant notes that supporting evidence in the form of industry standards for IT hardware replacement scheduling would be useful to further justify timelines. The report provides a breakdown of the types of assets up for replacement, and justifies the increased spending rates in 2018 as necessary in order to avoid deferral of storage asset replacement beyond their planned lifecycle. The priority of the replacements is such that the largest impact due to asset failure is mitigated first.

The regulations and standards cited ensure that THESL is replacing its current fleet with IT hardware that is industry accepted, and forwards OEB goals such as cyber security and Smart Grid development. Adherence to internal policy also ensures the program in line with Toronto Hydro's historical strategy towards IT hardware. The report assesses the alternatives to the approach the program is proposing, such as the run to failure option, and outsourcing device management. Due to risks involved with reactive replacement of assets, such as lack of planning causing poor integration of devices and high operational expenditure, run to failure is generally discounted, which demonstrates THESL's commitment to proactive asset management in this late filing. Furthermore, Toronto Hydro justifies internal replacement of its assets through decreased cyber security risks, mitigation of system lag/latency, and the flexibility to modify hardware asset maintenance without needing to communicate with external vendors.

Facilities Management & Security

THESL's facilities management and security plan is designed to make infrastructure improvements to specialized facilities that perform unique functions. These improvements include changes and enhancements to building security, mechanical, electrical, civil and architectural areas at 500 Commissioners, 14 Carlton, 160 Eglinton and several THESL stations. It is important to note that the security aspect of station facilities covered under this program will be coordinated with other improvements covered by Stations Building Infrastructure Renewal program. Total program cost is estimated to be $28.8 million between 2015 and 2019.

Most of the investment ($22.9 million) is proposed in the 2015 through 2016 time frame. High level items covered by this program include:

- Security – Locking hardware, card readers, fencing/gates, lighting, and intercom systems
- Mechanical – Plumbing, heating, air conditioning, and elevators
- Electrical – power distribution system, building automation system (BAS) and the fire and security monitoring systems
- Civil – Interior and exterior coverings, surfaces of the buildings, access ways, walk ways and windows
- Architectural – foundation and building envelope, roof and building masonry

THESL's business case justifies the upgrade based on security related incidents like theft, forced entry, vandalism, trespass, injury and safety. Pictures and associated details provide reasonable evidence to the deteriorating conditions in mechanical, electrical and architectural areas. The primary objective of this program is to maintain critical facilities that support efficient operations, replace assets that are at end of life, and to move toward alignment with NERC security standards. Secondary drivers include health and safety of employees and a reduction of failure risk that could affect reliability.

Methods THESL used to justify this program are in line with the processes applied and encountered at other utilities. THESL clearly articulates the facilities included in the program, the current state analysis of each facility, expected improvements, and the cost of each improvement. THESL's evaluation of alternatives clearly suggests the activities planned for this program are superior compared to the status quo option or repairing facilities reactively. Detailed cost analysis of the first year of investment provides additional justification.

Voice Radio System

THESL's Voice Radio System Upgrade Program is designed to replace voice communications equipment that field crews and external contractors use to communicate with control room personnel. THESL has accelerated the program to be completed between 2015 and 2016 due to the aging communication equipment and lack of vendor support. THESL expects the program to cost about $20 million over two years. The assets to be replaced in this program include the Data network, associated facilities; and backend equipment such as antennas, gateways, base stations; and front end equipment such as dispatch consoles. Spending is front loaded with $15 million of the investment proposed for 2015 and $5 million in 2016.

THESL justifies the program by citing two key facts: First, most communication hardware has been in service past the expected lifespan and second, vendor support contract expiring in 2016 with no future plans to support the existing communication hardware, the business is

justifies the renewal program. The voice communication infrastructure is critical to THESL's core distribution operations as it enables field crews to report injuries, emergencies and operations feedback. The tables and graphs clearly show an increase in component failure and proportional increases in repair costs. The limitations with the current system and dead zones within Toronto are preventing some communications, which affects THESL's core distribution functions.

In its business case, THESL evaluated other options such as,

1. Maintaining the existing system beyond 2016 on a "best effort" basis
2. Migrate to a contracted radio service
3. Replace the existing analog system with new digital radio system TETRA
4. Upgrade the existing analog system to digital radio system P25

THESL cites Option 4 as the preferred alternative, as it requires minimum investments and lower risk in safety, vendor and operational categories. THESL's evaluation and justification is in line with practices seen by Navigant at other utilities and with other programs within THESL.

Fleet and Equipment

The Fleet and Equipment services program is intended to replace THESL's aging fleet of vehicles in a timely manner to avoid expensive repairs and benefit from related efficiencies. There are a total of 660 units from various classes of vehicles and trailers that include cars, backhoes, minivans, among other equipment. The program is expected to cost about $18 million between 2015 and 2019. Annual spending averages about $3.5million, which includes vehicle replacements and equipment such as GPS trackers and associated services. The fleet replacement lead times vary from 3 to 12 months depending on the type and required vehicle equipment.

THESL's fleet replacement program is driven primarily by system maintenance and capital investment support with safety, reliability and business operations efficiency as secondary drivers. Analysis of vehicle life cycle costs, maintenance cost and reliability with age and odometer over 2008 to 2012 clearly presents rising maintenance costs with decreased reliability as the average age of the fleet exceeds 16 years and approximately 150K kilometers. THESL is considering the replacement of GPS/Telemetry systems as a part of this program. Year 2015 is the final year of the support contract for these systems, and replacement is justified because newer systems with enhanced features are available at lower cost due to technological advancements.

The methods THESL uses to justify the program are consistent with practices at other utilities. Various vehicle classes and related replacement criteria has been considered, and options such as "run to failure", "status quo" and "managed fleet replacement" were explored. The benefits of managed fleet replacement outweigh the risk and demerits of the other two options.

Program Support

Program Support investments include a study of customer interruption cost (CIC) and a climate adaptation study. Through surveys of various customer classes, the CIC study will provide THESL with better information on localized outage costs for customers. The primary benefit of the CIC study is the incorporation of the resulting data into the Feeder Investment Model (FIM). The climate adaptation study will improve system resiliency with regards to weather related risk, thus reducing the frequency and duration of outages caused by these events. Program Support will cost $1.7 million between 2015 and 2019 with all of the spending occurring in 2015 and 2016. The climate adaptation studies will cost $0.5 million annually, while the CIC study will be executed in 2015 and cost $0.7 million.

The most significant driver for the program is the need to support system maintenance programs through a robust knowledge of climatic impact on assets and cost of localized outages caused by asset failure. This program is framed by THESL in terms of a mechanism to improve its numerous capital investments in asset renewal for this rebasing. The report makes use of recent singular events, and historical impacts that Major Event Days have had on SAIDI and SAIFI metrics, and to quantify the necessity for climatic asset resiliency. In addition, the report summarizes the findings of studies conducted by other electrical utilities.

The report provides sound justification for the pacing of the program. The desire to incorporate the results of this program to enhance business cases for other investments is restated and is reasonable justification towards completing the CIC survey and climate adaptation studies early in the 2015-2019 rate period. THESL proposes to minimize cost by opening the studies to competitive vendor bidding. To reduce risk, THESL proposes to restrict the pool of vendors to those that have previously completed similar studies in conjunction with other electrical utilities.

/C

September 16, 2014
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RIDER to Navigant Consulting Ltd. Report Titled:

INDEPENDENT ASSESSMENT OF TORONTO HYDRO BUSINESS CASES

Ontario Energy Board EB-2014-0116.

The following summarizes Navigant's review and assessment of updates for certain projects included in Toronto Hydro, Electric System Limited's (THESL) July 31, 2014 Custom Incentive Rate-setting (Custom IR) application for 2015 – 2019 Electric Distribution Rates and Charges before the Ontario Energy Board (OEB) under EB-2014-0116. The findings and conclusions presented in our report are based on our independent assessment of THESL's Distribution System Plan (DSP), the Schedule of Exhibits accompanying the DSP and all updated business cases for programs that THESL now seeks authorization from the OEB, and which Navigant originally evaluated in its July 29, 2014 report titled "Independent Assessment of Toronto Hydro's Distribution System Plan and Business Cases" (Exhibit 1B, Tab 02, Schedule 4, Appendix B) submitted in EB-2014-0116).

The 2014 Evidence Update includes a supplemental exhibit (E.8.3) titled "Operating Centres Consolidation Program", which requests additional capital funds of $52.2 million over 2015, 2019. Navigant completed a post-filing and independent review and assessment of THESL's business case presented in E.8.3, which is attached to this rider as Attachment A. Thus, the findings and conclusions presented below are intended to amend and supplement those contained in our July 29, 2014 report with respect to the business cases and exhibits reviewed by Navigant in the 2014 Evidence Update, in addition to new evidence provided in E.8.3 justifying the consolidation of THESL operating centres.

Navigant's independent review of the Custom IR project revisions contained in THESL's September 2014 Evidence Update resulted in a determination that the conclusions we reached in our July 29, 2014 assessment have not changed. Among other findings, the total capital funds THESL now requests for 2015 – 2019 are virtually the same as the amounts that appear in our July 29, 2014 report, i.e. slightly less than $500 million annually.

Most important, THESL's justification for each project, including costs versus expected benefits, has not materially changed. Notably, findings in our July 29, 2014 report were not premised on specific dates or times when specific projects and jobs should be completed. Rather, our report highlights on page 9 that: "Navigant reviewed in detail

THESL's DSP framework presented in Section A through D, and specific business cases in Section E, and has determined that THESL has developed a DSP with sufficient rigour and supporting analysis to justify the proposed levels of spending throughout the rate period [emphasis added]."[11] The adjustments that THESL proposes are entirely consistent with this statement.

Given these facts, Navigant has no reason to change any of the key findings, conclusions or any of the findings presented in its July 29, 2014 report with respect to the business cases and exhibits reviewed by Navigant in THESL's September 2014 Evidence Update.[11] With respect to the Operating Centres Consolidation Program, Navigant finds the proposed investments and activities associated with the reduction or relocation of THESL operating centres is warranted and will produce net economic, reliability and customer service benefits to its ratepayers.

Attachment 1A

Operating Centres Consolidation Program

THESL proposes to continue to invest in its Operating Centres Consolidation Program (OCCP) that it initiated prior to the Custom IR filing. The OCCP for 2015 through 2019 includes $52.2 million of investments to fund the reduction and relocation of four operating centres at several locations. This is in addition to amounts that have been or will be spent in 2014 and prior years. Two of the operating centres ("OC") are owned by THESL and will be sold. The other two operating centres are leased facilities that are set to expire within the 2015 through 2019 rate period. Staff, equipment and work activities from these four centres will be transferred to three existing THESL operating centres or vacant properties owned by THESL. All funds will be used for upgrading or purchasing of equipment for use in closing of the operating centres, termination of leases, transfer of staff and equipment, and the purchase of new equipment. None of the funds will be used for facilities or equipment for the delivery of electricity to THESL customers.

The following illustration highlights the location of operating centres that will be closed and the locations of existing THESL operating centres or properties that will be expanded or built to accommodate the relocations.

THESL proposes to implement the OCCP over 4 phases, the first involving the closure and sale of 5800 Yonge, with most staff, equipment and related operating functions transferred to 500 Commissioners Street. (THESL has a 99 year lease for 500 Commissions.) Yonge Street currently houses THESL's Data Centre, the Call Centre and Control Centre. The Commissioners Street facility has sufficient space to accommodate the additional staff and activities, and will include enhancements to communications, infrastructure and security features needed for each of the three above operating functions. It includes use of highly reliable fiber optics communication systems and uninterruptible power supply at Commissioners Street for critical Control and Call Centre functions. Approximately 300 employees will transfer from 5800 Yonge to 500 Commissioners.

The second and third phases involve constructing new OC's at 7151 Milner (currently a vacant building) and 741 Rexdale due to termination of leases at nearby OC's at 6011 Milner and 161 Monogram. The existing OC's are used primarily as crew work centres for maintenance and construction, and are needed to serve northeastern and northwestern sections of THESL's service territory, respectively. The new OC's will provide assurance of property tenure and provide greater efficiency in building utilization and work activities. The new OC's will include more efficient space utilization and modern office facilities and equipment.

The fourth and final phase involves the permanent closure and relocation of THESL personnel, mostly restoration crews ("System Response"), from 28 Underwriters to other OC's, including the new OC's at Rexdale and Milner. The property will be completely vacated and sold. THESL expects that the de,centralization of System Response functions will reduce travel times for crews to response to emergencies or service interruptions.

The OCCP is expected to provide benefits to THESL customers in terms of reduced cost, better reliability and improved customer service. Among these benefits is improved efficiency and asset utilization. The consolidation is expected to reduce total THESL OC square footage from 4.21 to 2.61 million, or 43%, thereby improving utilization of existing and new facilities. The sale of the 8.11 acre Yonge Street property is expected to provide direct economic benefits to ratepayers via reduced taxes, lower maintenance and proceeds from the sale of property located in a desirable, high growth area. The transfer of restoration personnel from 28 Underwriters to other OC's is expected to improve reliability as crews will require shorter travel time from the dispersed work locations to restore service. Downside risk is low as THESL owns or occupies each of the three properties where staff and operating activities will be relocated.

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Navigant's experience and review of THESL's OCCP confirms the proposed consolidation is consistent with utility practices throughout North America. The reasons and analysis THESL performed to support the OCCP demonstrates that it is a better choice when compared to continuation of existing leases and facilities ("Base Case") or "Do Nothing" options. Specifically, the OCCP will provide net economic, reliability and customer service benefits to THESL's customers, and reduces the risk of higher long-term costs associated with currently leased properties when compared to other options. As a result of these findings, Navigant has determined that THESL's funding request for the OCCP is justified and warranted.

EFFICIENCY, PRODUCTIVITY AND CONTINUOUS IMPROVEMENT

1. INTRODUCTION

The purpose of this schedule is to provide an overview of the evidence that that Toronto Hydro has filed this application to enable the Ontario Energy Board ("OEB") to evaluate the utility's ongoing efforts to achieve sustained improvements in efficiency and productivity.

In response to the OEB's Guidance in the RRFE Report,[1] Toronto Hydro has filed evidence detailing the utility's past, present and future productivity accomplishments, including continuous improvement as part of the utility's proposed custom rate-setting index. This evidence presents an evaluation of the utility's productivity levels, confirms the reasonableness of the utility's application through empirical benchmarking analysis, and explains how Toronto Hydro is appropriately incented to continue seeking further efficiency and productivity gains during the 2015 – 2019 rate period.

Toronto Hydro has a long-standing productivity culture which has evolved over time in line with emerging operating challenges, changes in government policy and expectations underlying the regulatory regimes that govern the utility's operations. Toronto Hydro's framework of current and planned productivity processes and initiatives are in alignment with the spirit of the RRFE Report. These processes and initiatives emphasize increasingly sophisticated performance measurement tools, bottom-up approach to identifying new efficiency opportunities, as well as streamlining labour-intensive processes through technological improvements and rationalization of supporting infrastructure.

[1] Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (October 18, 2012) [the "RRFE Report"].

Consistent with the OEB's guidance in the RRFE Report (as briefly summarized below and discussed in more detail in Exhibit 1B, Tab 2, Schedule 2) the remainder of this schedule addresses the utility's productivity and efficiency levels and the culture of continuous improvement. The evidence is presented in two sections:

(i) the Past and Present, detailing the utility's accomplishments up to and including its 2015 Test Year; and

(ii) the Future, discussing the utility's plans for continued improvement of productivity and efficiency, together with the tools and processes needed for the utility to deliver the desired outcomes.

2. OEB GUIDANCE ON PRODUCTIVITY, EFFICIENCY AND CONTINUOUS IMPROVEMENT FOR THE DISTRIBUTORS FILING CUSTOM IR APPLICATIONS

The OEB's RRFE Report indicates the OEB's expectation that Custom Incentive Rate-Setting ("Custom IR" or "CIR") applications will enable "an assessment of the adequacy of past and future productivity levels."[2] Elsewhere in the RRFE Report, the OEB states that it expects to use benchmarking evidence "to assess the reasonableness of the distributor's forecasts."[3]

Toronto Hydro has endeavoured to address, and submits that it has effectively addressed, the OEB's guidance in the RRFE Report through information contained in, and appended to, this schedule. In particular, the utility's productivity evidence showcases,

(i) the long-standing nature of Toronto Hydro's culture of productivity;

(ii) the reasonableness of the utility's current and forecasted costs in light of its atypical operating conditions; and

[2] RRFE Report, supra note 1 at page 70.
[3] RRFE Report, supra note 1 at page 13.

(iii) the sufficiency of productivity and efficiency incentives embedded within the Toronto Hydro's proposed CIR ratemaking framework and capital efficiency performance measures underlying the utility's Distribution System Plan ("DSP).

2.1. Past and Present Productivity Initiatives

The adequacy, scale, scope of Toronto Hydro's productivity levels, together with its past and present productivity culture is subdivided into three general components:

1) Past Accomplishments – Case Studies and Cultural Evolution;
2) Empirical Evaluation – Econometric Benchmarking Study;
3) Ratemaking Incentives –The Effect of the IRM Framework

2.1.1. Past Accomplishments – Case Studies and Cultural Evolution

To showcase the range, nature and evolution of Toronto Hydro's past productivity accomplishments the utility has filed, at Appendix A to this schedule, a review of past productivity initiatives implemented by the utility between 1998 and 2011, inclusively. The review uses a narrative structure (with high-level quantification) to showcase the evolution of Toronto Hydro productivity culture since the utility's amalgamation.

As further discussed in Appendix A, Toronto Hydro's productivity was in large part shaped by the amalgamation of six neighbouring municipal electric utilities with distinct operating practices, unique asset bases and long-standing management philosophies. Following amalgamation, Toronto Hydro was dedicated to streamlining and rationalizing the legacy tools, processes, assets and workforce, while working towards creating a unified operating model supported by a common corporate philosophy.

As the utility matured and the operating practices became progressively harmonized, the focus shifted to enhancing its capabilities to plan for and implement comprehensive and

sustainable longer-term staffing and asset management strategies, along with expanding its ability to operate the distribution system in a reliable and coordinated manner. Critically, the systems and processes put in place during the 2004-2006 timeframe facilitated Toronto Hydro's ability to accommodate the increase in the volume of the utility's capital program starting in 2007. Among the key initiatives that drove productivity and efficiency improvements were the implementation of the Outage Management and Distribution Management Systems ("OMS" and "DMS", respectively), the adoption of the reliability-centered maintenance framework, and job description harmonization.

More recently, Toronto Hydro's productivity-enabling activities were primarily focused on supporting the utility's growing capital investment program and facilitating improvements to its customer service offerings. The specific initiatives included the adoption of new asset management tools and procedures, implementation of comprehensive health and safety management practices, outsourcing of capital work execution, and the introduction of a new Customer Care and Billing ("CC&B") system. Throughout this period, the utility also focused on maximizing the value of output from its internal labour force through such programs as performance and attendance management, the employee health and safety management system ("EHSMS"), and enhanced field supervision practices.

2.1.1.1. Asset Management Productivity Evolution

Among other examples of continuous improvement showcased within the Past Productivity Review is the evolution of Toronto Hydro's asset management practices and tools. Having inherited six distinct distribution systems with varying asset types, vintages and configurations, Toronto Hydro made significant progress in standardizing its asset base and implementing progressively more sophisticated asset management tools and processes.

The utility's initial challenge, at the outset of its amalgamated existence, was to develop and implement a consistent framework of asset nomenclature across all six legacy distribution territories. This was a complex and labour-intensive process, the outcome of which was to simplify and streamline the execution of field work. Toronto Hydro also consolidated and systematized all of its asset records into a comprehensive Geospatially Enabled Asset Registry ("GEAR") application, which remains a fundamental asset management and design application used by Toronto Hydro's engineers and technicians. Using Geographical Information System ("GIS") technology, GEAR has streamlined the utility's asset management and planning procedures, allowing Toronto Hydro to support the growing capital program.

The standardization of asset nomenclature and records also enabled Toronto Hydro to adopt the Reliability-Centered Maintenance ("RCM") approach for its distribution plant maintenance activities. This approach, first adopted in the airline industry, has allowed Toronto Hydro to schedule and prioritize its maintenance activities on the basis of highest probability and the impact of failure, contrary to past approaches that were largely reactive, or planned maintenance activities on the basis of equipment manufacturer specifications. In a similar manner, the implementation of the Worst Performing Feeder ("WPF") program and tracking of the supporting Feeders Experiencing Sustained Interruptions ("FESI") measure enabled the utility to effectively and efficiently target the most vulnerable parts of its system, driving performance improvements through targeted reliability-driven investments[4].

The utility further improved its asset analytical capabilities by implementing the Feeder Investment Model ("FIM"). The FIM application allows the utility to determine the optimal intervention times for the replacement or refurbishment of its distribution plant

[4] For more information about the WPF program and FESI measure, refer to the utility's Distribution System Plan at Exhibit 2B, Sections C.2.2 and E.6.21

on the basis of interruption costs and other risk-based considerations. This helps to identify the areas where capital investments provide the highest value for Toronto Hydro and its customers at a given time.

2.1.2. Empirical Evaluation – Econometric Benchmarking Study

To further support the appropriateness of Toronto Hydro's productivity/efficiency levels and provide the OEB with an objective evaluation of the reasonableness of the utility's 2015-2019 rate request,[5] Toronto Hydro has filed, as Appendix B to this schedule, a Custom Econometric Benchmarking Study prepared by Power System Engineering Inc. (the "PSE Report"), based on empirical analysis of total cost levels and reliability of all Ontario distributors and 85 utilities from the United States.

In addition to the OEB's guidance in the RRFE Report with respect to the use of benchmarking in evaluation of custom IR applications, in commissioning this study, Toronto Hydro was also guided by the OEB's commentary in Toronto Hydro's 2012 - 2014 rate application (EB-2011-0144), in which the OEB stated that it is "always open to applicants to bring forth alternative benchmarking evidence which incorporates comparators from other jurisdictions if the distributor believes those comparisons are more relevant."[6]

As further detailed in the appended PSE Report, Toronto Hydro believes that broadening the sample of analyzed utilities, while maintaining the presence of Ontario data points and the core methodology endorsed by the OEB, allows Toronto Hydro to strike a balance between maintaining relevance to the Ontario economic and regulatory context,

[5] Nicole Stewart, Missing in Action: Absenteeism Trends in Canadian Organizations (Ottawa: Conference Board of Canada, 2013), online: Sun Life Financial <http://www.sunlife.ca/static/canada/Sponsor/All%20Group%20Benefits/Focus%20Update/2013/Special%20Edition%20-%20Sept.%2023%20-%20%20Sun%20Life%20co-sponsors%20major%20new%20Conference%20Board%20of/MissinginAction_SUN%20LIFE_EN.pdf>.

[6] EB-2011-0144, Decision with Reasons and Order on the Preliminary Issue (January 5, 2012) at page 17.

and exploring the effect of additional business conditions that distinguish Toronto Hydro's operations from other Ontario local distribution companies ("LDCs").[7]

Based on its econometric benchmarking analysis, the PSE Report concludes that Toronto Hydro's past costs, as well as its 2015-2019 cost levels proposed in this application are lower than the reasonable levels of spending predicted by the econometric efficiency model. Toronto Hydro submits that these findings support the sufficiency of Toronto Hydro's past cost performance and confirm the efficiency and reasonableness of the forecasted costs underlying this application. The Utility attributes the results of this assessment at least in part to the benefits of productivity initiatives described in the Past Productivity Review (Appendix A to this schedule) and those detailed elsewhere in this application.

In addition to examining the total cost efficiency levels, the PSE Report undertakes an econometric benchmarking analysis of Toronto Hydro's reliability levels. Similar to the econometric cost benchmarking exercise, the PSE Report determines the expected System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") levels for Toronto Hydro based on an examination of the business conditions that affect the utility's reliability performance. The sample of observed utilities comes from a combination of Ontario distributors and utilities in the United States.[8] As discussed in more detail in the appended PSE Report and Exhibit 2B, Section E2 discussing the utility's reliability performance, Toronto Hydro's historical and projected outage duration (SAIDI) performance is better than expected by benchmarking analysis, while its historical outage frequency (SAIFI) results are poorer than predicted by the econometric model. In discussing these results of this analysis, PSE observes that

[7] The PSE Report provides additional discussion of the technical, economic, demographic and topographic factors underlying Toronto Hydro's decision to expand the study's sample to include a subset of U.S. utilities, including PSE's commentary on these factors.
[8] The samples of observed U.S. utilities differs between the Total Cost and the reliability benchmarking studies due to the availability of public information that was necessary to conduct both studies.

above-average SAIDI results speak to the quality of Toronto Hydro's operations, which allow the utility to detect and quickly address the outages occurring on its system. As to the utility's below-average past SAIFI results, PSE largely attributes them to the current age and condition of Toronto Hydro's distribution plant. Consistent with the nature and volume of Toronto Hydro's proposed 2015-2019 capital investment program, the utility's SAIFI projections are expected to converge towards the benchmark over the five-year CIR period.

The PSE Report utilizes the translogarithmic (or translog) method of statistical modelling to evaluate Toronto Hydro's efficiency on a total cost basis, using a set of key business conditions derived through analysis of a comprehensive sample of electric utilities from Ontario and the United States. The translog methodology used by PSE is substantially similar to the approach employed by the OEB's own productivity consultant, Pacific Economics Group ("PEG"), for the purposes of placing Ontario's distributors into five efficiency cohorts and assigning the corresponding annual stretch factor values.[9]

Among the custom elements distinguishing the PSE model from the PEG approach used by the OEB is an extended sample of electric utilities, with data from a full sample of Ontario LDCs complemented by a set of 85 utilities from the United States, a number of which are comparable to Toronto Hydro in size, share with the utility a number of key business conditions that are largely absent across the Ontario electricity distribution sector.[10] In addition, the PSE benchmarking model leverages the inclusion of additional data points, thereby expanding upon the scope of key business conditions used to derive the predicted efficient cost levels for all utilities examined.

[9] Pacific Economics Group (2013), Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario, (corrected January 24, 2014) at page 12 [the "PEG Report"].
[10] See PSE Report (Appendix B) for a comprehensive discussion of the business conditions that Toronto Hydro shares with many of the U.S. utilities included in the sample, which, in PSE's assessment are largely absent from the Ontario distribution landscape.

Chief among the additional business conditions is the "Presence of a Large Urban Core," a variable that cannot be derived from the Ontario-only sample, where Toronto Hydro is an outlier in terms of its size and the density of its urban service territory. A distinct feature of Toronto Hydro's urban downtown system is an asset-intensive downtown underground secondary distribution network, which provides increased reliability to Toronto Hydro's customers in the downtown core. These customers include critical loads such as hospitals, major bank headquarters, and the Toronto Stock Exchange. The downtown secondary network, which in PSE's assessment significantly influences the utility's total operating and capital costs, is unique in its span and configuration among the Ontario utilities. At the same time, similar secondary network configurations are relatively commonplace among the U.S. utilities serving major urban centres such as New York, Chicago, Baltimore, San Francisco, and Washington DC, all of which are included in the expanded sample set used by PSE.

Beyond the downtown secondary networks, as confirmed by PSE's cost analysis, serving large and densely populated downtown cores involves significant incremental capital expenses, all of which are largely uncommon to other Ontario's distributors given the age and configuration of their systems. Factoring the effect of this business condition into the benchmarking model enables PSE to assess the efficiency of Toronto Hydro's operations in a more comprehensive manner, by comparing it to other utilities that are exposed to similar cost drivers. The cost consequences of serving a dense urban-metropolitan era are further examined in the appendix to the PSE report. This appendix contains an engineering study that concludes that serving a dense urban area requires significantly more capital infrastructure (and thus a higher capital cost per kW) than supplying less dense suburban and medium-density areas that are more typical in Ontario's distribution landscape.[11]

[11] The referenced engineering study appended to the PSE Report does, however, find that it is similarly more expensive to serve sparsely populated rural areas.

Furthermore, the appendix to the PSE Report includes a comprehensive description of other business conditions that are largely absent from other Ontario distributors' service territories. Among these atypical business conditions are:

- Spatial restrictions for underground and overhead corridors;
- Excavation challenges due to the lake proximity and unmapped legacy infrastructure;
- Large-scale and frequent plant relocations driven by third-party requests;
- Vertical city growth and incremental costs of serving high-rise buildings;
- Heavy traffic congestion and municipally driven road work restrictions;
- Mature and dense tree canopy adjacent to or within utility corridors;
- Specialized skill requirements for work on legacy assets (pilc, box construction);
- Physical and economic topography (rivers, ravines, major highways and railroad corridors);
- High customer mobility, and large proportion of low-income customers;
- Safety costs of confined space work and the presence of controlled substances in the plant; and
- High commercial real estate prices.

Toronto Hydro's assessment is that the cumulative effect[12] of these and other related business conditions has a significant impact on the utility's operating and capital costs – an impact that is beyond the typical levels expected from Toronto Hydro based on its customer count, load or energy throughput. By expanding the number of model observations to include the U.S. utilities serving territories characterized by a wide variety of conditions, the cumulative effect of these atypical business variables can be better accounted for. Moreover, in the combined Ontario-U.S. dataset, Toronto Hydro is

[12] Toronto Hydro understands that most of these business conditions exist to varying degrees in the service territories of other Ontario distributors. However, the utility believes that the aggregate effect of the scope and magnitude of these operating characteristics within its service territory has a significant influence on its costs, above the levels experienced by other Ontario distributors.

approaching the sample average in terms of customer size, total expenditures, load and energy throughput unlike the OEB Ontario-only model where the utility is a clear outlier.

The OEB acknowledged the outlier status of Toronto Hydro in the Ontario context, by excluding results of the utility's historical Total Factor Productivity ("TFP") assessment from the calculation of the Productivity Factor for rate-setting under the 4th Generation Incentive Rate-Setting ("4th Generation IR") regime.[13] The variability in the scale of operation and costs of observed utilities in PSE's combined dataset makes it possible to produce benchmark cost models that evaluate Toronto Hydro's performance in a rigorous manner, and allow PSE to account for the effect of business conditions not present elsewhere in Ontario (e.g., large urban core).

2.1.3. Ratemaking Incentives – the IRM Framework

Toronto Hydro's base rates have been set using a cost of service in accordance with the OEB's 3rd Generation Incentive Rate-Setting Price Cap Index ("PCI") mechanism since 2011, when the utility underwent its last rebasing proceeding (EB-2010-0142). In ensuring that its operating costs conformed to the funding levels provided by the PCI framework over the 2012-2014 period, the utility took a number of cost-saving steps to enhance the efficiency and promote sustainability of its operations, including:

- Conducting a Restructuring Program in 2012, which reduced the utility's headcount by approximately 200 full-time unionized and non-union employees;[14]
- Improving efficiency of its supply chain and warehousing operations by introducing a new Warehouse Management System, outsourcing a portion of warehousing operations and automating low-value activities;[15]

[13] EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (December 4, 2013) at page 14.
[14] Exhibit 4A, Tab 4.
[15] Exhibit 4A, Tab 2, Schedule 12.

- Reducing administrative burden and improving service quality by outsourcing the management of 100+ facilities contracts to a single Facilities Management Organization;[16]
- Taking steps to rationalize the size of the utility's vehicle fleet and reducing the associated expenditures through a combination of outsourcing and process streamlining;[17]
- Improving the efficiency and scalability of its information technology operations by virtualizing the majority of the utility's servers and standardizing and streamlining the governance of all key IT processes;[18]
- Driving down injury frequency and avoiding the associated costs by implementing industry-leading health and safety standards and investing in safety awareness;[19]
- Introducing a new Customer Care and Billing ("CC&B") system and broadening the scope of available online self-service tools, including move processing, electronic billing etc, which improved service levels and had a positive impact on the utility's working capital requirements;[20]
- Other initiatives described throughout this application.

2.2. Future Productivity and Toronto Hydro's Productivity Culture

The utility's evidence in support of the productivity incentives built into the proposed Custom IR rate framework and the reasonableness of the utility's forecasted expenditures over the 2015-2019 horizon is based on:

1) Structural Elements of the CIR Framework;
2) Empirical Evaluation of the 2015-2019 Expenditure Forecasts;
3) Productivity Culture over the CIR Timeframe.

[16] Exhibit 4A, Tab 2, Schedule 11.
[17] Exhibit 4A, Tab 2, Schedule 10.
[18] Exhibit 4A, Tab 2, Schedule 16.
[19] Exhibit 4A, Tab 2, Schedule 14.
[20] Exhibit 4A, Tab 2, Schedule 13; Exhibit 2A, Tab 3.

2.2.1. Structural Elements of the CIR Framework

Toronto Hydro's proposed Custom IR framework contains two key elements that are expected to incent the utility to seek further efficiency and productivity improvements over the 2015-2019 timeframe. These elements are:

(a) The Custom Rate-Setting Index; and

(b) Distribution System Plan (DSP) Capital Efficiency Measures.

2.2.1.1. The Custom Rate-Setting Index

Toronto Hydro's proposed 2015-2019 rate framework entails a custom index, whereby the portion of the utility's Operations, Maintenance & Administration (OM&A) expenditures built into the 2015 base rates will increase on the basis of the OEB's Price Cap Index ("PCI") in 2016-2019 (i.e., years 2-5 of the CIR plan), while the funding for capital expenditures during this time will be provided through a Custom Capital Factor ("CCF" or "C-Factor").[21]

More specifically, the utility's OM&A expenditures built into 2015 base rates, will increase by the value determined through application of the OEB's long-standing I-X formula, where the value of both Inflation ("I") and Productivity and Stretch Factors (collectively "X") will be set by the OEB on an annual basis consistent with the traditional 4th Generation IR rate-setting policies. As a part of its annual update process, Toronto Hydro will apply to the OEB to adjust its base rates on the basis of updated I and X values along with the custom value of the C-factor.

As described in more detail in Exhibit 1B, Tab 2, Schedule 3, Toronto Hydro seeks a 0.3% stretch factor based on the findings of PSE Report, which indicate that Toronto Hydro's total cost are within +/- 10% of its model-predicted levels, and thereby

[21] See Exhibit 1B, Tab 2, Schedule 3 for more information about the proposed rate framework.

correspond to a Medium Efficiency Cohort (0.3% stretch factor) based on the OEB's 4th Generation IR methodology.

The Productivity Factor and Stretch Factor values built into the rate-setting mechanism facilitate the sharing of benefits from efficiency/productivity gains with customers on an ongoing basis. Toronto Hydro notes that that PEG's 2013 empirical research of Ontario distribution industry's Total Factor Productivity (TFP) trends commissioned by the OEB for the purposes of setting the Productivity and Stretch Factor values for the 4th Generation IR framework initially supported a negative (-0.3%) productivity factor[22], based on the Ontario distribution sector's historical (2002-2012) productivity trends. Moreover, PEG's findings in support of a negative productivity factor excluded the TFP performance results of Toronto Hydro and Hydro One Networks (which were also negative) on the basis that these utilities are industry outliers. The OEB has ultimately determined that the value of the Productivity Factor for the 4th Generation IR regime should be 0%. Considering the cumulative effect of the OEB-determined 0% Productivity Factor, the proposed 0.3% Stretch Factor, and the actual empirical results of the industry TFP performance which could warrant a negative productivity factor, the cumulative effect of incentives built into Toronto Hydro's proposed Custom IR index is effectively greater than the 0.3% value of X factor, and is likely in the range of 1% or higher. Toronto Hydro submits that this effective value of the X factor applied to the utility's OM&A expenditures constitutes a sufficient incentive for the 2015-2019 CIR rate period, especially in light of the amount of productivity efficiency gains achieved in the preceding years, as confirmed by PSE.

The elements of the PCI framework embedded within the proposed Custom IR index effectively guarantee the OEB and Toronto Hydro customers the achievement of an

[22] Pacific Economics Group (PEG), "Productivity And Benchmarking Research In Support Of Incentive Rate Setting In Ontario: Final Report to the Ontario Energy Board" 21 November 2013, p.5.

outcome of future cost efficiencies through formulaic increases of the utility's operational expenditures capped at a level significantly below inflation. Accordingly, and in light of the requested five-year rate term, Toronto Hydro submits that the proposed rate framework builds in a sufficient amount of long-term incentives to drive continuous improvement with respect to the utility's efficiency and productivity levels.

2.2.1.2. DSP Capital Efficiency Metrics

The second component of productivity and efficiency built into Toronto Hydro's Custom IR framework are the performance measures proposed as part of the utility's Distribution System Plan ("DSP")[23]. These measures relate to the efficiency and cost effectiveness of the DSP planning and implementation, in accordance with section 5.2.3 of the Chapter 5 Filing Requirements.

The proposed measures allow the utility to closely monitor, and take actions (where warranted and/or possible) to ensure continuous improvement in the efficiency of execution of key operating tasks that ultimately form part of total capital costs and future in-service additions. The activities captured by these measures relate to the capitalized costs of supply chain and warehousing operations, as well as capitalized costs of engineering, design and related administrative functions. Toronto Hydro believes that the optimal means of driving efficiency of its capital program involves reducing the input costs of activities that are ultimately capitalized.

In addition to the above-noted measures, Toronto Hydro's DSP performance measurement framework contains two new measures of capital implementation efficiency: (i) Annual Contractor vs. Internal Construction Costs benchmarking exercise, and (ii) a nascent project aimed at developing a comprehensive framework of construction labour input costs for planned capital projects executed by the utility's

[23] Exhibit 2B, Section C.

internal crews, which is expected to improve and simplify the processes currently in use. While the former measure enables the utility to conduct annual comparisons of its internal construction efficiency relative to the costs of identical work provided by contractors competing on the open market, the latter measure is aimed at developing a comprehensive activity-based costing framework that underlies operations of industry leaders.[24] By refining and developing these performance measurement tools over the next five years, Toronto Hydro expects to enhance its ability to obtain detailed insights as to the nature and scale of work execution challenges faced by its construction crews, and to develop appropriate tools and measures to mitigate these challenges, thus facilitating further capital efficiency and productivity improvements.

In addition to the performance measurement framework, and as further detailed in Toronto Hydro's Supply Chain OM&A program,[25] the utility continues to work on strategic materials sourcing, vendor management and automation of low-value tasks associated with management of materials and implements supporting its capital program. In a similar manner, the anticipated improvements of the utility's capital planning tools and applications, such as the proposed FIM enhancements,[26] are expected to facilitate productivity and continuous improvement of the utility's capital planning processes. In addition to the incentives provided through the capital productivity performance measurement framework discussed above, this is expected to enable Toronto Hydro to measure and, where feasible, control the costs of capital assets that it puts in service.

2.2.2. Empirical Evaluation of the 2015-2019 Expenditure Forecasts

In respect of productivity/efficiency incentives and a re-affirmation of the reasonableness of the utility's 2015-2019 total expenditure forecasts, Toronto Hydro refers to the Total

[24] For further discussion of activity-based costing please see the "Continuous Improvement" subsection of this schedule, which details the lessons learned by Toronto Hydro by examining the operations of leading North American distributors, whose operating environments are similar to the utility's.
[25] Exhibit 4A, Tab 3, Schedule 12.
[26] Exhibit 2B, Section A.

Cost Econometric Benchmarking Study prepared by PSE and appended to this Schedule as Appendix B (the "PSE Report"). As discussed above, the PSE Report examines and confirms the efficiencies associated with the utility's expenditure levels leading up to and including the 2015 Test Year. The PSE Report also applies empirical benchmarking practices to assess the reasonableness of Toronto Hydro's cost forecasts over the 2015-2019 Custom IR rate period. Similar to the conclusions regarding the utility's past expenditures and the 2015 Test Year, PSE finds that Toronto Hydro's 2016-2019 forecasted expenditures are reasonable when compared to average results predicted by the efficiency model; the utility's cost forecasts for each out-year are below the levels predicted by the econometric analysis.

Toronto Hydro believes that the approach adopted by PSE is the optimal means of conducting a forward-looking benchmarking assessment of future costs in the Ontario and broader North American context, where five-year utility business plans are typically not published due to commercial sensitivity or the lack of normative frameworks requiring such publications. Toronto Hydro submits that the approach used by PSE constitutes a reasonable estimate of the utility's future efficiency and productivity levels, as contemplated by the OEB in the RRFE Report.

2.2.3. Productivity Culture over the CIR Timeframe

Toronto Hydro employs a number of tools, processes and approaches to facilitate the culture of continuous improvement and achievement of further efficiency and productivity gains for the benefit of the utility and its customers. Among other things, Toronto Hydro seeks to create an environment that enables employees to perform their work efficiently, incorporates corporate goals into the daily actions of front-line staff, provides effective performance feedback, and creates a support structure for implementing continuous improvement ideas.

The remainder of this section presents a summary of Toronto Hydro's activities, currently in place or contemplated during the CIR period, as they relate to a culture of productivity. The activities are separated according to their underlying objectives according to the four general areas:

(a) Executing on projects with big savings potential;
(b) Creating a right environment for employees to perform their work productively;
(c) Translating corporate goals into daily actions for the front-line staff; and
(d) Creating a support structure for implementing continuous improvement ideas.

2.2.3.1. Executing on Projects with Big Savings Potential

Toronto Hydro expects to proceed with four initiatives:

- Upgrade of the Utility's Enterprise Resource Planning ("ERP") capability;
- Operating Centres Consolidation Program ("OCCP");
- Fleet Management Initiative;
- Standard Asset Assemblies Framework.

ERP Implementation

As detailed in Toronto Hydro's DSP,[27] Toronto Hydro's proposed ERP implementation is driven primarily by the need to upgrade Toronto Hydro's functionally obsolete Ellipse application, along with a number of other key IT applications that support the utility's key business processes. Beyond facilitating information technology service reliability and enabling sufficient technical support for upgrades for the Legacy Systems, Toronto Hydro views the ERP upgrade as an opportunity to streamline and automate a number of key asset management, human resources and financial processes that currently require a significant amount of manual effort or complex workarounds due to the lack of necessary IT functionalities. Accordingly, by implementing the upgraded ERP capability over the

[27] Exhibit 2B, E8.6

2015-2019 timeframe, Toronto Hydro expects to improve the execution efficiency of a number of critical processes supporting its operations.

Operating Centres Consolidation Program

Toronto Hydro's Operational Centres Consolidation Program ("OCCP")[28] aims to secure tenure for Toronto Hydro in the northwest and northeast areas of the City while delivering benefits to ratepayers. Under the program, Toronto Hydro would vacate four facilities, two of which it currently owns, and relocate staff, equipment and operations to three facilities already owned by Toronto Hydro to achieve efficiencies and improve space utilization. The two surplus Toronto Hydro-owned facilities would be sold and the net after-tax gains on sale and related tax savings arising would be credited to ratepayers through rate riders.

Fleet Management Initiative

The Fleet Management Strategy is an ongoing project that is already yielding efficiencies at Toronto Hydro. The project's aim is to rationalize the size of the utility's vehicle fleet and attain further operating efficiencies through competitive procurement of servicing functions, and leveraging GPS capabilities to optimize maintenance cycles. By the end of 2014, the utility expects to have removed 86 vehicles from its fleet from the time of the program's inception in 2011, which amounts to a 12% reduction. Further reductions are expected as the utility continues phasing its vehicle sharing program, which is currently in a pilot stage. For more information on the vehicle sharing program please refer to Fleet and Equipment Services OM&A program.[29]

[28] Exhibit 2B, E8.2
[29] Exhibit 4A, Tab 2, Schedule 10.

Standard Asset Assemblies Framework

As discussed above, and further detailed in the utility's DSP[30], the Asset Assemblies Framework (an undertaking that is currently in the early stages), aims to develop an enhanced framework of standard labour hour inputs for construction of a standard unit of Toronto Hydro's distribution plant. The framework is also expected to include standard adjustment factors to account for project-specific circumstances (e.g., installation in a ravine), as well as allocations for "non-work" time, such as regular breaks, set-up/takedown etc. Ease of performance tracking by crew leaders and supervisors is expected to be enabled through the development of a user-friendly application installed at handheld devices issued to staff. To ensure alignment between field conditions and performance expectations as well as drive continuous improvement, the input unit values would be periodically updated on the basis of field results.

While the framework is in the early stages and will undergo further testing and development during the 2015-2019 CIR timeframe, Toronto Hydro expects that it will provide the utility with key insights that will enable the optimization of construction practices, and in turn, lead to efficiency gains. As further discussed below, the implementation of standard asset assemblies is one of several key initiatives that Toronto Hydro identified during its recent outreach effort to several large U.S. utilities whose operating conditions are similar to those of Toronto Hydro, and whose operating practices are seen as industry-leading.

Over the 2015-2019 timeframe, Toronto Hydro plans to investigate opportunities for additional large initiatives that have value propositions and the potential for significant efficiency and productivity gains. As discussed earlier in this schedule, the incentive elements built into the utility's proposed custom rate framework are expected to incent

[30] Exhibit 2B, Section C.

Toronto Hydro to seek out and realize further productivity improvements during the CIR period.

2.2.3.2. Creating a Right Environment for Employees to Perform Their Work Productively

At the core of this strategy lies Toronto Hydro's corporate commitment to employee health and safety, supported by a comprehensive framework of safety rules, audits and education/awareness programs. Beyond facilitating employee welfare and job satisfaction, Toronto Hydro believes that a corporate focus on employee health and safety leads to significant financial benefits. For example, the utility estimates that a lifetime cost of a permanent shoulder injury to a frontline worker is approximately $1 million, comprised of rehabilitation and accommodation costs, lost productive time, insurance premiums and other components. As discussed in more detail in the utility's Human Resource and Safety OM&A evidence,[31] permanent shoulder injuries have been relatively commonplace at Toronto Hydro prior to the introduction of the current health and safety framework. The last permanent shoulder injury at Toronto Hydro occurred in 2011.

A related area of Toronto Hydro's productivity culture focus is employee attendance, as paid lost time due to absences, injuries or illnesses provides no value to the employer or ratepayers. A 2013 Conference Board of Canada study estimates that absenteeism costs Canada's economy $16.6 billion. Having put in place a comprehensive attendance management program starting in 2007, Toronto Hydro achieved a 45% reduction in absenteeism rates between 2008 and 2013, which ranks significantly below the municipal, provincial, and national averages according to the 2013 Conference Board of Canada study.[32] Toronto Hydro will continue its attendance management program over

[31] Exhibit 4A, Tab 2, Schedule 14.
[32] The Conference Board Of Canada, "Missing in Action: Absenteeism Trends in Canadian Organizations", Briefing, September 2013;

the 2015-2019 CIR timeframe to drive sustained improvements for the benefit of the utility and its ratepayers.

Toronto Hydro also continues to leverage technological advancements in order to create optimal work surroundings and drive employee productivity. Toronto Hydro has upgraded employee work stations by replacing standard desktop computers with laptops, which employees can take home or bring along to internal or external meetings. All laptops are equipped with software, which allows Toronto Hydro's employees to access all corporate applications and databases offsite via a secure connection. In addition, all of Toronto Hydro's work centres are also Wi-Fi enabled to allow the employees easy access to any required applications from anywhere in the buildings. These strategic hardware and software upgrades enable Toronto Hydro employees to perform their duties from home, while commuting, or under any other circumstances that require employees to be away from their primary work locations. In addition to facilitating productivity, this capability assists the utility's personnel in maintaining a healthy work-life balance, which improves job satisfaction and further incents productivity.

In a similar manner, Toronto Hydro is in the process of equipping all of its service vehicles with mobile laptops and GPS capabilities, which facilitates the execution of administrative tasks in the field, provides employees access to required applications and resources, and allows dispatchers to quickly locate a crew in the proximity of a reported incident. In addition, and as further described in the following section, mobile capability allows Toronto Hydro to implement new short-interval performance measurement systems, which allow the utility to quickly identify problem issues and incent its field employees to achieve performance improvements. Presently, mobile capability is

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http://www.sunlife.ca/static/canada/Sponsor/All%20Group%20Benefits/Focus%20Update/2013/Special%20Edition%20-%20Sept.%2023%20-%20%20Sun%20Life%20co-sponsors%20major%20new%20Conference%20Board%20of/MissinginAction_SUN%20LIFE_EN.pdf

installed on all service vehicles that respond to system outages. The utility plans to equip the remainder of its service vehicles with mobile technology over the CIR period.

In addition to continuously evaluating its internal practices for improvement opportunities, Toronto Hydro also considers productivity/efficiency ideas in the practices of utility sector leaders. In 2012, Toronto Hydro conducted several visits to major U.S. electric utilities in an effort to identify and adopt the most successful productivity and performance management practices. The utilities that Toronto Hydro visited were Baltimore Gas and Electric ("BG&E") in Maryland and Commonwealth Edison ("ComEd") in Chicago. Toronto Hydro is in the process of implementing several of the work practices observed during these visits, including:

- short-interval performance controls for System Response Crews (discussed below);
- changes to temperature and infrared criteria for safe entry limits into confined spaces;
- outsourcing the traffic management set-up activities for roadway work; and
- implementing a standard Asset Assessment labour input methodology.

Each of the above-mentioned practices is in various stages of development and implementation and is expected to generate productivity and performance improvements. Toronto Hydro will continue seek and implement additional industry best practices by maintaining dialogue with industry peers in the context of various industry associations and other issue-specific engagements.

2.2.3.3 Translating Corporate Goals into Daily Actions for the Front-line Staff

Key Performance Indicators

Toronto Hydro maintains a comprehensive framework of Key Performance Indicators ("KPIs") that is integrated with the utility's performance pay program and is a part of a Balanced Corporate Scorecard. The KPI framework is structured in a way to create a direct link between the individual performance expectations of each Toronto Hydro employee and the corporate performance goals for each year. Such a structure allows the utility to foster accountability and continuous improvement at every level of corporate structure.

System Response Crew Performance Monitoring

In addition to corporate-wide performance measurement, Toronto Hydro continues to implement an increasing number of sophisticated program-specific performance measurement systems, which monitor employee achievement of key operational outcomes relevant to their particular area of responsibility. One such performance measurement system has been implemented in 2013 to enable more advanced tracking of the utility's responses to Police, Fire and Ambulance ("PFA") calls. Pursuant to the conditions of its distribution licence, Toronto Hydro is required to respond to 90% of all PFA calls within one hour from receiving the call. While Toronto Hydro has historically maintained its compliance with the OEB standard, the utility obtained the idea for a more advanced tracking system from one of its U.S. utility peers.

To ensure measurement accuracy, Toronto Hydro utilizes the GPS capability installed on all of its service vehicles to gauge each system response crew's success in meeting the internal benchmark. The summary of daily activities is electronically summarized in a user-friendly dashboard, which enables in-depth performance analysis at the next day's crew meetings with supervisors and managers. Performance trends are also reviewed at

monthly meetings, where employees are provided an opportunity to suggest practice improvements. Since this initiative has been put in place, Toronto Hydro's PFA performance rate has improved by approximately 20%, when adjusting for Major Event Days. Continuous tracking of performance statistics also allows Toronto Hydro to periodically increase the internal standards, thus driving continuous improvement in service levels and efficiency. Over the IRM period, Toronto Hydro plans to investigate opportunities for extrapolation of the PFA response tracking methodology to other areas of utility's operations, such as regular maintenance activities.

Other Activity-Based Performance Measurement

Toronto Hydro employs activity-based performance measurement across a number of its other operational programs, including:

- First Call Resolution and Average Call Duration stats for its contact centre employees;
- On Time and in Full ("OTIF") order fulfillment rate for it warehouse operations;
- Order completion rate for the utility's materials and supplies vendors;
- Service request resolution metrics for the IT program staff;
- Internal request response timelines for the Legal program staff;
- Order to Operate ("OTO") execution rates for the Control Centre employees;
- Office time spent by crew supervisors;
- Maintenance attainment rates for the utility's fleet; and
- Other activity-specific measures and metrics.

Performance Measurement over the 2015-2019 Timeframe

Over the 2015-2019 timeframe Toronto Hydro plans to continue expanding the scope and sophistication of its performance management and evaluation undertakings. Among the key areas of focus over the five-year period includes the investigation, piloting and introduction of the previously described Asset Assemblies Framework discussed earlier

in this document. Other initiatives targeting increasingly precise and sophisticated measurement of specific activities will also be considered.

2.2.3.4. Creating a Support Structure for Implementing Continuous Improvement Ideas

The utility places a significant value on the ideas generated by employees, and has put in place a number of formal channels for the identification and discussion of these ideas. The main means of soliciting productivity-enhancing feedback are meetings between Toronto Hydro employees and members of the management team that occur across the utility at regularly scheduled intervals. Toronto Hydro encourages its employees to provide open feedback on the operating practices they use in the field, including ways to improve the safety or efficiency of work execution. Toronto Hydro plans to put into place other tools for grassroots productivity initiatives identification. Among them are plans to conduct a survey across the utility's operations to address potential productivity opportunities during the CIR term. Initiatives that receive support and have potential to affect multiple programs may be further refined and considered for implementation.

Toronto HydrorElectricrSystem Limited: Historic Performance and Productivity Initiatives

From Amalgamation to Present

Toronto HydrorElectric System Limited

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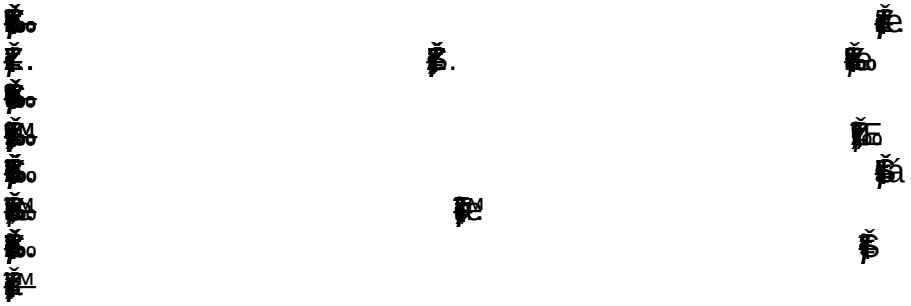
E Summary 35

A Introduction

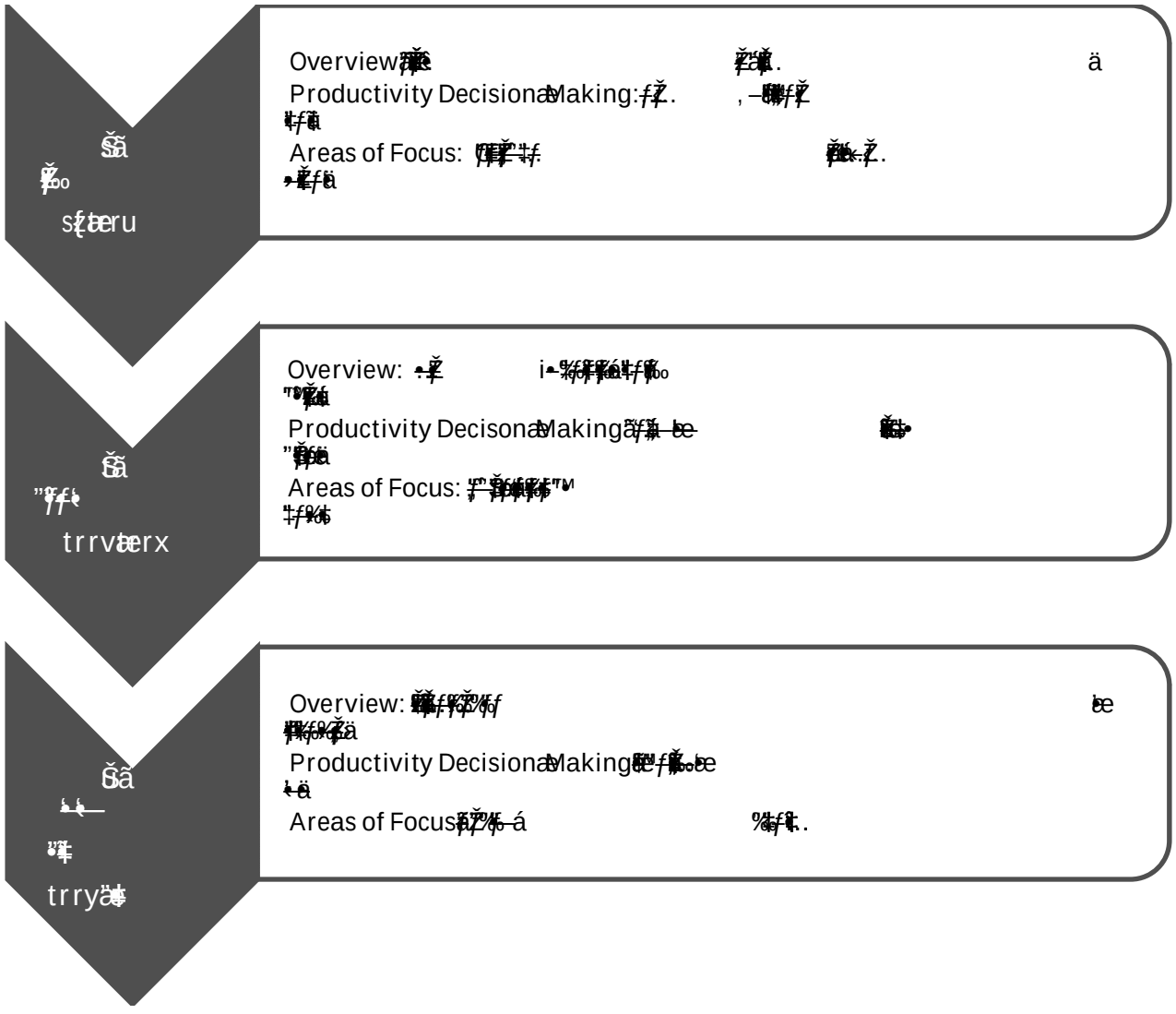
Phase1 æAmalgamation(1998 – 2003)ãManagingthe mergeraftermath .



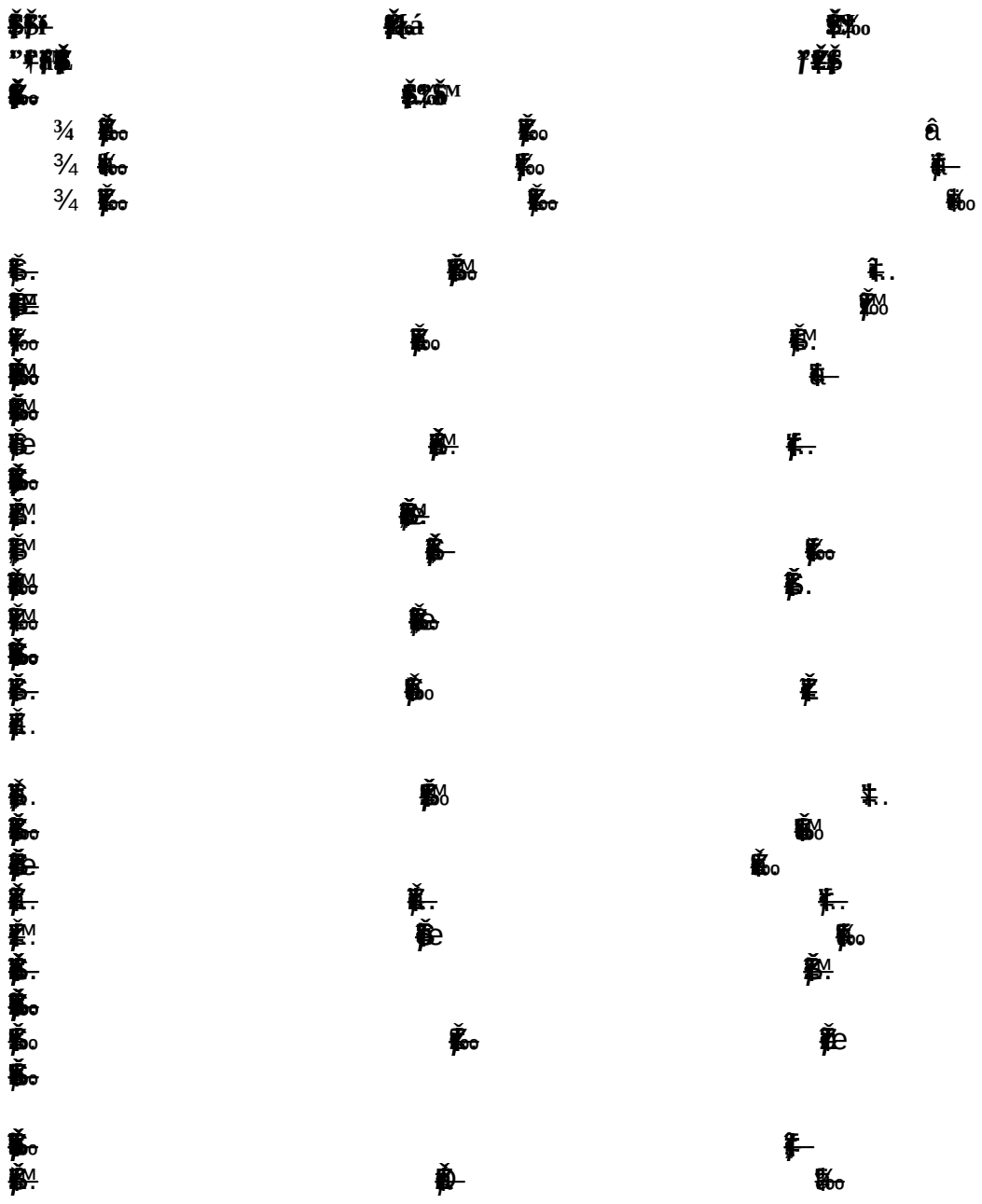
Phase2 æTransformation(2004 æ2006)ãContinuingon thepath ofhuman capital and assetmanagementharmonization ä



Phase3 æContinuousImprovement (2007 æ2014):Enabling the capital program ramp æ upand grid operation efficienciesä



B Amalgamation 1998-2003



People	Physcial	Systems
æCall Center Outsourcing æStaff Reductions, Job Harmonization and Voluntary Exit Program ("VEP")	æHarmonization of Nomenclature æInvestment Recovery æVendor Consolidation æFacilities Consolidation æControl Room Reductions	æBanner æEllipse æManagement Control and Reporting System æConsumables Management

Figure 1: Amalgamation Period Productivity Initiatives

Initiative	Basisof Estimated Savings	EstimatedNPVof Benefitsto date
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
TOTALQUANTIFIED BENEFITS		$2.2billion

Figure 2: Quantified Estimates of NPV of Productivity Initiatives – Amalgamation Phase

B.1 Call Center Outsourcing

[illegible]

[illegible]

B.2 Staff Reductions, Job Harmonization and Voluntary Exit Program

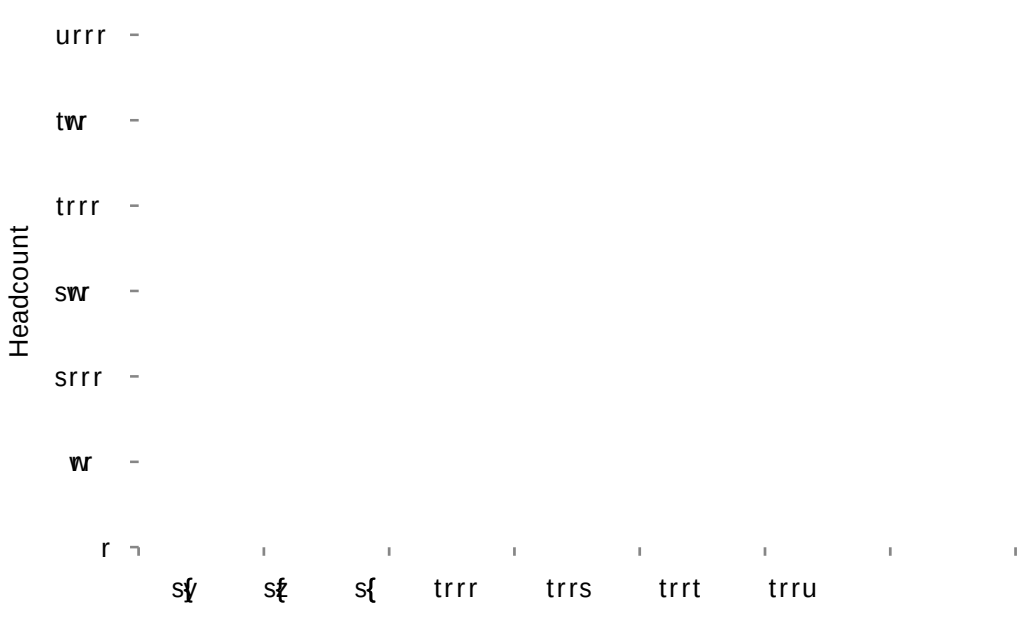


Figure 3: Toronto Hydro Employee Count (1997 – 2003)

B.3 Harmonization of Nomenclature

- SafetyConcerns
- LostProductivity
- Operational Costs

B.4 Vendor Consolidation

B.5 Facilities Consolidation

B.6 Control Room Rationalization

B.7 Investment Recovery

B.8 Centralized CIS Implementation

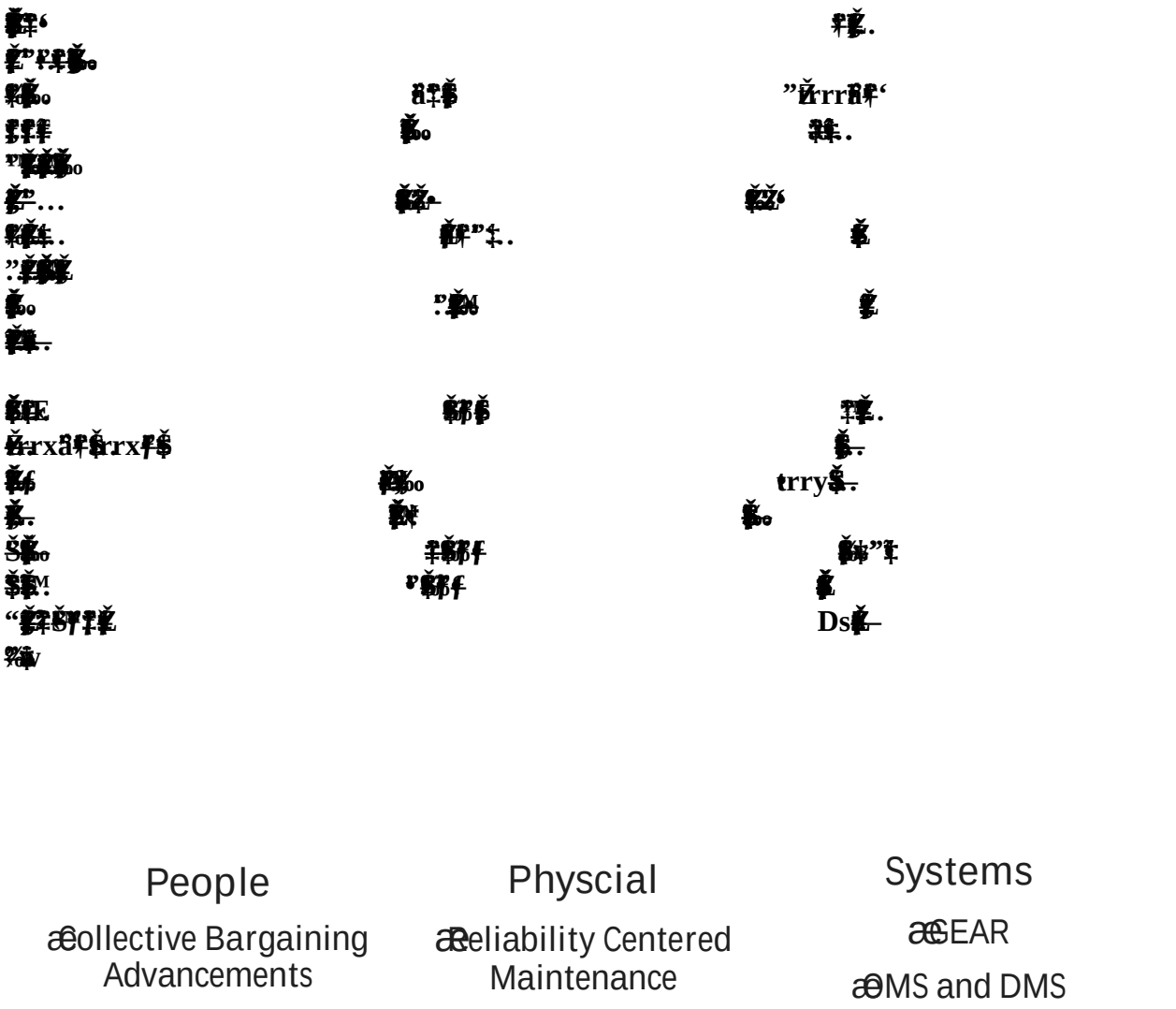
B.9 ELLIPSE

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B.10 Management Control and Reporting System (MCRS)

B.11 Consumables Management

C Transformation: 2004-2006



People

æCollective Bargaining Advancements

Physcial

æReliability Centered Maintenance

Systems

æGEAR

æMS and DMS

Figure 4: Transformation Period Productivity Initiatives

Initiative	Basisof Estimated Savings	EstimatedNPVof Benefits todate
		DsŽ
TOTALQUANTIFIED BENEFITS		$1million

Figure 5: Quantified Estimates of NPV of Productivity Initiatives – Transformation Stage

C.1 Collective Bargaining Advancements

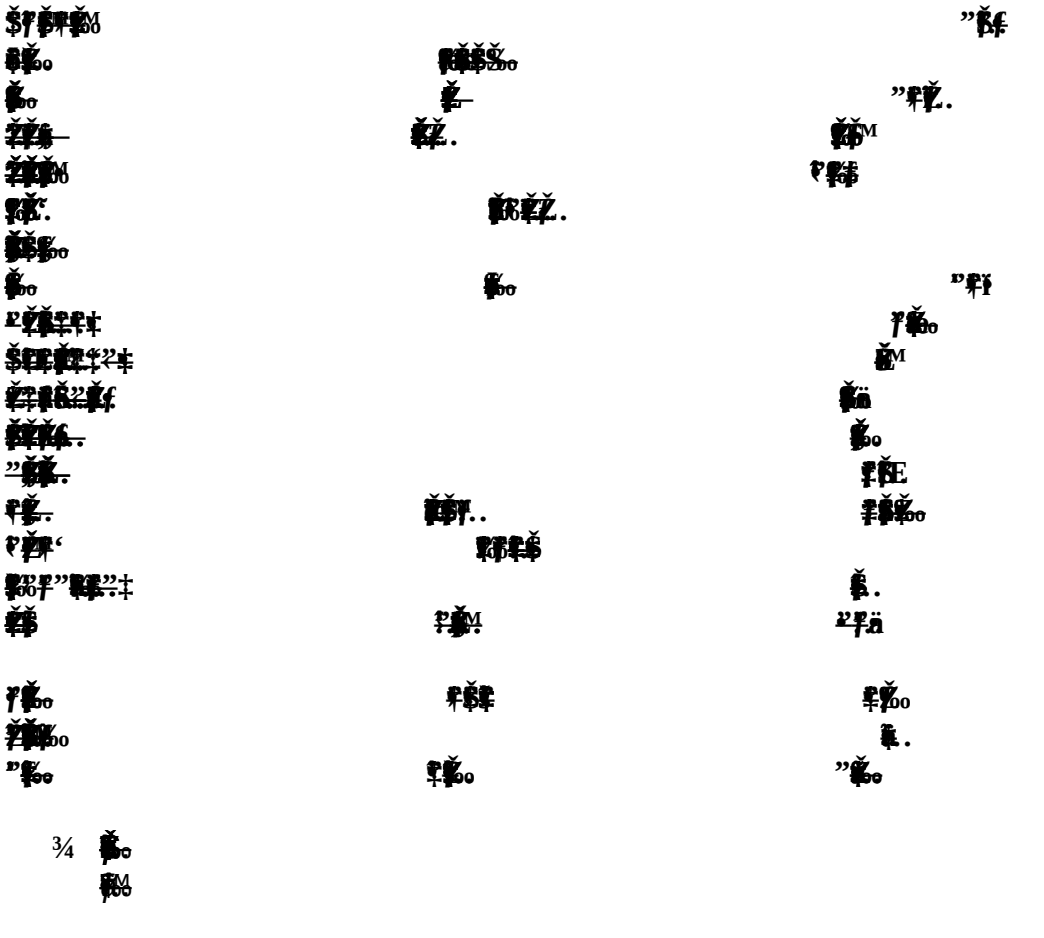
Table1: Collective BargainingSummary

Collective Agreement	Change	Benefits
sfers	¾ ¾ ¾	
te	¾ ¾ ¾	
te	¾ ¾ ¾	

Collective Agreement	Change	Benefits
trrẹesu	¾ ¾ ¾ ¾	
	x x x x x x	

C.2 Reliability Centered Maintenance

C.3 Geospatially Enabled Asset Registry (“GEAR”)



[v]

C.4 Outage and Distribution Management Systems

D Continuous Improvement 2007-Present



Figure 6:Continuous Improvement Productivity Initiatives

Initiative	Basisof Estimated Savings	EstimatedNPVof Benefits todate
—‡..	‰ DŽ	
‡‰ ‰		Dsx
Ž ‰ Ž	‰	Drü
‰ ‰	‡‰ Dü	
¬	. Duä	
‡. ‰		Dv
‰	‰ Dr	
‰ ‰		Dt
‡	‰	Dtv
TOTALQUANTIFIED BENEFITS		$214million

Figure 7: Quantified Estimates of NPV of Productivity Initiatives – Continuous Improvement Stage

D.1 Attendance

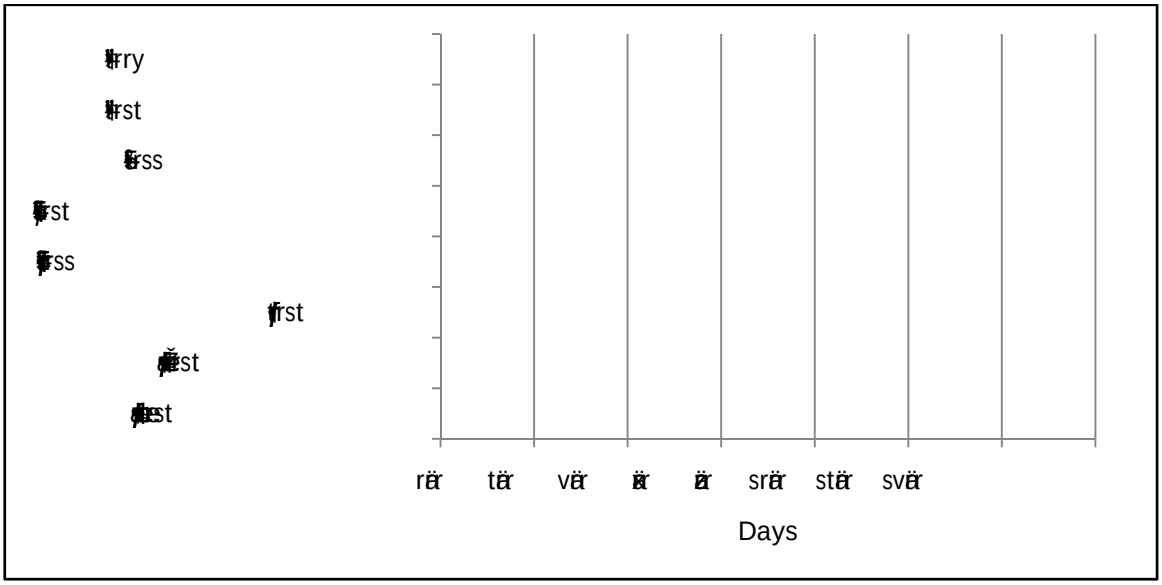


Figure 8: Absenteeism Rate Comparison

D.2 Emergency Response Staff Consolidation and Utilization

Missing in Action: Absenteeism Trends in Canadian Organizations, (Ottawa: Conference Board of Canada, 2013), online: Sun Life Financial <http://www.sunlife.ca/static/canada/Sponsor/About%20Group%20Benefits/Focus%20Update/2013/Special%20Edition%20r%20Sept.%2023%20r%20%20Sun%20Life%20corsponsors%20major%20new%20Conference%20Board%20of/MissinginAction_SUN%20LIFE_EN.pdf>

D.3 Voluntary Exit Program

D.4 Capital Program Contracting

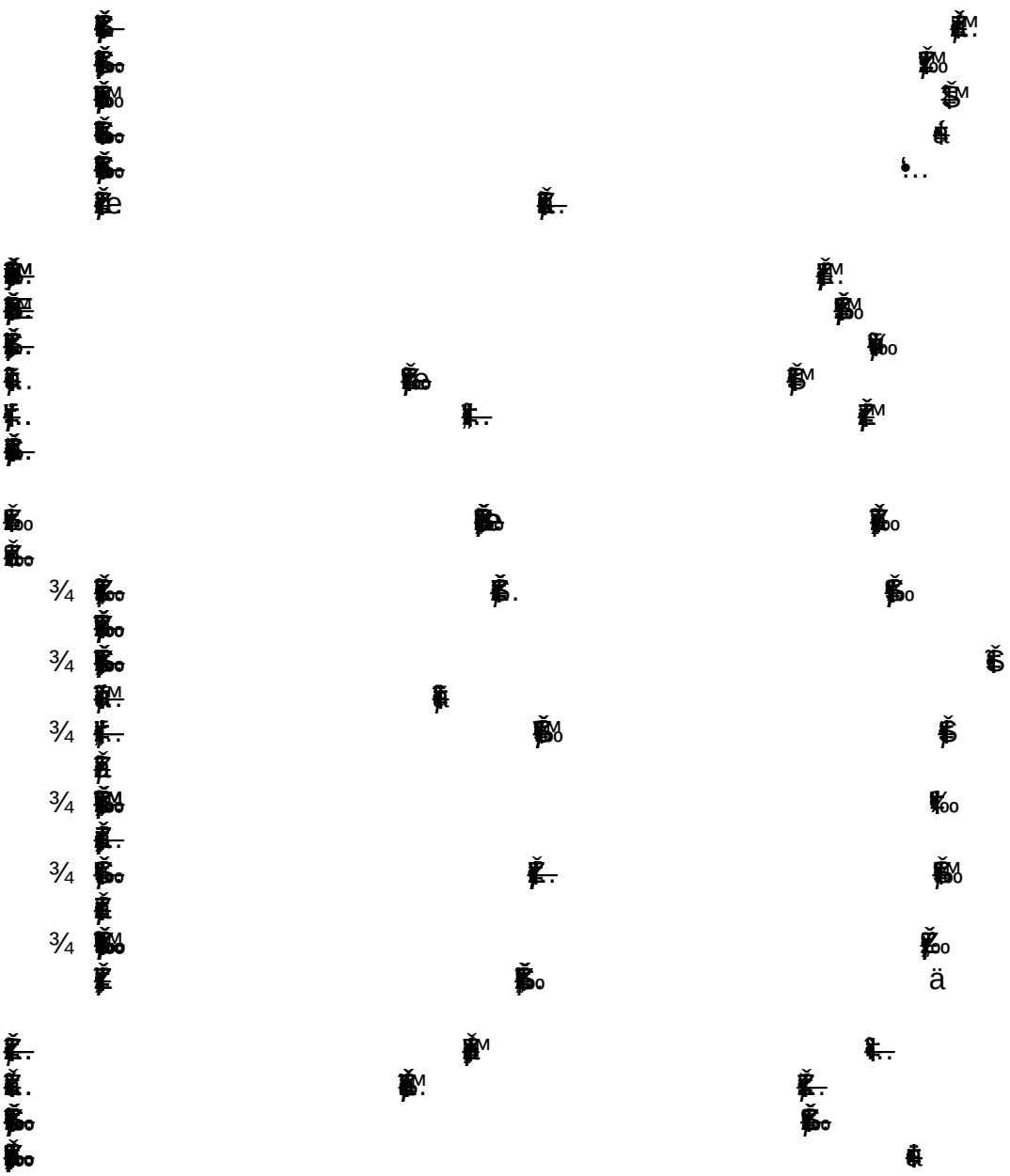
D.5 Advanced Metering Infrastructure

D.6 Fleet Stock Outsourcing

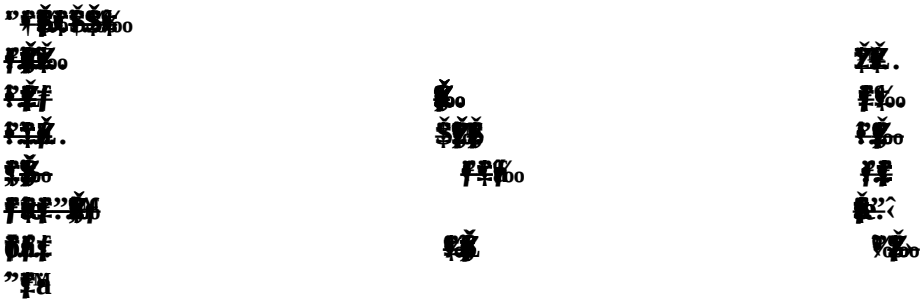
D.7 Feeder Investment Model (“FIM”)

D.8 Vegetation Management Model

D.9 Customer Care & Billing (“CC&B”)



D.10 Accounts Receivable



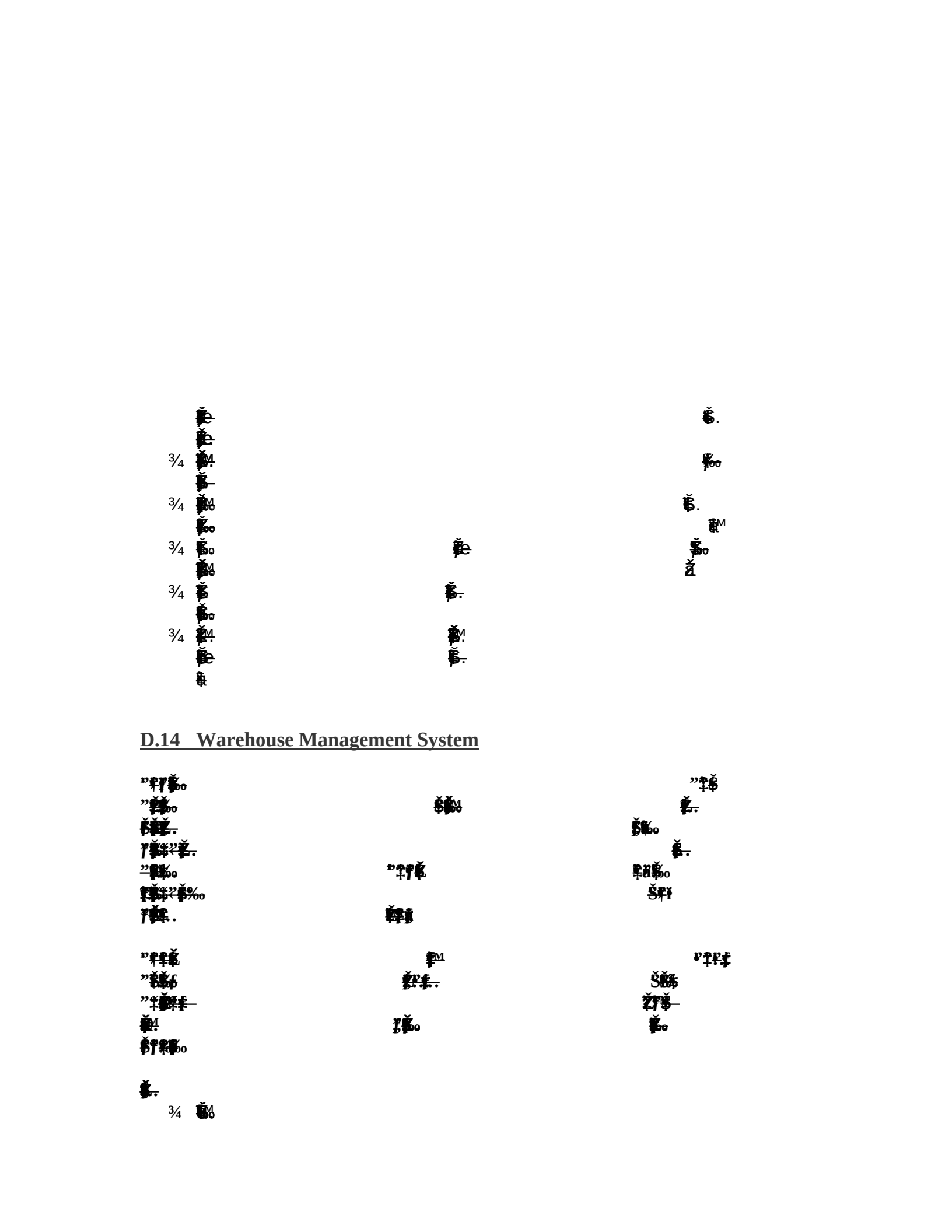
D.11 Field Supervision

D.12 Dispatch and Nightly Dispatch

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- ¾
- ¾
- ¾

D.13 Mobile eSRR

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D.14 Warehouse Management System

D.15 Warehouse Outsourcing

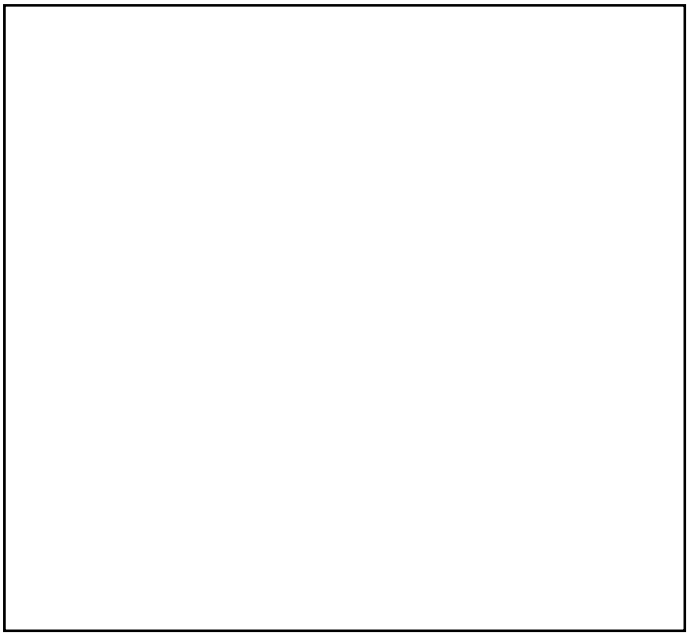


Figure 9: 4 Warehouse model of operation

D.16 Safety Gains

Environment,Health, and Safety Management System (“EHSMS”)

Reductionin Occupational Injury

ManualData EntryAutomation

OccupationalHealthand Safety Act

MaterialSafety Data Sheet(“MSDS”) Management

Occupational Health and Safety Act

Contractor PrequalificationOutsourcing

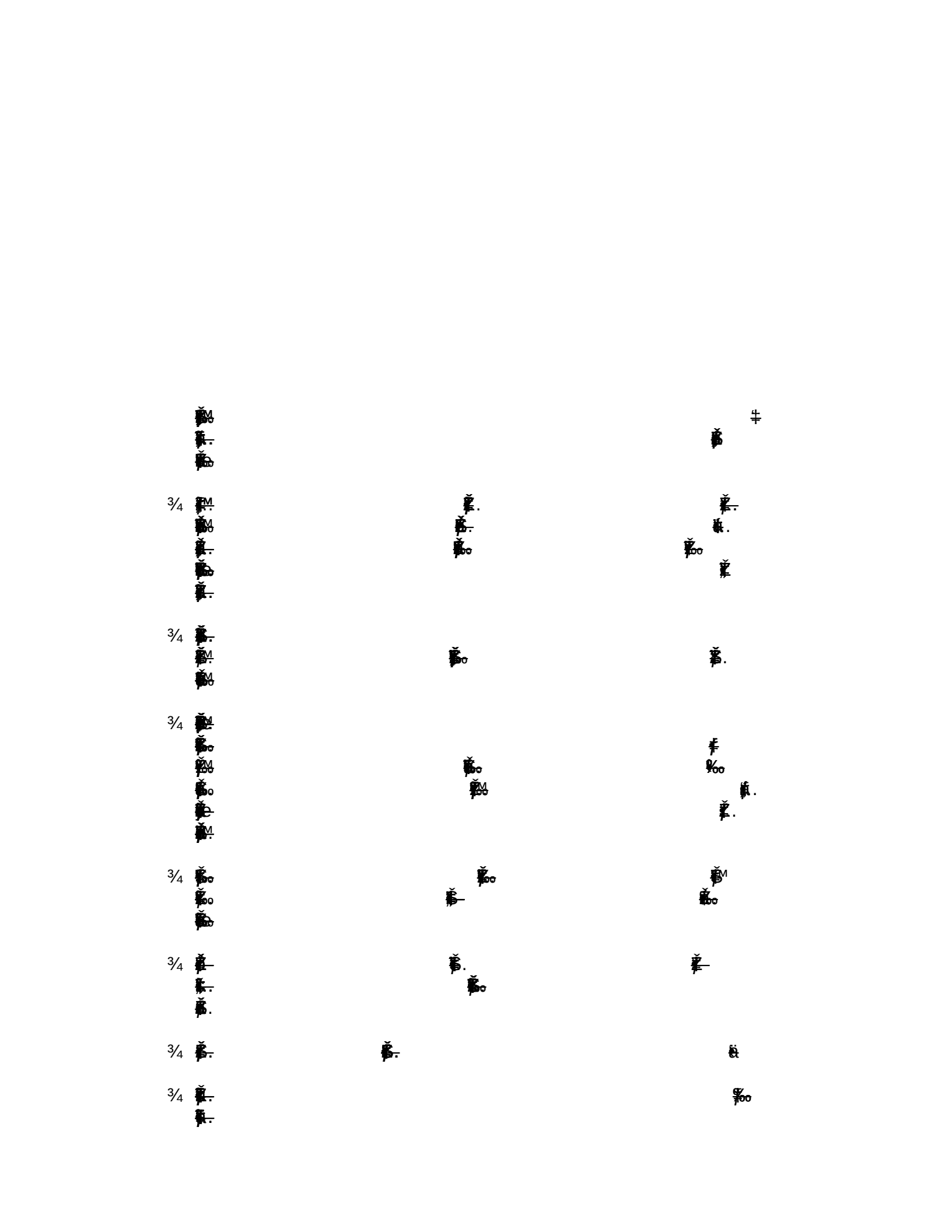
DesignatedSubstance Management

AutomationofEHSAdministrative Tasks

ContinuousEnvironmental Scanning

WSIBClaim Automation

D.17 Call Center Continuous Improvement



E Summary

Power System Engineering, Inc.

Full-service consultants

Toronto Hydro-Electric System Lir



Econometric Benchmarking of 7RURQWR +\GUR¶V Proposed and Projected Total Cost and Reliability Levels

Prepared at the Request of:

Toronto Hydro-Electric System Limited

Prepared by:

Power System Engineering, Inc.

Updated on September 19, 2014

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Projected Total Cost and Reliability Levels

for

Toronto Hydro-Electric System Limited

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This report is an update to the original PSE report dated July 31, 2014. This report contains results which incorporate updated cost and customer forecasts provided to PSE from Toronto Hydro.

1 ([HFXWLYH 6XPPDU\

2Q 2FWREHU WKH 2QWDULR (QHUJ\ %RDUG ³WKH ³5HQHZHG 5HJXODWRU\ )UDPHZRUN IRU (OHFWULFLW\ 'LVWULEXWRUV´ ³55)´ ,Q WKH 55) setting methods were discussed. One of those methods was labeled ³custom incentive regulation,´ or ³Custom IR.´

2Q SDJH RI WKH 55) WKH %RDUG VWDWHV WKDW ³,Q WKH &[ILYH \HDU IRUHFDVW RI D GLVWULEXWRU¶V UHYHQXH UHTXLU out the use of benchmarking as a key element used to inform the Board of the reasonableness of the revenue forecasts.[1]

In a November 21, 2013 Report of the Board WLWOHG ³5DWH 6HWWLQJ 3DUDPHWH under the Renewed Regulatory)UDPHZRUN IRU 2QWDULR¶V ([HFXWLYH &RPSHWLWLYH \ '[%RDUG 5HSRUW´ the Board clearly indicates its preference for econometric benchmarking over peer group benchmarking. Furthermore, the Board indicates its preference for total cost benchmarking over partial cost benchmarking.[3]

Power System Engineering, Inc. was asked by Toronto Hydro to conduct a benchmarking study RI 7RURQWR +\GUR¶V SDVW DQG SURMHFWHG WRWDO FRVW DQ XWLOLW\ 2019 Custom IR application. Toronto Hydro asked PSE to investigate the possibility of expanding the scope of utility observations in the study beyond Ontario, in order to assess the potential effect of certain business conditions experienced by Toronto Hydro.

1.1 2YHUYLHZ RI 36(¶V %HQFKPDUNLQJ

In accordance with the RRF and the November 2013 Board Report, Power System Engineering, ,QF ³36(´ FRQGXFWHG HFRQRPHWULF total cost benchmarking of Toronto Hydro-Electric System Limited ³7RURQWR +\GUR´ This benchmarking was done as part of 7RURQWR +\GUR¶V proposal. In its 2015 Custom IR proposal, Toronto Hydro estimates its projected costs from 2015 to 2019, and its projected reliability metrics from 2015 to 2019. The SXUSRVH RI 36(¶V benchmarking analysis is to evaluate the reasonableness of 7RURQWR +\GUR¶V historical and projected total cost amounts and system reliability metrics. This is done by comparing Toronto +\GUR¶V actual or SURMHFWHG YDOXHV ZLWK WKH EHQFKPDUNLQJ PRG[4]

[1])RXQG LQ ³7DEOH RI &RQWHQWV´ RQ SDJH RI WKH 55) ´2YHUYLHZ RI (OHPHQWV RI 7KUHH 0HWKRGV´ RQ SDJH RI WK

[2] Case EB-2010-0379.

[3] See page 19 of the November 2013 Board Report.

[4] ,Q WKLV SDSHU ZH ZLOO XVH ³IRUHFDVWHG´ RU ³SURMHFWHG´ WR GHVFULEH 7RURQWR +\GUR¶V VDOHV RU WKRVH YDOXHV LQ WKH IXWXUH DQG ³SUHGLFWHG´ RU ³H[SHFWHG´ RU

The benchmarking analysis uses historical cost and reliability data from a dataset comprised of multiple utilities to create a model; this model relates cost and reliability to certain variables. The PRGHO LV WKHQ XVHG WR SUHGLFW (benchmarked) cost and reliability. In past stretch factor research, the Board has used an Ontario-only dataset to create the econometric model. In the present report, PSE DXJPHQWHG WKH %RDUG¶V 2QWDULR EHQ data from U.S. investor-owned utilities. Thus the general approach of our benchmarking analysis is as follows:

1. PSE assembled the historical costs of all utilities in the dataset, along with the variables that affect cost, such as customer levels, weather, wage levels, density, etc.
2. Using the historical data, PSE estimated an econometric model that expresses the relationship between the variables and cost.
3. For each utility in the sample, we can WKHQ SURGXFH ³EHQFKPDUN´ YDO +\GUR¶V FDVH WKHVH EHQFKPDUNV represent the costs we would expect for an average-performing utility with the number of customers, weather, wage levels, density, percent undergrounding, etc. faced by Toronto Hydro.
4. We then compare the costs that are expected (predicted) for Toronto Hydro by the model WR 7RURQWR +\GUR¶V historical and projected costs, which allows us to: (1) evaluate the historical performance, and (2) determine whether forecasted costs are reasonable.

We used D VLPLODU SURFHVV WR DQDO\]H 7RURQWR +\GUR¶V SDV general strategy is the same whether using a U.S.-only dataset, or a combined Ontario/U.S. dataset.

1.2 7KH 1HHG IRU D &RPELQHG 8 'DWDVHW

In the November 2013 Board Report, the Board recognized that certain distributors may have ³H[WHQXDWLQJ FLUFXPVWDQFHV´ [5] The summary for why different treatment is needed in the present case is that the unique size and urban characteristics of Toronto H\GUR¶V VHUYLFH make it an outlier among Ontario distributors. For a suitable benchmarking analysis, using a dataset that includes U.S. utilities is necessary. A brief summary RI 7RURQWR +\GUR¶V RXWOLHU VWDWXV and why PSE believes WKLV VI Toronto Hydro is a candidate for a different treatment in regards to its benchmarking evaluation and stretch factor assignment is found in Section 6.

To see why Toronto Hydro is an outlier, consider that the number of customers served is generally recognized as the leading driver of cost for electric distribution utilities. In terms of customers served, Toronto Hydro is practically without peers in the Ontario industry. Perhaps Hydro One Networks could be considered a peer in terms of sheer number of customers served, yet it has operating circumstances vastly different than those found in the Toronto area. The next

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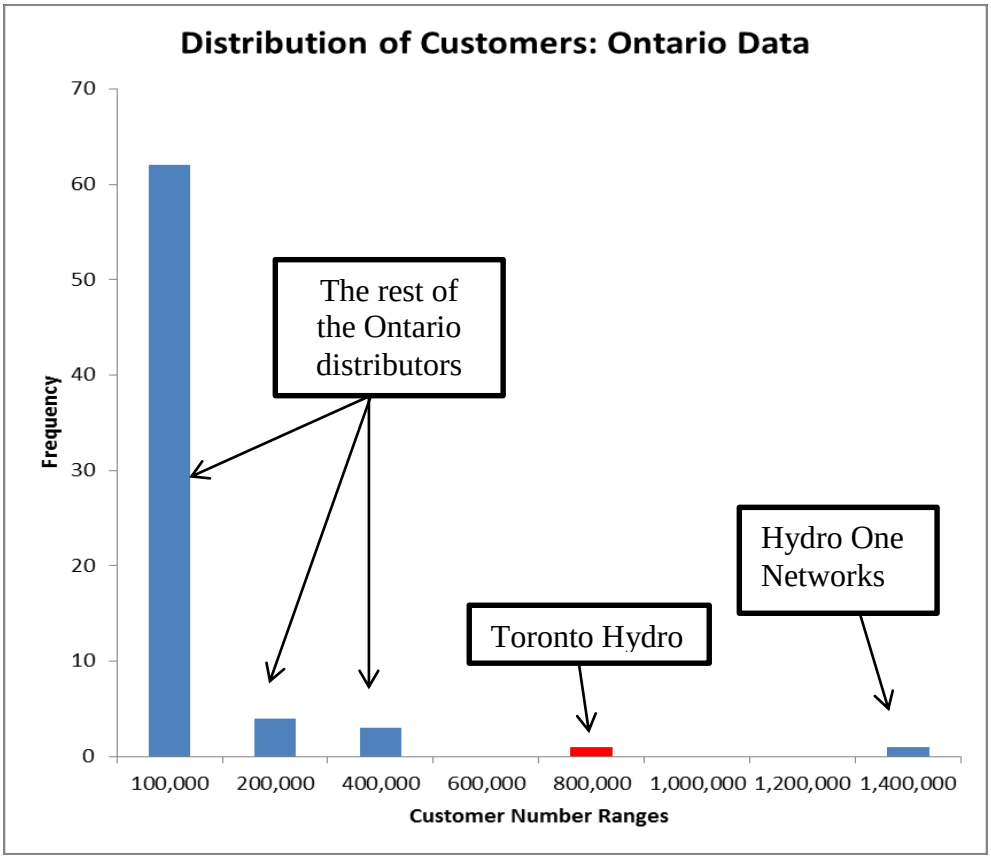
HFRQRPHWULF PRGHO¶V RXWSXWV IRU WKRVH PHWULFV

[5] See page 22 of the November 2013 Board Report.

largest distributor in terms of customers served, Powerstream Inc., has fewer than half the number of electric customers of Toronto Hydro.

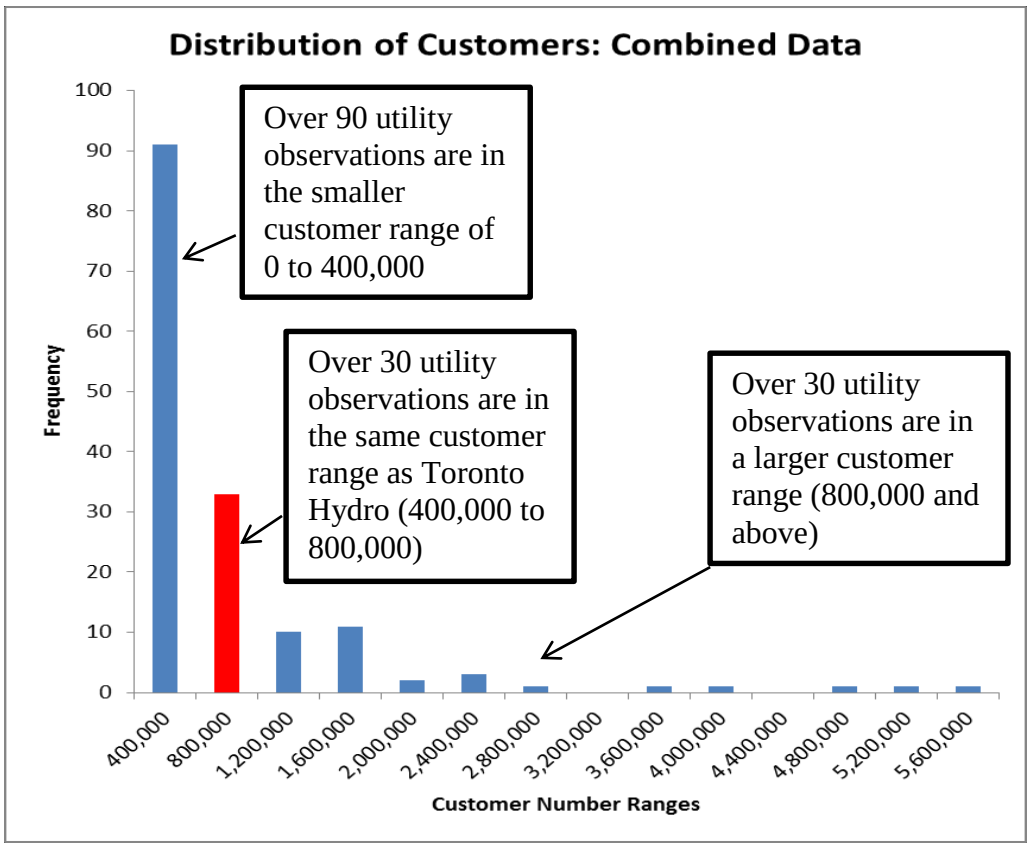
Figure 1 illustrates the vast differences between Toronto Hydro and the rest of the Ontario distributors, in terms of number of customers served. Related to this difference is the fact that Toronto Hydro also serves a large urban core (the Toronto area). Serving a large urban core presents unique cost challenges that are discussed further in another PSE report attached as an Appendix to this report entitled, [illegible].

Figure 1 Distribution of Customers: Ontario Dataset



After adding U.S. utilities to the Ontario dataset, Toronto Hydro ceases to be an outlier in terms of the number of customers. Figure 2 illustrates how in the combined Ontario/U.S. dataset, there are many utilities with more customers than Toronto Hydro, and many with fewer. When conducting econometric benchmarking, having a data sample with variable values that encompass those of the studied utility is essential to the accuracy of the exercise.

Figure 2 Distribution of Customers: Combined Dataset



1.3 7RWDO &RVW %HQFKPDUN)LQGL

As stated earlier, the RRF requests distributors include benchmarking of revenue forecasts in their Custom IR applications. In the November 2013 Board Report, the Board cites total cost econometric benchmarking as its preferred method for setting stretch factors.

3((EHOLHYHV WKH %RDUG¶V SUHIHUHQFH IRU WRWDO FRVW approach when benchmarking cost levels. Total costs are defined as the sum of (1) OM&A expenses, and (2) the depreciation and opportunity costs of capital. This is quite similar to how revenue requirements are calculated, and so total costs are somewhat analogous to the distribution portion of revenue requirements.[6] Partial cost benchmarking approaches, such as OM&A benchmarking, exclude large swaths of cost, which can skew performance evaluations.

PSE also endorses econometric benchmarking because of its increased accuracy relative to peer group approaches. The econometric benchmarking method contains the ability to statistically test included variables and results, includes a relatively large number of variables that enter the analysis, and does not require the researcher to choose a peer group or exclude large portions of

[6] Total costs are not exactly analogous to revenue requirements, however, because of the generalizations needed to offer a fair analysis between utilities with varying depreciation rates, rate of returns, historical capital addition patterns, and cost definitions.

the available data.

PSE used a total cost econometric benchmarking model to benchmark 7 R U R Q W R + \ G UlR ¶V K L V V costs, and its projected total costs during the Custom IR period (2015 to 2019). PSE first derived an econometric model from the historical dataset. Using that model and its parameter values, we then calculated total cost benchmarks. For past years, we used historical variables to calculate the benchmarks. For 2014 to 2019 benchmarks, we used Toronto Hydro projections for the variables that enter the model. This process serves as a E H Q F K P D U N H Y D O X D W I R U Projected I W K H F F total costs.

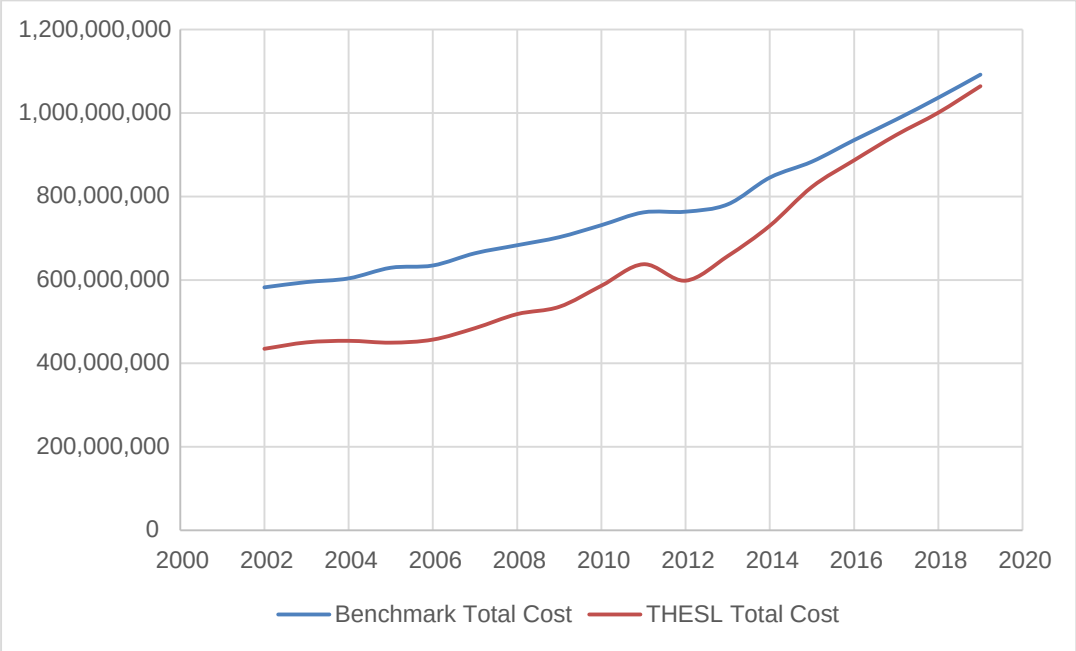
Our total cost econometric benchmarking results indicate the following findings.

1. The historical total cost levels of Toronto Hydro are below benchmark expectations at a 90% confidence level when using a dataset that includes both Ontario and U.S. utilities.

2. The projected total cost levels during the Custom IR period remain below the benchmark predictions, although they do converge towards benchmark expectations, and the statistically E H O R Z H [S H F W D W L R Q Vno longer appropriate at a 90% confidence level.

The following graph illustrates the historical and projected benchmarked costs and company costs for Toronto Hydro using a dataset comprised of 156 distributors from Ontario and the U.S.

Figure 3 Historical and Projected Total Costs vs. Benchmarked Costs



PSE also conducted benchmarking research using a U.S.-only dataset, which indicates similar findings to the combined dataset. Both samples show Toronto Hydro has been below its total cost benchmark values, and this persists through the projected years, albeit with a convergence towards benchmark costs. Further details and results for the U.S.-only dataset, along with the

combined Ontario-U.S. dataset, are provided in later sections.

1.4 5HOLDELOLW\ %HQFKPDUN)LQG

In addition to total cost benchmarking, PSE conducted econometric reliability benchmarking of 7RURQWR +\GUR¶V V\VWHP DYHUDJH LQWHUUXSWLRQ IUHTXH LQWHUUXSWLRQ GXUDWLRQ LQGLFHV that necessitate a combined U.S. and Ontario sample when performing total cost benchmarking for Toronto Hydro also apply to benchmarking its reliability. Thus, we use a reliability dataset comprised of both Ontario and U.S. utilities WR EHQFKPDUN 7RURQWR +\GUR¶V 6$,), DQG 6$,',

When Ontario distributors report SAIFI and SAIDI to the Board, they include all outages regardless of the cause and concentration of interruptions. In many jurisdictions throughout North America, on the other hand, utilities report SAIFI and SAIDI on a weather-normalized EDVLV 7KH\ GR WKLV E\ H[FOXGLQJ PDMRU HYHQW GD\V 30('V which permits them to gauge reliability performance during normal operating conditions. In order to compare reliability performance on an equal footing, PSE used data from U.S. utilities that include all outages in their reliability metrics, regardless of the concentration of outages in a given time period.[7]

Furthermore, Ontario distributors report indexes based on a definition of ³sustained outage´ as lasting at least 1 minute. In the US, some distributors define a ³sustained outage´ as lasting at least 1 minute, while others define it as lasting at least 5 minutes.[8] We tested for this difference in the econometric modelling by including a variable for the ³sustained´ definition. We found it to have a negative correlation with SAIFI (i.e., one minute definition ³VXVWDLQHG raises the expected SAIFI metric) and a positive correlation with SAIDI (i.e., one minute GHILQLWLRQ´ lowers the expected SAIDI metric). The inclusion of the variable did QRW PHDQLQJIXOO\ FKDQJH ,7 5 and it also reduced the size of the U.S. sample, because some utilities do not disclose their sustained outage definition. For these reasons, we left out the ³sustained´ variable from the final models.

PSE gathered Ontario distributor ¶data for WKH UHOLDELOLW\ LQGH[HV IURP WK We gathered U.S. data on XWLOLWLHV¶ non-normalized reliability indexes and their sustained outage definitions from publicly-available regulatory filings.

3(¶V UHOLDELOLW\ EHQFKPDUNLQJ analysis indicates the following findings.

1. Historical SAIFI metrics for Toronto Hydro are higher than the benchmark values.
2. Projected SAIFI metrics converge towards the benchmark values through 2019.
3. Historical SAIDI metrics for Toronto Hydro are lower than the benchmark values.

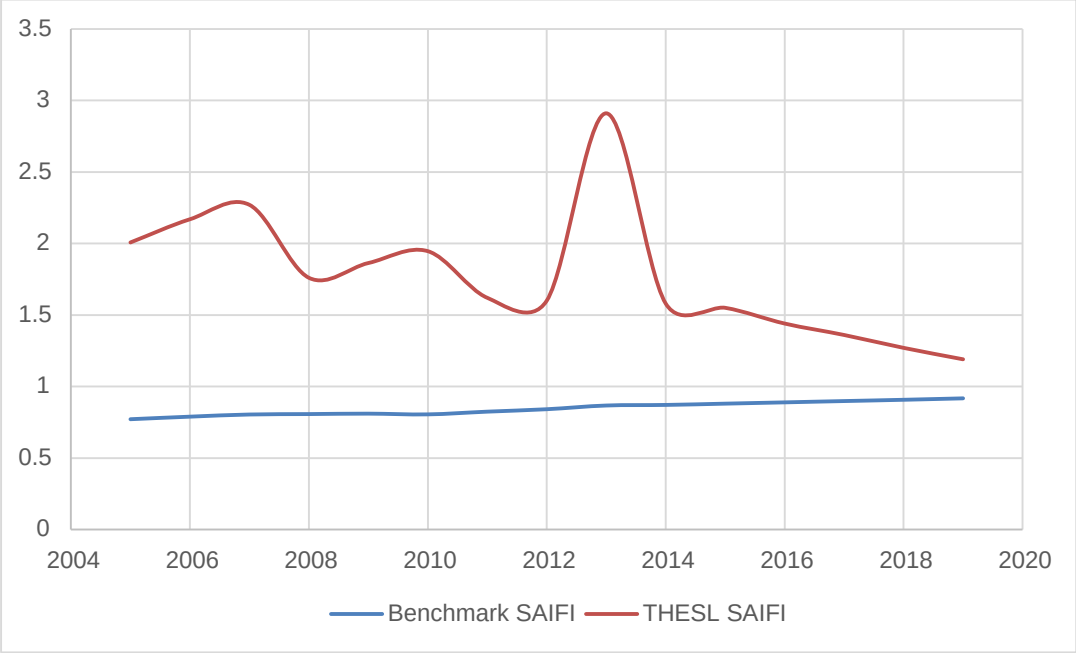
[7] The disadvantage of using indexes that include all outages is that the volatility in the indexes will be quite large, making confidence intervals larger than in (1) total cost benchmarking, and/or (2) cases where the reliability metrics excluded extreme storms.

[8] 6RPH 8 6 GLVWULEXWRUV GRQ¶W GLVFORVH WKHLU VXVWDLQHG RXWDJH

4. Projected SAIDI metrics for Toronto Hydro continue to be lower than the benchmark values.

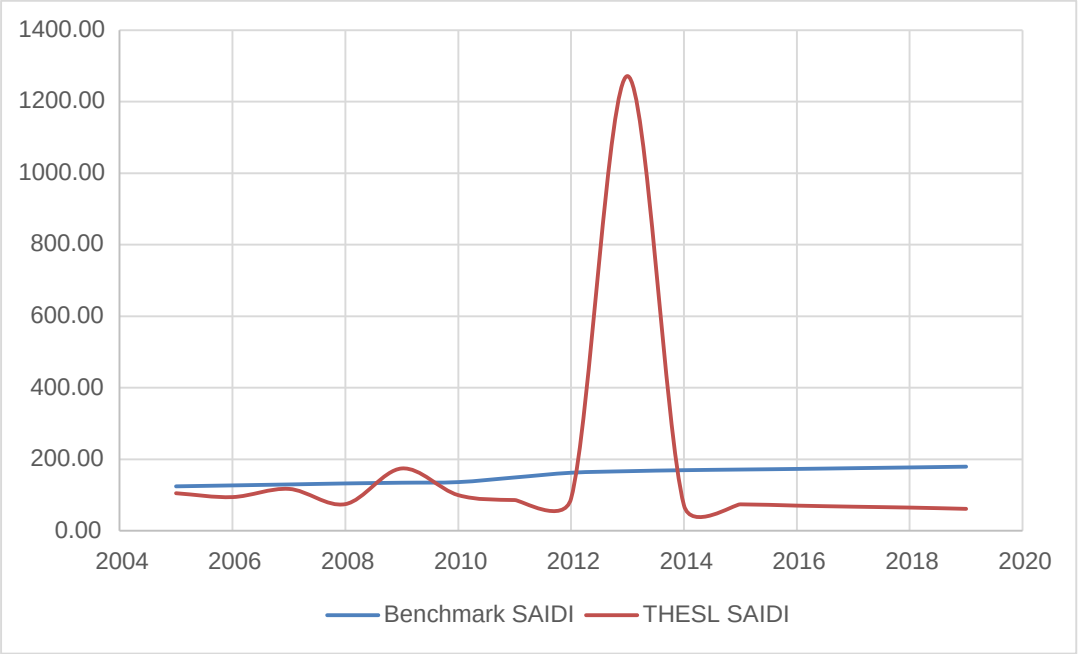
The following graph illustrates the historical and projected SAIFI values for Toronto Hydro [2] benchmarks and actual/projected values, using a dataset comprised of 116 Ontario and U.S. distributors. The large one-\HDU LQFUHDVH LQ WKH FRPSDQ\¶V 6$,), Z weather event that occurred in December of that year.

Figure 4 Historical and Projected SAIFI vs. Benchmarked SAIFI



The following graph illustrates the historical and projected SAIDI values for Toronto Hydro against the benchmarked values, using a dataset comprised of 117 Ontario and U.S. distributors. The large one-\HDU LQFUHDVH LQ WKH FRPSDQ\¶V 6$,', ZDV GXH that occurred in December of that year.

Figure 5 Historical and Projected SAIDI vs. Benchmarked SAIDI



PSE also conducted benchmarking research using a U.S.-only dataset for both reliability indexes. Results were again similar to the combined model, with SAIFI metrics for Toronto Hydro being higher than benchmarks, yet converging in the forecasted years, and SAIDI metrics being below benchmark values in the projected time period. Further details and results for that dataset, along with details about the combined dataset, are provided in Chapters 4 and 5.

1.5 (YDOXDWLRQ RI 7RURQWR +\GUR¶V $SSOLFDWLRQ

The JUDSKV EHORZ LOOXVWUDWH KRZ 7RURQWR +\GUR¶V historical total cost and reliability performances relate. Our results indicate that the company is missing its SAIFI benchmark value by a large margin (see yellow dot in Figure 6), while beating its SAIDI and total cost benchmarks (yellow dot in Figure 7). While more research would be necessary to ascertain Toronto Hydro ¶V customers ¶ exact preferences for how reliability should balance against higher rates, it seems reasonable that a large metropolitan city such as Toronto should at least strive to be at the benchmark value for the number of outages its system causes its customers. Outages are caused when the distribution system fails. A possible cause of WKH FRPSDQ\¶V KLJK R levels is the aged system infrastructure. In order to address SAIFI, system investments may be needed.[9]

From a benchmark perspective, the projections to 2019 show that Toronto Hydro ¶V spending

[9] 7KLV GRHV QRW LPSO\ WKDW 7RURQWR +\GUR¶V FDSLWDO VSHQGLQJ SURJ It is our understanding that there are a number of other considerations, such as public and employee safety. +RZHYHU UHOLDELOLW\ LV D ODUJH SRUWLRQ RI WKH UDWLRQDOH DQG L readily lends itself to be benchmarked and evaluated.

IRUHFDVWV ZLOO FRQYHUJH WKH FRPSDQ\¶V 6$,), DQG WRWDO the benchmark expectations (red dot in Figure 6). SAIDI is projected to remain at a very strong level. Based on the projections, the projected spending will result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective.

Figure 6 illustrates the convergence of SAIFI-to-total cost towards the benchmark values in the forecast period (the projected value gets closer to the center).

Figure 6 Toronto Hydro 2012-to-2019 SAIFI-to-Total Cost Progression Relative to 2010-2012 Sample Average

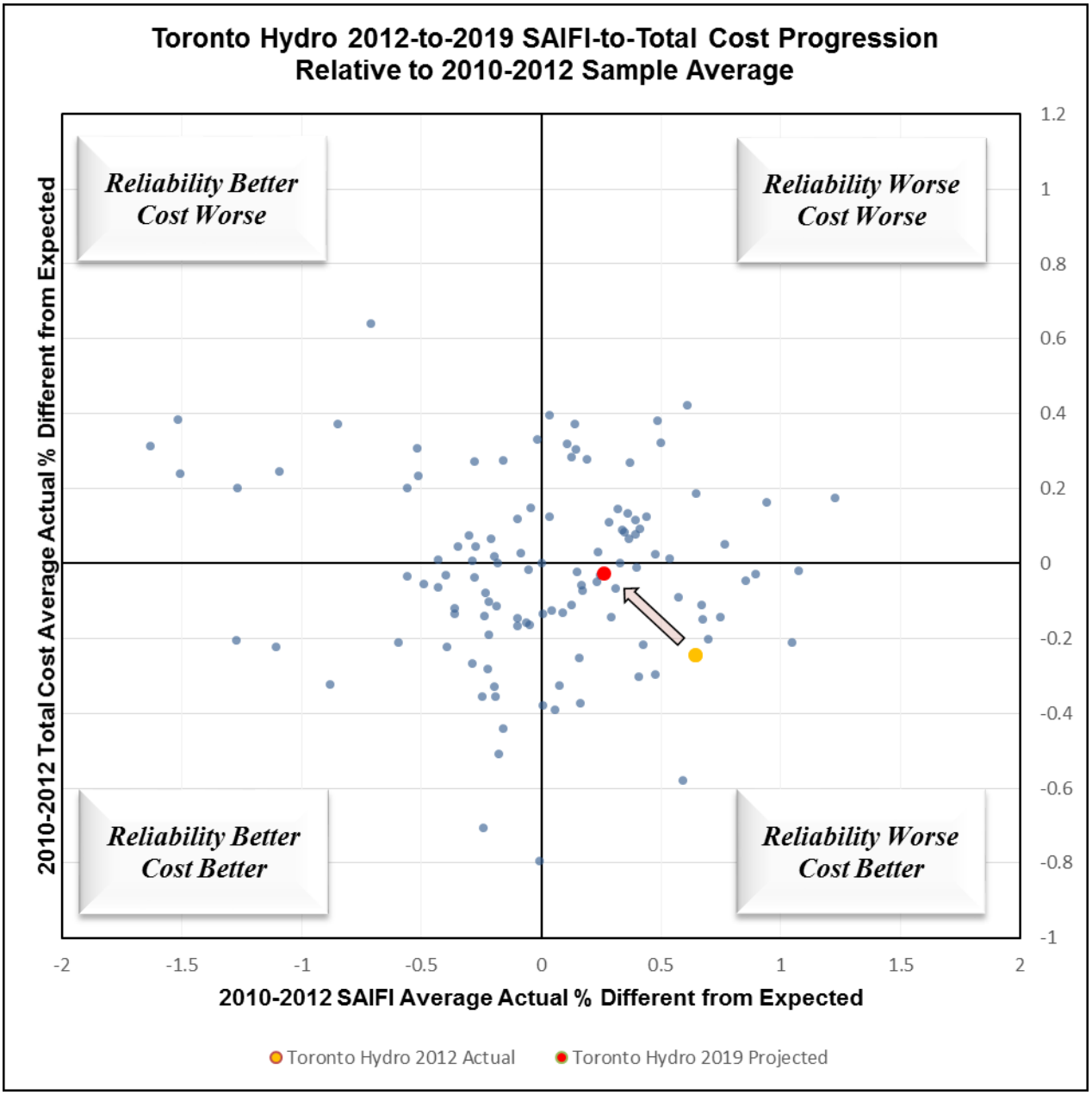
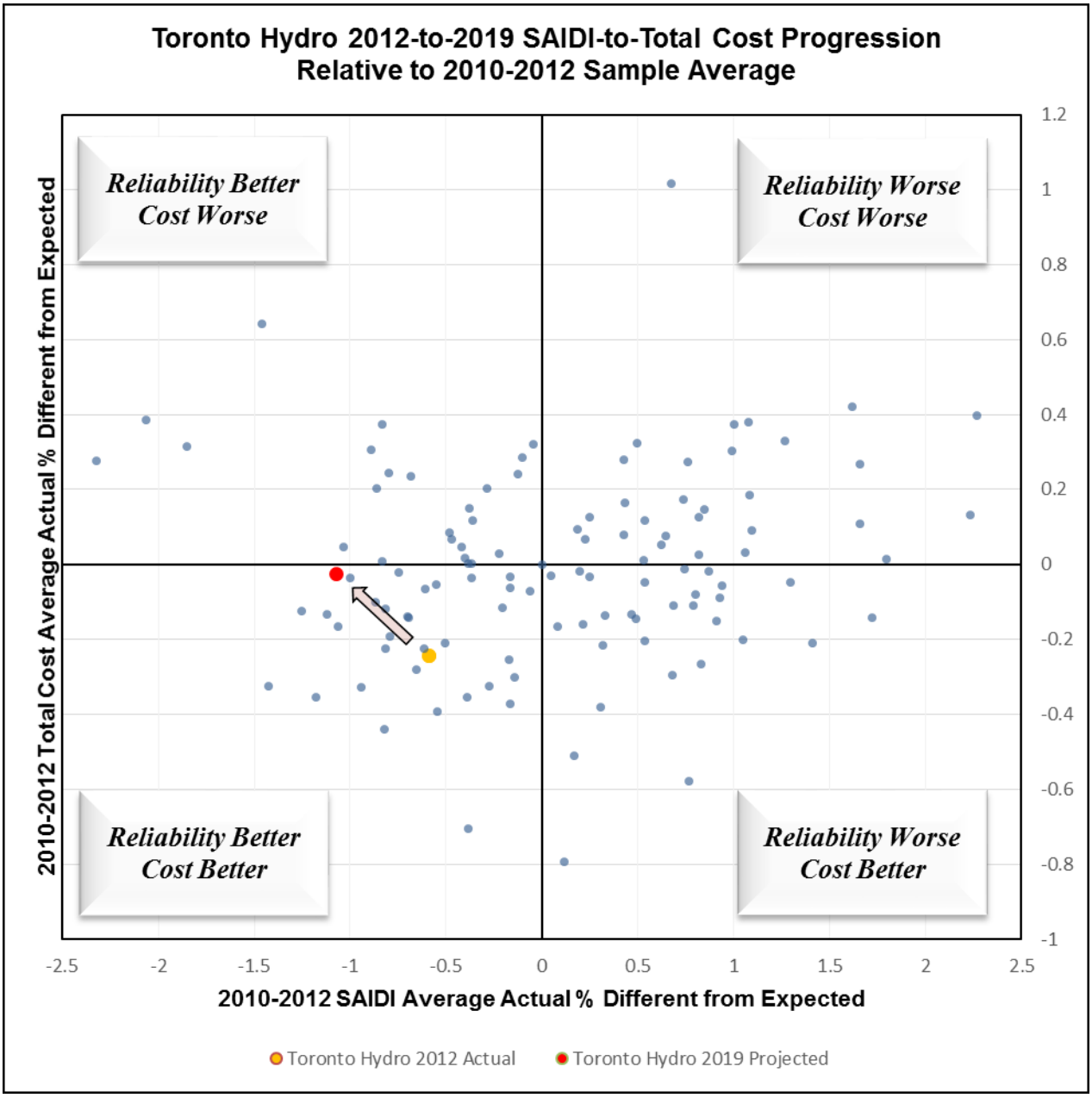


Figure 7 L O O X V W U D W H V W K H F X U U H Q W D Q G S U R M H F W H G S R V L W L
The company is currently better than the model expectations in both of these categories, and remains that way through 2019.

Figure 7 Toronto Hydro 2012-to-2019 SAIDI-to-Total Cost Progression Relative to 2010-2012 Sample Average



I Q 3 6 (¶ V R St Li Qe ar Q ly p o ssible that poor SAIFI performance is a symptom of the condition of the distribution network. On this basis, increased capital spending should address SAIFI metrics through upgrading the distribution network and decreasing the number of times it fails. While poor SAIFI performance tends to be an indicator of old and failing infrastructure, and thus provides a rationale for increased capital spending, strong SAIDI (and CAIDI) performance is an indicator that the company identifies and swiftly responds to outages when

they occur. Thus, SAIDI performance tends to be more related to OM&A spending, whereas SAIFI performance is related more to capital spending.

1.6 &XVWRP ,5 &RQFOXVLRQV

36(¶V EHQFKPDUN UHVHDUFK OHDGV XV WR WKH IROORZL
Custom IR proposal:

1. Toronto Hydro is entering the Custom IR period with strong recent cost performance (i.e., costs are below the expected values), with its average 2010 to 2012 total costs being estimated at 21.5% below benchmark values using the combined dataset results.[10]

2. This strong cost performance persists to 2015, although with some moderation. Toronto +\GUR¶Vtotal cost level forecast is estimated to be 7.1% below benchmark values, and is, in our opinion, reasonable from a benchmarking perspective.

3. 7RURQWR Custom IR period (2015 through 2019) total cost level projections remain below benchmark expectations. By 2019, the company is estimated to still be below benchmark values by 2.6 %DVHG RQ WKLV WKH projections Q\¶V &X are, in our opinion, reasonable from a benchmarking perspective.

4. Total costs are projected to be well within the 0.3% stretch factor range of plus/minus 10% set in the November 2013 Board Report. In terms of ranking, in the combined total cost rankings based on historical performance, Toronto Hydro is 30th out of the 156 Ontario/U.S. utilities. If Ontario distributors are isolated in the rankings, for the combined model, Toronto Hydro is ranked 15th out of the 71 distributors. Based on these findings, reducing the stretch factor from 0.6% to 0.3% seems LQ OLQH ZLWK WKH % LQWHQWLRQ RI DVVLJQLQJ D VWUHWFK IDFWRU WR benchmark evaluations.

5. 7RURQWR +\GUR¶V FDSLWDO LQIUDVWUXFWXUH expected VHHPV number of outages. 7KH FRPSDQ\¶V 2010-2012 SAIFI is 73% above benchmark expectations. This implies Toronto Hydro customers experience 73% more outages then our models predict. The SAIFI projections, assuming full funding, move the company towards the benchmark SAIFI value, reducing the number of outages experienced by customers 7KXV WKH FRPSDQ\¶V SODQ WR LQFUHDVH LV FDSLWD in our opinion, reasonable from a benchmarking perspective.

6. 7RURQWR +\GUR¶V outages, measured by SAIDI, is quite strong and is projected to continue to be strong. 7KH FRPSDQ\¶V 2010-2012 average is 48% below benchmark expectations. This implies that Toronto Hydro customers experience 48%

[10] In this section, we discuss only the results for the combined dataset. The U.S.-only results are similar, although they indicate Toronto Hydro is even further below its benchmark values than when using the combined dataset (i.e. when using the U.S.-RQO\ GDWDVHW 7RURQWR +\GUR¶V costs are higher, thus its performance more impressive).

fewer outage minutes than our models predict. % \ W K H F R P S D Q \ ¶ V 6 $, ' ,
projected to be nearly 84% below benchmark expectations.

From a benchmark perspective, the benchmark analysis shows W K D W 7 + (6 / ¶ V V S H Q G L Q J I
should F R Q Y H U J H W K H F R P S D Q \ ¶ V 6 $,) , D Q G W R W D O F R V W V W R Z I
(while SAIDI remains at a strong level). Based on the projections, the projected spending should result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective.

2 7RWDO &RQWKPDUNLQJ 'DW
0HWKRGV 9DULDEOH 'HILQL

The data for both the Ontario and U.S. utilities used in the study were acquired from publicly available data sources. There are 71 Ontario and 85 U.S. utilities in the combined sample, and 85 U.S. utilities plus Toronto Hydro in the U.S.-only sample. The data in each sample span the years 2002 to 2012.[11] The large number of observations in each sample is more than sufficient for the creation of statistically robust econometric models.

2.1 2QWDULR D'QG 86 6RXUFHV DQG 9
'HILQLWLRQV

The only Ontario utility serving a larger customer base than Toronto Hydro is Hydro One Networks. The next largest Ontario distributor is less than half the size of Toronto Hydro (when measured by the number of retail customers served). Furthermore, Toronto Hydro is the only Ontario distributor that serves a highly dense urban core, which provides substantial cost challenges that cannot be captured by an Ontario-only dataset. More information on the cost impacts of serving a metropolitan urban core can be found in a report located in the Appendix of this report W L W O H G [3] & D S L W D O 5 H T X L U H P H Q W V . R I 6 H U Y L Q J ' H Y H O R

Given the fact that Toronto Hydro is an extreme outlier in the Ontario data, augmenting the Ontario dataset with U.S. observations should increase the accuracy of the Toronto Hydro result. This statement is not meant to imply, however, that an Ontario-only benchmarking dataset is inaccurate for the vast majority of Ontario distributors. Most of the Ontario distributors have output levels and business condition variables that are encompassed by the Ontario-only dataset, making the evaluation an appropriate one in those cases. Section 6 provides a more detailed discussion of the reasons for the inclusion of data from U.S. utilities in the benchmarking of Toronto Hydro.

The utilities included in the combined sample, and the number of retail customers served in 2011, are provided in the following table. The Ontario distributors are shaded in green.

Table 1 Combined Sampled Utilities

Company	Number of Customers (2011)	Company	Number of Customers (2011)
Alabama Power Co	1,434,487	United Illuminating Co	323,738
Ameren UE	1,190,478	Virginia Electric and Power Co	2,438,226
Arizona Public Service Co	1,120,236	West Penn Power Co (Allegheny Power)	717,269
Atlantic City Electric Co	547,762	Western Massachusetts Electric Co (Northeast Utilities)	206,279
Appalachian Power Company	961,129	Wisconsin Electric Power Co	1,120,964

[11] Data for 2013 is now available for U.S. utilities, but not yet, to our knowledge, for Ontario distributors.

Avista Corp	358,303	Wisconsin Power and Light Co	458,041
Baltimore Gas & Electric Co	1,240,291	Wisconsin Public Service Co	439,481
Black Hills Power Inc	68,172	Algoma Power Inc.	11,581
Carolina Power & Light Co	1,445,158	Atikokan Hydro Inc.	1,661
Central Hudson Gas & Electric Corp	274,152	Bluewater Power Distribution Corporation	35,772
Central Maine Power Co	606,813	Brant County Power Inc.	9,741
Cincinnati Gas & Electric Co (Duke Energy OH)	685,859	Brantford Power Inc.	37,967
Cleco Corp	280,857	Burlington Hydro Inc.	64,329
Cleveland Electric Illuminating Co (First Energy)	748,935	Cambridge And North Dumfries Hydro Inc.	51,586
Commonwealth Edison Co	3,818,690	Canadian Niagara Power Inc.	28,397
Connecticut Light & Power Co	1,212,276	Centre Wellington Hydro Ltd.	6,496
Consolidated Edison Co of New York Inc	3,329,304	Chapleau Public Utilities Corporation	1,293
Consumers Energy Company	1,788,799	Collus Power Corporation	15,723
Dayton Power & Light Co	513,539	Cooperative Hydro Embrun Inc.	1,954
Delmarva Power & Light Co	500,998	E.L.K. Energy Inc.	11,276
Detroit Edison	2,120,262	Enersource Hydro Mississauga Inc.	195,381
Duke Energy Corp	2,396,555	Entegrus Powerlines	40,120
Duquesne Light Co	587,610	Enwin Utilities Ltd.	85,083
El Paso Electric Co	378,547	Erie Thames Powerlines Corporation	18,094
Empire District Electric Co	166,207	Espanola Regional Hydro Distribution Corporation	3,299
Entergy Arkansas Inc	695,397	Essex Powerlines Corporation	28,094
Entergy Mississippi Inc	438,140	Festival Hydro Inc.	19,885
Entergy new Orleans Inc	159,431	Fort Frances Power Corporation	3,775
Florida Power & Light Co	4,547,047	Greater Sudbury Hydro Inc.	46,748
Florida Power Corp	1,642,146	Grimsby Power Incorporated	10,307
Georgia Power Co	2,360,487	Guelph Hydro Electric Systems Inc.	50,859
Green Mountain Power Corp	95,542	Haldimand County Hydro Inc.	21,078
Gulf Power Co	432,401	Halton Hills Hydro Inc.	21,232
Idaho Power Co	493,532	Hearst Power Distribution Company Limited	2,817
Indiana Michigan Power Co	582,822	Horizon Utilities Corporation	235,327
Indianapolis Power & Light Co	468,195	Hydro 2000 Inc.	1,208
Jersey Central Power & Light Co	1,099,194	Hydro Hawkesbury Inc.	5,521
Kansas City Power & Light Co	512,082	Hydro One Brampton Networks Inc.	137,856
Kentucky Power Co (AEP)	173,641	Hydro One Networks Inc.	1,211,071
Kentucky Utilities Co	540,839	Hydro Ottawa Limited	305,266
Louisville Gas and Electric Co	394,063	Kenora Hydro Electric Corporation Ltd.	5,572
Madison Gas and Electric Co	141,414	Kingston Hydro Corporation	26,844
MDU Resources Group, Inc.	125,802	Kitchener-Wilmot Hydro Inc.	87,965
Metropolitan Edison Co	552,631	Lakefront Utilities Inc.	9,976
Mississippi Power Co	185,768	Lakeland Power Distribution Ltd.	9,598
Monongahela Power Co	386,819	London Hydro Inc.	148,331
Nevada Power Co	838,482	Midland Power Utility Corporation	6,951
New York State Electric & Gas Corp	878,845	Milton Hydro Distribution Inc.	30,485
Niagara Mohawk Power Corp (National Grid)	1,297,616	Newmarket-Tay Power Distribution Ltd.	33,338
Northern Indiana Public Service Co	456,937	Niagara Peninsula Energy Inc.	51,162
Northern States Power Co (XCEL)	1,399,830	Niagara-On-The-Lake Hydro Inc.	8,000
Ohio Edison Co (First Energy)	1,034,534	Norfolk Power Distribution Inc.	19,032
Ohio Power Co (AEP)	1,459,875	North Bay Hydro Distribution Limited	23,850
Oklahoma Gas and Electric Co	786,522	Northern Ontario Wires Inc.	6,059
Orange and Rockland Utilities Inc	224,608	Oakville Hydro Electricity Distribution Inc.	63,614
Pacific Gas and Electric Co	5,248,288	Orangeville Hydro Limited	11,248
Pennsylvania Electric Co	589,651	Orillia Power Distribution Corporation	13,035
Pennsylvania Power Co	160,250	Oshawa Puc Networks Inc.	53,083

Portland General Electric Co	823,171	Ottawa River Power Corporation	10,555
Potomac Edison Co	388,814	Parry Sound Power Corporation	3,441
Potomac Electric Power Co	787,137	Peterborough Distribution Incorporated	35,270
PP&L Inc	1,403,889	Powerstream Inc.	332,993
PSI Energy Inc (Duke Energy IN)	782,879	Puc Distribution Inc.	32,998
Public Service Co of Colorado	1,372,892	Renfrew Hydro Inc.	4,183
Public Service Co of New Hampshire	498,175	Rideau St. Lawrence Distribution Inc.	5,839
Public Service Co of New Mexico	503,963	Sioux Lookout Hydro Inc.	2,755
Public Service Co of Oklahoma	532,395	St. Thomas Energy Inc.	16,436
Puget Sound Energy	1,083,395	Thunder Bay Hydro Electricity Distribution Inc.	49,765
Rochester Gas and Electric Corp	367,300	Tillsonburg Hydro Inc.	6,745
San Diego Gas & Electric Co	1,385,784	Toronto Hydro-Electric System Limited	709,323
Sierra Pacific Power Co	322,492	Veridian Connections Inc.	113,709
South Carolina Electric & Gas Co	663,433	Wasaga Distribution Inc.	12,324
Southern California Edison Co	4,921,228	Waterloo North Hydro Inc.	52,612
Southern Indiana Gas and Electric Co (Vectern)	146,136	Welland Hydro-Electric System Corp.	21,768
Southwestern Electric Power Co (AEP)	521,601	Wellington North Power Inc.	3,626
Southwestern Public Service (Xcel)	376,160	West Coast Huron Energy Inc.	3,697
Tampa Electric Co	675,799	Westario Power Inc.	22,257
Tucson Electric Power Co	403,340	Whitby Hydro Electric Corporation	40,337

The output variables used in the total cost econometric benchmarking research are:

- Retail customers, and
- Peak demand.

The business condition variables used in the combined total cost econometric benchmarking research are:

- Regional input prices,
- Percent residential deliveries,
- Percent electric customers (out of total gas and electric customers),
- A binary variable for urban population above one million,
- Percent electric distribution in total electric gross plant, and
- Customers per distribution line mile.

Additional variables included in the U.S.-only total cost model are:[12]

- Percent forestation,
- Elevation standard deviation, and
- Percent plant underground.

Both OM&A and total costs used in the benchmarking models for the U.S. distributors are derived using FERC Form 1 filing data.[13] U.S. electric utilities are required to file FERC Form 1

[12] The U.S.-only model uses all the other variables used for the combined model, except for customers per distribution line mile. This variable was dropped due to it not being statistically significant and/or plausibly signed.

[13] All FERC form data was down O R D G H G E \ 3 6 (I U R P 6 1 / (Q H U J \ ¶ V G D W D E D V H W R R O

data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g. distribution, transmission, generation, customer billing, administrative and general). Form 1s also include plant in service and accumulated depreciation information that is used in constructing capital costs.

The historical calculations for U.S. utilities capital costs follow the procedures implemented by Pacific Economics Group ("PEG") in their benchmarking and productivity research found in Case EB-2010-0379 4th Generation Incentive Regulation". This was done in order to match the capital cost calculations used in Ontario with those used for the U.S. sample. Ontario's OM&A cost and total costs are computed based on the same information available in the Board's 4th Generation Incentive Regulation data. The capital costs for Ontario distributors use the same values and procedures implemented by PEG in the 4th Generation IR proceeding.

For U.S. utilities, the output variables are calculated from FERC Form 1s and Platts UDI directories.[14] The output data for Ontario utilities comes from the Board's fourth generation incentive regulation data. We note that the PEG model used in their 4th Generation Incentive Regulation research also included kilowatt hours delivered as an output variable. This variable, however, did not come in plausibly signed and statistically significant in our models. PSE believes that energy delivered will have minimal to no impact on distribution total costs. Distribution capital and OM&A costs are ordinarily driven by the number of customers served and the peak demand the system needs to be built to serve. For these reasons, we excluded kilowatt hours delivered from the models.

Input prices are divided into two categories: capital and OM&A. The capital input price calculation is discussed in detail in the following section. The OM&A input price captures the regional market price level that each sampled company encounters when procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price. These are labour and non-labour.

The labour component is calculated by taking wage levels of numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics' occupation weights in the Electric Power Generation, Transmission, and Distribution Industry. The BLS has estimates for wage levels for each job occupation by city and metropolitan area. For Ontario distributors, we gathered job occupation wage estimates from Statistics Canada, mapped each distributor to the most appropriate observation, translated job occupations to match their U.S. counterparts and then weighted the job occupation wages by the BLS estimates. This provides consistency from the U.S. and Ontario samples regarding labour input prices and also puts the input price index in terms of each country's currency. Labour prices for U.S. utilities using BLS employment cost indexes for the utility sector and escalated Ontario prices using the Ontario average weekly earnings estimates.

The non-labour component of the OM&A input price uses the gross domestic product price index (GDP-PI) for U.S. The Ontario non-labour component uses the same GDP-PI in each

[14] We gathered data from annual editions of Platts UDI Directory starting in 2003 through 2013.

year, but adjusted for the purchasing power parity (PPP) index. This translates the non-labour input price component into Canadian dollars. To construct the overall OM&A input price we weighted each index using a 70% labour and a 30% non-labour rate. This was the same weighting used by PEG in their benchmarking research.

The ³UHVLGHQWLDO percentage of sales volume´ variable is also calculated based on data from)(5&)RUP IRU 8 6 XWLOLWLHV 4th Generation Incentive Regulation Data for Ontario utilities. The percentage of residential volume compared to total volume is a proxy for the variance in electricity loads. Commercial and industrial customer loads tend to be more level across hours of the day. As the proportion of residential volume increases, distribution systems tend to increase their system peaks and load variability. This results in higher volatility in the loads served by the system.

The variable that measures the percentage of electric customers out of total gas and electric customers is derived from both the FERC Form 1 and the FERC Form 2. The FERC Form 2 data includes the number of gas customers served by a natural gas distributor. This variable measures the economies of scope available from serving both electric and gas customers. All Ontario electric distributors distribute only electricity, and have values of 100 percent for this variable.

Toronto Hydro serves the urban core of Toronto, Ontario. Serving a densely populated urban core presents challenges that are not present in suburban or rural settings. The urban core YDULDEOH XVHG LQ WKH WRWDO FRVW EHQFKPDUNLQJ PRGHO variable provides key information on the added costs of serving electricity to a highly urban area. All utilities are given a value of zero unless they serve the urban core of a city whose population is above one million (U.S. cities are designated by the 2010 U.S. census). Toronto Hydro is the only Ontario utility that serves an urban core of this magnitude. For more information on the cost LPSDFWV RI VHUYLQJ KLJKO\ GHQVH PHWURSROLWDQ DUHDV located in the Appendix of this report entitled, ³&DSLWDO 5HTXLUHPHQWV IRU 6HUYLQJ 'HY

The percentage of electric distribution plant in total distribution plant measures the available economies of scope that result from being a vertically integrated utility, as opposed to a distribution-only utility. We expect distribution unit costs to be lower for utilities that also have transmission and generation activities. For U.S. utilities, data for this variable is found from the XWLOLWLHV¶)(5&)RUP V $OO WKH 2QWDULR XWLOLWLHV DU Form 1. All Ontario utilities have a value of 100 percent for this variable.

The customer density variable measures how many retail customers are served per length of line. 7KH FXVWRPHU GDWD LV WKH VDPH GDWD WKDW LV XVHG IR OLQH´ GDWD IRU ERWK 8 6 and Canadian utilities. Data for various editions of *Electrical World's* *Directory of Electric Producers and Distributors*. This variable measures the challenges of serving rural areas and having customers spread across a large service territory. The lower the customer density, the higher the expected costs. Again, for more information on the cost impacts of serving a lower density and rural area please refer to the report found in the Appendix.

The percentage of forestation variable is based on GIS (geographic information system) forestation maps. Such maps are matched with the areas served by each utility to create the variable. We would expect that the higher the level of forestation, the higher OM&A costs

required for right-of-way clearing and service restoration activities. GIS variable data is available for all sampled U.S. utilities and only available for a subset of the Ontario distributors. For this reason the variable is only included in the U.S.-only sample.[15]

The elevation standard deviation variable is computed using GIS maps of elevation in each utility¶ service territory. The variability of elevation levels poses both construction and maintenance challenges for local delivery systems. We capture this difficulty by computing the standard deviation of the elevation levels obtained from GIS maps. As stated in the last paragraph, GIS variable data is available for all sampled U.S. utilities and only available for a subset of the Ontario distributors. For this reason the variable is only included in the U.S.-only sample.[16]

The percentage of electric distribution plant that is underground can raise the capital cost of distribution delivery, but lowers maintenance (and hence OM&A) expenses. Data for this variable comes from FERC Form 1 filings for U.S. utilities and is not available for Ontario distributors.[17] For this reason, the variable is only included in the U.S.-only sample.

7KH YDULDEOHV DQG WKH DYHUDJH YDOXHV IRU WKH 8 6 V
provided in the following table. These are the averages for 2010-2012.

[15] We did, however, find very similar total cost results to the combined model when including the subset of Ontario distributors that did have GIS data available.

[16] See prior footnote.

[17] Ontario distributors do report on the kilometers of underground and overhead line. However, they do not report the plant in service breakdowns that would enable us to construct this variable for the entire Ontario sample.

Table 2 Variables in the Total Cost Benchmarking Study: 2010-2012 Averages

Variable	Units	U.S. Sample Average	Ontario Sample Average	Combined Sample Averages	Toronto Hydro Average
Total Power Delivery Cost	Dollars ('000)*	671,994	50,735	389,241	607,375
Number of Customers	Count	960,965	67,757	554,441	709,457
Peak Demand	MW	5,501	335	3,150	4,845
Price of Capital Services	Index Number	10.094	11.938	10.933	12.516
Price of OM&A Input	Index Number	1.072	1.150	1.107	1.250
Urban Core Dummy	Binary	0.047	0.014	0.032	1.000
Percent Residential Deliveries in Total Deliveries	Percent	0.374	0.453	0.410	0.489
Percent Electric Customers in Gas & Electric Customers	Percent	0.877	1.000	0.933	1.000
Percent Distribution in Total Electric Plant	Percent	0.469	1.000	0.710	1.000
Density: Customers/Line Miles	Ratio	35.899	65.492	49.368	48.842
Percent of Service Territory Forested	Percent	0.591	NA	NA	0.183
Elevation Standard Deviation	Index	154.239	NA	NA	55.343
Percent Plant Underground	Percent	0.205	NA	NA	0.497
***U.S. cost and prices are in U.S. dollars and Canadian cost and prices are in Canadian dollars**					

We present the utilities included in the U.S.-only sample and the number of retail customers they served in 2011 in the following table.

Table 3 Sampled U.S. Utilities

Company	Number of Customers (2011)		Company	Number of Customers (2011)
Toronto Hydro-Electric System Limited	709,323		Metropolitan Edison Co	552,631
Alabama Power Co	1,434,487		Mississippi Power Co	185,768
Ameren UE	1,190,478		Monongahela Power Co	386,819
Appalachian Power Company	961,129		MDU Resources Group, Inc.	125,802
Arizona Public Service Co	1,120,236		Nevada Power Co	838,482
Atlantic City Electric Co	547,762		New York State Electric & Gas Corp	878,845
Avista Corp	358,303		Niagara Mohawk Power Corp (National Grid)	1,297,616
Baltimore Gas & Electric Co	1,240,291		Northern Indiana Public Service Co	456,937
Black Hills Power Inc	68,172		Northern States Power Co (XCEL)	1,399,830
Carolina Power & Light Co	1,445,158		Ohio Edison Co (First Energy)	1,034,534
Central Hudson Gas & Electric Corp	274,152		Ohio Power Co (AEP)	1,459,875
Central Maine Power Co	606,813		Oklahoma Gas and Electric Co	786,522
Cincinnati Gas & Electric Co (Duke Energy OH)	685,859		Orange and Rockland Utilities Inc	224,608
Cleco Corp	280,857		Pacific Gas and Electric Co	5,248,288
Cleveland Electric Illuminating Co (First Energy)	748,935		Pennsylvania Electric Co	589,651
Commonwealth Edison Co	3,818,690		Pennsylvania Power Co	160,250
Connecticut Light & Power Co	1,212,276		Portland General Electric Co	823,171
Consolidated Edison Co of new York Inc	3,329,304		Potomac Edison Co	388,814
Consumers Energy Company	1,788,799		Potomac Electric Power Co	787,137
Dayton Power & Light Co	513,539		PP&L Inc	1,403,889
Delmarva Power & Light Co	500,998		PSI Energy Inc (Duke Energy IN)	782,879
Detroit Edison	2,120,262		Public Service Co of Colorado	1,372,892
Duke Energy Corp	2,396,555		Public Service Co of new Hampshire	498,175
Duquesne Light Co	587,610		Public Service Co of new Mexico	503,963
El Paso Electric Co	378,547		Public Service Co of Oklahoma	532,395
Empire District Electric Co	166,207		Puget Sound Energy	1,083,395
Entergy Arkansas Inc	695,397		Rochester Gas and Electric Corp	367,300
Entergy Mississippi Inc	438,140		San Diego Gas & Electric Co	1,385,784
Entergy new Orleans Inc	159,431		Sierra Pacific Power Co	322,492
Florida Power & Light Co	4,547,047		South Carolina Electric & Gas Co	663,433
Florida Power Corp	1,642,146		Southern California Edison Co	4,921,228
Georgia Power Co	2,360,487		Southern Indiana Gas and Electric Co (Vectern)	146,136
Green Mountain Power Corp	95,542		Southwestern Electric Power Co (AEP)	521,601
Gulf Power Co	432,401		Southwestern Public Service (Xcel)	376,160
Idaho Power Co	493,532		Tampa Electric Co	675,799
Indiana Michigan Power Co	582,822		Tucson Electric Power Co	403,340
Indianapolis Power & Light Co	468,195		United Illuminating Co	323,738
Jersey Central Power & Light Co	1,099,194		Virginia Electric and Power Co	2,438,226
Kansas City Power & Light Co (MO)	512,082		West Penn Power Co (Allegheny Power)	717,269
Kentucky Power Co (AEP)	173,641		Western Massachusetts Electric Co (Northeast Utilities)	206,279
Kentucky Utilities Co	540,839		Wisconsin Electric Power Co	1,120,964
Louisville Gas and Electric Co	394,063		Wisconsin Power and Light Co	458,041
Madison Gas and Electric Co	141,414		Wisconsin Public Service Co	439,481
Number of Sampled Firms	86			
Average Customer Number of Sample Utilities	959,902			

2.2 3HUSHWXDO ,QYHQWRULHV&DSLWD

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36(¶V PHDVXUH RI FDSLWDO FRVW LV EDVHG RQ D VHUYLF

This approach has a sound basis in economic theory, and is the same method chosen by PEG in their 4th Generation IR research.[18] It allows for a clear-cut and standardized way to account for differences between utilities with respect to historical plant additions. The service price approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry.

Based on this approach, the cost of capital in each period *t* is the product of indices of the capital service price and capital quantity in place at the end of the prior period. The formula for this is given by:

$$CK_t = WKS_t \tilde{X} XK_{t-1}$$

Here, in each period *t*, CK_t is the cost of capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value at the start of the period.

The capital quantity index is constructed using inflation-adjusted data on the value of net utility plant in a benchmark year, and on gross plant additions in subsequent years. It also uses an assumption about service lives. For the sake of consistency, we use either 1989 or 2002 as the benchmark year in the current study for Ontario sampled utilities, EDVHG RQ 3(*¶V SULRU GH their benchmarking work. We use 1989 for all U.S. sampled utilities. Based on the benchmark year, D ³WULDQJXODWHG ZHLJKWHG DYHUDJH´ LV XVHG WR FDOFXODWH WKH FDSLWDO stock in either 1989 or 6XEVHTXHQW \HDUV XVH WKH SUHYLRXV \HDU¶V FDSLWDO minus depreciation. For consistency, the plant DGGLWLRQV KDYH EHHQ FDOFXODWHG methodology found in their 4th Generation IR research. This method is used both for the Ontario and U.S. distributors. The formulas for the capital quantity index in 1989 and in subsequent years are provided below.

$$:-_{5=<=}^{Ü} L \frac{0\,A\,P2\,H=_{5=<=}^{Ü} P}{6\,9\,\#_{5=<=}^{Ü}}$$

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$$\#\,@_{ç@}L :)\,NK\,O2\,0H=_{ç}JP)\,NK\,O2\,0H=_{ç,}P; E\,ä\,r\,wÛ)\,NK\,O2\,0H=_{ç,}P$$

Under the service price approach employed in this study, capital cost has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

[18] See Hall and Jorgensen (1967) for a seminal discussion of the use of service price methods for measuring capital cost.

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Here, r_t L V W K H D O O R Z H G U D W H R I U H W X U Q E D V H G R Q W K H % R D U annual value is also used in the capital service price computation for the U.S utilities in the dataset. Setting the same rate of return for all distributors provides consistency in determining the capital costs, so that decisions by regulators do not enter into the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter d_t is the economic depreciation rate. We use the same value as PEG did, 4.59%, for this parameter in the study.

The variable that the capital service price components have in common is WKA_t. This is an index of the price of capital assets used in power distribution. We compute this index using data on differences in the cost of constructing utility plant between regions, and within regions over time. In particular for U.S. distributors, we use the Handy-Whitman indexes for total power distribution plant, which vary over time and across six geographic regions. For Ontario distributors we use the annual Electric Utility Construction Price Index (³EUCPI ´).

We determine the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RS 0 H D Q 1 H Z Y *Heavy Construction Cost Data*.[19] These indexes measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are raceways; conductors and grounding; boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution. The level of the asset price index for each utility is the simple average of the RS Means index values for cities in the service territory. This same source is used for both U.S. and Ontario distributors. The index is already adjusted for currency differences between the two countries.

[19] RS Means (2011).

2.3 (FRQRPHWULF 0HWKRG

The benchmarking approach used in this report is the econometric approach. PSE believes this is the most accurate and fair method to use when comparing utility cost and reliability levels. It is also the same method preferred by the Board in the November 2013 Board Report. This method is absolutely essential to use when a utility does not have a large number of very similar peers, which is certainly the case for Toronto Hydro.[20]

The econometric DSSURDFK H[SOLFLWO\ DGMXVWV IRU GLIIHUHQFHV power distribution industry, simple rate or reliability index comparisons do not provide appropriate benchmarks when evaluating performance. Uncontrollable factors influence attainable levels of total costs; such factors include geographical size, level of forestation, consumer density, regional wage levels, mix of consumer classes, or serving an urban core. Therefore, more sophisticated tools that normalize for specific influencing factors must be employed to accurately assess performance. With this concept in mind, PSE has developed econometric benchmarking models that take into account factors that have proven to be statistically influential on distribution utility costs and reliability indexes.

The econometric benchmarking approach relies on comparisons between observed data values to the predicted values obtained from regressions. The researcher determines an appropriate functional form for the relationship between the studied metric and factors that influence it, and develops appropriate econometric methods for obtaining good parameter estimates of the VSHFLILHG PRGHO ,Q WKLV UHSRUW WKH VWHIXQFWLRQDO IRUP 7WK HW³UW function is well established in academic literature and provides a high level of flexibility in estimating costs. This is also the same functional form preferred by the Board in the 4th Generation IR proceeding.

Cost predictions for each firm are obtained by inserting company-specific variable values into the estimated equation. Performance is defined as the percentage difference of the observed data to the predicted value of the data, as shown below.

$$2\,A\,N\,B\,K\,N?IA\text{Æ}LJ\check{Z}\,\bullet l\frac{1>O\,A\,N\,K\,F\,A\,?\%PKA\&P=P=}{2\,N\,A\,@\,E\,?\%PKA\&P=P=}p$$

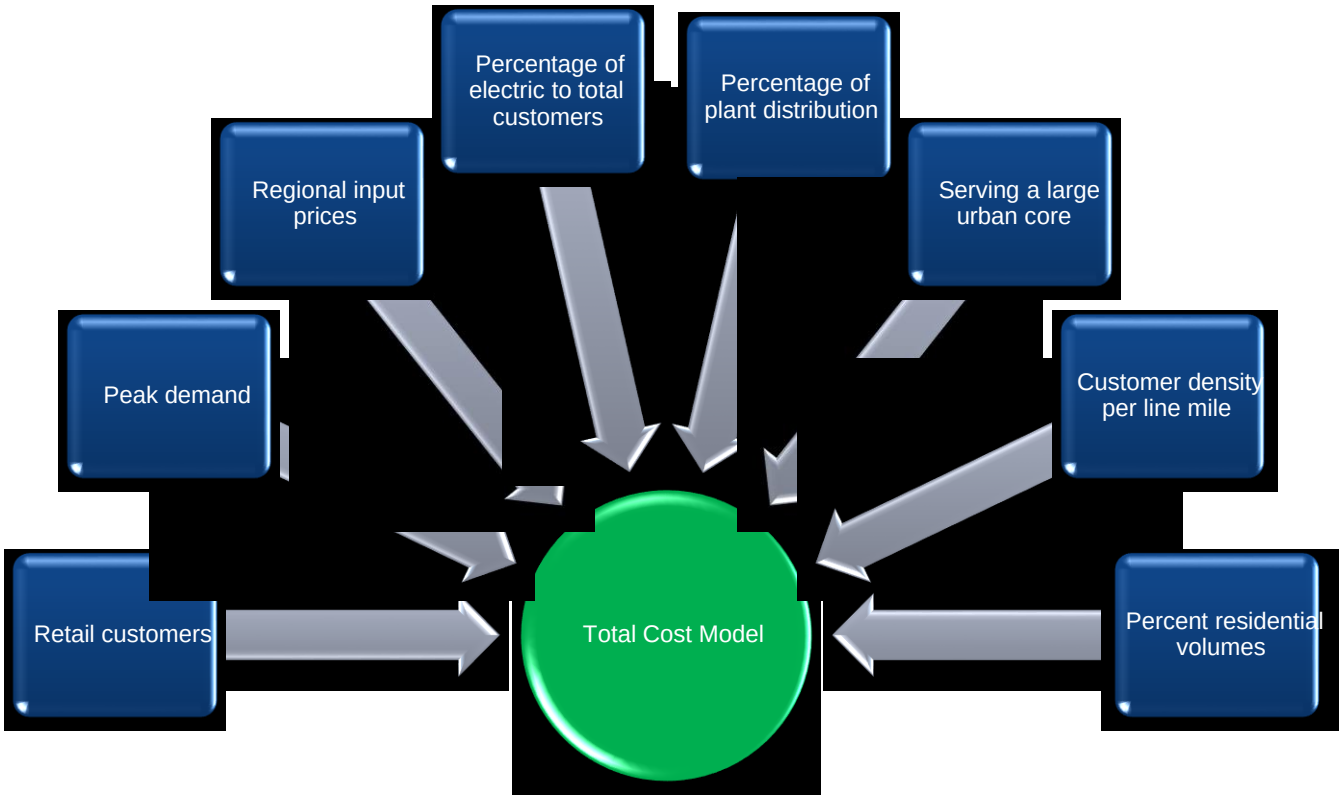
NOTE: 7KH WHUP ³OQ´ DERYH GHQRWHV WKH QDWXUDO O calculation for log arithmetically calculating percentage differences. It is typically used by both PSE and PEG to display benchmark scores.

[20] Even for utilities with a number of very similar peers, we would still advocate for using the econometric benchmarking method, because of the added variable information the model can account for and the extra information the approach can offer.

2.3.1 Variables Used

The variables included in the combined total cost analysis are shown in the figure below.

Figure 8 Variables in Econometric Cost Models



A diverse dataset which includes utilities with varying operational conditions is necessary to determine the influence on costs and reliability resulting from those conditions. There are many U.S. utilities which are either larger or smaller than Toronto Hydro, and Toronto Hydro falls well within the range of most variables. This is in contrast to an Ontario-only dataset, where Toronto Hydro tends to be an extreme outlier due to its size and urban characteristics. Due to this outlier status within the Ontario dataset, PSE considers the combined and U.S.-only benchmarking results to be more robust in revealing the cost and reliability performance of the company, relative to an Ontario-only sample.

The specification used in the cost models includes three types of variables: outputs, input prices, and business condition variables. Outputs are defined DV WKH 3ZRUN´ WKDW WKH XWL defined two variables as outputs: the number of retail customers served and peak demand.

The input prices are defined as the external market price for operation, maintenance, and administration (OM&A) expenses and capital service costs. The market prices for labour and capital will vary depending on the geographic location of each sampled utility. The business condition variables are the other service territory characteristics that statistically influence total cost levels. Examples of business condition variables are customer density, percentage of electric customers in total customers, percentage of forestation, etc.

2.3.2 Estimation Procedure and Translog Cost Function

As a starting point, we assume that the relationship between a XWLOLW\¶V FRVW WKDW DIIHFW LW FDOOHG ³FRVW GULYHUV´ FDQ EH TXDQWLILHG LQ IXQFWLRQ FDOOHG D ³FRVW IXQFWLRQ´ DOORZV 36(WR VSHFLI explained by relevant independent or explanatory variables and associated parameters; the latter capture the effect of the independent variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

$V LPSOLHG E\ WKH WHUP ³LQGHSHQGHQW´ RQH RI WKHVH DV used in the model are factors that are outside the control of utility decision-makers. For instance, the wage paid to labour is driven by market conditions in the service territory and is largely RXWVLGH WKH FRQWURO RI D ILUP¶V PDQDJHUV 2QH WKH RWK ZLWKLQ PDQDJHPHQW¶V FRQWURO DQG WKXV FDQQRW VHUYH

In general, cost is assumed to be a function of input prices, the output produced by the firm, and RWKHU LQGHSHQGHQW YDULDEOHV WKDW DIIHFW FRVW EXW function specified in this manner can capture a reasonable level of cost variability, it does not explain all the elements that affect cost. Therefore, the function includes a random noise term to account for such idiosyncratic factors.

The following equation provides an example of a simple cost function:

$$C = E_0 + E_1 * Y + E_2 * P + \varepsilon$$

In this equation, the terms C, Y, and P denote cost, output, and input prices, respectively. The E terms denote model parameters that capture the magnitude and sign of the effect of the explanatory variables on cost, and the error term captures random noise. The latter is assumed to be independent of the explanatory variables.

The data used to estimate this cost relationship can be from a single firm with multiple time observations (time series data), from many firms observed at a single time period (cross-sectional data), or from many firms with multiple time observations (cross-sectional time-series or panel data). The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the model. In our present study, we have a panel dataset with cost data from multiple firms with observations starting in 2002 and extending to 2012. Additionally, we LQFOXGHG 7RURQWR +\GUR¶V cost projections through 2019, allowing us to also benchmark those forecasts ³RXW RI VDPSOH´ WR WHVW WKH model that is based on historical data and apply the estimated coefficients and projected independent variable values for Toronto Hydro to calculate a predicted benchmark value. This predicted benchmark value is then compared to Toronto +\GUR¶V SURMHFWHG WRWDO FRVW DPRXQW

A cost function can be specified as a single equation or a system of equations to get parameter estimates. A single equation model is specified as noted above. A system of equations results from applying economic theory that permits the derivation of cost share equations that are estimated along with the cost function to obtain more precise parameter estimates. The estimation procedure used for the total cost studies incorporates a system of equations that are

based on the cost shares of OM&A and capital costs. This produces more precise estimates and benchmark results. The reliability benchmarking exercise uses a single equation model only.

2.3.2.1 Statistical Tests

The precision of parameter estimates is an important dimension of the cost estimation exercise. It identifies business condition variables that have a statistically significant effect on cost. In particular, standard errors of parameter estimates, which measure the precision with which a parameter is estimated, are used to construct a test of a relevant hypothesis. The hypothesis to be WHVWHG LV ³WKH H[SODQDWRU\ YDULDEOH LQ TXHVWLRQ KDV procedure is called the *t*-test. A variable is statistically significant if this hypothesis is rejected at a pre-specified level of confidence. We use a 90 percent confidence threshold in our research.

A cost model with plausibly signed and statistically significant parameter estimates is ultimately used to assess the cost pHUIRUPDQFH RI HDFK ILUP LQ WKH VDPSOH %\ ³ that its sign (positive/negative) accords with our intuitive understanding of the relationship EHWZHHQ WKDW SDUDPHWHU DQG WKH YDULDEOH)RU H[DPSO number of customers served increases (a positive sign for the customer parameter).

A cost model with estimated parameters is fitted with the business conditions of each utility to generate cost benchmarks, against which actual cost is evaluated. A cost benchmark reflects the performance of an average utility facing the business conditions of the utility whose values are used to generate the benchmark.

,I D JLYHQ XWLOLW\¶V DFWXDO FRVW LV EHORZ WKH EHQFKP average ² it spent less than did a hypothetical utility (with the same particular characteristics) would be expected to spend. If its actual cost is above the benchmark cost, its cost performance is worse than average. A statistical test of a cost efficiency hypothesis, based on the *t*-test, can also be constructed to identify whether the cost performance identified by the above exercise is statistically significantly different from average.

2.3.2.2 Model Specification

A translog function is selected for the total cost model estimated in this study. The translog cost function was the same functional form chosen by PEG in their 4th Generation Incentive Regulation benchmarking research and the same one preferred by the Board in the November 2013 Board Report. Its general form, after suppressing time and firm subscripts, is given by:

$$\ln C = D_0 + \sum_i D_i \ln Y_i + \sum_j E_j \ln W_j + \sum_h J_h \ln Z_h + \frac{1}{2}\left[\sum_i \sum_k D_{ik} \ln Y_i \ln Y_k + \sum_j \sum_n E_{jn} \ln W_j \ln W_n\right] + \sum_i \sum_j D_{ij} \ln Y_i \ln W_j + D_t t + H$$

In this specification, Ds and Es are model parameters, and H is the random noise term. In addition, Y_i quantifies output, W_j input prices, Z_h other business condition variables, and *t* is a

time trend term. This form has been widely used in cost function research.[21] A major advantage is its flexibility, which permits it to provide a good approximation for the wide range of functional forms that the data can reflect.[22]

We also note several theoretical assumptions that aid in model specification and estimation. Among these is the idea that if all input prices rise, cost also rises proportionally. This is known as linear homogeneity, and it allows the restriction that the sum of input price parameters equals one. An additional restriction is symmetry in the parameters of the price interaction terms. In addition, we use 6KHSKHUG¶V OHPPD WR GHULYH FRVW VKDUH HTXDV the cost function. The general form of the cost share equation for input *j* is given by:

$$S_j = E_j \sum_i D_{ij} \ln Y_i \sum_n E_{jn} \ln W_n X_j$$

For the reliability models, we also specify quadratic models that include first-order explanatory terms and their squared counterparts. These models are specified as single equation models. The following presents the general form the reliability models take. Both the SAIDI and the SAIFI models are constructed in the same manner. We illustrate the basic form of the SAIDI model below.

$$SAIDI_j = E_0 \sum_i D_t \ln X_i \sum_i E_{ii} \ln X_i * \ln X_i D_t t F$$

2.3.2.3 Estimation Approach

One of the reasons for joint estimation of cost and cost share model parameters is that there is contemporaneous correlation between the error terms in these systems of equations. Such correlation allows the use of a system of regression equations that result in more efficient (precise) estimates. In this study, the systems estimator we use is Feasible Generalized Least Squares (³FGLS´).

In particular, PSE uses an iterative FGLS procedure that estimates the unknown error matrix consistently.[23] The estimates we compute are equivalent to Maximum Likelihood Estimates (³MLEs´).[24] Our estimates thus possess all the desirable properties of MLEs, which include consistency and efficiency. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and is dropped. This does not pose a problem, since yet another property of the MLE procedure is that it is invariant to any such parameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

The single equation model is estimated using generalized least squares (GLS) in order to correct

[21] In their 0RQWH &DUOR VWXGLHV RI IXQFWLRQDO IRUPV¶ SHUIRUPDQFH *DJQ EHQFKPDUN EHFDXVH ³LW LV WKH PRVW ZLGHO\ XVHG´ IXQFWLRQDO IRUP

[22] See Guilkey, et al. (1983)

[23] See Zellner, A. (1962).

[24] See Dhrymes, P.J. (1971), Oberhofer, W. and J. Kmenta (1974) and Magnus, J.R. (1978).

for cross-sectional heteroskedasticity and autocorrelation. The parameter estimates that result from this procedure are both consistent and efficient.

2.4 %HQFKPDUN)XWXUH<HDUV

The same econometric model and its associated parameter values that are estimated using historical data (DQG XVHG WR GHYHORS 7RURQWR) are also used to FDOFXODWH WKH FRPSDQ\¶V EHQFKPDUN YDOXHV. These parameter values are combined with projected variable values to calculate the expected total costs (or reliability) of Toronto Hydro in the future years of the Custom IR period.[25]

As a hypothetical and illustrative example of this procedure, assume we have a simple econometric model that only includes a constant and the number of customers as independent variables when predicting total cost levels. Using the historical sample data from 2002-2012, we estimate this simple model and find an equation that indicates:

Costs = 100 + (10*N)

where N is the number of customers served.[26] In this simplified case, the historical benchmarks would be calculated by inserting the actual number of customers for each year for the studied XWLOLW\ $VVXPH LQ 7RURQWR was 1,000, Toronto Hydro benchmark costs for 2002 would then equal 100 + (10*1,000), or $10,100. If by 2012, Toronto +\GUR¶V FXVWRPHU FRXQWV LQFUHDVH WR WKHQ LWV (10*2,000), or $20,100.

This same procedure is used for developing the future year benchmarks, but instead of using actual customer number estimates, we use company projections of those variables. So if the company projects the number of customers at 2,500 in 2015, the 2015 benchmark is 100 + (10*2,500), or $25,100.

This procedure assumes that future total costs will be influenced by the independent variables in the same way that historical costs have been estimated to be influenced by the independent variables. Absent robust projected costs from a large sample of utilities, PSE is of the opinion that using the historical relationships between variables found to be statistically significant in the models is the best and most straightforward way of benchmarking future total cost levels.

PSE was provided OM&A expense, plant addition, reliability, customer counts, and line length projections from Toronto Hydro.[27] We were also provided peak demand projections, but these

[25] 2014 is also a future year for this analysis.

[26] Again this is a hypothetical, simplified model only for illustrative purposes.

[27] We were only provided OM&A expenses for the year 2015. We then escalated this amount in each year for 2016, 2017, 2018, and 2019 using the I-X formula of projected inflation of 1.7% minus a 0.3% stretch factor.

were projections of non-coincident peaks at the substation level.[28] We then adjusted the non-coincident peak demand estimates based on the historical ratio of the coincident peak demand of the Toronto Hydro system and the sum of the non-coincident substation peak demands.

Input prices need to also be projected into the future years. For the labour and non-labour components of the OM&A input price, PSE used price forecasts of the GDP-IPI and Ontario weekly average earnings from the Conference Board of Canada (Spring 2014 forecasts). The forecasts only go to 2018, so for the 2019 observation we used the 2018 growth rate and applied that same growth rate to 2019. We used the average annual 40-year growth rate in the EUCPI for the capital construction cost estimates.[29]

The rate of return for the entire period is set at the 2014 Board-calculated weighted average cost of capital of 6.56%. This assumes that interest rates and returns will stay constant from 2014 to 2019. PSE believes this assumption is a fairly conservative one, as interest rates are probably more likely to increase, rather than decrease in the next five years.

Other projected variables that enter the models include percent residential, urban core, electric customers in gas and electric operations, electric distribution in total electric gross plant, percent forestation, elevation standard deviation, and the percent plant that is underground. Since these variables are not likely to meaningfully change, they were set at their most recently available historical value for the future years. The wind variable and lightning variables were set at the average of the values from the historical period.

[28] By non-coincident we mean the projected peak values were for the annual peaks of those specific substations and not the demand coincident, or at the same time as, the system as a whole.

[29] Forty years is the assumed service life of capital when calculating the triangularized weighted average of capital in the benchmark year. This long period also enables the smoothing out of interest rate impacts.

3 7RWDO &RVW %HQFKPDUNLQ

This section provides the total cost benchmarking results for both the combined dataset (includes both Ontario and U.S. distributors) and the U.S.-only dataset (includes only U.S. utilities plus Toronto Hydro). We begin with the combined sample results.

3.1 (FRQRPHWULF 5HVXOWV IRU W 'DWDVHW

The estimates from the total cost model based on combined data are presented in Table 4. We note that the cost function parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant.

Table 4 Combined Sample Total Cost Model Estimates

VARIABLE KEY						
		K=	Capital Price			
		N=	Number Retail Customers			
		D=	Peak Demand			
		UD=	Urban Core Dummy			
		DT=	Density: Customers/KM Line			
		PCE=	Percent Electric Customers in Gas & Electric Customers			
		PRV=	Percent Residential Deliveries in Total Deliveries			
		PDE=	Percent Distribution Plant in Total Electric Plant			

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC		EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
WK	0.539	264.115		PCE	0.104	3.637
KK	0.102	10.192				
KN	-0.019	-2.982		PDE	0.066	3.438
KD	0.017	2.717				
				PRV	0.016	2.152
N	0.967	43.413				
NN	0.021	1.178		Trend	0.003	2.943
ND	-0.024	-2.140				
				Constant	19.564	1428.487
D	0.114	5.339				
DD	0.029	4.707		System Rbar-Squared	0.985	
UD	0.007	3.614		Sample Period:	2002-2012	
DT	-0.149	-11.850		Number of Observations	1650	

Total cost increases with higher capital prices and output quantities. At the sample mean, a 1% increase in the number of customers and peak demand are estimated to raise cost by 0.97% and 0.11%, respectively. The number of customers served is clearly the dominant output-related cost driver, which is an expected result for an electric distribution total cost model. Input prices also will increase total costs. Holding the effect of all other variables constant, we find that a 1% increase in the price of capital raises cost by 0.54%. This is higher than the elasticity of the price of the OM&A input, which is about 0.46%. Based on linear homogeneity, the OM&A input price estimate is predetermined to be one minus the capital price estimate. The estimates reflect the capital intensiveness of the power distribution business.

The business condition coefficients are also signed as our hypothesis would suggest. Utilities serving largely rural areas experience greater challenges relative to their suburban counterparts.

Cost is also higher for utilities that serve an urban core, which is defined as serving a city with a population of at least one million. Unit capital costs tend to decrease as customer density increases (i.e., rural areas will cost more to serve than suburban areas), but will then begin to increase as the area transitions from a suburban setting to an urban or metropolitan setting. This QRQOLQHDU UHODWLRQVKLS´ FRVW VWUXFWXUH LV UXUDO XQLW FRVWV lower, and urban core unit costs increase again) is supported by an engineering design study found in the Appendix of this report.[30]

The density variable, therefore, adjusts for serving a rural service area, whereas the urban YDULDEOH DGMXVWV IRU VHUYLQJ D ODUJH XUEDQ FRUH $V negative and is statistically significant, which reflects the economies achieved from serving more customers per a given line length. The urban variable is positive and statistically significant, reflecting the added costs and difficulties of serving a large urban area.

The remaining coefficients are positive, reflecting: (1) the economies obtained from diversification, in the case of utilities that serve gas customers, (2) economies of scope, in the case of utilities that are vertically integrated and, (3) economies from serving more of a non-residential load. In particular, the higher percentage of electric customers (out of total electric and gas customers), the higher the cost, due to lack of economies of diversification. The higher the percent of electric distribution plant in total electric plant, the higher the cost. This indicates that vertically integrated utilities enjoy economies of scope that are not available to distribution-only utilities. Finally, the higher the percentage of residential deliveries (out of total power deli Y H U L H V W K H P R U H - [illegible] times.

The estimate of the trend variable parameter is 0.3%. This suggests a modest upward shift in cost over time. This econometric trend indicates a modest negative productivity trend for the combined U.S. and Ontario electric distribution industry.

The next table presents the Toronto Hydro benchmark results from the combined total cost model for an average of the 2010 to 2012 years.

Table 5 Average 2010-2012 Toronto Hydro Combined Sample Total Cost Benchmark Results

Year	Actual	Predicted		% Difference	P-Value
Average 2010-2012	607,374,528	752,360,858		-21.5%	0.082

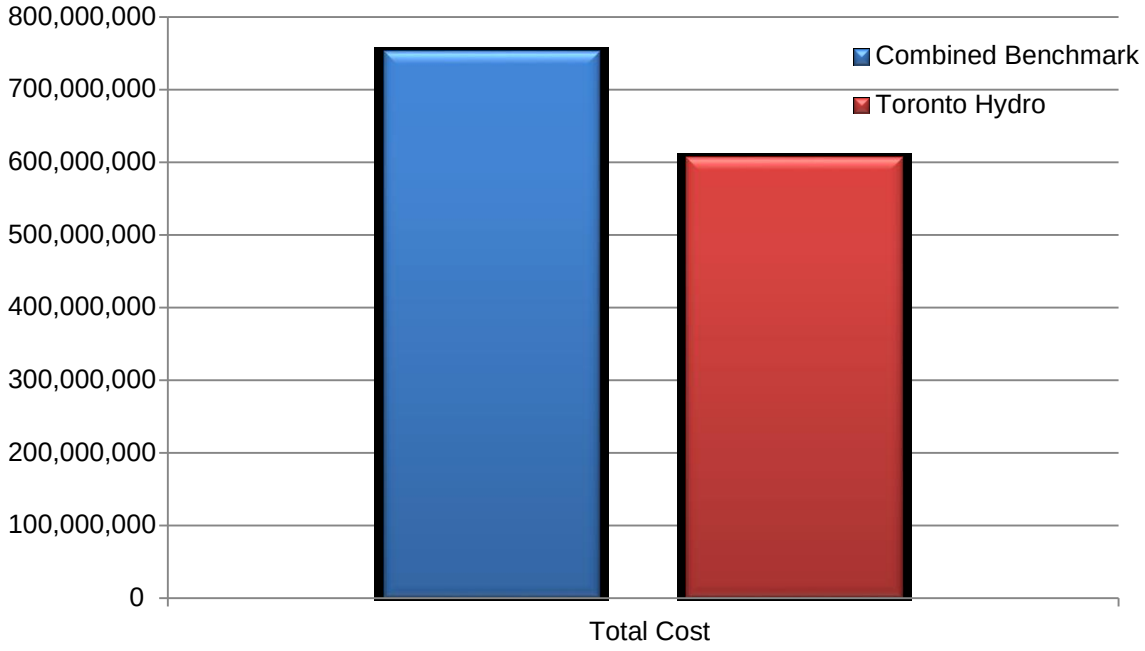
Actual cost is below the predicted or benchmark value by about 21.5 percent. This is a statistically significant difference with a 90 percent degree of confidence, and shows that when benchmarked relative to the power distributors of Ontario and the U.S., Toronto Hydro has a statistically significantly superior total cost performance.[31]

[30] 7KH UHSRUW LV WLWOHG ³&DSLWDO 5HTXLUHPHQWV RI 6HUYLQJ 'HYHORS

[31] The 90 percent confidence level assumes a one-tailed rather than a two-tailed test and is the same one used by

Put into dollar terms, the 2010-2012 average total costs of Toronto Hydro were expected to be $752.4 million, but were actually $607.4 million. This is $145.0 million per year below the benchmark expectation over the 2010-2012 period. This result is illustrated in the figure below.

Figure 9 2010-2012 Combined Sample: Benchmarked Total Costs vs. Actual Costs (3-Year Average)



The following table breaks down the historical and forecast year benchmark and company total costs from 2002 to 2014 and then during the Custom IR period of 2015 to 2019. During the historical period Toronto Hydro has consistently been below its expected benchmark levels. In the second column, the percent below benchmark is illustrated. Notice that prior to 2007 the company was consistently near 30% below benchmark expectations. This is suggestive that the F R P S D Q \ ¶ V was in need of investment. It is our understanding that around 2006 or 2007 the company increased L W V F D S L W D O L Q Y H V W P H Q W V 7 K L V K D V P R Y performance from 30% below benchmark to 17% below by 2013. This movement to invest more in capital during that time frame is a reason Z K \ 7 R U R Q W R + \ G U R ¶ V W R W D O I D F [3] 7) 3 ´declined in the recent past.

7 K H F R P S D Q \ ¶ V forecasts for OM&A and capital spending keep the company below benchmark levels, although not by as much as in the historical years. Nevertheless, they indicate W K D W W K H F R P S D Q \ ¶ V S U R S R V H G V S H Q G L Q J O H Y H O V D U H U H D the model expectations.

[3] PEG in both the 3rd and 4th Generation Incentive Regulation benchmarking reports.

Table 6 2002-2019 Combined Sample Benchmark Total Costs vs. Historical and Projected

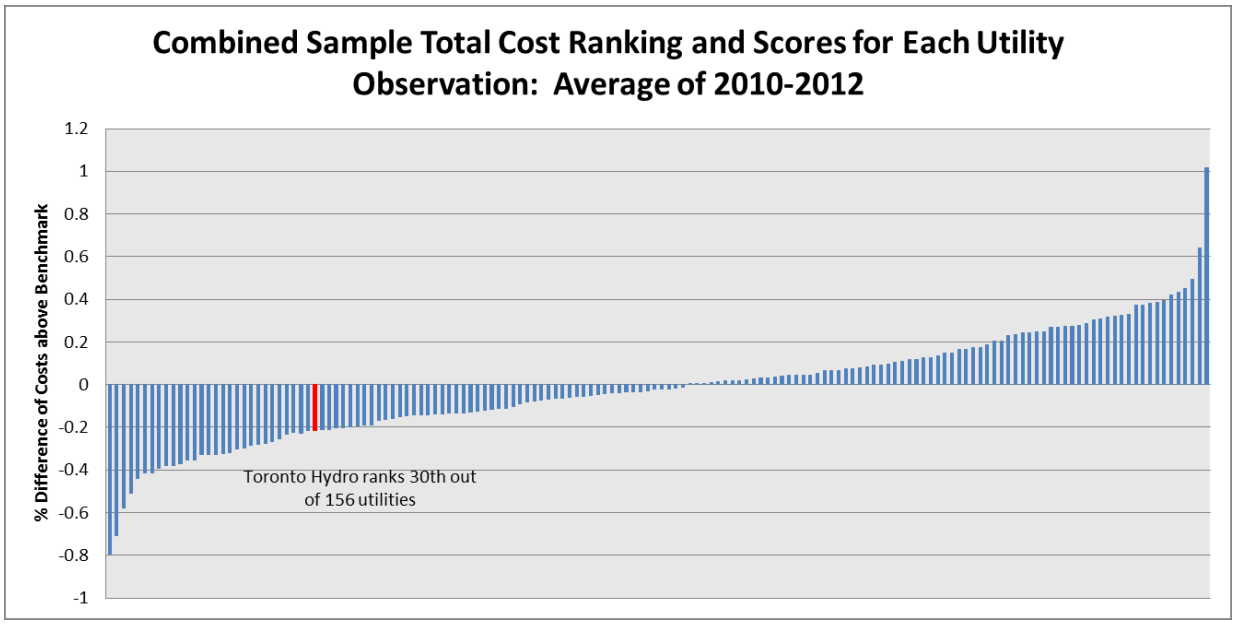
Year	Percent Below Combined Sample Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Actual Total Cost THESL, $M
2002	29.2%	$582	$435
2003	27.8%	$595	$450
2004	28.5%	$604	$454
2005	33.6%	$629	$450
2006	32.8%	$635	$457
2007	31.5%	$664	$484
2008	27.7%	$683	$518
2009	27.1%	$703	$536
2010	22.1%	$731	$586
2011	17.8%	$762	$638
2012	24.4%	$764	$598
2013	17.3%	$781	$657
2014	14.7%	$845	$730

Custom IR Period

Year	Percent Below Combined Sample Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Projected Total Cost THESL, $M
2015	7.1%	$884	$823
2016	5.3%	$935	$887
2017	3.8%	$985	$947
2018	3.5%	$1,037	$1,001
2019	2.6%	$1,092	$1,064

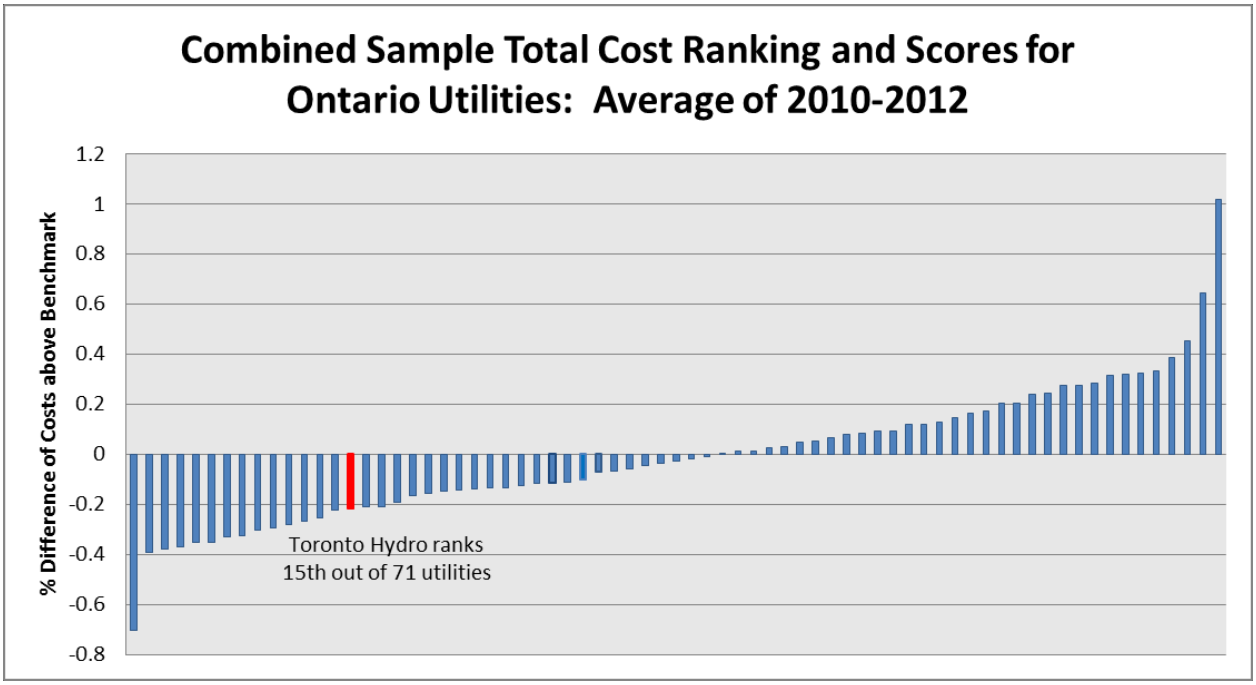
The combined sample total cost observations for each utility can be ranked based on the percent difference in the actual total costs to the benchmark total costs. Toronto Hydro finds itself 30th out of 156 utilities included in the combined sample when an average of the 2010-2012 G L I I H U H Q F H V D U H U D Q N H G 7 K H G L V W U L E X W L R Q t a k H n W L O L W L the following graph.

Figure 10 Combined Sample: Econometric Total Cost Ranking



The following figure takes the same combined benchmarking results as previously shown, but isolates the rankings to only include Ontario distributor observations. Toronto Hydro ranks 15th out of the 71 Ontario distributors in the combined benchmarking results.

Figure 11 Combined Sample, Ontario Utilities Only: Econometric Total Cost Ranking



3.2 (FRQRPHWULF 5HVXOWV2QU W 'DWDVHW

The estimates from the total cost model based on the U.S. data are presented in Table 7. The results in the table show that the cost function parameter estimates have plausible signs and magnitudes. The first order terms of all variables that are fully interacted have the theoretically expected signs and are statistically significant.

Table 7 U.S. Total Cost Model Estimates

		K=	Capital Price			
		N=	Number Retail Customers			
		D=	Peak Demand			
		UD=	Urban Core Dummy			
		PCE=	Percent Electric Customers in Gas & Electric Customers			
		PRV=	Percent Residential Deliveries in Total Deliveries			
		PDE=	Percent Distribution Plant in Total Electric Plant			
		UG=	Percent Distribution Plant Underground			
		ED=	Elevation Standard Deviation			
		PF=	Percent Forestation			
EXPLANATORY VARIABLE	**ESTIMATED COEFFICIENT**	**T STATISTIC**		**EXPLANATORY VARIABLE**	**ESTIMATED COEFFICIENT**	**T STATISTIC**
WK	0.555	143.656		PDE	0.122	7.596
KK	0.070	4.190				
KN	-0.010	-1.022		UG	-0.035	-2.305
KD	0.013	1.278				
				ED	0.013	2.140
N	0.732	30.652				
NN	0.270	3.274		PF	0.020	3.489
ND	-0.177	-2.197				
				Trend	0.003	2.872
D	0.220	8.916				
DD	0.141	1.677		Constant	20.098	1533.465
UD	0.016	5.687		System Rbar-Squared	0.958	
PCE	0.132	4.793		Sample Period:	2002-2012	
PRV	0.039	2.604		Number of Observations	880	

We note that cost is higher the higher the output quantities. At the sample mean, a 1% increase in the number of customers is estimated to raise cost by 0.73%. A one percent hike in peak demand is estimated to increase cost by 0.22%. As in the combined model, the number of customers served is clearly the dominant output-related cost driver.

The coefficients on the additional variables were also plausible. Utilities that serve an urban core with 1 million or more residents have higher costs than suburban utilities. Cost is also higher for utilities that only serve electric customers relative to those that serve both gas and electric customers. In addition, a utility that serves a more residential load, as measured by higher values

of percent deliveries that are residential, has greater cost relative to one that serves a more commercial and industrial load.

Further, the greater the percentage of the electric plant that is distribution-related, reflecting a lesser degree of vertical integration, the higher the OM&A cost incurred by the utility. On the other hand, undergrounding distribution capital lowers cost. Finally, greater variability in elevation and the higher the percentage of forestation of a service territory result in higher cost. The estimate of the trend variable parameter is 0.3%. This suggests a modest upward shift in cost over time (i.e., negative productivity). The estimates on all of the first order variable terms are statistically significant at the 90 percent confidence level. We present the benchmark results from the model in Table 8.

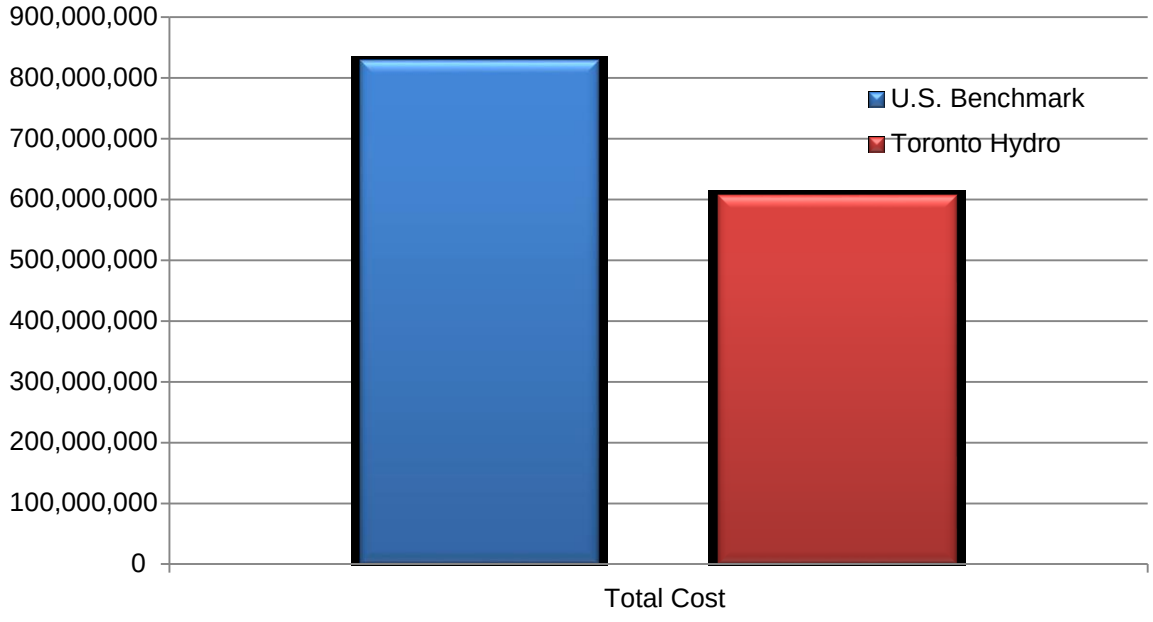
Table 8 2010-2012 Average Toronto Hydro U.S. Total Cost Benchmark Results

Year	Actual	Predicted		% Difference	P-Value
2010-2012 Average	607,374,528	828,660,305		-31.1%	0.005

: H Q R W H W K D W 7 R U R Q W R \ G U R ¶ V W K H U H Average cost performance is good. Actual cost is below the predicted or benchmark value by about 31%. This performance score is statistically significant at least at the 90% confidence level and shows that when benchmarked relative to the power distributors of the U.S., Toronto Hydro is a superior total cost performer.

Put into dollar terms, the 2010-2012 average total costs of Toronto Hydro were expected to be $828.7 million. The actual observed costs are 31 percent below this mark. This is an annual difference of $221.3 million. This result is illustrated in the graph below.

Figure 12 2010-2012 U.S.-Only Sample: Benchmarked Total Costs vs. Actual Costs (3-Year Average)



The next table breaks down the benchmark total costs and company total costs from 2002 to 2019. During the historical period (2002-2013), Toronto Hydro has consistently been below its expected benchmark levels. Its actual total cost is expected to remain below the benchmark in the Custom IR forecast years, though, to a lesser extent than in the historical years. A similar pattern is found for the U.S. benchmark results as was seen in the combined results. Prior to 2008, total costs were about 40% below benchmark expectations. After capital investments increased, by 2013, the benchmark scores moderated to 25% below expectations (which is still a low cost level). Similar to the combined results, this illustrates the movement to upgrade the capital infrastructure on the system lowered TFP growth.

Table 9 2002-2019 U.S.-Only Sample Benchmark Total Costs vs. Historical and Projected

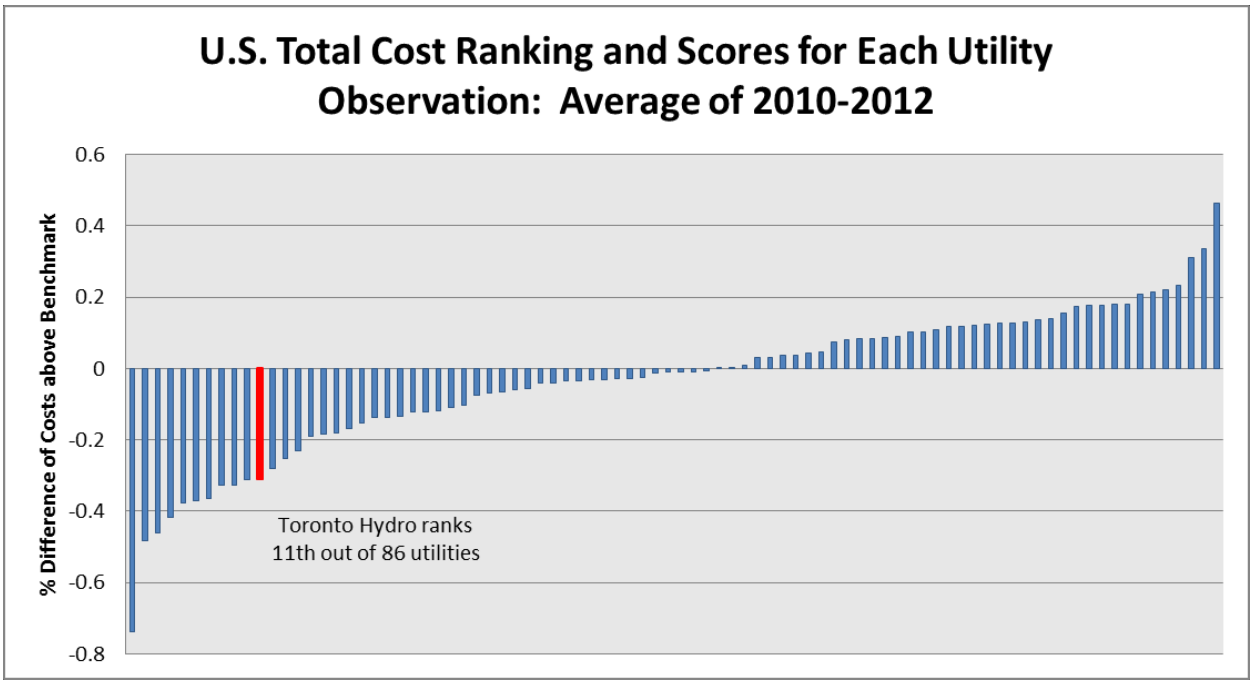
Year	Percent Below U.S. Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Actual Total Cost THESL, $M
2002	40.8%	$654	$435
2003	39.2%	$667	$450
2004	38.5%	$667	$454
2005	45.1%	$706	$450
2006	44.0%	$710	$457
2007	43.9%	$752	$484
2008	39.0%	$765	$518
2009	39.4%	$795	$536
2010	33.8%	$822	$586
2011	27.6%	$840	$638
2012	32.0%	$824	$598
2013	24.6%	$841	$657
2014	21.8%	$907	$730

Custom IR Period

Year	Percent Below U.S. Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Projected Total Cost THESL, $M
2015	13.1%	$938	$823
2016	11.4%	$994	$887
2017	9.9%	$1,046	$947
2018	9.5%	$1,101	$1,001
2019	8.5%	$1,159	$1,064

The U.S. total cost observations for each utility can be ranked based on the percent difference in the actual total costs to the benchmark total costs. Toronto Hydro finds itself 11th out of 86 utilities included in the U.S. sample when an average of the 2010-2012 differences are ranked. 7KH GLVWULEXWLRQ RI XWLOLWLHV DQG WKH FRPSDQ\¶V SODF

Figure 13 U.S.-Only Sample: Total Cost Econometric Ranking



4 5HOLDELOLW\ %HQFKPDUNLQJ 9DULDEOH
'HILQLWLRQV DQG 'DWD 6RXUFHV

Nearly all jurisdictions that require reporting of reliability indicators include the metrics of 6$,', 6$,), DQG &XVWRPHU $YHUDJH ,QWHUUXSWLRQ 'XUDWLRQ [32] SAIDI measures the average duration of sustained interruptions per utility customer. SAIFI is a gauge of the average frequency of sustained interruptions per customer. CAIDI evaluates the average duration time per sustained interruption. SAIDI is thus the product of SAIFI and CAIDI.

$$\text{SAIDI} = \frac{\Sigma_i \text{Minutes Customer } 'i' \text{ is without Service}}{\text{Total Number of Customers on System}}$$

$$\text{SAIFI} = \frac{\Sigma_i \text{Frequency Customer } 'i' \text{ is without Service}}{\text{Total Number of Customers on System}}$$

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

Several jurisdictions exclude extraordinary events from reliability statistics, with the goal of increasing historical comparability. The bulk of excluded events stem from major storms. These severe storms vary in number and intensity from year to year. MED definitions are determined by each regulatory commission. Definitions vary by state; some use the IEEE standard 1366-2003 to determine what constitutes a MED.[33] Other states have customized definitions. For example, for some states, if 10 percent of a ut L O L W \¶ V F X V W R P H U V H [S H U L H Q F H D Q than a 24-hour period, a MED has occurred. States are gradually shifting towards the IEEE standard; however, considerable differences across states remain. Ontario utilities do not record reliability ind L F H V W K D W H [F O X G H D Q \ 0 (' V $ V D U H V X O W Z H E H Q F using datasets with gross recorded reliability metrics which include all outages.[34]

4.1 'DWD 6RXUFHV

The industry reliability data for U.S. utilities is gathered through reports and rate case filings made public by state commissions. Reliability indices for the Ontario utilities are obtained from the annual RRR filings to the Board.

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[32] Some states only require reporting of two of these measures. However, the excluded indicator can still be determined by the researcher. SAIDI is equal to the product of SAIFI and CAIDI.

[33] The IEEE 1366- VWDQGDUG GHILQHV WKH ³EHWD´ PHWKRG ,I RXWDJHV IR deviations from the normal day, a major event day is declared. A normal day and the standard deviation are GHWHUPLQHG E\ WKH \HDUV RI QRUPDO GDWD (QRW LQFOXGLQJ WKH 0('V

[34] 7RURQWR +\GUR¶V UHOLDELOLW\ LQGH[HV DOVR GR QRW LQFOXGH 0('V ZLWK QR H[WUHPH VWRUPV 1DWXUDOO\ L D PDMRU VWRUP ZLOO EH ZLGHU WKDQ H YHQW RF the projections for that year.

The reliability benchmarking models we developed use the following variables:

- Density (customers per line mile);
- The number of retail customers;
- Percent plant that is distribution (out of total electricity plant);
- Forestation;
- The standard deviation of elevation in the service territory;
- The number of retail customers served
- Whether a utility serves an urban core with 1 million or more residents;
- The level of wind and lightning within a given service territory; and
- A time trend.

The sources for all the variables (except for the measures of weather) are detailed in Section 2.1 since they are also used in the total cost research. The variables used to construct the wind and lightning values are collected from National Climatic Data Center (³NCDC ´) of the National Oceanic and Atmospheric Administration (³NOAA ´).[35]

We constructed the wind variable using hourly weather station data for each service territory within the sample. In each hour, we subtracted the recorded wind speed by ten knots. If the wind speed was at or below ten knots, we set the value equal to zero. Similar to how cooling and heating degrees are calculated, we determined the level of wind speed above the 10 knot threshold in each hour for each service territory and summed up that value for each year.

The lightning variable measures the total number of strikes in each utility ¶ service territory. Both the wind and lightning variables are calculated at a county-by-county level for the U.S. distributors. Wind data for the Ontario sample is generated using the closest weather station observation to each distributor. Lightning data is not available for Ontario distributors; Toronto Hydro was assigned the lightning value of Rochester Gas & Electric, which serves on the New York side of Lake Ontario.

$V LQ WKH FDVH RI WRWDO FRVW ZH EHQFKPDUN 7RURQWR +\ (made up of U.S. and Ontario utilities), and a U.S.-only sample. The former includes 46 U.S. and 70 Ontario utilities, while the latter includes 46 U.S. utilities and Toronto Hydro. The data for the U.S. utilities in each sample spans the years 2002 to 2012. In each sample, some utilities have GDWD DYDLODEOH IURP WKH HDUO\ more limited data available. The OH R W K H data for the Ontario utilities spans the years 2005 to 2012. We also inserted future reliability metric projections from Toronto Hydro, which assume full funding of the proposed capital program. The following table lists the utilities found in the combined analysis.

[35] http://www.ncdc.noaa.gov/

Table 10 Sampled Utilities for Reliability Benchmarking

Company	SAIFI (Avg last 3 years)	SAIDI (Avg last 3 years)	Company	SAIFI (Avg last 3 years)	SAIDI (Avg last 3 years)
Ameren UE	1.085	173.973	E.L.K. Energy Inc.	1.048	180.624
Avista Corp	1.262	165.575	Enersource Hydro Mississauga Inc.	1.644	42.819
Baltimore Gas & Electric Co	1.900	1006.231	Entegrus Powerlines	1.890	96.000
Central Hudson Gas & Electric Corp	2.338	1602.926	Enwin Utilities Ltd.	2.201	82.394
Central Maine Power Co	3.059	810.394	Erie Thames Powerlines Corporation	2.007	302.114
Cincinnati Gas & Electric Co (Duke Energy OH)	2.247	523.055	Espanola Regional Hydro Distribution Corp	0.408	51.285
Cleveland Electric Illuminating Co (First Energy)	1.388	317.131	Essex Powerlines Corporation	4.034	331.169
Commonwealth Edison Co	1.339	318.653	Festival Hydro Inc.	2.162	107.583
Connecticut Light & Power Co	2.029	2118.454	Fort Frances Power Corporation	0.269	15.159
Consolidated Edison Co of New York Inc	0.283	434.574	Greater Sudbury Hydro Inc.	1.125	79.855
Consumers Energy Company	1.469	539.602	Grimsby Power Incorporated	1.317	118.549
Dayton Power & Light Co	1.494	377.346	Guelph Hydro Electric Systems Inc.	1.987	62.237
Detroit Edison	1.150	498.848	Haldimand County Hydro Inc.	2.244	249.969
Empire District Electric Co	2.808	1279.733	Halton Hills Hydro Inc.	2.058	96.942
Entergy Arkansas Inc	1.853	197.820	Hearst Power Distribution Company Ltd.	3.018	584.026
Florida Power & Light Co	1.189	89.704	Horizon Utilities Corporation	1.830	95.547
Florida Power Corp	1.800	113.730	Hydro 2000 Inc.	2.364	442.461
Green Mountain Power Corp	1.708	302.452	Hydro Hawkesbury Inc.	1.106	59.543
Gulf Power Co	1.839	200.885	Hydro One Brampton Networks Inc.	1.306	43.025
Indianapolis Power & Light Co	0.976	87.313	Hydro Ottawa Limited	1.621	107.665
Kansas City Power & Light Co	0.935	176.922	Kenora Hydro Electric Corporation Ltd.	3.494	142.736
Kentucky Power Co (AEP)	3.226	1073.722	Kingston Hydro Corporation	1.222	87.818
Louisville Gas And Electric Co	1.615	566.919	Kitchener-Wilmot Hydro Inc.	1.205	64.594
Madison Gas And Electric Co	0.593	53.617	Lakefront Utilities Inc.	2.215	187.156
New York State Electric & Gas Corp	2.025	970.388	Lakeland Power Distribution Ltd.	1.075	220.369
Niagara Mohawk Power Corp (National Grid)	1.136	198.910	London Hydro Inc.	1.554	68.317
Northern Indiana Public Service Co	1.393	431.224	Midland Power Utility Corporation	1.281	163.675
Ohio Edison Co (First Energy)	1.536	271.432	Milton Hydro Distribution Inc.	1.016	56.554
Ohio Power Co (AEP)	1.567	578.371	Newmarket-Tay Power Distribution Ltd.	0.467	41.571
Oklahoma Gas And Electric Co	1.743	875.749	Niagara Peninsula Energy Inc.	1.477	147.760
Orange And Rockland Utilities Inc	1.634	506.472	Niagara-On-The-Lake Hydro Inc.	0.523	65.914
Pacific Gas And Electric Co	1.250	211.285	Norfolk Power Distribution Inc.	2.141	212.790
Portland General Electric Co	0.893	188.739	North Bay Hydro Distribution Limited	4.275	152.359
Potomac Electric Power Co	2.345	545.678	Northern Ontario Wires Inc.	2.574	439.109
PSI Energy Inc (Duke Energy IN)	1.707	298.270	Oakville Hydro Electricity Distribution Inc.	1.027	39.351
Rochester Gas And Electric Corp	0.914	129.115	Orangeville Hydro Limited	2.050	172.702
San Diego Gas & Electric Co	0.878	148.776	Orillia Power Distribution Corporation	1.923	79.548
Southern California Edison Co	0.991	152.418	Oshawa Puc Networks Inc.	1.127	69.436
Southern Indiana Gas And Electric Co (Vectern)	1.398	195.629	Ottawa River Power Corporation	2.667	209.857
Tampa Electric Co	1.144	108.600	Parry Sound Power Corporation	0.341	18.487
United Illuminating Co	1.446	1204.454	Peterborough Distribution Incorporated	2.110	183.288
Virginia Electric And Power Co	2.071	335.144	Powerstream Inc.	1.245	62.529
Western Massachusetts Electric Co	1.713	615.368	PUC Distribution Inc.	3.046	185.259
Wisconsin Electric Power Co	0.667	80.988	Renfrew Hydro Inc.	2.110	115.494
Wisconsin Power And Light Co	0.978	140.719	Rideau St. Lawrence Distribution Inc.	1.378	121.799
Wisconsin Public Service Co	1.558	425.646	Sioux Lookout Hydro Inc.	1.954	213.565
Algoma Power Inc.	6.464	821.297	St. Thomas Energy Inc.	1.007	30.387
Atikokan Hydro Inc.	1.231	37.673	Thunder Bay Hydro Electricity Distribution	3.780	131.703
Bluewater Power Distribution Corporation	3.492	191.637	Tillsonburg Hydro Inc	4.793	201.273
Brant County Power Inc.	1.714	126.412	Toronto Hydro-Electric System Limited	1.715	91.620
Brantford Power Inc.	1.439	32.554	Veridian Connections Inc.	2.160	94.568

Burlington Hydro Inc.	1.178	61.495	Wasaga Distribution Inc.	1.464	92.060
Cambridge And North Dumfries Hydro Inc.	1.215	54.669	Waterloo North Hydro Inc.	1.217	84.426
Canadian Niagara Power Inc.	2.642	162.256	Welland Hydro-Electric System Corp.	1.620	87.407
Centre Wellington Hydro Ltd.	1.976	186.557	Wellington North Power Inc.	1.288	15.172
Chapleau Public Utilities Corporation	1.307	294.017	West Coast Huron Energy Inc.	0.841	62.683
Collus Power Corporation	0.775	58.723	Westario Power Inc.	2.972	265.459
Cooperative Hydro Embrun Inc.	0.322	50.072	Whitby Hydro Electric Corporation	1.128	52.952
Total Number of Sampled Firms	116				
Number of U.S. Sampled Firms	46				
Number of Ontario Sampled Firms	70				

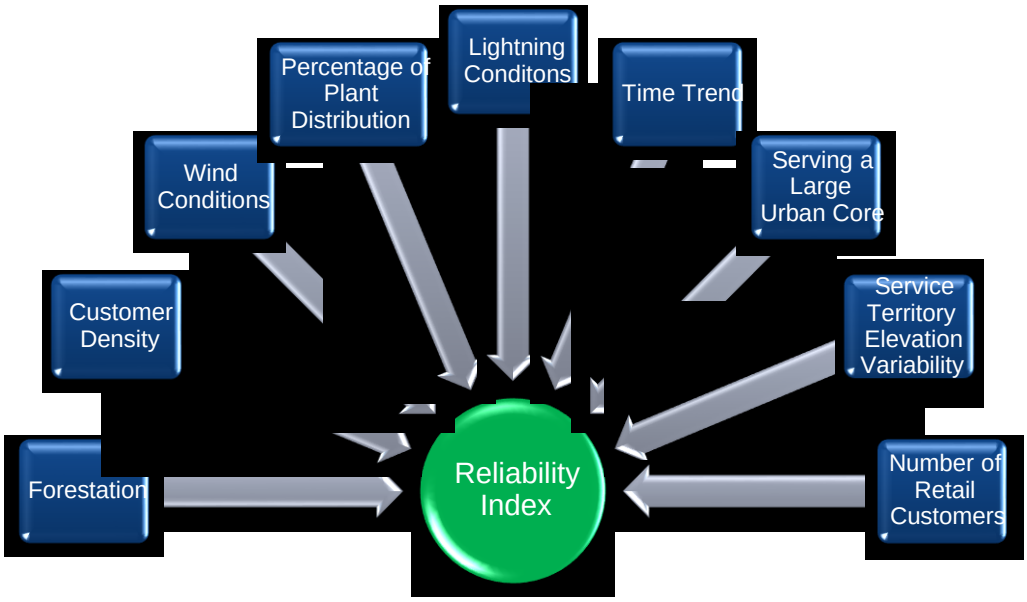
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7KLV VHFWLRQ RIIHUV EDFNJURXQG LQIRUPDWLRQ RQ 36(explains how the benchmarks were calculated. The parameter estimates and benchmarking results for both the SAIFI and SAIDI models are provided in Section 5.

36(¶V PHWKRG RI HFRQRPHWULF PRGHOLQJ is to use sampled data from the past to form a mathematical model. The model accepts inputs (operating conditions, service territory data, etc.) and produces an expected reliability index for each observation. By using the model, given a set of operating conditions, PSE can estimate an ³expected´ or benchmark reliability level for each utility in each year.

The variables included in the econometric model for SAIDI and SAIFI are shown in the figure below.[36]

Figure 14 Variables in Econometric Reliability Models



7 K L V W H F K Q L T X H D-0-DRSZO HIR U F3RPSDULVRQV DQG WKHUHIRU accurate assessment of performance relative to simply making industry comparisons of SAIDI and SAIFI.

5 5HOLDELOLW\ %HQFKPDUNLQ

Four econometric models were developed which measure reliability metrics which include all outages: a combined sample model and a U.S.-only sample model for SAIDI, and a combined and U.S.-only sample model for SAIFI. The explanatory variables in the models include:

- The forestation le Y H O V L Q H D F K X W L O L W \¶ V V H U Y L F H W H U U L W R U
- Customer density (measured by the number of retail customers divided by distribution line miles),
- Sum of wind knots above ten in each hour of the year,
- The percentage of underground plant in total distribution plant,
- Whether a utility serves an urban core with more than 1 million residents,
- The number of retail customers,
- Lightning, and
- Variability in elevation within the service territory.

The models also include a time trend variable. The trend variable examines how reliability data

[36] The illustration shows all the variables used in both the combined and U.S.-only models. Not all of the variables are in both models.

has changed over time.

SAIDI and SAIFI are modeled using a quadratic functional form, where model variables include logged first order and square terms. The number of customers is logged but not squared, and is included to control for scale effect. The urban core dummy is neither logged nor squared, because it is a binary variable. This form allows us to adjust for non-linearity in variables in determining reliability levels.

Each model includes utilities with varying time-series lengths covering the years 2002 to 2012.[37] This type of dataset requires an estimation procedure that accounts for the cross-sectional time-series ³panel´ nature of the data. We use a feasible generalized least sq X D U H V ³) * / 6´ estimator that corrects for cross-sectional heterogeneity and addresses the panel form of the data. The estimator accomplishes this by correcting for group-wise (utility-by-utility) heteroskedasticy, and results in parameter estimates that are more accurate, consistent, and precise than methods that do not correct for group-wise heteroskedasticy.

The results from the SAIDI models based on the combined and U.S.-only datasets are presented in the following two tables.

Table 11 Combined Sample SAIDI Econometric Model Coefficients

Variable	Coefficient Estimate	T-Stat
Constant	5.251	79.880
Customers (Y)	0.127	9.840
Customer Density (D)	-0.764	-15.237
Urban (U)	-0.025	-5.206
D*D	0.238	1.930
Trend	0.018	2.019

Table 12 U.S.-Only SAIDI Econometric Model Coefficients

Variable	Coefficient Estimate	T-Stat
Constant	5.405	64.025
Customers (Y)	0.025	0.703
Wind (W)	0.168	1.842
Customer Density (D)	-0.173	-2.115
% Forestation (F)	0.517	4.701
W*W	0.157	1.068
D*D	-2.116	-6.751

[37] Utilities in the States began reporting reliability metrics at different times.

F*F	-0.244	-0.861
Trend	0.048	4.485

All first order parameter estimates, except the number of customers, have the expected signs and are statistically significant.[38] Utilities that serve more densely populated and highly urban service territories have shorter outage durations per customer. On the other hand, utilities that serve more forested and windy service territories have longer outage durations per customer.

The SAIFI models are similarly based on a quadratic specification. The results are presented in the tables below.

Table 13 Combined Sample SAIFI Econometric Model Coefficients

Variable	Coefficient Estimate	T-Stat
Constant	0.299	8.802
Customers (Y)	0.014	1.585
Customer Density (D)	-0.159	-5.522
Wind (W)	0.061	2.124
% Plant Distribution (DS)	0.101	3.452
Urban (U)	-0.031	-7.144
D*D	0.301	3.585
W*W	0.087	3.488
DS*DS	0.033	0.948
Trend	0.012	2.714

Table 14 U.S.-Only SAIFI Econometric Model Coefficients

Variable	Coefficient Estimate	T-Stat
Constant	0.423	9.932
Customers (Y)	-0.027	-1.780
Customer Density (D)	-0.154	-4.645
% Forestation (F)	0.241	5.234
Elevation (E)	0.109	4.414
Lightning (L)	0.217	9.862
D*D	-0.970	-8.907
F*F	0.211	1.797

[38] We kept the number of customers in the model because it is basically acting as a quadratic variable that is measuring scale economies. The reason it is considered a quadratic variable is because the left-hand side variable is defined as the number of outage minutes divided by the number of customers.

E*E	0.035	1.848
L*L	0.061	4.116
Trend	0.008	1.808

Utilities with more densely populated and highly urban service territories experience fewer outage frequencies per customer. Conversely, utilities with service territories that experience more lightning, windier conditions, and are more forested have more frequent outages per customer. In addition, those whose service territory elevation levels are more variable also experience more frequent outages per customer. Finally, utilities that have more distribution plant (as a percent of all electric plant) also have higher outage frequencies per customer.

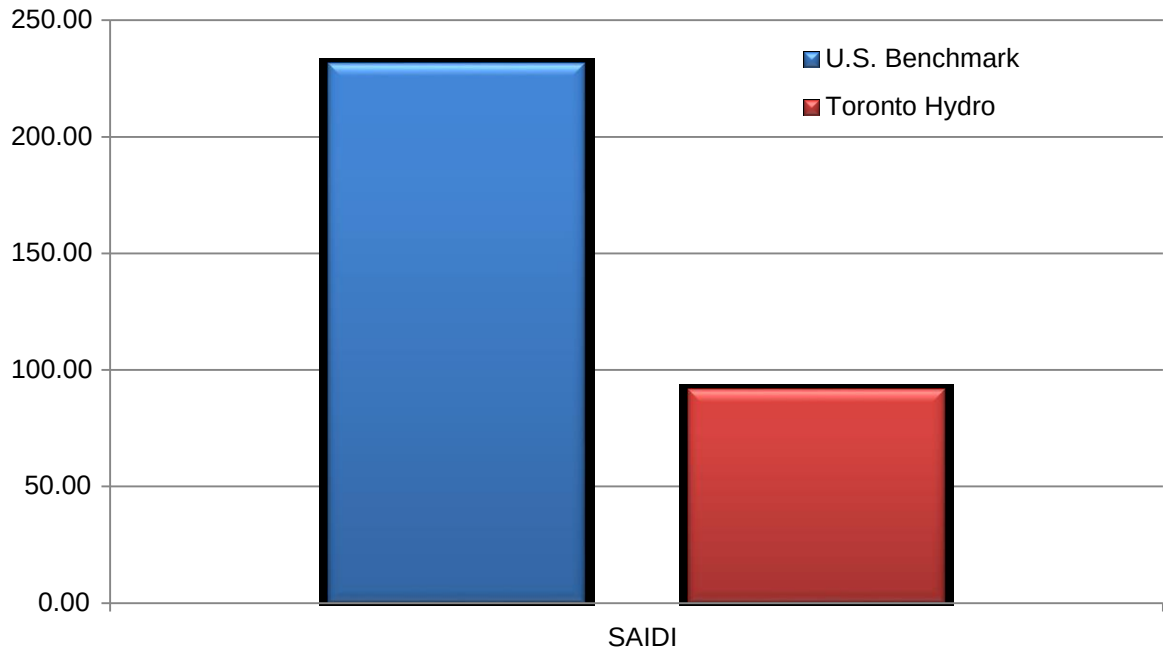
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:H ILQG WKDW 7RURQWR +\GUR¶V 2012 average SAIDI is 48 percent below the benchmark value when using the combined sample. This result is not, however, statistically significant at the 90 percent confidence level.

2XU UHVHDUFK RQ 7RURQWR +\GUR¶V 2012 average SAIFI indicates that the reliability level in the combined dataset model is 73.4 percent above the benchmark value. This implies worse than average SAIFI performance, and is statistically significant at a 90 percent confidence level.

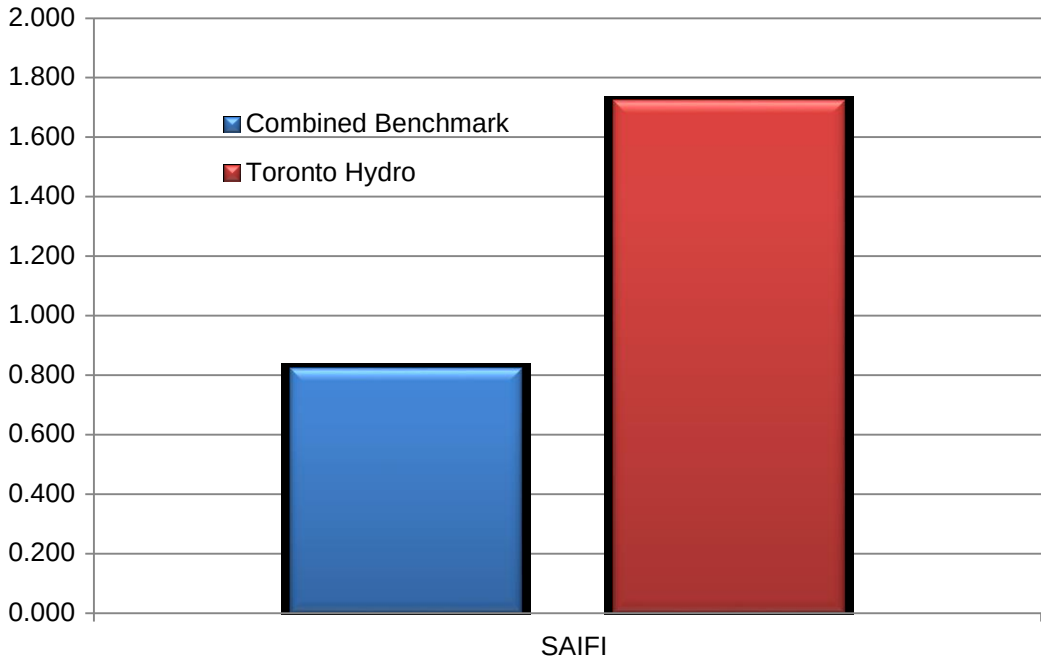
The benchmark comparisons for SAIDI are summarized in the following graph.

Figure 15 2010-2012 Combined Sample: Benchmarked SAIDI vs. Actual SAIDI (3-year Average)



The benchmark comparisons for SAIFI are summarized in the following graph.

Figure 16 2010-2012 Combined Sample: Benchmarked SAIFI vs. Actual SAIFI (3-Year Average)



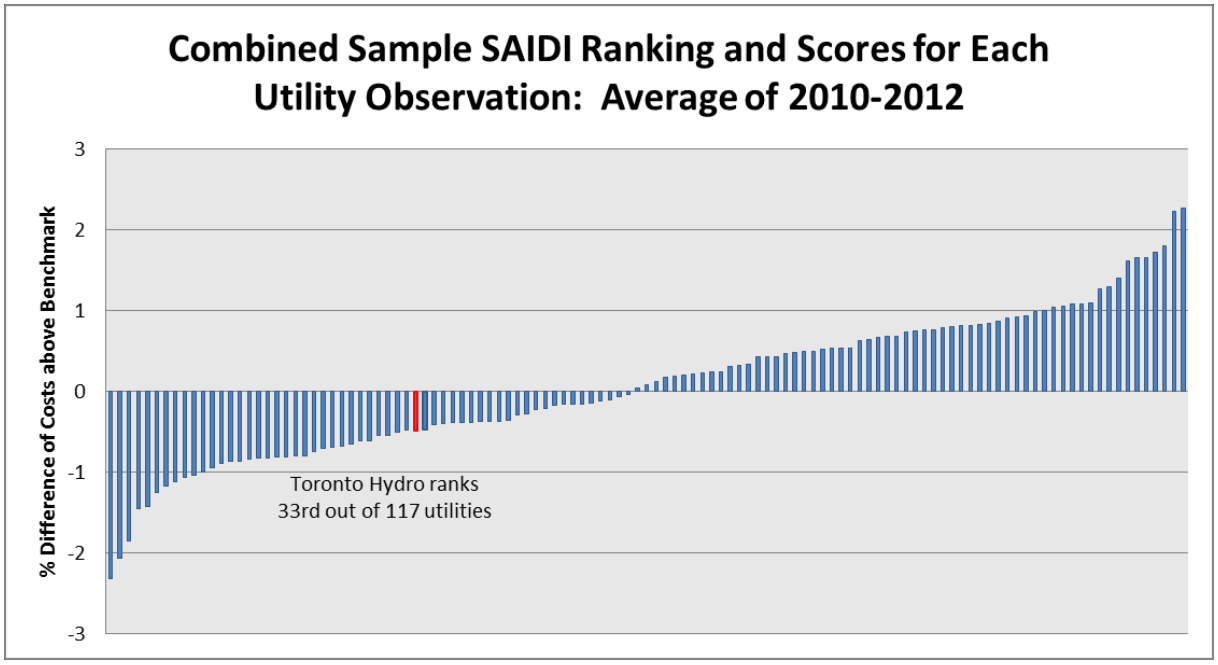
The year-by-year breakdowns for both SAIDI and SAIFI are provided in the following table. This table provides both the actual reliability values for Toronto Hydro, along with the econometric benchmark value. Notice that Toronto Hydro has consistently been below its benchmark values for SAIDI, and consistently above its benchmark values in regards to SAIFI. 7KLV LV WKH FDVH LQ WKH KLVWRULFDO DQG IRUHFDVW \HDUV, its high SAIFI metrics will converge towards the benchmark value during the forecasted time period, although still remain higher than benchmark values. The Custom IR period is shaded in green.

Table 15 Combined Sample: Econometric Reliability vs. Actual and Projected Reliability

Year	SAIDI (Econometric Benchmark)	SAIDI (THESL Value)	SAIDI (% Difference)	SAIFI (Econometric Benchmark)	SAIFI (THESL Value)	SAIFI (% Difference)
2005	124.13	104.89	-17%	0.77	2.01	+96%
2006	126.75	94.06	-30%	0.79	2.17	+101%
2007	129.43	117.00	-10%	0.80	2.27	+104%
2008	132.23	74.40	-58%	0.81	1.76	+78%
2009	134.30	174.17	+26%	0.81	1.86	+83%
2010	135.97	99.60	-31%	0.81	1.95	+88%
2011	148.96	85.80	-55%	0.82	1.62	+68%
2012	162.18	90.00	-59%	0.84	1.60	+64%
2013	166.50	1271.40	+203%	0.87	2.91	+121%
2014	169.34	71.40	-86%	0.87	1.58	+60%
2015	171.13	73.80	-84%	0.88	1.55	+57%
2016	172.81	70.20	-90%	0.89	1.44	+48%
2017	174.92	67.20	-96%	0.90	1.36	+42%
2018	177.04	64.80	-101%	0.91	1.27	+34%
2019	179.14	61.20	-107%	0.92	1.19	+26%

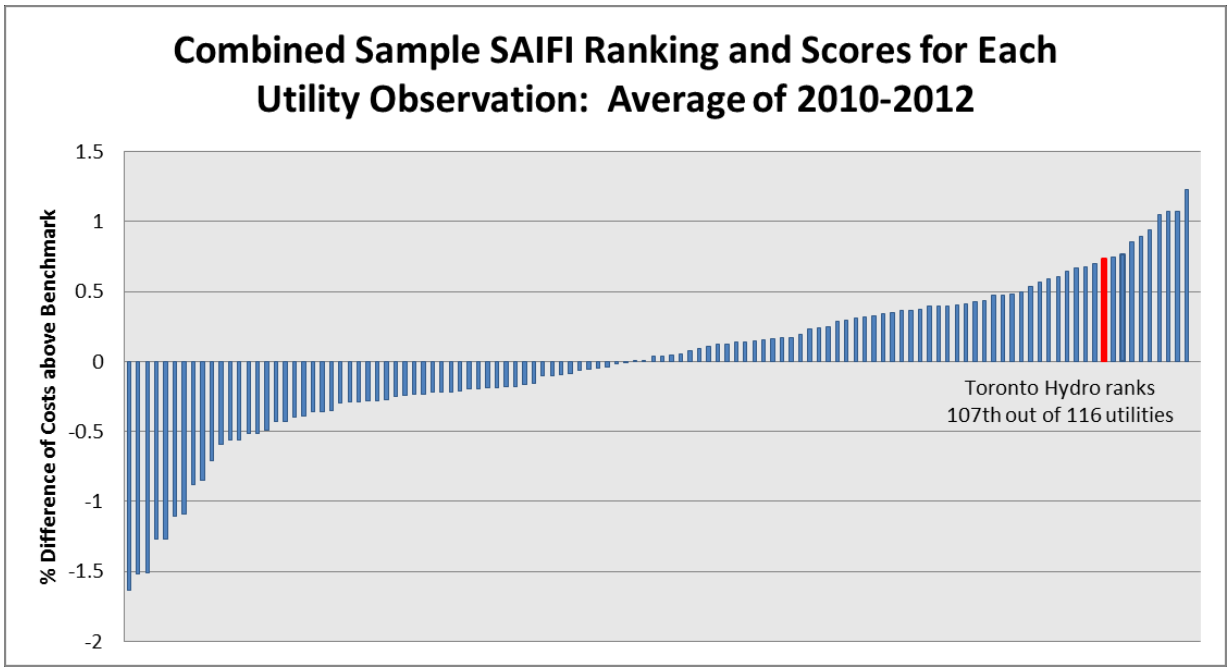
7KH JUDSK EHORZ LOOXVWUDWHV 2012 average SAIDI performance relative to the scores for the rest of the sample. The company ranks 33rd out of the 117 utilities, with its three year average SAIDI score of 48 percent below its benchmark value.

Figure 17 Combined Sample: SAIDI Econometric Ranking and Scores



7KH JUDSK EHORZ LOOXVWUDWHV 7RURQWR +\GUR¶V three year average SAIFI performance relative to the scores for the rest of the sample. The company ranks 107th out of the 116 utilities, with its three year average SAIFI score of 73 percent above its benchmark value.

Figure 18 Combined Sample: SAIFI Econometric Ranking and Scores



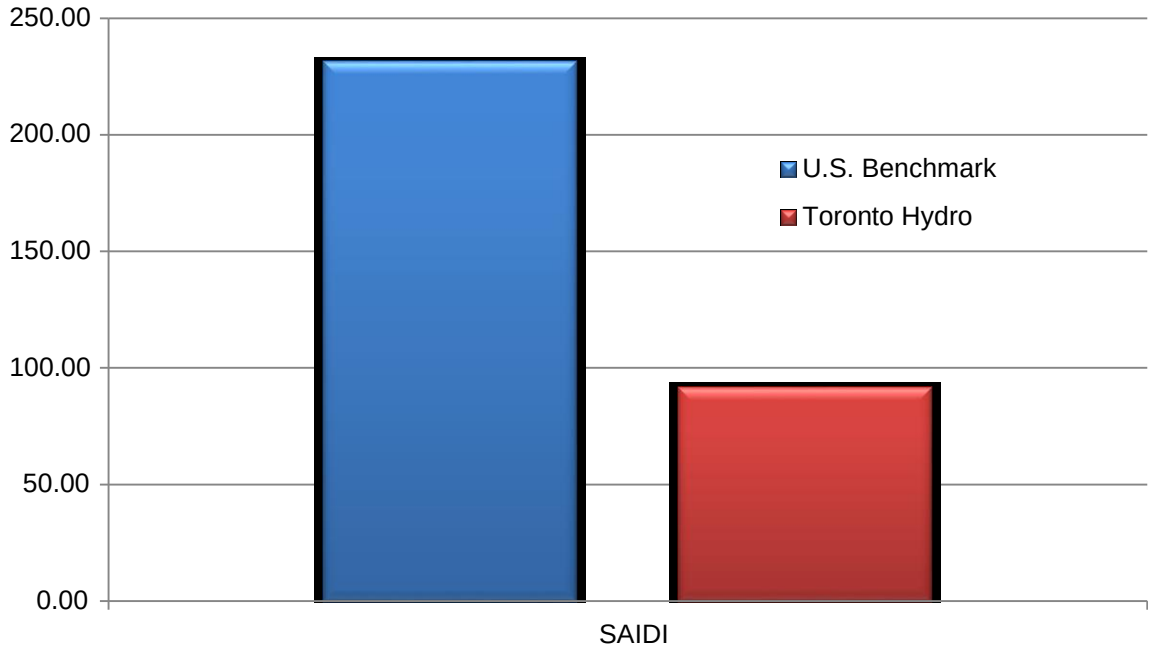
5.2 8 6 6DPSOH (FRQRPHWULF 5HVXOWV

7RURQWR +\GUR¶V 2012 average SAIDI value is 92.2 percent below the benchmark value when using the U.S.-only plus Toronto Hydro sample. This benchmark value indicates a statistically superior reliability performance in outage duration management. It is statistically significant at a 90 percent confidence level.

7RURQWR +\GUR¶V 2012 average SAIFI value is 49.5 percent above the benchmark value when using the U.S. sample, which is a worse than average SAIFI performance. This finding is significant at a 90 percent confidence level.

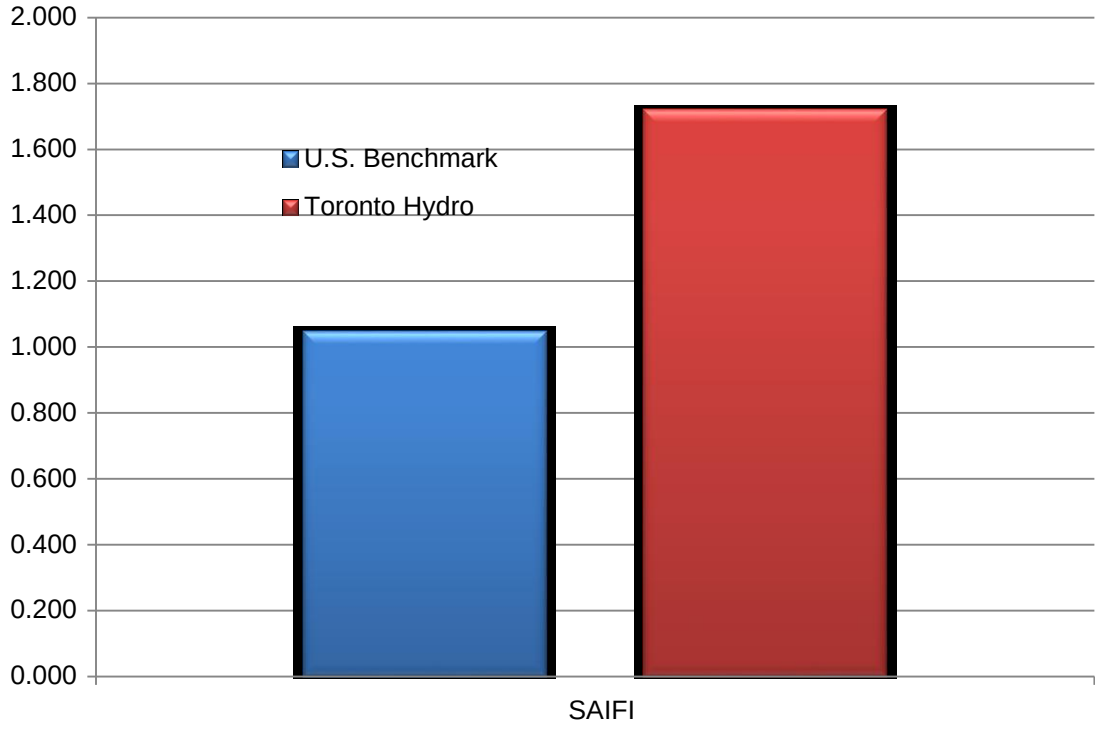
The benchmark comparisons for SAIDI are summarized in the following graph.

Figure 19 2010-2012 Average U.S.-Only Econometric Benchmarked SAIDI vs. Actual SAIDI (3-Year Average)



The benchmark comparisons for SAIFI are summarized in the following graph.

Figure 20 2010-2012 Average U.S. Econometric Benchmark Comparisons for SAIFI (3-Year Average)



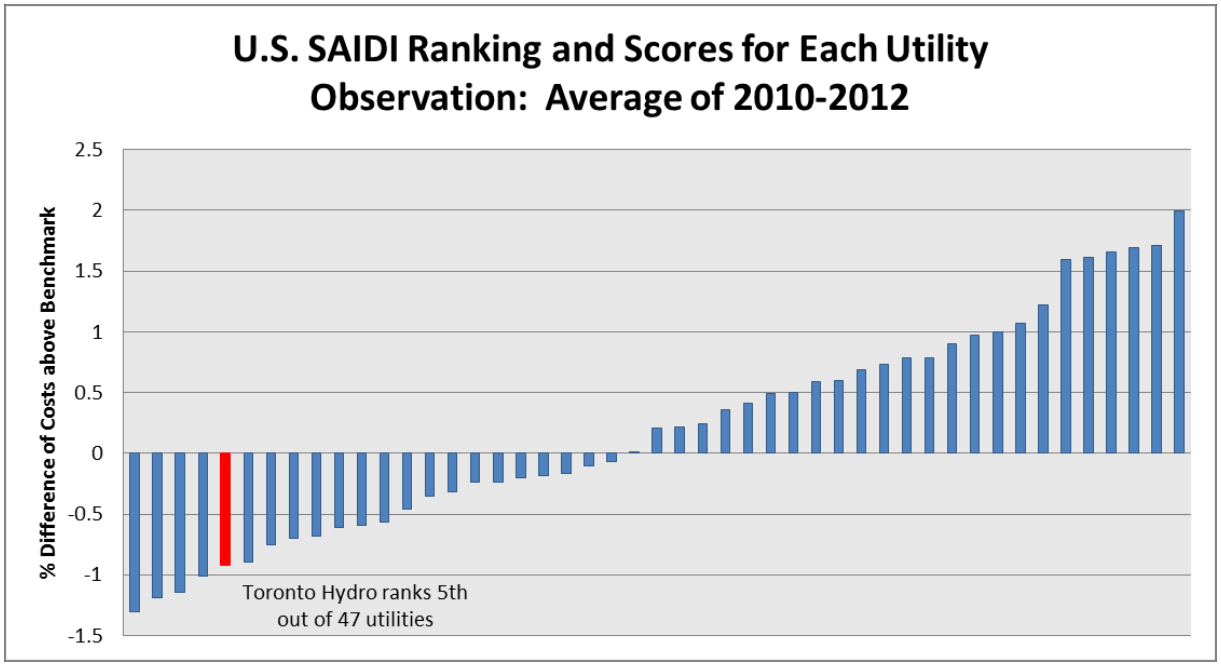
The year-by-year breakdowns for both SAIDI and SAIFI are provided in the following table. This table provides both the actual reliability values for Toronto Hydro, along with the econometric benchmark value. We note that Toronto Hydro has consistently been below its benchmark values for SAIDI, and consistently above its benchmark values in regards to SAIFI in the historical years. This pattern generally persists in the forecast years, with convergence towards the benchmark value for SAIFI. The Custom IR period is shaded in green.

Table 16 U.S. Econometric Reliability Results for All Years

Year	SAIDI (Econometric Benchmark)	SAIDI (THESL Value)	SAIDI (% Difference)	SAIFI (Econometric Benchmark)	SAIFI (THESL Value)	SAIFI (% Difference)
2005	169.89	104.89	-48%	1.07	2.01	+63%
2006	189.38	94.06	-70%	0.97	2.17	+80%
2007	205.33	117.00	-56%	0.99	2.27	+83%
2008	208.25	74.40	-103%	1.03	1.76	+54%
2009	210.14	174.17	-19%	1.00	1.86	+62%
2010	201.50	99.60	-71%	0.93	1.95	+74%
2011	234.12	85.80	-100%	1.12	1.62	+37%
2012	259.14	90.00	-106%	1.10	1.60	+38%
2013	297.35	1271.40	+145%	1.13	2.91	+95%
2014	302.72	71.40	-144%	1.13	1.58	+33%
2015	315.71	73.80	-145%	1.13	1.55	+31%
2016	328.85	70.20	-154%	1.14	1.44	+24%
2017	343.10	67.20	-163%	1.14	1.36	+18%
2018	357.75	64.80	-171%	1.14	1.27	+11%
2019	372.75	61.20	-181%	1.14	1.19	+4%

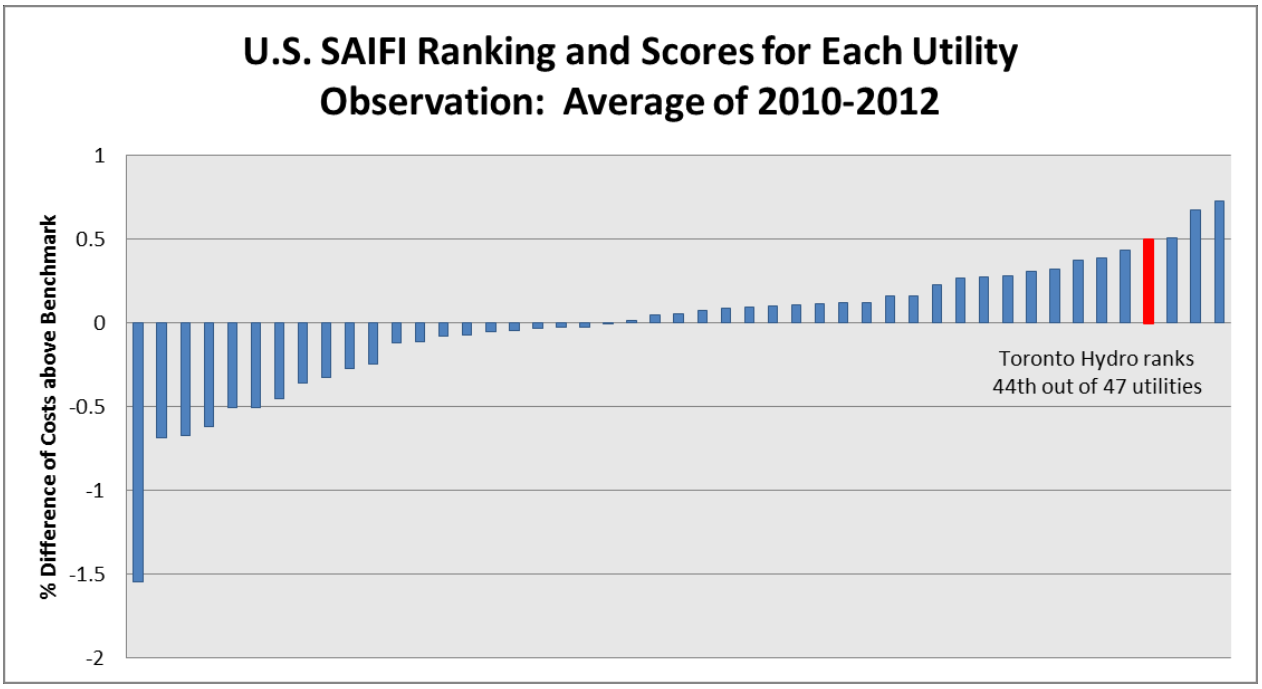
7KH JUDSK EHORZ LOOXVWUDWHV 2019 average SAIDI performance relative to the scores for the rest of the sample. The company ranks 5th out of the 47 utilities, with its three year average SAIDI score of 92.2 percent below its benchmark value.

Figure 21 U.S. SAIDI Econometric Ranking and Scores



7KH JUDSK EHORZ LOOXVWUDWHV 2012 Average SAIDI Performance relative to the scores for the rest of the sample. The company ranks 44th out of the 47 utilities, with its three-year average SAIFI score of 49.5 percent above its benchmark value.

Figure 22 U.S. SAIFI Econometric Ranking and Scores



6 ,PSRUWDQFH RI 8 6IRU'D %HQFKPDUNLQJ 7RURQWR +\GUR

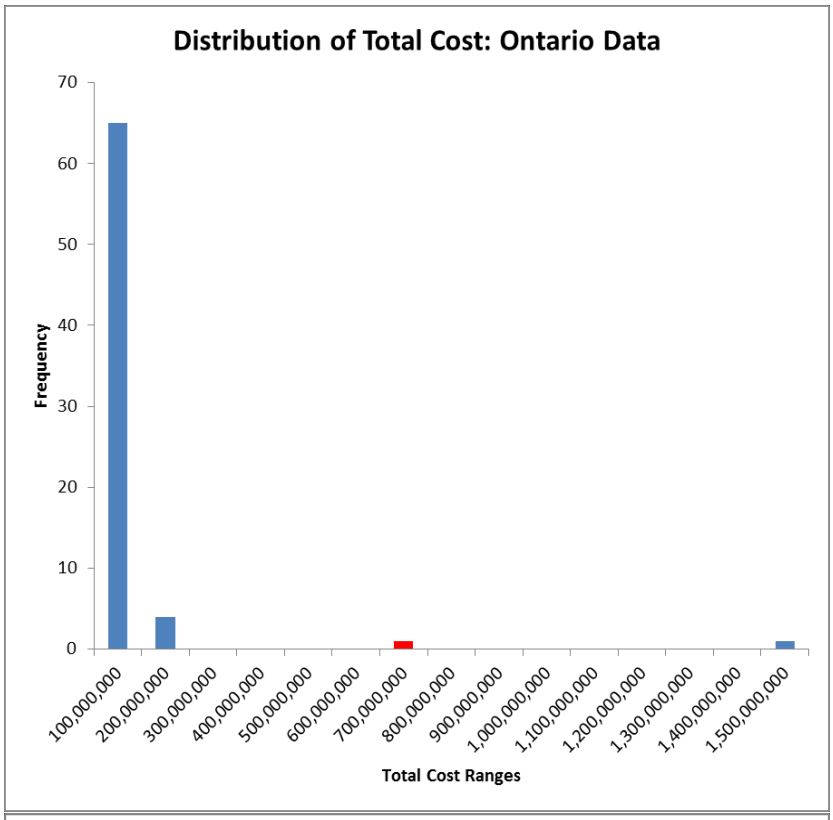
The benchmarking exercise evaluates utility performance relative to a given sample, which produces a benchmark value for each utility in the sample. The benchmark value is generated XVLQJ WKH VSHFLILF XWLOLW\¶V LQGHSHQGHQW YDULDEOH Y relative to the sample. 7KXV 7RURQWR +\GUR¶V EHQFKPDUN YDOXHV UH H[SHFW IURP DQ DYHUDJH XWLOLW\ ZLWK 7RURQWR +\GUR¶V V If the average efficiency embodied in the benchmark value is generated using firms that are very dissimilar than the utility being benchmarked (i.e., the benchmarked utility is an outlier), then its performance evaluation has a high chance of being inaccurate.

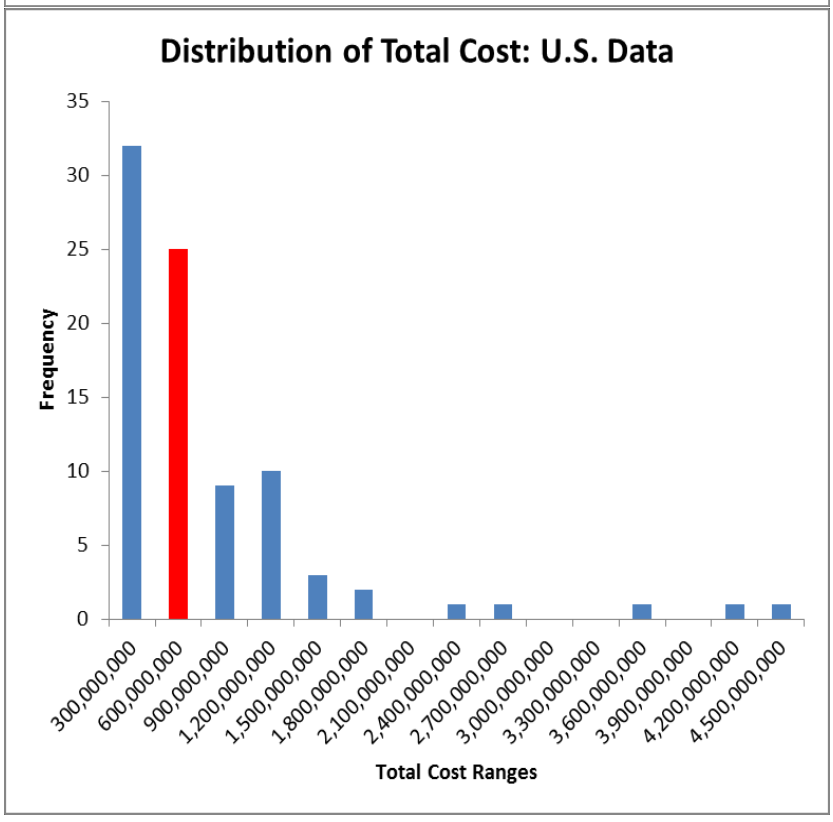
PSE authored a separate report that attempts to quantify the capital cost challenges of serving different types of developed areas.[39] In that report, PSE explains why unit capital costs will tend to decrease as customer density increases (i.e., rural areas will cost more to serve than suburban) but will then begin to increase as the developed area transitions from a suburban setting to urban or metropolitan settings.

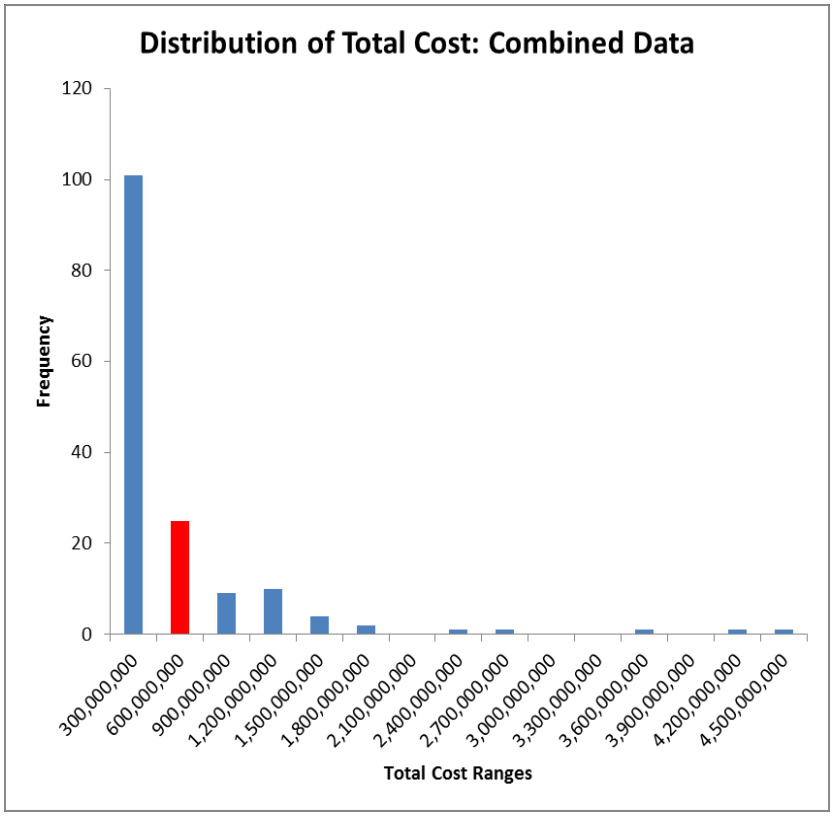
We examine the distribution of total cost data in the Ontario, U.S. and combined samples using average values of the variable over the last three years. As the figures below illustrate, Toronto +\GUR¶V W KHUHH \HDU average total cost (flagged in red) is one of two extreme outliers in the distribution of Ontario distributors with regard to total cost. (The company on the far right in the 2QWDULR VDPSOH LV +\GUR 2QH 2Q WKH RWKHU KDQG 7RUR ranges of the total cost distribution in the U.S. and combined dataset (i.e., there are numerous utilities with lower costs, and numerous utilities with higher total costs).

[39] 3OHDVH VHH 36(¶V UHSRUW IRXQG LQ WKH $SSHQGL[³&DSLWDO 5HTXLUH more details.

Figure 23 Distribution of Total Costs for Ontario-Only, U.S.-Only, and Combined Datasets

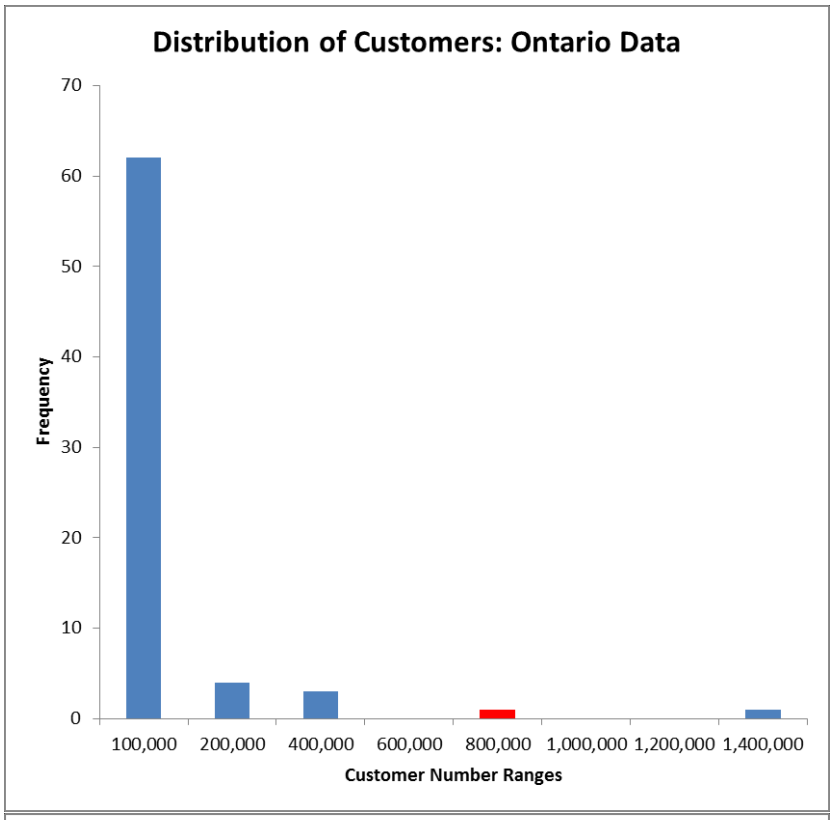


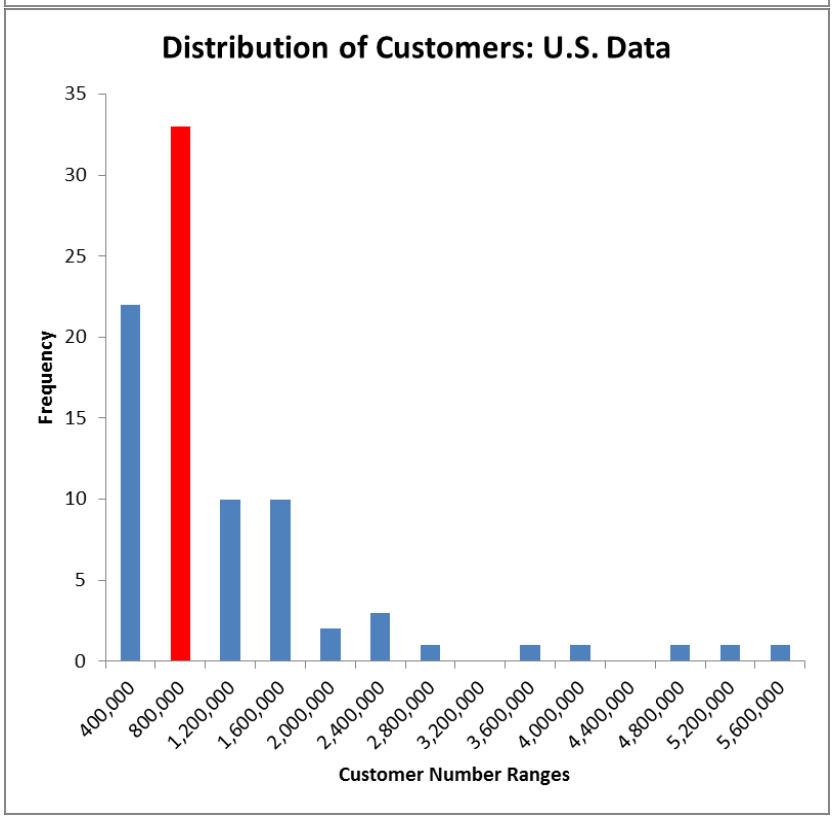


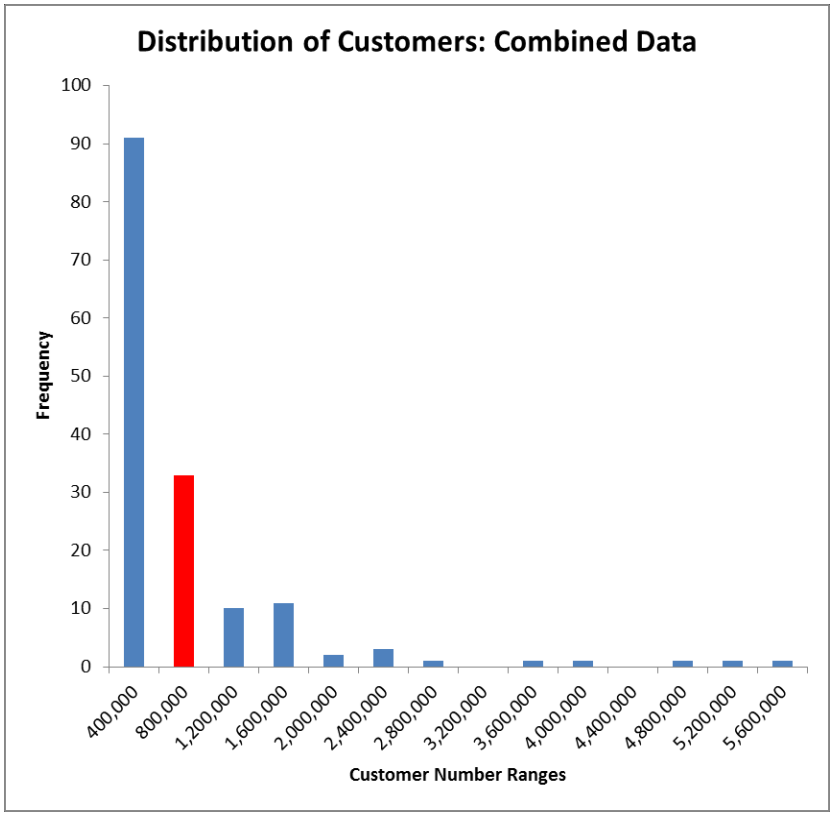


Similarly, as the top panels of Figure 24 and Figure 25 illustrate, the customer number and peak demand of Toronto Hydro are outliers in the Ontario data. Toronto Hydro ¶ V W K U H H customer total, as shown in red, is one of two extreme outliers in the Ontario dataset. However, 7 R U R Q W R + \ G U R ¶ V in the middle range in the U.S. and Combined datasets.

Figure 24 Distribution of Customer Totals for Ontario-Only, U.S.-Only, and Combined Datasets

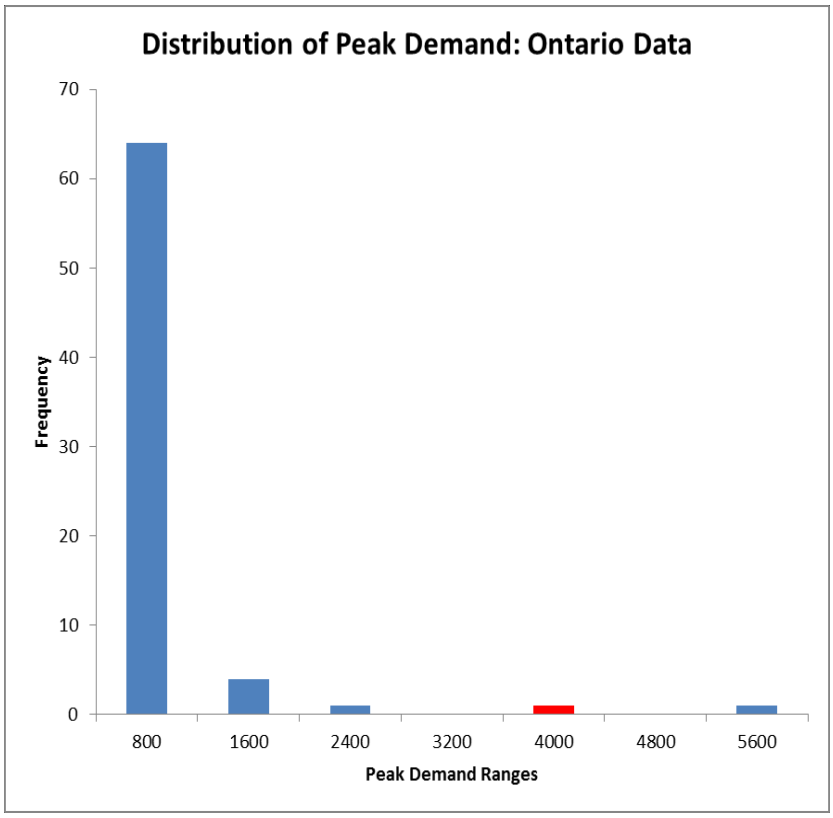


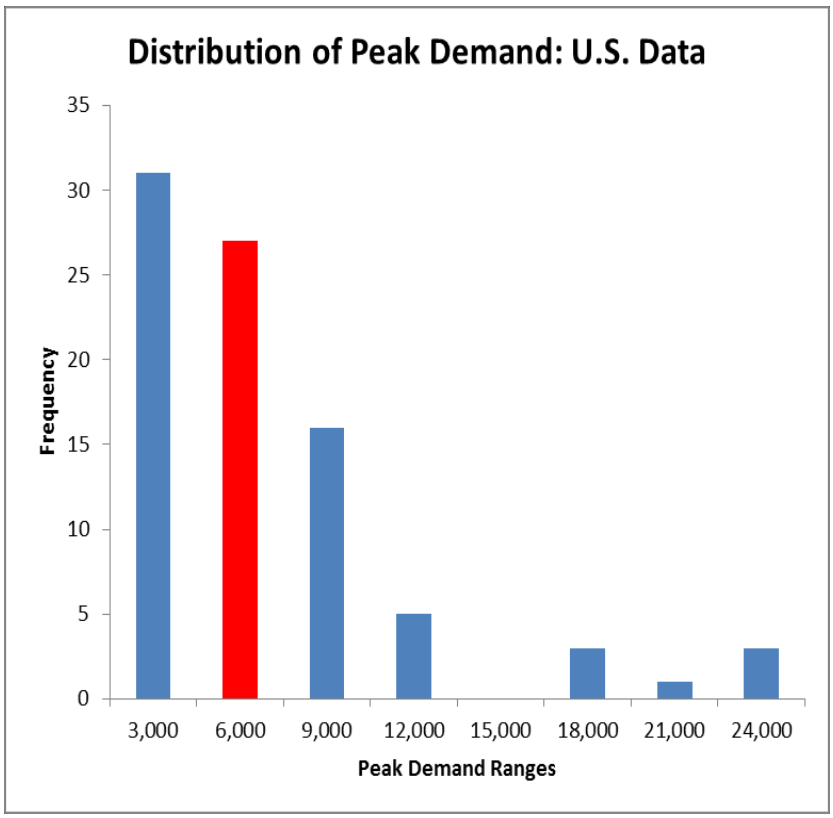


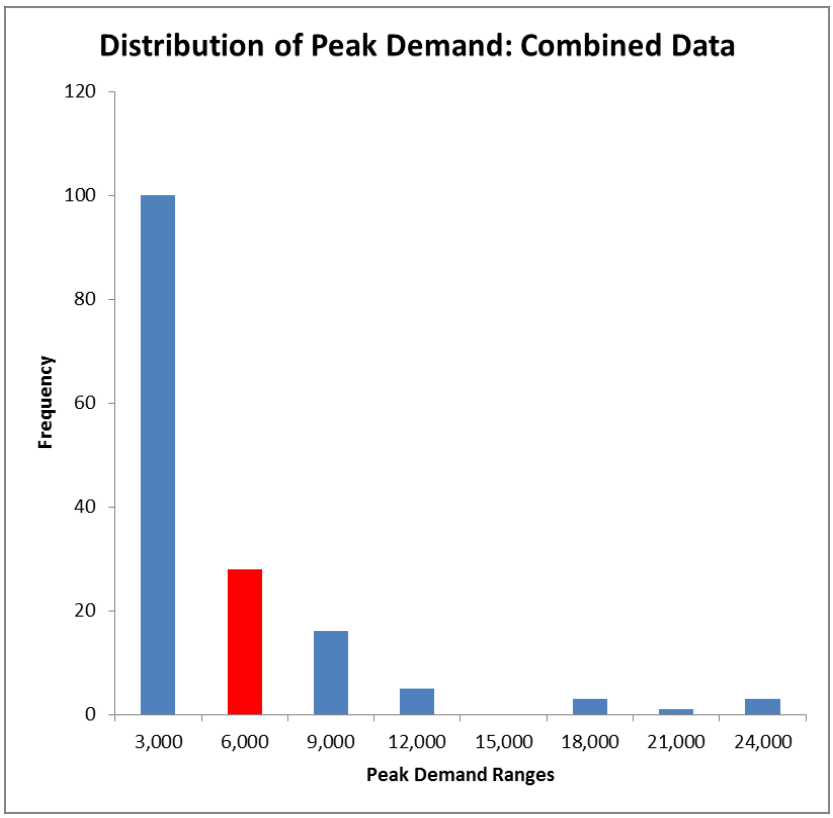

Distribution of Customers: Combined Data
Frequency
100
90
80
70
60
50
40
30
20
10
0
400,000
800,000
1,200,000
1,600,000
2,000,000
2,400,000
2,800,000
3,200,000
3,600,000
4,000,000
4,400,000
4,800,000
5,200,000
5,600,000
Customer Number Ranges

The distributions of three-year average peak demand also show Toronto Hydro to be an exterme outlier in the Ontario dataset; however, it is within the middle ranges in the U.S. and combined datasets.

Figure 25 Distribution of Peak Demand for Ontario-Only, U.S.-Only, and Combined Datasets







Based on W K H S U H Y L R X V I L J X U H V Z H F D Q F R Q F O X G H W K D W D Q D

cost performance against only Ontario utilities is unlikely to produce a fair assessment. Even when accounting for the external conditions that affect its performance, the model used to generate the benchmark will embody performance based on utilities whose scale of operation is FRPSOHWHO\ XQOLNH 7RURQWR +\GUR¶V

The estimation procedure is designed to fit the data through the mean of model variables. As a result, parameter estimates are most accurate for those utilities with operating conditions that vary within a reasonable range of the mean of model variables 7KH IXUWKHU D XWLOLW conditions are from the mean, especially if there are minimal sample observations nearby, the less accurate the cost benchmark based on the model. Also, if only one utility faces a certain external condition (e.g. serving a large urban core), it is impossible to incorporate the effect of that condition in the benchmark analysis.

No other distributor within Ontario comes close to serving an urban center like Toronto. Therefore, any model based on the Ontario dataset is unable to capture the added costs of serving an urban core. This is in contrast to models based on the U.S. and combined datasets, which reflect the conditions of several utilities that serve a densely populated urban center. Furthermore, the U.S. and combined datasets reflect operating conditions that encompass and ³surround´ WKRVH RI 7RURQWR +\GUR¶V

In addition, due to the variation and extensiveness of the utilities represented, the U.S. and combined datasets make it possible to identify the effect of several relevant business condition variables with greater precision. They also permit the inclusion of business conditions in the model such as percent forestation, urban core, and the standard deviation of elevation within each service territory.

7 &RQFOXVLRQV

This report develops a framework for evaluating 7RURQWR +\GUR¶V 2015-2019 Custom IR application. The parameters of this framework are set by considering three important questions: : K D W L V 7 R U R Q W R +\GUR¶V electric distribution cost performance, relative to the combined dataset and the U.S.-only dataset " : K D W L V W K H liability performance, relative to the combined dataset and the U.S.-only dataset? (3) Are the projected spending and reliability levels during the Custom IR period reasonable from a benchmarking perspective?

4XHVWLRQ : K D W L V 7 R U R Q W R +\GUR¶V total electric distribution cost performance, relative to the combined dataset and the U.S.-only dataset?

- **7RURQWR +\GUR¶V KLVWRULFDO WRWDO FRVW SHUIRUP** sample and the U.S.-only sample reflects statistically significant superior performance at D FRQILGHQFH OHYHO 7KLV UHVXOW LQGLFDWHV WKD for those years were lower than they would have been LI WKH FRPSDQ\ ZDV DQ ³D cost performer with the same operating conditions.

- For both samples, projected total costs remain below benchmark values for 2015 to 2019. However, the difference is no longer statistically significant at a 90 percent confidence level, and the projected costs converge towards the benchmark values.

- For the project HG \HDUV 7 R U R Q W R +\G U R ¶V cost benchmark scores are in the +/- 10% range set for a 0.3% stretch factor. 7 R U R Q W R + \ G U R ¶V ranking from the combined set of utilities (30th out of 156) and just for Ontario utilities (15th out of 71) indicate solid total cost performance.

4XHVWLRQ :KDW LV WKH FRPSDQ\¶V UHOLDELOLW\ SHUIR dataset and the U.S.-only dataset?

- **7RURQWR +\GUR¶V KLVWRULFDO DQG SURMHFWHG 6$,'** Ontario-U.S. sample and U.S.-only sample is better than expected. This indicates good response times by the company when outages occur.

- **7RURQWR +\GUR¶V KLVWRULFDO 6$,), SHUIRUP-DQFH UH** U.S. and the U.S.-only electric industry is considerably worse than expected, based on the F R P S D Q \ ¶V specific operating conditions. The performance scores are significant at the 90% confidence level. This performance moderates and converges towards benchmark values through the projected future time period, and is no longer statistically different from average at the 90 percent confidence level.

Question 3: Are the projected spending and reliability levels during the Custom IR period reasonable from a benchmarking perspective?

The projections to 2019 show that Toronto Hydro ¶V VSHQGLQJ reliability projections should F R Q Y H U J H W K H F R P S D Q \ ¶V 6$,), DQG W R W D O F R V W V W R Z D U G V

SAIDI should remain at a strong level). Based on the projections, the projected spending should result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective. 7 K X V W K H S U R M H F W H G V S H Q G L Q J D Q G U H O I opinion, reasonable from a benchmarking perspective.

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Founded in 1974, PSE is a full-VHUYLFH FRQVXOWLQJ ILUP 36(¶V EHQFKPDU research for regulatory purposes and utility management improvement. Our benchmarking team consists of economists, planning and design engineers, rate and financial analysts, communications infrastructure consultants, and smart grid technology experts. In addition to our statistical benchmarking UHVHDUFK 36(¶V (FRQRPLFV DQG 0DUNHW 5HVH the areas of demand response, energy efficiency, value-based reliability planning, T&D merger valuations, load forecasting, load research, survey design, alternative regulation, and cost of service studies. For more information on PSE and a full list of services, visit our website at www.powersystem.org.

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Power System Engineering, Inc.

Full-service consultants



Capital Requirements for Serving Developed Environments

Prepared at the Request of:

Toronto Hydro Electric System Limited

Prepared by:

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July 25, 2014

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Exhibit I ±Areas by Square Kilometer

1 ,QWURGXFWLRQ

Electric distribution utilities operate in a capital intensive industry. There are significant costs for materials and labor associated with the installation of overhead and underground distribution lines, transformers, substations, and other associated facilities. These costs need to be depreciated over many years to ease the financial impact on electric rates. In addition to being capable of having a long life, distribution facilities must be designed and constructed in a safe and reliable manner while balancing a level of efficiency.

One important component that drives the cost of electric distribution infrastructure installations is the environment in which the facilities must be constructed. Several things may vary based on the surrounding environment, including design and construction standards utilized, equipment installed, and supporting civil infrastructure required. For example, it is typical in most rural and suburban areas for underground cable to be trenched or plowed, either directly or in conduit. This is possible because these areas contain relatively ample unsurfaced corridors that are available for utilities to install and maintain their facilities. In urban areas, underground cable is typically installed in concrete encased duct banks due to limited utility corridors and complications associated with congestion. Although there are significant cost differences between installing underground cable directly and within concrete encased duct banks, there is typically a correlation between the two based on the amount of customers served and the associated load. However, at a certain point, infrastructure costs rise at a faster rate than the associated number of customers and load needed to balance the costs.

A factor that affects the efficiency of an electric distribution utility is the capital cost of infrastructure, which may vary based on the service territory environment in which the utility serves and constructs facilities. Simply comparing the total plant value or incremental plant value year over year against the energy and/or demand the utility delivers does not provide a true representation. Rather, the cost effectiveness of distribution infrastructure for the environment in which it is installed needs to be factored into the evaluation.

The purpose of this report is to demonstrate how serving different developed environments impacts the effectiveness of capital requirements for a distribution utility. Specifically, the report closely looks at WKH VHUYLFH WHUULWRU\ RI 7RURQWR +\GUR (O
+\GUR´ DQG RWKHU QHDUE\.GHYHORSHG HQYLURQPHQWV

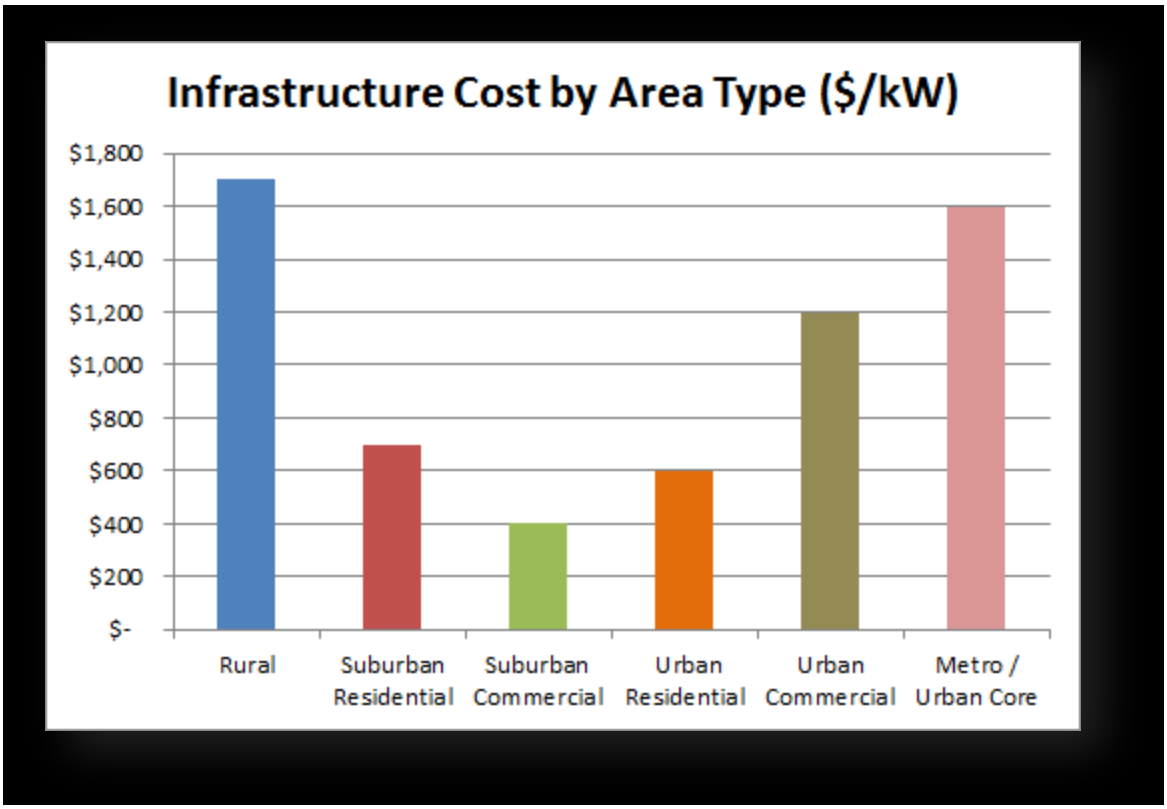


Figure 1-1 Infrastructure Cost by Area Type

Figure 1-1 illustrates the results of research and analysis completed by Power System Engineering [3 3 6 (.´ Suburban residential, suburban commercial, and urban residential areas resulted in the lowest electric distribution infrastructure cost in relation to the load level served when compared to other environments. Conversely, rural, urban commercial, and metro/urban core environments require a higher cost of electric distribution infrastructure in relation to the load level served. Factors driving these results include the density of load over which infrastructure costs can be spread, as well as the magnitude and complexity of the infrastructure required to serve the load within the given environment. Toronto Hydro ¶ service territory comprises mainly of urban residential, urban commercial, and metro/urban core areas.

2 7RURQWR6+\GURHOHFWULFV\VWHP

Toronto Hydro is the largest municipal electrical distribution company in Canada, serving approximately 733,000 customers in the city of Toronto. Comparatively speaking, the service territory is very unique from other distributors in Ontario due to its significant population density. The evolution of the city and its supporting infrastructure is common to other major cities found in the United States.

2.1 &LW\ RI 7RURQWR

In 1834, Toronto became a civic incorporation. Mostly occupied by British and Irish immigrants at the time, Toronto's population grew between 1831 and 1891. By the 1900s, more immigrants arrived from continental Europe, including Jews, Italians, and Ukrainians, followed by Germans, Poles, Hungarians, Slavs, Greeks, and Portuguese. By the 1920s, new suburban municipalities were appearing due to an overflowing city center of approximately 500,000 people. $IWHU :RUOG :DU ,, 7RURQWR¶V HFRQRP\ ERRPHG DQG WKH FLW\ JUHZ RYHU 1,000,000 by 1951. In the 1970s and 1980s, migrants from West India, South Asia and East Asia arrived. Present-day Toronto is made up of the former municipalities of Toronto, North York, Scarborough, York, Etobicoke, and East York, all of which merged into a six-municipality configuration in 1967. In 1998, the six municipalities were amalgamated into a single municipality, or the present-GD\ &LW\ RI 7RURQWR &XUUHQWO\ 7RURQWR LV WKH ILIWK PXQLFLSDOLW\ DQG 1RUWK $PHULFD¶V IRXUWK ODUJHVW FLW\ $FFRUGLQJ WR GDWD UHSRUWHG E\ WKH municipal government, the population of the City of Toronto was approximately 2.8 million in 2012, while the census metropolitan area population of the Toronto area was approximately 5.5 million in 2011.

Toronto is located on a shore plain of a harbor of Lake Ontario. The core downtown area of Toronto still resides along this shore line, while the rest of the city extends east, west, and north of the harbor. The city is intersected by three rivers and numerous tributaries, including the Humber River, the Don River, and the Rouge River, which have created densely forested ravines. The ravines have affected the original grid plan, and are noticeable on Finch Avenue, Leslie Street, Lawrence Avenue, and St. Clair Avenue. The ravines are useful for drainage of the FLW\¶V VWRUP VHZHU V\VWHP EXW RIWHQ H[SHULHQFH IORRGLQJ GXULQJ SHULRGV RI KHDY\ UDLQ

The City of Toronto was originally developed according to a small-town plot with a plain grid of straight streets. The straight grid pattern was extended as the city grew, but in 1834, uncoordinated private developments replaced the grid pattern. By the 1840s, the cityscape began to take shape. King Street was a main commercial east-west pathway, while Yonge Street served as the main north-south route. During the early 1900s, skyscrapers were being built and industry grew around Yonge Street, King Street, Queen Street, and Bay Street. A picture of present-day downtown Toronto is provided below.



Figure 2-1 Image of Downtown Toronto

7RGD\ 7RURQWR¶V FRUH GRZQWRZQ DUHD FRQVLVWV PRVWO condominiums. In the heart of downtown, the surrounding landscape is almost completely paved, with little to no grassy boulevards, medians, or curbs. Moving away from the city center, housing and business can be classified as urban. The inner suburbs, close to downtown, feature mostly single-family homes and apartment buildings that range in size. Due to population density, duplexes are common, and stand-alone houses are built closely together with limited yard space. Urban commercial areas have similarly closely positioned structures, and range in height. Designated green spaces or parks, some which are quite large, are located throughout 7RURQWR¶V GRZQWRZQ DQG XUEDQ DUHDV)XUWKHU IURP traditionally suburban, with larger single-family homes and more individual yard space. Suburban commercial areas have more space between buildings, and structures are mostly two to four stories tall. In rural areas surrounding Toronto, housing and commercial operations are widely spread apart, often separated by large farm fields. Homes are mostly large, single-family homes with extensive green space. Properties may be located at the ends of long driveways and not directly next to neighboring properties.

Downtown Toronto has many interesting and noteworthy structures. These include the original Fort York complex (rebuilt 1813-15), the Grange, a gentry mansion built around 1817, St Lawrence Hall (1850), originally a public building containing a hall and shops, Osgoode Hall (rebuilt 1857-60), headquarters of the Law Society of Upper Canada, University College (1859), the Ontario Parliament Buildings (1892), the City Hall (designed 1890, completed 1899), the Royal Alexandra Theatre (1907) and Union Station (opened 1927). Later eras have largely produced more and bigger office buildings, hotels and shopping centers. However, some newer buildings, like the new City Hall (1965) and Roy Thomson Hall (1982) are noteworthy structures.

An example of the sheer magnitude of construction in the core downtown area is the First Canadian Place building, located at the corner of King Street and Bay Street. This 72 story office tower offers approximately 2.7 million square feet of office and retail space and is the

operational head office of the Bank of Montreal. At 978 feet tall, the structure is known as & D Q D G D ¶ V W D O O H V W E X V L Q H V V B X L O G L Q J L Q W K H V X P P H U R I 2 0 H and records a daily pedestrian traffic of 83,000 people. A picture is provided below.



Figure 2-2 Image of First Canadian Place

Today, T R U R Q W R ¶ V largest industries are financial services, real estate, and wholesale and retail trade. Several head banking offices are located in Toronto. In addition, Canadian insurance and investment companies are centrally based in the city, as well as the Toronto Stock Exchange. The core downtown area is also home to many Canadian head offices of industrial, resource, and retail corporations, and of American or multinational companies. Today, there are approximately 90,000 businesses in the City of Toronto, and about 196,000 businesses in the Toronto region. The city's workforce is chiefly based in professional, clerical, manufacturing, retail and service work, in that order. Toronto struggled with the effects of the Free Trade

Agreement with the U.S., as well as with the recession of the early 1990s and the global financial crisis of 2008, resulting in high unemployment. The economy has slowly improved. As of June 2014, Tor R Q W R ¶ V X Q H P S O R \ P % H Q W U D W H Z D V

Buses, trucks and cars use Highway 401, a multi-lane crosstown throughway, and Highway 400, now the prime route north. Automobile routes such as the Gardiner Expressway along the southern edge of downtown, or the Don Valley Parkway running north, bear heavy loads. Traffic congestion can be extreme during peak travel times. In a recent study released by TomTom, Toronto was ranked as the second worst city in Canada for traffic congestion. However, the City has successfully maintained its public streetcar, bus and subway systems. According to 2013 data 7 R U R Q W R ¶ V L L L Transit network averaged approximately 900,000 passenger trips each weekday, operating four lines and 69 stations. The Government of Ontario also operates a rail and bus transit system called GO Transit in the Greater Toronto Area, which transports over 250,000 passengers every weekday.

Toronto has underground infrastructure for fresh water distribution, as well as for natural gas distribution. Much of the electrical infrastructure is also located underground due to limited aboveground space. Toronto is so densely populated and saturated that its local landfills reached capacity and municipal waste had to be shipped elsewhere. Due to the extremely tall buildings located in the core downtown area, radio towers have been built still higher in order to accurately transmit signals.

2.2 3RSXODWLRQ RI 7RURQWR DQG

According to population and dwelling account information collected by the Government of Canada[1], the total population of Ontario in 2011 was 12,851,821. Of this total population, the city of Toronto is categorized as a large urban area with a population of over 5 million, or nearly 40% R I 2 Q W D U L R ¶ V total population. The next largest urban area is the Ontario part of Ottawa-Gantineau metropolitan area with a total Ontario population of 697,267, followed by Hamilton with 670,580 residents and Kitchener with 444,681 residents. The other 11 cities classified as large urban areas have between 100,000 and 370,000 residents according to 2011 data. The remainder of Ontario is comprised of 19 medium cities and 239 small cities. Figure 2-3, shown below, is a graph with data points demonstrating population density, or the number of people per square kilometer, for the large urban and medium cities in Ontario. Toronto has a population density of 2931 people per square kilometer.

[1] *RYHUQPHQW RI &DQDGD 6WDWLVWLFV &DQDGD ³3RSXODWLRQ DQG GZHOOLQJ DQG SRSXODWLRQ FHQWUHV´ DQG Statcan.gc.ca/census-recensement/2011/dp-pd/hlt-fst/pd-pl/Table-Tableau.cfm?LANG=Eng&T=802&PR=35&S=51&O=A&RPP=999

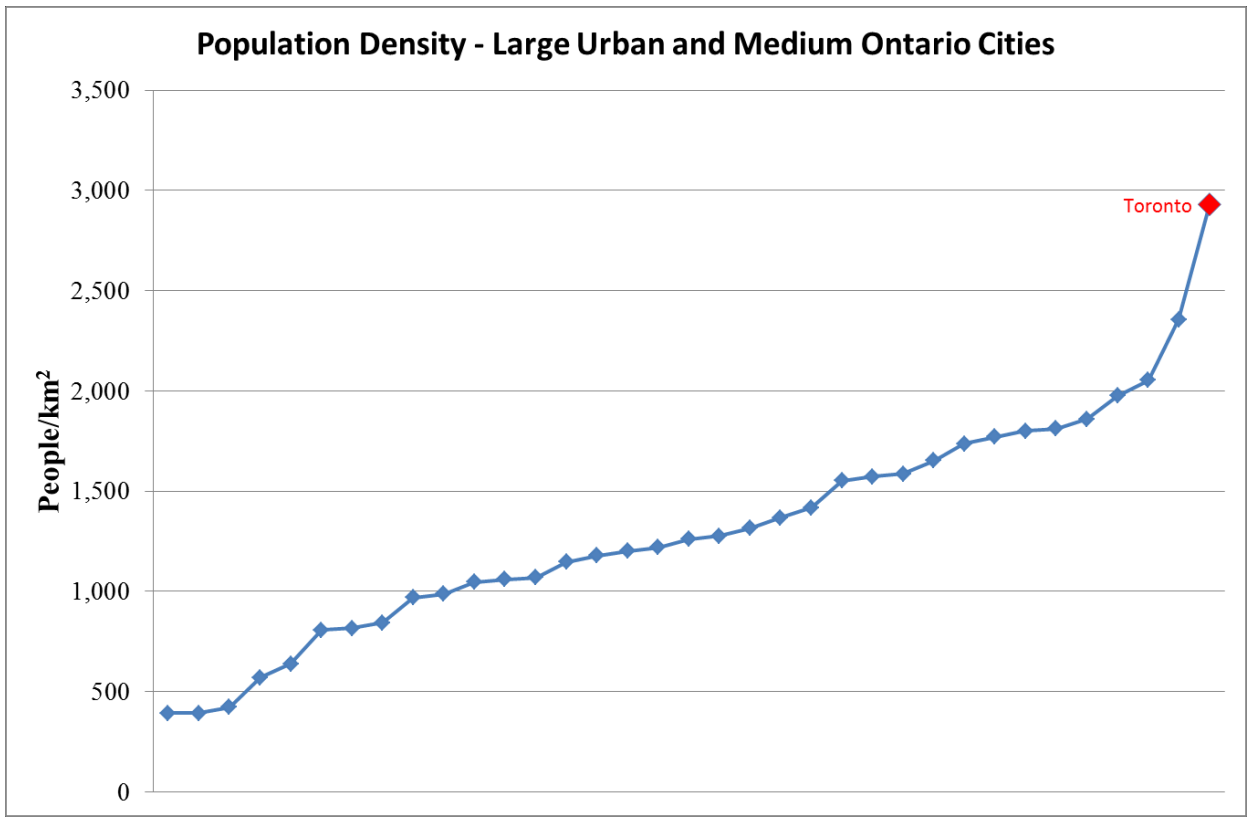


Figure 2-3 Ontario Metro Area Population of Large Urban and Medium Cities

2.3 8QLTXH 2SH&URDQWGLQWLRQV

There are many unique operating conditions that apply to a highly dense urban area. For the purposes of this report, the city of Toronto will be referenced in accordance with the effect these conditions have on Toronto Hydro Electric System Limited.

7RURQWR¶V FRUH GRZQWRZQ DUHD FRQVLVWV RI FORVHO\ S commercial properties and apartments and condominiums. The extreme urban density experienced in the city of Toronto creates a variety of unique assets or factors that affect Toronto Hydro¶V DELOLW\ WR HIIHFWLYHO\ DQG HIILFLHQWO\ VHUYH LW customers.

Toronto Hydro operates a unique and dated downtown underground system, which features a network of secondary-YROWDJH FDEOHV 7KH QHWZRUN¶V FRQILJXUDW RU ³*ULG 1HWZRUN´ GHSHQGLQJ RQ WKH WLPH RI FRQVWUXI downtown service for a high rise building is provided from a vault with two transformers, each FRQQHFWHG WR WZR GLIIHUHQW IHHGHUV 2WKHU EXLOGLQJV due to the large industrial load in the downtown area, Toronto Hydro installs and maintains additional regulating and safety devices, such as transfer trips. This network contains many redundancies to buildings throughout the downtown area and is not typically used in new construction, but is maintained by Toronto Hydro to fulfill expectations of reliability.

'XH WR WKH FLW\¶V DJH WKH RsUdonHrQ of legacy systeQ IUDVWU configurations that correspond with the surges of growth Toronto has experienced in past decades. In addition to the secondary network and complex vault configurations, as described above, Toronto Hydro¶V V\VWHP includes rear-lot construction, overhead box construction, and Paper Insulated Lead Cable (PILC) cable. All of these distinguishing characteristics require additional skills and costs to maintain and operate compared to utilities that do not serve dense urban and city environments.

Many buildings in Toronto have been built to the edge of the lot line which leaves no room for burying electrical equipment. This requires Toronto Hydro to pull network and connection cables to stations with available capacity that are further away. It also means that as the population grows and shifts, Toronto Hydro will need to build new stations or modify existing stations to accommodate additional breaker positions. Finally, as new high rise buildings are constructed in the limited space of the downtown core area, unconventional connection arrangements must be applied, which increases connection and expansion costs per customer.

Many overhead structures in Toronto Hydro¶V WHUULWRU\ LQFOXGH DQ RXWGD design, which is being replaced over time with a more modern structure. There are limitations for working near or with box construction, including safety concerns and the need for special training due to the large number of closely positioned live circuits. In residential communities, rear-lot facilities have become difficult to maintain over the years as a result of limited access for utility equipment. Bucket trucks cannot be used and insulated protective equipment must be in place before for work can be completed safely.

Along with the Ontario EPA regulations for working around and disposing of lead, additional regulations for PILC increase costs due to additional administrative staff, certification of vehicles, and safety training for field workers.

Furthermore, Toronto Hydro crews have physical limitations to contend with, such as equipment located in confined spaces, minimal road or sidewalk space available, and infrastructure installed under roadways. When working in a confined space, legislative requirements state that a dedicated observer must be present, so Toronto Hydro often needs to dispatch crews with multiple workers in order to be compliant. Limited sidewalk and road space causes issues with staging materials and fitting new infrastructure into existing corridors. Underground infrastructure is often located in the middle of roadways, which translates to safety concerns, as well as the need for assistance with traffic control and a schedule for working during non-critical hours. In addition, the city experiences heavy traffic congestion, which can impact the response time that a crew is able to arrive at a job site to complete a repair. These factors increase the need for staff and the difficulty of completing work safely and quickly.

Because it is an older city, Toronto has a mature urban setting, which means there may be excavation challenges when performing underground work, such as abandoned infrastructure that iV QRW PDUNHG RQ WKH FLW\¶V UHFRUGV DORQJ ZLWK RW must be preserved and worked around. In addition, Toronto Hydro utilizes a special communications infrastructure to support communications between field staff and the control room, and to enable collection of Smart Meter Data. Toronto Hydro has an extensive two-way radio system, as well as 10 communications antennae located on top of high rise towers to ensure

reliable radio communications. In addition, due to the number of multi-story buildings, more wireless collectors are needed for Smart Meter Data Collection and SCADA communication.

3 6HUYLFH 7HUULWRU\ (QYLUR

To answer the question of how different types of service territory environments affect the level of required infrastructure and associated capital, six areas have been identified within Ontario of varying customer densities and types. These areas are not all within the same service territory of a single electric distribution provider. Rather they were identified by their characteristics and evaluated on an individual basis. These six areas will be referred to as the following for the purposes of this report:

- Area 1 ±Rural
- Area 2 ±Suburban Residential
- Area 3 ±Suburban Commercial
- Area 4 ±Urban Residential
- Area 5 ±Urban Commercial
- Area 6 ±Metro / Urban Core

All locations were analyzed using Google Earth and PSE internal ESRI GIS maps. The land mass of these six areas ranged from approximately 0.28 to 4.13 square kilometers and were within 50 kilometers from each other. Exhibit I illustrates the general location of each area, the proximity of the locations to each other, and the land mass for each location by square kilometer.

With the exception of the urban commercial area, the class of customers and associated proprieties were identified for each area. For residential properties, Google Earth was used to identify the number of single-family or multi-family homes. For commercial properties, a general category was established (such as office, retail, etc.) and total floor space was estimated for each building.

The following provides a summary of each area, including a description of the assessment that was completed and a screenshot image from Google Earth.

3.1 $UHD±5XUDO

The selected rural area (Area 1) is located approximately 40 km north-northwest of downtown Toronto. The area is classified by PSE as a low density area primarily consisting of farm land, farm operation buildings, single-family homes, and recreational areas. The land mass of the area was measured at 4.13 square kilometers. An aerial image of Area 1 is shown in Figure 3-1.



Figure 3-1 Rural Area

8QGHU 36(¶V DVVHVVPHQW single-family homes were identified, as well as two dairy operations, two livestock operations, and seven distinguishable farmed fields (six of which appeared to be crops and one of which appeared to be a tree farm). In addition, one golf course and one commercial landscaping business were found in the area. Single-family homes were designated as such based on what appeared to be a private residence, as opposed to buildings related to farm operations, such as barns or storage sheds. In the identification of a dairy, livestock, or crop farm, buildings used for farm operations were not individually identified, but these types of buildings were found on these properties.

3.2 $UHD±6XEXUEDQ 5HVLGHQWLDO

The selected suburban residential area (Area 2) is located approximately 24 km north of downtown Toronto. The area is classified by PSE as a saturated and moderately dense residential area consisting of mostly single-family homes. Buildings with commercial or retail functions and other properties of interest were also identified. The land mass of the area was measured at 1.36 square kilometers. An aerial image of Area 2 is shown in Figure 3-2.



Figure 3-2 Suburban Residential Area

8QGHU 36(¶V DVVHVVPHQW Over [illegible] single-family homes were identified, many of which have sizable private green space. In addition, a strip mall with a combination of retail and commercial businesses was identified in the northwest corner of the selected area. The identifiable businesses included four food retail operations, one bank, one dentist, and one pharmacy. In addition, the reviewed area included one elementary school located in the center of the area, and one community center, located in the northeast corner of the area. The community center includes a large building, a baseball diamond, a soccer field, and several tennis courts.

3.3 $UHD±6XEXUEDQ &RPPHUFLDO

The selected suburban commercial area (Area 3) is located approximately 24 km north of downtown Toronto. The area is classified by PSE as a moderately dense commercial area consisting of mostly commercial office space, as well as some retail operations, such as restaurants or small stores. The majority of the buildings in this area ranged from two to four stories. The land mass of the area was measured at 1.04 square kilometers. An aerial image of Area 3 is shown in Figure 3-3.



Figure 3-3 Suburban Commercial Area

8QGHU 36(¶V DVVHVVPHQW of commercial properties were identified. The property with the largest floor space is estimated to be 29,260 square meters, while the property with the smallest floor space is estimated to be 1,390 square meters. The total commercial floor space within the area is estimated to be 491,450 square meters.

3.4 $UHD±8UEDQ 5HVLGHQWLDO

The selected urban residential area (Area 4) is located approximately 3 km north-northwest of downtown Toronto. The area is classified by PSE as a highly dense residential area consisting of single-family homes, apartments and condominiums, and retail operations, like restaurants and small stores. The majority of the properties in this area consisted of single-family homes, nearly all of which were side-by-side two-story duplex construction with two single-family homes located in one structure. The land mass of the area was measured at 0.39 square kilometers. An aerial image of Area 4 is shown in Figure 3-4.



Figure 3-4 Urban Residential Area

8QGHU assessment, approximately 1000 single-family homes and 250 individual apartment or condominium units were identified. Also present in the area were approximately 75 small businesses, including approximately 25 restaurants and 50 retail storefronts. In addition, the area included several churches, two schools, and one medical clinic.

3.5 $UHD±8UEDQ &RPPHUFLDO

The selected urban commercial area (Area 5) is located approximately 2 km north-northeast of downtown Toronto. The area is classified by PSE as a highly dense commercial area consisting of mostly commercial office space. The land mass of the area was measured at 0.32 square kilometers. An aerial image of Area 5 is shown in Figure 3-5.



Figure 3-5 Urban Commercial Area

3.6 $UHD±0HWUR 8UEDQ &RUH

The selected metropolitan/core downtown urban area (Area 6) is located directly in the heart of downtown Toronto. The area is classified by PSE as a highly dense, mostly commercial area consisting of skyscrapers that serve as office towers, apartments and condominiums, hotels, and retail operations, including restaurants and large and small stores. The structures in this area range from 2 to 72 stories. The land mass of the area was measured at 0.28 square kilometers. An aerial image of Area 6 is shown in Figure 3-6.

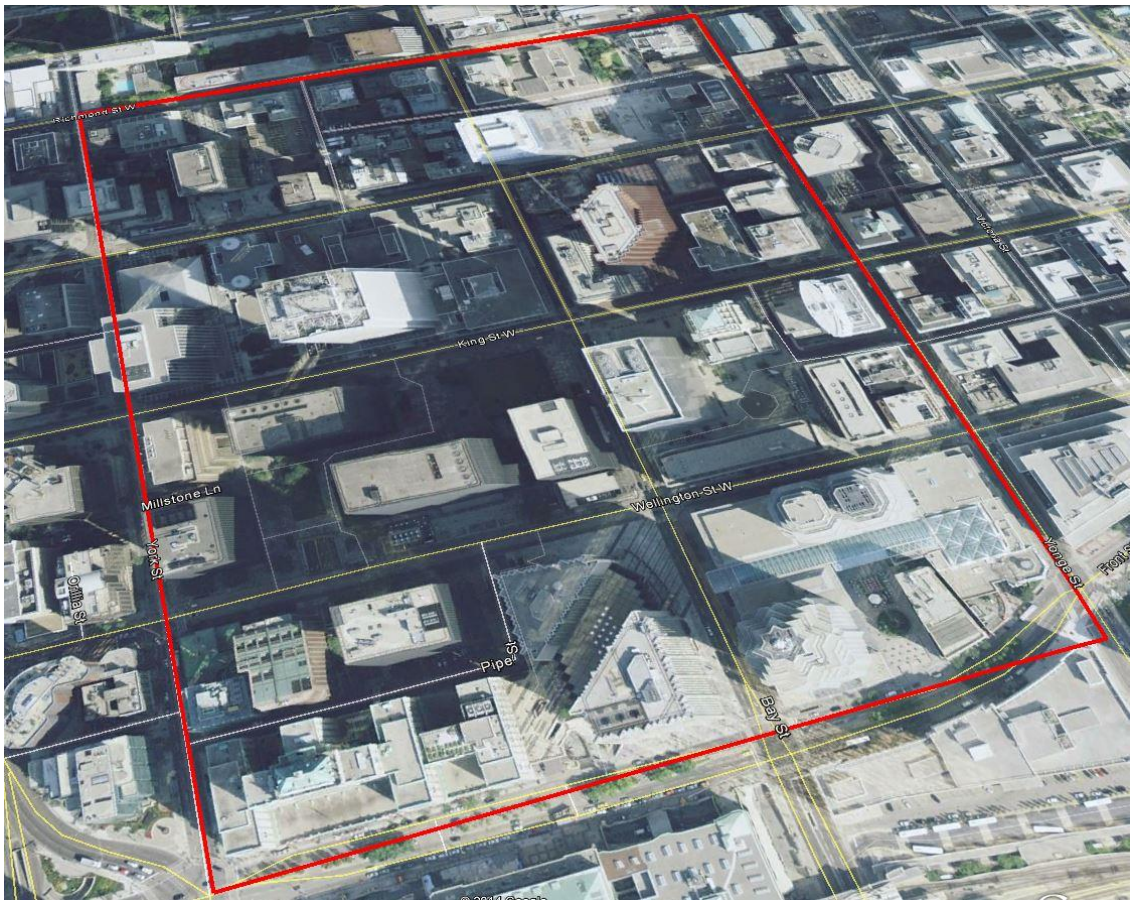


Figure 3-6 Core Downtown Area

8QGHU 36(¶V DVVHVVPHQW DSSURDFK, properties were identified. The property with the largest floor space is estimated to be 251,000 square meters, while the property with the smallest floor space is estimated to be 670 square meters. Approximately 75% of the properties in the area were 10 stories or taller. The total commercial and residential floor space within the area is estimated to be 2,500,000 square meters.

4 /RDG 'HQVLW\

For each of the studied areas, PSE estimated the coincident peak load based on a combination of factors. These factors included:

- Type of customers (ex. single-family home, retail, office space, medical, etc.)
- Quantity of each customer type
- Enclosed floor space of each customer type

Being that Toronto Hydro ¶V VHUYLFH WHUULWRU\ FRYHUV $UHDV DQG provided estimated coincident peaks for the corresponding areas to be used as a comparison.

4.1 $UHD± 5XUDO

There were a total of 41 services estimated within Area 1. The customer types included residential single family, farm ± livestock, farm ± dairy, farm ± crop, and commercial ± landscaping. The total non-coincident demand for the area was estimated at 850 kW. Applying a coincident factor for each customer type, the coincident peak demand was estimated at 582 kW. Table 4-1 VKRZV D VXPPDU\ RI 36(¶V HVWLPDWH

Table 4-1 Rural Estimate

	No. of Services	Non-Coincident (kW)	Coincident Factor	Coincident (kW)
Residential Single Family	28	280	0.54	152
Farm - Livestock	2	80	0.86	69
Farm - Dairy	2	150	0.86	129
Farm - Crop	7	280	0.65	181
Commercial - Landscaping	2	60	0.86	51
Coincident Demand (kW)	**41**	**850**		**582**

4.2 $UHD±6XEXUEDQ5HVLGHQWLDO

There were a total of 821 services estimated within Area 2. The customer types included residential single family, education, medical ±hospital/clinic mix, commercial ±office space, commercial ±restaurant, government ±building/center, and other. The total non-coincident demand for the area was estimated at 9,150 kW. Applying a coincident factor for each customer type, the coincident peak demand was estimated at 4,990 kW. Table 4-2 shows a summary of 36(¶V HVWLPDWH

Table 4-2 Suburban Residential Estimate

	No. of Services	Non-Coincident (kW)	Coincident Factor	Coincident (kW)
Residential Single Family	808	8,100	0.50	4,063
Education	1	200	1.00	200
Medical - Hospital / Clinic Mix	2	40	0.86	34
Commercial - Office Space	1	10	1.00	10
Commercial - Restaurant	4	400	0.73	291
Government - Building/Center	1	370	1.00	370
Other	4	30	0.73	22
Coincident Demand (kW)	**821**	**9,150**		**4,990**

4.3 $UHD±6XEXUEDQ &RPPHUFLDO

There were a total of 61 services estimated within Area 3. The customer types included commercial ±office space, commercial ±textile retail, and warehouse. The total non-coincident demand for the area was estimated at 24,160 kW. Applying a coincident factor for each customer type, the coincident peak demand was estimated at 12,890 kW. Table 4-3 shows a VXPPDU\ RI 36(¶V HVWLPDWH

Table 4-3 Suburban Commercial Estimate

	No. of Services	Building sqft	Non-Coincident (kW)	Coincident Factor	Coincident (kW)
Commercial - Office Space	49	4,838,450	21,773	0.52	11,425
Commercial - Textile Retail	11	419,425	2,307	0.60	1,384
Warehouse	1	32,000	80	1.00	80
Coincident Demand (kW)	**61**	**5,289,875**	**24,160**		**12,890**

4.4 $UHD±8UEDQ 5HVLGHQWLDO

There were a total of 1,333 services estimated within Area 4. The customer types included residential single family urban, residential multiple family, education, church, medical ± hospital/clinic mix, commercial ±textile retail, and commercial ±restaurant. The total non-coincident demand for the area was estimated at 15,147 kW. Applying a coincident factor for each customer type, the coincident peak demand was estimated at 8,853 kW. Table 4-4 shows a VXPPDU\ RI 36(¶V HVWLPDWH

Table 4-4 Urban Residential Estimate

	No. of Services	Building sqft	Non-Coincident (kW)	Coincident Factor	Coincident (kW)
Residential Single Family Urban	1,000		8,000	0.50	4,010
Residential Multiple Family	250		1,500	0.50	757
Education	2		420	0.86	360
Church	5		200	0.69	138
Medical - Hospital / Clinic Mix	1	27,000	189	1.00	189
Commercial - Textile Retail	50	425,000	2,338	0.52	1,225
Commercial - Restaurant	25		2,500	0.55	1,368
Infrastructure Support					805
Coincident Demand (kW)	**1,333**	**452,000**	**15,147**		**8,853**

As previously mentioned, Area 4 is within Toronto Hydro¶V VHUYLFH AUHD Zand UHVLGHQWLDO YDOLGDWH 36(¶V Toronto Hydro has established an estimated coincident peak load for the same area. This estimate was reported at 9,960 kVA. Assuming a 90% power factor, this equates to 8,964 kW, ZKLFK LV ZLWKLQ RI 36(¶V HVWLPDWH

4.5 $UHD±8UEDQ &RPPHUFLDO

At the time of this report, PSE was not able to survey Area 5 with the purpose of estimating the quantity and type of customers or total enclosed floor space. As a result, PSE directly used Toronto Hydro ¶V HVWLPDWHG FRLQFLGHQW SHDN GHPDQG IRU WKH results of Area 4 and Area 6 between PSE and Toronto Hydro, it is believed that additional comparison for Area 5 is not necessary.

Toronto Hydro estimated the coincident peak for Area 5 at 24,380 kVA. Assuming a 90% power factor, this equates to 21,942 kW.

4.6 $UHD0HWUR 8UEDQ &RUH

Based on the number of towers and floors, it was difficult to accurately estimate the number of services within Area 6. The customer types included residential multiple family, hotel, commercial ±office space, commercial ±textile retail, commercial ±restaurant, and government ±building center. The total non-coincident demand for the area is estimated at 122,005 kW. Applying a coincident factor for each customer type, the coincident peak demand is estimated at 67,656 kW. Table 4-5 shows a summary of PSE¶V HVWLPDWH

Table 4-5 Metro/Urban Core Estimate

	Building sqft	Non-Coincident (kW)	Coincident Factor	Coincident (kW)
Residential Multiple Family	2,191,425	8,766	0.50	4,390
Hotel - 1 Service = 1 Unit		3,413	0.50	1,709
Commercial - Office Space	20,530,670	92,388	0.50	46,250
Commercial - Textile Retail	1,103,799	6,071	0.52	3,183
Commercial - Restaurant		11,038	0.51	5,642
Government - Building/Center	60,000	330	1.00	330
Coincident Demand (kW)	23,885,894	122,005		67,656

As previously mentioned $UHD LV ZLWKLQ 7RURQWR +\GURV VHUYLFH DWH 3 6 (¶V HVWLPDWH Toronto Hydro also established an estimated coincident peak load for the same area. This estimate was reported at 77,800 kVA. Assuming a 90% power factor, this equates to 70,020 kW, ZKLFK LV ZLWKLQ RI 3 6 (¶V HVWLPDWH

5 &DSLWDO &RVWV

A combination of developed electrical design plans by PSE and actual installations identified by Toronto Hydro were used to identify required electric distribution infrastructure to serve each of the six areas. The PSE design plans included routing overhead and underground distribution lines, placing transformers to serve the residences or businesses, and running secondary service drops to homes and other buildings located in each area. Based on the design and actual installations, a cost estimate was created by breaking down the electric distribution infrastructure into the quantity of individual poles, switches, duct banks, vaults, conductors, and transformers needed to supply electricity to the area.

Following the quantification of infrastructure facilities for each area, replacement cost estimates were established. These estimates were also based on a combination of construction cost data developed and maintained by PSE, as well as actual unit construction contract costs provided by Toronto Hydro.

5.1 $UHD±5XUDO

For design of the Rural area, it was assumed that the area will be served by an overhead three-phase main line and single-phase tap lines. Residences and farms located close to the road would be served by overhead line and those with long driveways would be served by underground line fed off of the overhead line. Both overhead and pad-mounted transformers were used in the design. The minimum size of transformer used was 25 kVA and approximately one transformer would serve each residence or farm. The design utilizes a combination of overhead and underground infrastructure. The total estimated cost of a replacement installation is estimated at $963,995. A breakdown of major infrastructure components and costs are shown in Table 5-1.

Table 5-1 Rural Infrastructure Components and Costs

Poles	
Design Total	Estimated Cost
120	$217,275
Transformers	
Design Total	Estimated Cost
31	$71,100
Underground Cable Risers	
Design Total	Estimated Cost
20	$34,200

3 Phase Primary Overhead Circuit	
Design Total	Estimated Cost
2.055 kM	$49,731
1 Phase Primary Overhead Circuit	
Design Total	Estimated Cost
5.702 kM	$54,397
1 Phase Primary Underground Circuit	
Design Total	Estimated Cost
4.955 kM	$136,858

Secondary Overhead Circuit	
Design Total	Estimated Cost
0.225 kM	$3,910
Secondary Underground Circuit	
Design Total	Estimated Cost
1.17 kM	$14,824

5.2 $UHD±6XEXUEDQ 5HVLGHQWLDO

For design of the Suburban Residential area, it was assumed that the area will be served by a main three-phase underground line, while single-phase underground lines would be routed through the neighborhoods. The minimum size of transformer used was 25 kVA and each transformer would serve an average of five homes. All the transformers used in the design were pad-mounted. The commercial and public buildings within the reviewed area had transformers sized to serve the load level assumed. The design utilizes mostly underground infrastructure. The total estimated cost of a replacement installation is estimated at $3,564,907. A breakdown of major infrastructure components and costs are shown in Table 5-2.

Table 5-2 Suburban Residential Infrastructure Components and Costs

Poles	
Design Total	Estimated Cost
114	$329,542
Switches	
Design Total	Estimated Cost
1	$6,420
Transformers	
Design Total	Estimated Cost
161	$570,343

3 Phase Primary Overhead Circuit	
Design Total	Estimated Cost
4.392 kM	$138,173
3 Phase Primary Underground Circuit	
Design Total	Estimated Cost
1.451 kM	$201,589
1 Phase Primary Underground Circuit	
Design Total	Estimated Cost
11.791 kM	$423,368

Underground Cable Risers	
Design Total	Estimated Cost
20	$44,460
Secondary Underground Circuit	
Design Total	Estimated Cost
28.773 kM	$455,170

5.3 $ U H D Æ 6 X E X U E D Q & R P P H U F L D O

For design of the Suburban Commercial area, it was assumed that area will be served by overhead and underground, large conductor, three-phase lines. Taps would be made to the main lines through the use of pad-mounted switches and then routed through the business park. All the transformers used in the design were pad-mounted and were sized to serve the load level assumed. The design utilizes mostly underground infrastructure. The total estimated cost of a replacement installation is estimated at $5,662,235. A breakdown of major infrastructure components and costs are shown in Table 5-3.

Table 5-3 Suburban Commercial Infrastructure Components and Costs

Poles	
Design Total	Estimated Cost
21	$60,673
Switches	
Design Total	Estimated Cost
15	$340,180
Transformers	
Design Total	Estimated Cost
61	$808,830

3 Phase Primary Overhead Circuit	
Design Total	Estimated Cost
0.833 kM	$26,206
3 Phase Primary Underground Circuit	
Design Total	Estimated Cost
11.877 kM	$1,626,330
Secondary Underground Circuit	
Design Total	Estimated Cost
2.745 kM	$77,676

5.4 $UHD±8UEDQ 5HVLGHQWLDO

For design of the Urban Residential, it was assumed that the area will be served by main three-phase underground lines, while single-phase underground lines would then be routed through the neighborhoods. The underground conductors would be run in duct banks and the equipment would be located in underground vaults. Secondary feeders would either run underground in duct to the homes and businesses or rise up on poles and overhead to the buildings. All the transformers used in the design were vault type and were sized to serve the load level assumed. The design utilizes mostly underground infrastructure with some overhead infrastructure. The total estimated cost of a replacement installation is estimated at $25,366,348. A breakdown of major infrastructure components and costs are shown in Table 5-4.

Table 5-4 Urban Residential Infrastructure Components and Costs

Vaults	
Design Total	Estimated Cost
26	$9,649,107
Cable chambers	
Design Total	Estimated Cost
16	$1,133,988
Secondary Handwells	
Design Total	Estimated Cost
60	$261,000
Underground Duct	
Design Total	Estimated Cost
5.896 kM	$2,738,677

3 Phase Primary Underground Circuit	
Design Total	Estimated Cost
11.487 kM	$2,217,722
3 Phase Primary Overhead Circuit	
Design Total	Estimated Cost
2.079 kM	$49,822
Secondary Underground Circuit	
Design Total	Estimated Cost
6.494 kM	$1,098,608
Secondary Overhead Circuit	
Design Total	Estimated Cost
20.060 kM	$548,389

Poles	
Design Total	Estimated Cost
403	$3,669,315
Switches	
Design Total	Estimated Cost
58	$1,397,568
Transformers	
Design Total	Estimated Cost
15	$296,119

5.5 $UHD±8UEDQ &RPPHUFLDO

For design of the Urban Commercial area, it was assumed that area will be served by underground, large conductor, three-phase lines. The underground conductors would be run in multiple duct concrete encased banks and the equipment would be located in underground vaults. Taps would be made to the main lines through the use of switches and then routed through the downtown area. All the transformers used in the design were vault type and were sized to serve the load level assumed. The design utilizes primarily underground infrastructure. The total estimated cost of a replacement installation is estimated at $81,988,908. A breakdown of major infrastructure components and costs are shown in Table 5-5.

Table 5-5 Urban Commercial Design Cost Estimate

Poles	
Design Total	Estimated Cost
198	$2,403,720
Switches	
Design Total	Estimated Cost
102	$3,277,056
Network Protectors	
Design Total	Estimated Cost
70	$7,112,490
Transformers	
Design Total	Estimated Cost
75	$1,974,129

Vaults	
Design Total	Estimated Cost
56	$27,710,256
Cable chambers	
Design Total	Estimated Cost
101	$9,544,399
Secondary Handwells	
Design Total	Estimated Cost
49	$284,200
Underground Duct	
Design Total	Estimated Cost
15.506 kM	$9,603,331

3 Phase Primary Underground Circuit	
Design Total	Estimated Cost
30.456 kM	$7,846,013
Secondary Underground Circuit	
Design Total	Estimated Cost
20.515 kM	$4,627,623
Secondary Overhead Circuit	
Design Total	Estimated Cost
4.174 kM	$152,154

5.6 $UHD±0HWURSROLWDQ&RUH

For design of the Core Downtown / High Density Urban area, it was assumed that the area will be served by underground, large conductor, three-phase lines. The underground conductors would be run in multi-duct banks and the equipment would be located in underground vaults. Taps would be made to the main lines through the use of switches and then routed through the downtown area. Extensive use of network protectors was included in the Core Downtown design to ensure very reliable service. All the transformers used in the design were vault type and were sized to serve the load level assumed. The costs associated with this area are significantly higher than the other five areas due to the difficulty in constructing and operating in such a congested area. The design utilizes almost entirely underground infrastructure. The total estimated cost of a replacement installation is estimated at $105,901,695. A breakdown of major infrastructure components and costs are shown in Table 5-6.

Table 5-6 Metro/Urban Core Design Cost Estimate

Poles	
Design Total	Estimated Cost
309	$3,751,260
Switches	
Design Total	Estimated Cost
109	$3,501,952
Network Protectors	
Design Total	Estimated Cost
65	$6,604,455
Transformers	
Design Total	Estimated Cost
62	$1,631,947

Vaults	
Design Total	Estimated Cost
68	$33,648,168
Cable chambers	
Design Total	Estimated Cost
291	$27,499,209
Secondary Handwells	
Design Total	Estimated Cost
116	$672,800
Underground Duct	
Design Total	Estimated Cost
11.828 kM	$7,325,435

1 Phase Primary Underground Circuit	
Design Total	Estimated Cost
0.223 kM	$57,475
3 Phase Primary Underground Circuit	
Design Total	Estimated Cost
26.540 kM	$6,837,253
Secondary Underground Circuit	
Design Total	Estimated Cost
21.028 kM	$4,743,331
Secondary Overhead Circuit	
Design Total	Estimated Cost
0.027 kM	$984

6 5HVXOWV

In reviewing the estimated coincident peak load, land mass, required electric infrastructure, and capital cost of the infrastructure for each area, a number of observations can be made. These observations include the demand density, infrastructure cost density, and infrastructure cost effectiveness.

The demand density is the amount of coincident demand within a unit of land mass. In the case of this analysis, kW per square kilometer was used. As shown in Table 6-1, the range greatly varies from 141 kW per square kilometer for the studied rural area, to 22,470 kW per square kilometer for the urban residential area, to 238,140 kW per square kilometer for the metro/urban core area.

Table 6-1 Demand Density Table

	Rural	Suburban Residential	Suburban Commercial	Urban Residential	Urban Commercial	Metro / Urban Core
Demand Density (kW/km^2)	141	3,656	12,395	22,470	68,185	238,140

The results are also illustrated in Figure 6-1. Excluding the rural area, the demand density from one area to the next increases by a factor of 1.8 to 3.5.

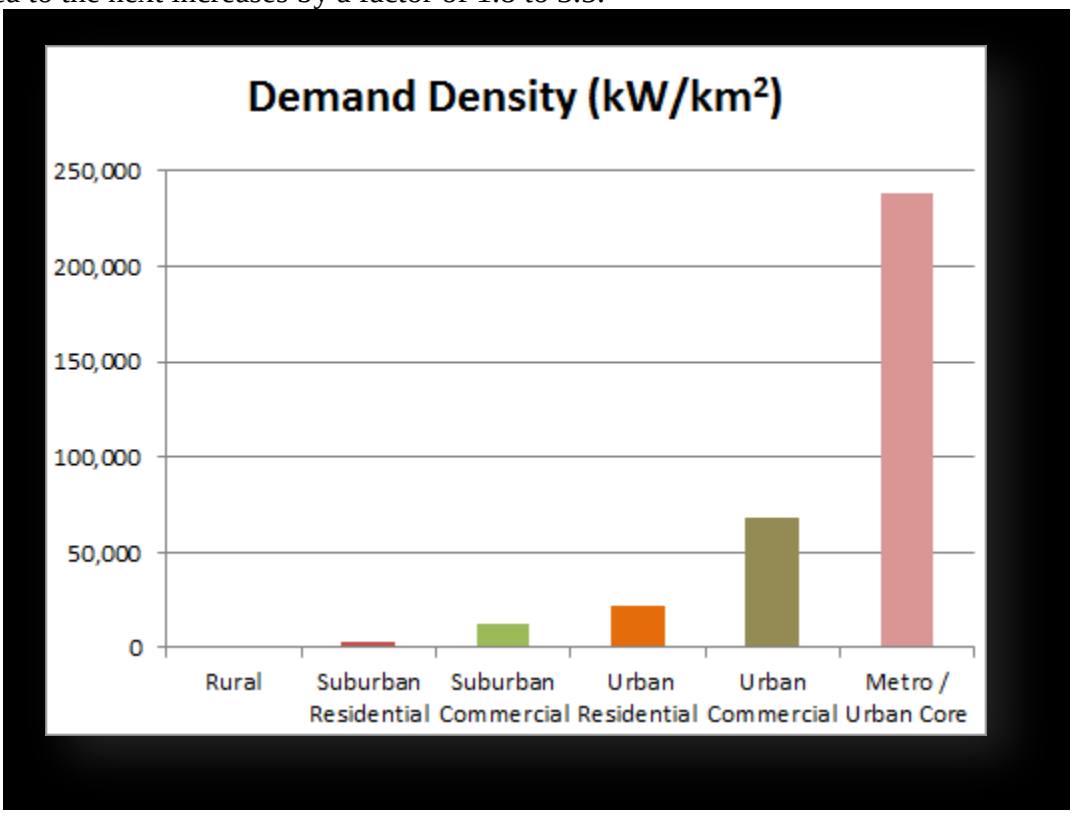


Figure 6-1 Demand Density

The infrastructure cost density, or plant cost density, is the amount of required infrastructure cost within a unit of land mass. In the case of this analysis, dollars per square kilometer was used. As shown in Table 6-2, the range greatly varies from $233,000 per square kilometer for the studied rural area to $12,690,000 per square kilometer for the urban residential area to $372,762,000 per square kilometer for the metro/urban core area.

Table 6-2 Infrastructure Cost Density

	Rural	Suburban Residential	Suburban Commercial	Urban Residential	Urban Commercial	Metro / Urban Core
Plant Cost Density ($1,000/km^2)	$ 233	$ 2,612	$ 5,445	$ 12,690	$ 78,826	$ 372,762

The results are also illustrated in Figure 6-2. Excluding the rural area, the infrastructure cost density from one area to the next increases by a factor of 1.7 to 6.2.

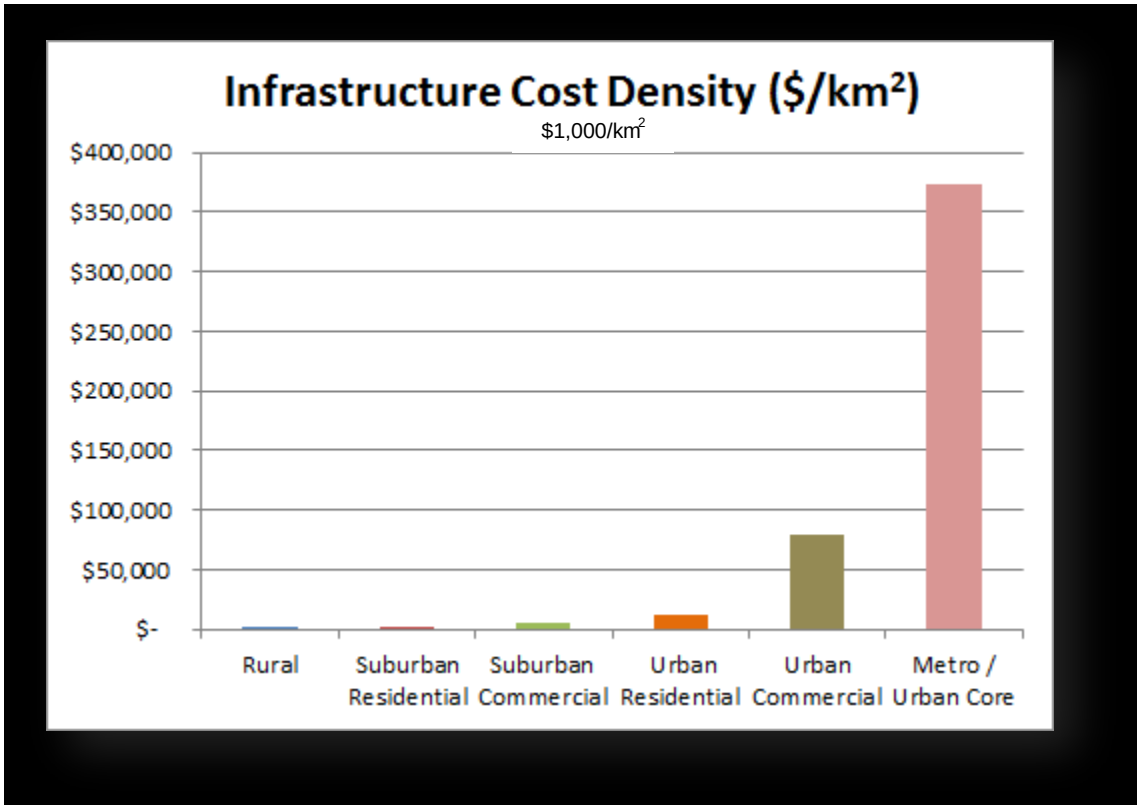


Figure 6-2 Infrastructure Cost Density

The infrastructure cost effectiveness is the cost of infrastructure required to serve a unit of coincident demand. In the case of this analysis, dollars per kW was used. As shown in Table 6-3, the range varies from $1,700 per kW for the studied rural area, to $600 per kW for the urban residential area to $1,600 per kW for the metro/urban core area.

Table 6-3 Infrastructure Cost by Area Type Table

	Rural	Suburban Residential	Suburban Commercial	Urban Residential	Urban Commercial	Metro / Urban Core
Plant Cost/Demand ($/kW)	$ 1,700	$ 700	$ 400	$ 600	$ 1,200	$ 1,600

The results are also illustrated in Figure 6-3. The infrastructure cost effectiveness from one area to the next increases or decreases by a factor of 1.3 to 2.3.

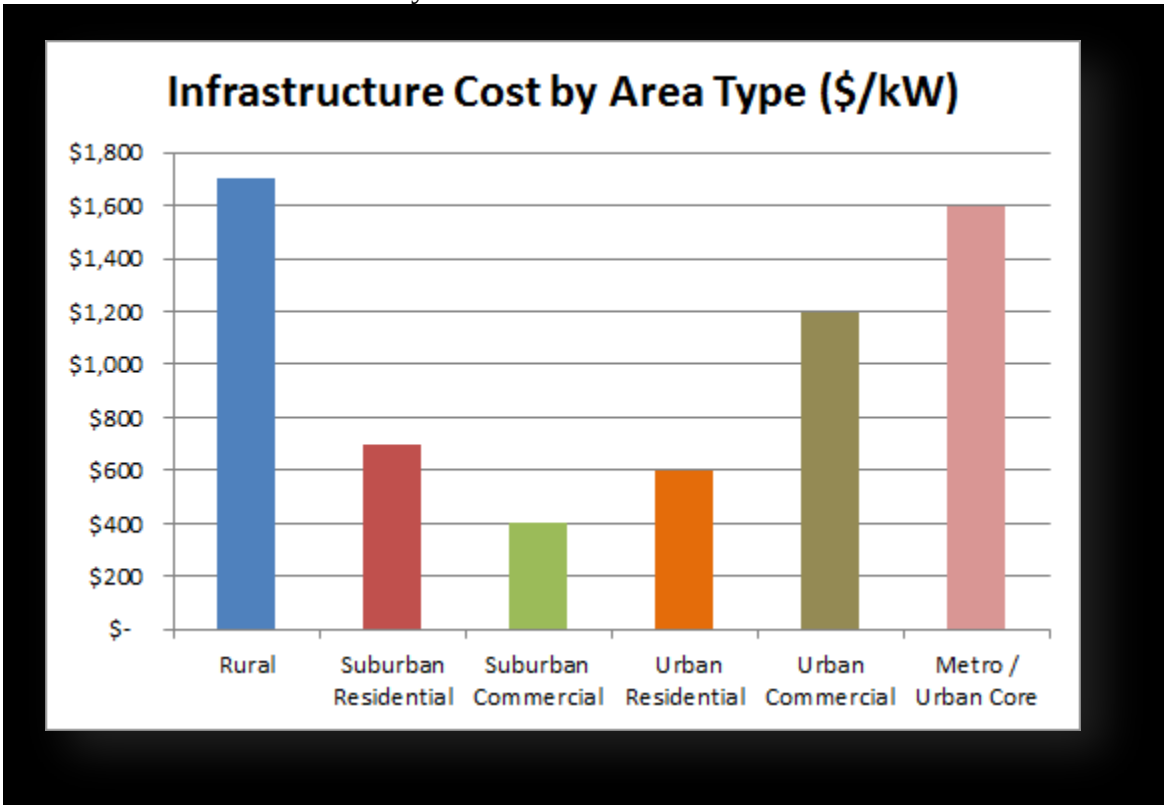


Figure 6-3 Infrastructure Cost by Area Type

It can be easily seen that the cost effectiveness of required infrastructure for the six areas studied does not result in an upward or downward trend as demand density increases. Rather, the cost effectiveness represents a U-shape where rural and metro/urban core areas are the least cost effective in terms of required infrastructure to serve the loads within the given environments. Conversely, suburban residential, suburban commercial, and urban residential areas are the most cost effective environments to serve.

In conclusion, the results of this report demonstrate that higher infrastructure costs per kW load served should be expected from a utility when serving a metro/urban core area. As demonstrated by the graphs above, both demand density and infrastructure cost density are extremely high in a metro/urban core service territory in comparison to all other types of service territories. The physical limitations for a utility operating within a highly dense, saturated downtown environment increase the costs associated with maintaining and installing electrical infrastructure to the extent that serving a core downtown area is almost as inefficient as serving a rural area. :LWKRXW VDFULILFLQJ D XWLOLW\¶V HIILFLHQF\ WR GRZQWRZQ FXVWRPHUV, LQ SUR efficiency is simply limited by the operating conditions a utility faces in this type of environment. While a utility should still fulfill all expectations of efficiency, regardless of service territory, these expectations should be reflective of the developed environment served.

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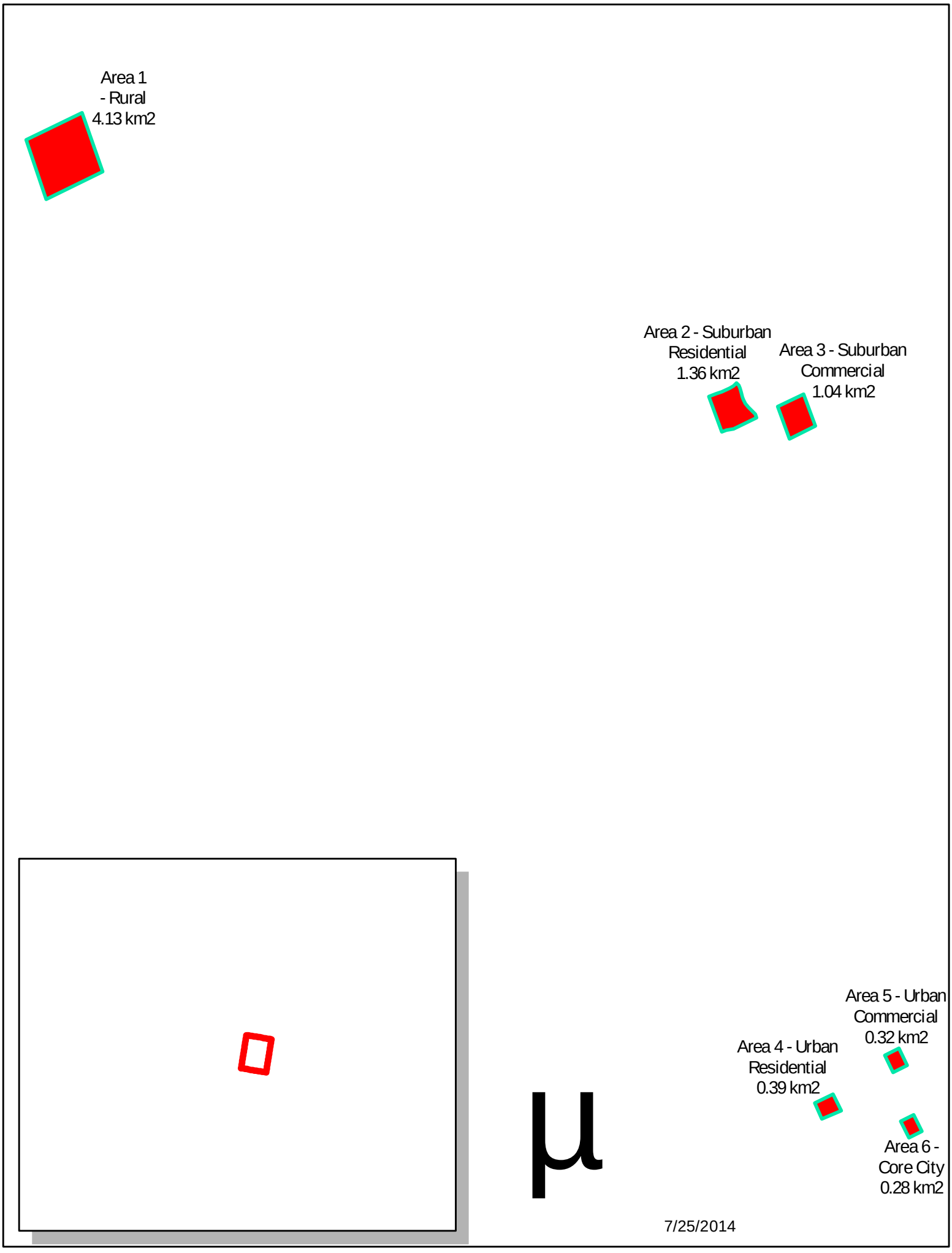
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http://www.gotransit.com/public/en/aboutus/whatisgo.aspx

My First Canadian Place web page. General Info.
http://myfirstcanadianplace.ca/General-Info.aspx

7RP7RP 1HZV ZHE SDJH ³7RP7RP Shows the World's Best Cities for Traffic in &DQDGD DQG $UXQG WKH :RUOG ´ 'DWHG 1RYHPEHU
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Area 1
- Rural
4.13 km2
Area 2 - Suburban
Residential
1.36 km2
Area 3 - Suburban
Commercial
1.04 km2
Area 5 - Urban
Commercial
0.32 km2
Area 4 - Urban
Residential
0.39 km2
Area 6 -
Core City
0.28 km2
7/25/2014

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December 2014 Report

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36(5HSO\ 5HSRUW WR 3(*¶V 'HFHPEHU 5

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4 3 6 (5 H V S R Q V H W R 3 (* ¶ V 6 W D W H P H Q W V . . . R Q . * H Q H U D O % H Q F
4.1 5 H V S R Q V H W R 3 (* ¶ V & K D S W H U) L Y H ³ 6 L P X O W D Q H O
% H Q F K P D U N L Q J ´ 12
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1 ([HFXWLYH 6XPPDU\

This report WKH ³36(5HSRUW´ is in reply to:

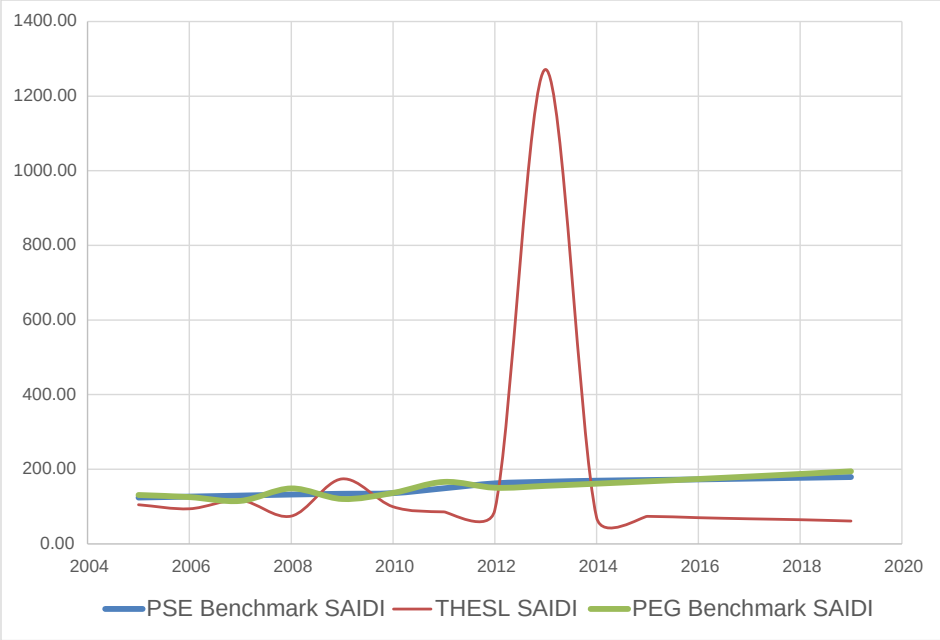
- 3(*¶V 'HFHPEHU UHSRUW ³3RUWODQG *HQHUDO (OHFWULF &RPSDQ\ 6\VWHP &RVW DQG 5HOLDELOLW\ Application and PSE Report: (FRQRPHWULF %HQFKPDUNLQJ RI 7RURQWR *HQHUDWLRQ &RVWV *HQHUDWLRQ &RVWV *HQHUDWLRQ &RVWV

2. PEG and PSE Reliability Benchmarks

PEG states that PEG and PSE agree that THESL's 3(*'V ILQGLQJV GLIIHU VRPHZKDW IURP WKRVH RI 36(¶V EHORZ H[SHFWHG OHYHO 3(* also below benchmarks, but not as far below as PSE found. However, the results seemingly differ because in the PEG Report, PEG was referring to the more dated time period of 2009-2011, and in the PSE September Report, we used the most recent time period of 2010-2012, it has THESL at 49% below SAIDI benchmark values, as compared to the 48% below in the PSE September Report. Both PSE and PEG find that THESL's SAIDI is projected to be 100% below benchmark values by 2019.

The fact that PEG's results are nearly identical to PSE's is slightly obscured by modifying the graph that PSE provided in its September Report, comparing THESL's actual SAIDI values to benchmarks (see Figure 1 in PSE's September Report). PEG's calculated SAIDI benchmarks (green line) PSE's September Report. Figure 1 below shows the three values and THESL's actual and projected SAIDI results (red line). Figure 1 below shows the three values and illustrates why there is little difference in benchmarks.

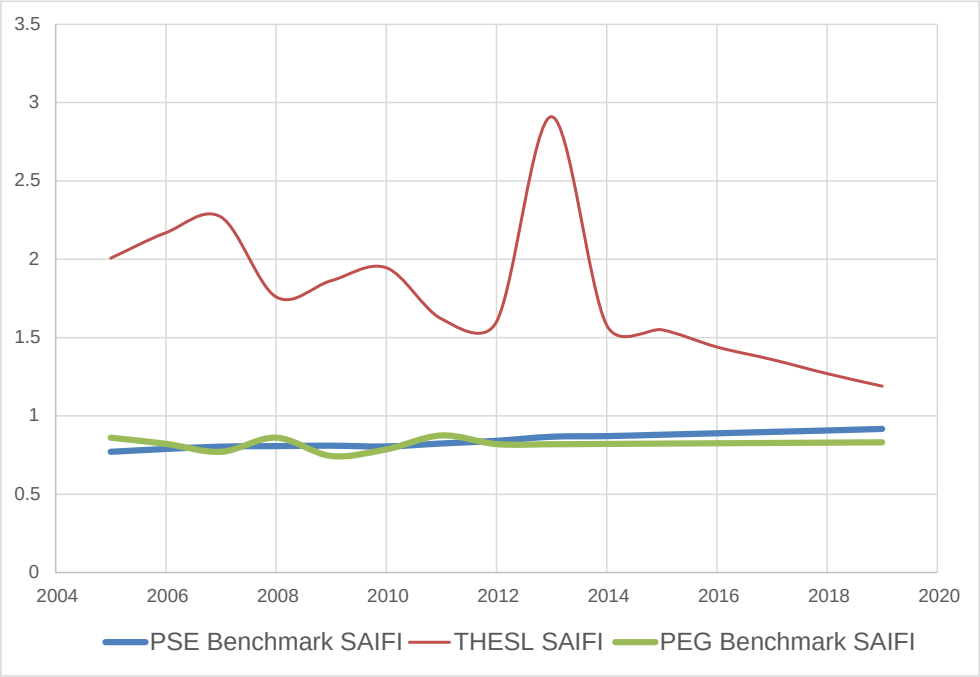
Figure 1 SAIDI: PSE, PEG, and Actual



As PSE has already noted, PEG has arrived at nearly identical benchmarks. In Figure 2 below, PSE has added PEG's benchmarks (green line) to PSE's graph of THESL's actual/projected results (red line). Notice again how similar the PEG and PSE reliability results are.

[1] Page 5 of the PEG Report.

Figure 2 SAIFI: PSE, PEG, and Actual



'HVSLWH 3(*¶V FRQWHQWLRQ WR WKH FRQWUDU\ WKHUH LV 3(*¶V 6$,', EHQFKPDUN 6$,', those in PSE's Exhibit No. 6 (DQG the only difference arises from the different time periods being compared. The PEG Report focused on the reliability performance scores in the past (2009-2011) rather than using the Custom IR projections to formulate conclusions. Although PEG has conducted this analysis, the PEG Report did not display the future reliability projections (THESL is projected to improve in this area). 7KLV LV LQFRQVLVWHQW ZLWK 3(*¶V total costs, where PEG¶V FRQFOXVLRQV ZHUH EDVHG RQ 7+(6/¶V UHVXOW

PEG notes that it made a numb HU RI UHOLDELOLW\ GDWD VHW UHYLVLRQV based on whether the data could be verified with the source document, or whether the value aligned ZLWK WKH FXUUHQW GRFXPHQW 3(* VWDWHV RQ SDJH [3] RI LWV RPLVVLRQV ´ 3(*¶V exaggerated. The adjustments PEG made WR 36(¶V UHOLDELOLW are minor revisions. PSE made a good faith effort to gather data from hundreds of sources scattered around the internet over the course of many years. PEG made minor changes that did not have a PHDQLQJIXO LPSDFW RQ WKH UHVXOWV 7KH 36(* WKDW WKH this fact.

The consistency in 7+(6/¶V UHVXOWV is notable, given that two separate experts used different data sets, time periods, and models to derive them. While PSE is unconvinced WKDW 3(*¶V included variables should have replaced those in PS(¶V 6HSWHPEHU issue is of little WKH consequence in this case, given the extreme similarity of results.[2] The similar results should provide the Board with a high level of confidence in the reliability benchmarking provided by PSE in this proceeding.

[2] PEG inserted cooling degree days, heating degree days, undergrounding, and precipitation into the models and took out percent forestation, customer density, wind, and the number of customers from the PSE models.

3 7RWDO &RVW 5HVXOWV DQG 0RGHO

As the experience of incentive regulation in Ontario has shown, benchmarking tends to be an iterative process. Putting together data sets, explanatory variables, and models takes time and requires input from multiple stakeholders. Throughout this process, benchmarking evaluations tend to become more accurate, comprehensive, and trustworthy, resulting in improved evidence to better inform decisions.

5 H O D W L Y H th W Generation 3 (* ¶ V Incentive Regulation benchmarking model, the PEG Report made strides in conducting a fair total cost benchmarking evaluation in relation to THESL. This was primarily done by using the U.S. data set.[3] PSE agrees with PEG that excluding uncollectible account expenses from the U.S. data is appropriate, given that bad debt expenses were excluded for all of the Ontario utilities.[4] 3 (* DOVR LQFOXGHG 7 + (6 / ¶ V VPDUW PHWHU definition. While this is unfair to THESL, since only a handful of U.S. utilities in the dataset have fully deployed smart meters, in an effort to only focus on major issues, PSE will QRW PRGLI\ 3 (* ¶ V treatment of smart meters in the Reply Report results.

+ R Z H Y H U W K U H H D G M X V W P H Q W V Q H F H V V D U \ W R 3 (* ¶ V 5 H Y L V H G 7 + (6 / ¶ V F R V W and to make the model align with benchmarking best practices. These are:

1. 0 D N H 7 + (6 / ¶ V I R U H F D V W H G F R V W V E \ H [F O X G L Q J E D G G H E W H [S H Q V H V ,
2. Make cost definitions comparable and more comprehensive between THESL and the U.S. VDPSOH E\ DGGLQJ LQ 7 + (6 / ¶ V &,0 FXVWRPHU VHUYLFH and UHinformation expenses for the U.S. sample, and
3. Re-introduce in the model the logical, properly signed, and statistically significant urban core variable, and exclude the incorrectly signed and statistically insignificant high voltage variable.

These three adjustments are discussed in the following sections.

3.1 $GMXVWPHQW IRU 'HEW ([SHQVHV

PEG correctly states that uncollectible account expenses should be subtracted for the U.S. sample. PSE agrees that this improves the comparability of costs, but we note that PEG should also subtract RXW EDG GHEW H[SHQVHV IRU 7 + (6 / ¶ V IRUHFDVWHG WHVW SHUL PSE requested this data from THESL and has subtracted bad debt expenses, along with other non-comparable costs such as property taxes that were previously in the forecasted cost data. This was done in an effort to define forecasted costs in the same way in 7 + (6 / ¶ V DQG 8 6 XWLOL historical costs.

---

[3] Recall that PSE did estimate two models, a U.S. only and a combined U.S. and Ontario model. Both models showed similar results for THESL. In the interests of brevity and time, we only discuss the U.S. model in this report. PSE does dispute, however, PEG ¶ statement in its Responses to Interrogatories (1-THESL- WKDW 3 (* EHOLHYHV W is no value in PSE ¶ Ontario benchmarking, because PSE selected the TFP-based cost measure for THESL while the Ontario distributors were intentionally benchmarked using a different, benchmarking-EDVHG FRVW PHDVXUH ´ 7 incorrect; PSE used the same cost definition for both THESL and the rest of the Ontario distributors. The only H[FHSWLRQ WR WKLV 2019 7+(6/¶V EHLQJ

[4] 3 6 (XVHG 3 (* ¶ V GDWD th V HW Q HUXQGL R Q ,W KW R DWWHPSW WR UHSOLFDWH 3 (* ¶ possible. In doing that, PSE was unaware that bad debt expenses were excluded ZKLFK LV ZK\ 7 + (6 / ¶ V SURMH costs include bad debt expenses). PEG made it clear that these were excluded; thus, excluding those same type of expenses from the U.S. data set DQG IURP 7 + (6 / ¶ V cost projections is appropriate.

In PEG ¶ response to THESL ¶ Interrogatories, 1-THESL-23, PEG asserts that its estimates of THESL ¶ 2013- SURMHFWHG FRVWV ³LPSOLFLWO\´ VXEWUDFW EDG
PEG takes its 2012 costs, which excluded bad debt, and for projected costs for 2013-2019 adjusts it by PSE ¶ annual percentage change (from Table 6 of the PSE September Report). This method does not explicitly or implicitly exclude bad debt expenses for the 2013-2019 period, because PSE ¶ 2013- FRVWV LQFOXGH 7+ (6/¶V EDG GHEW H[SHQVHV ZKHUHDV WKH KLVWRULFDO 2002-2012 costs do not.

As an illustration 3(*¶V WRWDO FRVW YDOXH LV FDOFXODWHG XVL
HVFDODWHG E\ WKH JURZWK UDWH LQ 36(¶V WRWDO FRVWV IU
way ³LPSOLFLWO\´ VXEWUDFWV RXW EDG GHEW H[SHQVHV +RZ
2012 value excludes bad debt expenses, whereas the 2013 value includes bad debt expenses. By
HVFDODWLQJ 3(*¶V WRWDO FRVWV E\ WKH JURZWK UDWH
LQWR WKHLU WRWDO FRVW SURMHFWLRQV IRU 7+(6/ FUHDW
projected costs and those of the rest of the sample. The PSE approach is to simply subtract out bad debt expenses in the projected data so the cost definition matches the rest of the sampled data.

3.2 $GMXVWPHQW WR 'HPDQG 0DQDJHPHQW ([SHQV

PEG H[FOXGHG WKH HQWLUHW\ RI WKH ³FXVWRPHU VHUYLFH DQ
utilities, in an effort to exclude CDM expenses for U.S. utilities, similar to the Ontario cost definition. However, three problems arise with this: 1) THESL and other Ontario utilities also incur non-CDM customer service expenses that are not being excluded by PEG, creating a cost comparability problem and making the treatment advantageous to the U.S. and disadvantageous to THESL; 2) Eliminating a large expense category makes the total cost definition far less
FRPSUHKHQVLYH GHVSLWH WKH %RDUG¶V SUHIHUHQFH IRU FR
There is no assurance that U.S. utilities record all of their CDM expenses within the customer service and information cost category. [5]

To solve the first two problems, PSE added in THESL ¶V &'0 expenses and re-added customer service and information expenses back into the total cost definition for U.S. utilities. This made the cost definitions comparable between THESL and the U.S. sample, addressed 3(*¶V FRQFHUQ and made the cost definitions far more comprehensive than the definition used by PEG (which excludes all customer service and information expenses).

It is not known if all U.S. utilities report CDM costs in the customer service category. PEG claims on page 25 of its Report that CDM often constitutes the largest expense for the customer service and information expenses, thus somehow justifying the exclusion of the entire cost category for the U.S. sample only (THESL non-CDM customer service and information expenses are still included in the PEG definition). However, PEG does not provide any evidence that CDM constitutes the largest expense component of the customer service and information category, when asked in 1-THESL-24 (d).

To assist with this issue, PSE contacted FERC directly; the ³FERC Form 1 team´ explained to PSE that each state records these expenses differently, and there is no clear guidance on the issue. More specifically, the FERC Form 1 team stated:

[5] PEG claims in its response to 1-THESL-24 (a) to have subtracted out all of the customer service and information expenses not related to CDM for both the historical and projected THESL costs. This statement is incorrect, based on PSE ¶ review of PEG ¶ working materials, where no such adjustment is apparent nor mentioned in the PEG Report.

> Demand-side management (DSM) is a distribution activity regulated at the local jurisdictional level, not at the Federal level. Each jurisdiction sets its own methods for the accounting for and recovery of DSM activities, including direct expensing or recovery through of some or all of the costs in a regulatory asset. They may also have specific reporting requirements for DSM activities. /RRN WR HDFK FRPSDQ\¶V WDULII jurisdictional authority, for specific information on the treatment of DSM activities, and in which regulatory accounts such activity is charged.[6]

In an effort to provide conservative evidence in this proceeding and only address clear-cut necessary changes, PSE will assume that U.S. utilities report all CDM activities in the customer service and information expense category (even though this is likely not the case for all U.S. utilities). 7KXV 36(LQFOXGHG DOO RI ,7¶V DQG 6 /¶V SURMHFWHG 6 0 H[SHQGLWXUHV in 2015. Along with the smart meter expense inclusions for THESL, this assumption also makes the PSE Reply Report less favorable to THESL (e.g., if we were able to ascertain all CDM expenses for each utility and how they were recorded 7+(6/¶V UHVXOWV ZRXOG PRV better).

3.3 $GMXVWPHQW WR GHO 6SHFLILFDWLRQ ZLWK 8UEDQ &RUH 9DULDEOHV

3(* PRGLILHG 36(¶V 8 6 PRGHO E removing the urban core variable and including a high voltage capacity variable.[7] In this PSE Reply Report, following established industry practice, PSE removed 3(*¶V KLJK YROWDJH YDULDEOH EHFDXVH LW LV VWDWLVWLFDOO\ LQVLJQLILFDQW DQG LQFRUUHFWO\ signed, and re-included 36(¶V XUEDQ FRUH YDULDEOH ZKLFK LV VWDWLVWLFDOO\ VLJQLILFDQW at a 99% confidence level.

The fact that the high voltage variable is signed incorrectly (it should be positive, but is negative in the PEG Report Corrections) and statistically insignificant at even the 90% confidence level disqualifies the variable from being included. Business condition variables that are incorrectly signed or statistically insignificant are not included in econometric benchmarking mo GHOV 3(*¶V use of this variable, and its exclusion of the urban core variable, are not in-line with benchmarking best practices. PEG has stated the need for business condition variables to be correctly signed and statistically significant in a report to the Board. In a report dated March 20, 2008 [3] %HQFKPDUNLQJ WKH &RVWV RI 2QWDULR 3RZHU'HOLYHU\ ´ RQ SDJH PEG writes:

> All included business conditions were required to have elasticity estimates that were plausible (e.g. sensibly signed) and significantly different from zero. All variables found to be statistically significant were included in the final model. Since, additionally, we consider for inclusion only variables that are predicted by theory or that seem relevant on the basis of our industry experience, the model is not a ³black box´ that confounds attempts at earnest appraisal.

In this proceeding, PEG has provided conflicting models with different signs for the high voltage variable, but LQ ERWK PRGHOV WKH YDULDEOH LV VWDWLVWLFDOO\ 2014 Report provided a model in Table Three that showed a statistically insignificant high voltage variable, but one that was positively signed. Then in PEG Report Corrections, PEG submitted a revised Table Three; this time the high voltage variable was negatively signed, but still statistically

[6] Correspondence from FERC.

[7] PEG also removed the percent undergrounding variable, although failed to mention this change or explain why the change occurred in the PEG Report.

insignificant. Neither model meets the benchmarking best practice principles previously stated by PEG.[8]

7KH $SSHQGL[RI 36(¶V 6HSWHPEHU 5HSRUW SURYLGHG DQ HQJL
will have different cost challenges based on the development characteristics of their service territories. Costs are found to be well over double for urban service territories, relative to suburban RQHV ([FOXGLQJ WKH XUEDQ YDULDEOH FUHDWHV DQ RPLWW
disadvantages THESL in the process.

Excluding the urban core variable also violates benchmarking best practice. PEG wrote in a 2010 report written on behalf of Public Service Company of Colorado:

> One important result is that an econometric cost model can yield *biased* predictions of the true benchmark if relevant business condition variables are excluded from the model. It is therefore desirable to include in an econometric benchmarking model all business conditions which are believed to be relevant, for which good data are available at reasonable cost, and which have plausible and statistically significant parameter estimates.[9]

7KH 36(XUEDQ FRUH YDULDEOH LV QHFHVVDU\ WR LQFOXGH
LQFOXVLRQ 3(*¶V KLJK YROWDJH YDULDEOH GRHV QRW PHHW
high voltage variable for the urban core variable is, therefore, a necessary change to the total cost model and one that is made in this PSE Reply Report.

PEG summarizes this issue by writing the following on page 3 and 4 of the PEG Report:

> 7KH WKLUG VWHS RI 3(*¶V DQDOVLV LV WR DGG DQ
> WZR QHFHVVDU\ FKDQJHV WR 36(¶V VHOHFWHG EXVLQHVV
> variable to reflect MVa of transformer capacity for stations with primary voltage levels at or above 50 kV. 7KLV YDULDEOH LV QHFHVVDU\ WR FRQWURO IRU
> YROWDJH DVVHWV 7KH VHFRQG ZDV HOLPLQDWLQJ WKH
> model because it is redundant, inappropriate in electricity distribution benchmarking, and appears to distort the estimated impact of other business condition variables (especially undergrounding).

PEG seems to have added new requirements for including business condition variables. PEG FODLPV WKDW WKH XUEDQ YDULDEOH LV ³UHGXQGDQW´ LQDSSU
and appears to distort the estimated impact of other business condition variables (especially XQGHUJURXQGLQJ ´ 36(DGGUHVVHV HDFK RI WKHVH FRQFHUQ

3.3.1 The Urban Core Variable Is Not Redundant

On page 29 of the PEG Report, PEG states ³6LQFH 36(¶V PRGHO DOUHDG\ LQFOXG
XQGHUJURXQG YDULDEOH LQFOXGLQJ DQ µXUEDQ FRUH GXPP\¶

[8] PSE also notes that the high-voltage expenses are included in the ³TFP-based´ cost measure used by PSE. PEG incorrectly criticizes PSE ¶ use of a TFP-based cost in its Responses to Interrogatories (1-THESL-61) and in the PEG Report. The TFP-based costs capture the high-voltage costs that PEG is describing in its response. The TFP-based cost definition also excludes contributions in aid of construction (CIAC), which PEG itself subtracts from their cost definition for THESL (see PEG ¶ response to 1-THESL-20). Besides adding smart meter expenses, the rationale for which PEG fails to empirically substantiate in its response to 1-THESL-19 , PEG is effectively advocating for the cost definition used by PSE, while at the same time criticizing PSE for its use.

[9] PEG Report of Dr. Mark Newton Lowry, President of PEG, filed on Behalf of Public Service Company of Colorado RQ 'HFHPEHU 5HSRUW WLWOH ³6WDWLVWLFDO $QDO\VLV RI 3XEOLF

to be saying that the percent underground variable should be sufficient to pick up the impacts of higher costs for urban areas. This is incorrect for several reasons.

1. In our experience with hundreds of distributors, undergrounding tends to cost a great deal more in urban centers than in rural or suburban settings. In more rural and suburban settings, direct bury cables with pad mounted equipment are typically used. These are much less expensive than concrete-encased duct bank installations with underground vaults, submersible equipment and massive civil infrastructure, which are found in urban settings.

2. Similarly, overhead line construction can be found within all service area environments, but will also cost a great deal more in urban settings; these costs are not captured by an undergrounding variable.

3. The underground variable is not found LQ 3(*¶V ILQDO LPSOHPHQWDWLRQ 6HSWHPEHU 5HSRUW states in 1-THESL-32 the undergrounding variable was excluded because it was either statistically insignificant or had the wrong sign. It is not sensible to exclude the urban variab OH RQ WKH EDVLV LW LV ³UHGXQGDQW ´ EXW WKHQ DO as its replacement.

The costs of all types of construction based on the developed areas are laid out in the Appendix to WKH 36(6HSWHPEHU 5HSRUW The percent underground variable will pick up the cost variations for an urban utility is not correct. In the end, serving an urban core simply increases costs, and our report shows that the urban core variable captures this fact.

3.3.2 The Urban Core Variable Is Not Inappropriate

:H QRZ PRYH WR 3(*¶V FODLP WKDW WKH XUEDQ FRUH Y GLVWULEXWLRQ EHQFKPDUNLQJ ´ 7KLV VWDWHPHQW LV FO

variable in prior gas distribution cost benchmarking studies. On page 28 of the PEG Report it lays out its rationale for this statement as follows:

> Some PEG studies have used this variable in gas distribution models, but the rationale for using such a dummy variable is much stronger for gas distribution because essentially all gas distribution assets are underground. A dummy variable is one means of distinguishing between the higher costs of installing and maintaining underground gas distribution assets in densely-populated, mature urban areas compare G ZLWK ³JUHHQILHOG´ VXEXUE

The reasons that costs increase for urban gas distributors are the exact same reasons costs increase for urban electric distributors. Constructing and maintaining either underground or overhead assets in a densely-populated and mature urban area will cost considerably more than constructing and maintaining either overhead or underground power lines in a suburban environment. This is the same message in the PSE September Report Appendix.

3.3.3 The Urban Core Does Not Distort the Impact of Other Variables

3(*¶V ODVW FULWLFLVP RI WKH XUEDQ FRUH YDULDEOH LV WKH RWKHU EXVLQHVV FRQGLWLRQ YDULDEOHV HVSHFLDO

eliminated the undergrounding variable from their model. Eliminating the undergrounding variable vitiates the distortion argument VLPLODU WR 3(*¶V UHJUHVVLRQ FRQFH using econometrics, any included variable will change the estimated impacts of the other business condition variables. This is why there needs to be a theoretical basis for including variables, and they must be correctly signed and statistically significant. To not include a variable that is predicted by theory, correctly signed, and statistically significant because it will change the other business condition variables would distort the model by creating what is known in econometrics

as DQ 3RPLWWHG .YD%\LHEEHXGLQV WKH XUEDQ FRUH YDULDEOH this bias.[10]

The system R-VTXDUHG VWDWLVWLFV RI 3(*¶V PRGHO DQG 36(¶V 5HS R-VTXDUHG VWDWLVWLFV DUH PHDVXUHV RI ³JRRGQHVV RI IL variation in the dependent variable (total cost) is explained by the mRGHO 3(*¶V 5 0.926, implying that 92.6% of the variation in the data set is explained in their model. After making WKH WKUHH DGMXVWPHQWV, the R-squared for the resulting model increases to 0.962. This supports 36(¶V SRVLWLRQ that the need to include variables that are logical, statistically significant, and properly signed.

In summary, standard industry practice results in including the urban core variable and excluding 3(*¶V KLJK YROWDJH. This will also capture a highly relevant cost driver (serving an urban core), which is necessary to provide a fair and accurate PRGHO WR HYDOXDWH 7+(6 performance.

3.4 36(5HSO\ 7RWDO &RVW 0RGHO 5HVXOWV

The model estimates are provided in Table 1. All first order and business condition variables are logical, correctly signed, and statistically significant at a 95% level of confidence.

The PSE Reply Report total cost results are provided in Figure 3 and Table 2. THESL¶V FRVWV DUH under WKH 36(5HSO\ 5HSRUW WRWDO FRVW EHQFKPDUNV XQWL SURMHFWHG WR PRYH KLJKHU WKDQ LWV EHQFKPDUNV E\ DUR DVVXPH WKDW WKH FRPSDQ\¶V SURSRVHG Custom IR approved in Docket 35854-UR-116, Table 2 shows the numerical PSE Reply Report model results. THESL Custom IR projections remain within the 4th Generation IR 0.3% stretch factor range of +\- 10%.

[10] 3OHDVH VHH 3(*¶V response on the prior page regarding what causes bias and how it can be prevented by including all business conditions that are plausibly signed, can have data gathered, and are statistically significant.

Table 1 PSE Reply Report Cost Model

		WK=	Capital Price			
		N=	Number Retail Customers			
		D=	Peak Demand			
		UD=	Urban Core Dummy			
		PCE=	Percent Electric Customers in Gas & Electric Customers			
		PRV=	Percent Residential Deliveries in Total Deliveries			
		PDE=	Percent Distribution Plant in Total Electric Plant			
		ED=	Elevation Standard Deviation			
		PF=	Percent Forestation			
EXPLANATORY VARIABLE	**ESTIMATED COEFFICIENT**	**T STATISTIC**		**EXPLANATORY VARIABLE**	**ESTIMATED COEFFICIENT**	**T STATISTIC**
WK	0.585	161.579		PDE	0.109	6.409
KK	0.062	3.472				
KN	-0.034	-3.051		ED	0.016	2.386
KD	0.042	3.626				
				PF	0.018	3.242
N	0.738	28.283				
NN	0.583	6.354		Trend	0.003	2.727
ND	-0.495	-5.394				
D	0.208	7.566				
DD	0.455	4.580		Constant	20.052	1418.424
UD	0.014	4.625		System Rbar-Squared	0.962	
PCE	0.122	4.238		Sample Period:	2002-2012	
PRV	0.037	2.133		Number of Observations	805	

Figure 3 PSE Reply Report Cost Model Results

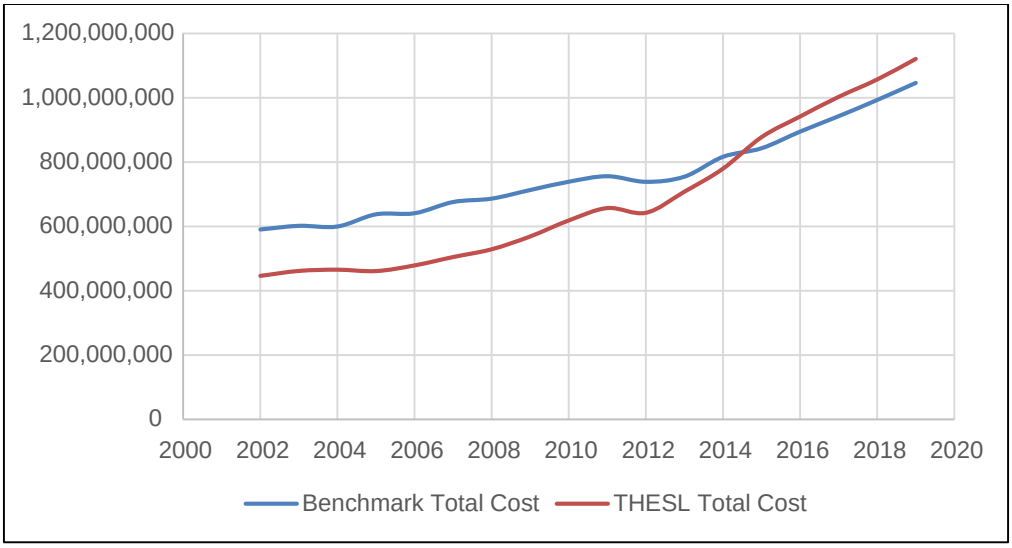


Table 2 PSE Reply Report Cost Model Results

Year	Percent of U.S. Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Total Cost THESL, $M
2002	-28.0%	$591	$446
2003	-26.5%	$602	$462
2004	-25.4%	$600	$466
2005	-32.4%	$638	$461
2006	-29.2%	$641	$479
2007	-29.2%	$676	$505
2008	-26.0%	$687	$529
2009	-22.6%	$713	$569
2010	-17.8%	$739	$619
2011	-14.0%	$756	$657
2012	-13.9%	$739	$643
2013	-6.3%	$755	$708
2014	-4.6%	$816	$780
2015	4.1%	$843	$878
2016	5.2%	$895	$942
2017	6.2%	$943	$1,003
2018	6.3%	$993	$1,057
2019	7.0%	$1,046	$1,121

4 3(* 5HVSRQVH WR 6WDWHPHQWV RQ *HQHUDO %HQFKPDUNLQJ 3UDFWLFHV

The PEG Report embarked on some discussions that did not directly pertain to the cost and reliability models 7KLV VHFWLRQ SURYLGHV 3(* general topics.

4.1 5HVSRQVH WR &KDSWHU 6LPXOWDQHRXV &RVW DQG 5HOLDELOLW\ %HQFKPDUNLQJ

In Chapter 5 of its report ("6LPXOWDQHRXV &RVW DQG 5HOLDELOLW\ %HQFKPDUNLQJ DQG 6SHQGLQJ 3UDFWLFHV WR 5HGXFH 5HOLDELOLW\ ,PSDFWV") PEG attempts to UHSOLFDWH D UHOLDELOLW\ LPSDFW DQDO\VLV WKDW[11] 3(* FRQG
In 2013, WPS proposed a large 5-year reliability-driven spending program to its Wisconsin UHJXODWRU :36 QDPHG WKLV VSHQGLQJ SURJUDP WKH "6\VW "36053´ ,Q WKDW SURFHHGLQJ 'U .DXIPDQQ RI 3(* SSURYLGH regarding the quantification of consumer benefits to improving reliability and compared these benefits to the five-year costs of the spending program. Mr. Fenrick of PSE also testified on behalf RI :36 DQG SUHVHQWHG 3(*¶V UHOLDELOLW\ LPSDFW EHQFKPDU model

PSE found that the SMRP beat industry benchmarks for reliability-improvement spending. The study showed increasing net distribution plant by 43% for an average utility would improve SAIDI by around 12%. Thus, the projected SAIDI improvement of 20 to 25% for WPS would beat industry benchmarks.

In Chapter 5 of the PEG Report in this proceeding, 3(* LPSOHPHQWHG 3(*¶V PRGHO L case incorrectly. PEG inserted the growth rate in capital expenditures, rather than the increase in distribution net plant, over the life of the plan. PSE explicitly stated in the WPS case that we used GLVWULEXWLRQ QHW SODQW DV WKH EDVLV IRU WKH FDOFXOD sur-surrebuttal testimony in Case 6690-CE-198 on May 6, 2013, page 2.

When asked in the THESL interrogatories about why PEG used annual capital expenditures rather than electric net distribution plant (1-THESL-52), PEG stated that it did not use the correct input because PSE had not provided the relevant WPS testimony. However, this testimony is on the public record, and PEG was aware of it, having been involved in the WPS case. In its report in this proceeding, PEG did not correctly reproduce PSE¶ prior research. When questioned in Interrogatory 1-THESL-52, PEG did not acknowledge nor correct this error in its reply, despite having access to the above-noted information that demonstrates that the error was made.

LYHQ WKDW 7+(6/¶V QHW SODQW LQFUHDVH around 25% for 7+(6/¶V five-year plan) with reliability improvement estimated to be very similar to WPS¶V (at 18.7% for THESL), we expect THESL to have a better finding than WPS did. In trying to replicate 3(¶V VWXG\ PEG GLVFRXQG WKDW 7+(6/¶V 6$,', SURMHFWLRQV IDOO D benchmarks. This conclusion is based on an incorrect LPSOHPHQWDWLRQ RI 3(*¶V SULR should be disregarded.

4.2 3(*¶V =RQH RI &RQWLQXRXV DQG 5HDVRQDEOH ,5 3ODQ

3(*¶V 6HSWHPEHU 5HSRUW VWDWHV projected spending should result in a utility more aligned with its externally-derived benchmark values from both a total cost and

[11] PSE did not put forth this model in its September report, it was only brought up in interrogatories by Board Staff, LQ TXHVWLRQLQJ E\ 'U .DXIPDQQ WR 0U)HQULFN DW WKH 7HFKQLFDO &RQ

6$,), SHUVSHFWLYH[12] discusses how a utility should strive to improve benchmark evaluations in both cost and reliability simultaneously. PEG illustrates this on page 19 with a graph that implies that a distributor should find ways to improve both total costs and reliability at the same time, thus entering the PEG concept of the ³]RQH RI FRQWLQXRXV LPSURYHPHQW

3(*¶V DQDO\VLV LV LQFRQVLVWHQW with industry practices; all utilities know there are trade-offs between improving reliability and costs. PEG acknowledges this later on page 43, when it states WKHUH LV -XVW VR PXFK PRQH\ DYDLODEOH´ EHWZHHQ FRVWV DQG UHOLDELOI[13]

PEG has not provided any detailed plans on how THESL can actually improve both reliability and WKHLU WRWDO FRVW SHUIRUPDQFH DW WKH VDPH WLPH 3(* speculation, not likely to be possible in practice, and ignores tKH ³FRPSURPLVH OLQNDJH´ EHV costs and reliability. Of course, it would be desirable if all utilities could simply reduce costs and enhance reliability, but in the real world, that is not feasible for the vast majority of utilities. Benchmarking can VHUYH DV D JXLGH WR KHOS DQVZHU ZKDW LV LC customers, thus offering customers with a better balance between two competing interests (low costs and high quality service).[14]

As discussed in the prior section, it appeared that Dr. Kaufmann of PEG had no issue with WPS ramping up capital spending for a five-year period in order to improve reliability. In fact, he estimated that the benefits outweighed the added costs. 2Q SDJH RI 'U .DXIPDQQ¶V U testimony on behalf of WPS, he states:

> Nevertheless, with an estimated value of more than $21 million per year to WPS customers after 2019, I believe the benefits generated because of the SMRP will certainly exceed the total costs of the program in less than 20 years, which is less than half of the 60-year expected life of the assets to be installed under the program.[15]

By conducting this capital spending program, :36¶V total cost benchmarks would suffer. Yet Dr. Kaufmann firmly rejected the idea that the program should be stretched out beyond the proposed five years. Dr. Kaufmann on behalf of WPS stated:

> Delaying the implementation of the SMRP would reduce benefits to customers. If the SURMHFW¶V LPSOHPHQWDWLRQ ZDV H[WHQGHG WR \HDU ben HILWV ODWHU %HFDXVH WKHUH LV D WLPH YDOXH RI benefits to customers.[16]

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[12] Page 12 of the PSE September Report.

[13] PEG clarified its agreement in its Responses to Interrogatory (1-THESL-48); it did not dispute the common-sense linkage, as described the last sentence in paragraph 2 on page 43 of the PEG Report, which states that:

> 6LQFH µROG DQG IDLOLQJ LQIUDVWUXFWXUH¶ FDQ EH UHPHGLHG E\ SX posits a relationship between changes in THESL costs (especially the investment costs associated with installing new capital) and future changes in its SAIFI.´

(Emphasis added). In other words, as costs go up (especially new capital costs), SAIFI improves.

[14] Other tools are also helpful to find the EHVW EDODQFH EHWZHHQ FRVWV DQG UHOLDELOLV 0RGHO ³),0´ LV DQ H[DPSOH RI WKH XWLOLW\ DWWHPSWLQJ WR ILQG WK investment and customer preferences for reliability.

[15] Case 6690-CE-198 Pre-filed Rebuttal Testimony of Lawrence Kaufmann for Wisconsin Public Service Corporation, April 23, 2013.

[16] Page 13 and 14, Case 6690-CE-198 Pre-filed Sur-Sur-Rebuttal Testimony of Lawrence Kaufmann for Wisconsin Public Service Corporation, May 6, 2013.

PSE believes WKLV VDPH ORJLF LV DSSOLFDEOH LQ 7KH (6/ RQH & RI W
FRQWLQXRXV LPSURYHPHQW´ that is likely to be impossible to achieve and, if attempted, would very likely result in far worse reliability than what would occur if the Custom IR plan is approved in full.

Furthermore, PSE sees no rationale for lengthening the Custom IR period from five years to eight years, as suggested by PEG. Improved reliability offers substantial benefits to customers. Even if THESL could deliver the same reliability outcomes in eight years rather than five (which is unrealistic given the reduced investment per year), there is little reason to delay a reliability outcome that is in the interests of customers. Dr. Kaufmann of PEG agrees in his WPS testimony quoted above. Providing a better alignment between costs and reliability is improvement.

4.3 7KH 0HDQLQJ RI WKH %HQFKPDUN 5HVXOWV

PEG states on page 12 of its Report: ³36(¶V FRQFOXVLRQ WKDW µWKH FRPSDQ\
RI LQYHVWPHQW¶ LV VLPSO\ VSHFXODWLRQ or empirically from FOXVLR
WKH EHQFKPDUN VWXGLHV LW SUHVHQWHG´ 36(ZRXOG OLNH
³WKH FRPSDQ\¶V FDSLWDO ZDV LQ QHHG RI LQYHVWPHQW´

What the PSE September Report DFWXDOO\ VWDWHG ZDV WKDW ware 36(¶V EH
³suggestive´ RI WKLV 3(* LV FRUUHFW statistically-derived basis for concluding LV QR
with certainty that ³WKH FRPSDQ\¶V FDSLWDO ZDV LQ QHHG RI LQYHVW
sense ³VXJJHVWV´ certain´ statements, even if they are not strictly empirical conclusions. A benchmarking result that shows a utility with lower than expected costs, yet higher than expected SAIFI, suggests to PSE that the capital infrastructure is failing more often than expected, and is likely in need of added investment.[17]

There is a common-sense linkage between cost management and reliability outcomes. The total cost benchmarking results show the expected total costs for each utility in the sample, given their business condition variable values. One method of increasing the cost efficiency benchmarking score is to have older infrastructure. All else being equal, older infrastructure will increase total costs less than newer infrastructure. Yet there are limits on increasing cost efficiency in this manner. At some point, investment is needed to renew the infrastructure.

36(¶V EHQFKPDUNLQJ UHVXOWV IRXQG WKDW 7+(6/ LV KLVWRU
is failing more often than our models suggest. Based on the common-sense linkage between costs and reliability, this result suggests to PSE WKDW 7+(6/¶V FDSLWDO LV LQ QHHG RI

[17] It should also be noted that PEG, in both its Report (p. 14) and its Response to Interrogatories (1-THESL-8) PLVFKDUDFWHUL]HV 36(¶V SRVLWLRQ RQ 6$,), DQG FDSLWDO VSHQGLQJ ,W to be reasonable because it is decl LQLQJ XQGHU &XVWRP ,5«´ 36(QHYHU VWDWHV RU
UHDVRQDEOH LQVWHDG 36(ILQGV 7+(6/¶V SODQ WR LQFUHDVH FDSLWDO V

5 36(&RQFOXVLRQV

$IWHU PDNLQJ WKH WKUHH VWUDLJKWIRUZDUG DGMXVWPHQ
total costs are 15.2% below benchmarks in 2010-2012. During the Custom IR period, THESL ¶V
costs remain within the 4th Generation IR 0.3% stretch factor range. 7+(6/¶V 6$,), LV KLVWRULO
above benchmarks, EXW FRQYHUJHV WRZDUGV EHQFKPDUNV GXULQJ W
SAIDI is below benchmarks, and is projected to continue to be lower during the Custom IR period.

%DVHG RQ WKHVH UHVXOWV DQG WKH GLVFXVVLRQV LQ WKURXJK

- A stretch factor GXULQJ 7+(6/¶V &XVWRP ,5 SODQ consistent with 4th Generation IR. 7+(6/¶V WRWDO FRVW UHVXOWV UHIOHFW and implies the 0.3% value. Reliability is mixed, with SAIFI being worse and SAIDI being better than expected. Throughout the Custom IR period, however, SAIDI is projected to be over 100% EHORZ EHQFKPDUNV DQG VWDWLVWLFDOO\ SURMHFWHG WR converge towards the benchmark and be statistically average during the Custom IR period.
- 3(*¶V VXJJHVWLRQ RI OHQJWKHQLQJ WKH &XVWRP ,5 S rejected. 7+(6/¶V 5-year Custom IR proposal provides an improved alignment between UHOLDELOLW\ DQG FRVWV ZKLOH PDLQWDLQLQJ WRWDO Lengthening the time period will stunt this improved alignment.
- 7+(6/¶V WHVW \HDU are reasonable from a benchmark perspective. (YHQ ZLWK WKH FRQVHUYDWLYH Report HQYLURQPHQW 7+(6/¶V 5HSRUW DUH LQ WKH ³QRUPDO´ UDQJH
- Given the enhancement LQ UHOLDELOLW\ UHVXOWV (in particular for 7+(6/¶V SAIFI), the Custom IR plan will better align THESL with its total cost and SAIFI benchmarks. This is an improvement and is likely to provide value to THESL customers.

ANNUAL REPORTING

This schedule details Toronto Hydro's proposed Annual Reporting activities with respect to its 2015-2019 Custom Incentive Rate-Setting ("CIR" or "Custom IR") application, which consist of three components:

1) Meeting the Ontario Energy Board's ("OEB") Scorecard Approach for Performance Measurement;
2) Reporting on the Proposed Performance Measures Framework as detailed in the Distribution System Plan (DSP)[1]; and
3) Filing a rate schedule for the following year upon the OEB's update of its inflation factor.

These activities will be filed with the OEB at different times throughout the year based on the nature and purpose of each filing.

1. REPORTING ACTIVITIES

The OEB's RRFE Report[2] concluded that the appropriate device to monitor utility performance was a scorecard, noting that distributors would be required to report annually on their progress against metrics aligned with four core objectives:

1) Customer Focus;
2) Operational Effectiveness;
3) Public Policy Responsiveness; and
4) Financial Performance

The OEB is clear that its scorecard would apply to all distributors. Accordingly, annual reporting requirements will be the same for CIR, 4th Generation Incentive Rate-Setting or

[1] Exhibit 2B, Section C.
[2] Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (October 18, 2012) [the "RRFE Report"].

Annual Incentive Rate-Setting applicants, such as the utility proposes to do so at its discretion. Toronto Hydro proposal for its annual reporting requirements is consistent with this view.

1.1. OEB's Scorecard

Toronto Hydro intends to comply with the OEB's Scorecard, as summarized in Figure 1:[3]

Figure 1: Measures of the Four Performance Outcomes in the OEB's Scorecard

[3] EB-2010-0379, Report of the Board Performance Measurement for Electricity Distributors: A Scorecard Approach (March 5, 2014) at page ii, Table I.

1.2. DSP Metrics

As part of its DSP, Toronto Hydro has developed a set of 12 metrics to monitor quality and drive continuous improvements in its distribution system planning and implementation efforts.[4] These metrics are summarized in Table 1.

Table 1: Proposed DSP Performance Measures Framework

Customer-Oriented Performance	Cost Efficiency/ Effectiveness of Planning and Implementation	Asset/System Operation Performance
1. System Average Interruption Duration Index "SAIDI"). 2. System Average Interruption Frequency Index ("SAIFI"). 3. Customer Average Interruption Duration Index ("CAIDI"). 4. Feeders Experiencing Sustained Interruptions ("FESI"). 5. Momentary Average Interruption Frequency Index ("MAIFI").	1. Distribution System Plan Implementation Progress. 2. Planning Efficiency: Engineering, Design and Support Costs. 3. Supply Chain Efficiency: Materials Handling On-Cost. 4. Construction Efficiency: Internal vs. Contractor Cost Benchmarking. 5. Construction Efficiency: Standard Asset Assembly Labour Input.	1. Outages caused by defective equipment. 2. Stations capacity availability.

[4] Exhibit 2B, Section C.

Toronto Hydro proposes to file an annual update on these metrics by June 30th of the year following the reporting year. For clarity, the first report would be filed in 2016 and would cover the utility's performance in the year 2015.[5] The manner of reporting is described in further detail in Exhibit 2B, Section C1.1.1, pages 4 and 5. /C

1.3. Annual Distribution Rates

Toronto Hydro's proposed rate framework[6] for the CIR application uses a custom Price Cap Index ("PCI") as the annual adjustment mechanism for its base distribution rates in 2016 to 2019. The custom PCI employs the OEB's inflation factor as an input to the formula. Accordingly, Toronto Hydro proposes to submit a distribution rate adjustment on an annual basis followings OEB's determination of the newest inflation factor (which typically occurs later in the calendar year) and at a date prior to when those rates are to come into effect. /C

[5] Although Toronto Hydro's 2015 rate year will not commence until at least May 1, 2015, the utility's proposal is to report the DSP performance measures results on a calendar year basis. In other words, the 2016 results will cover the timeline from January 1 to December 31, 2015. /C
[6] See Exhibit 1B, Tab 2, Schedule 3.

CUSTOMER ENGAGEMENT

The diversity of Toronto Hydro's customer base requires the use of a variety of engagement tools. This schedule first describes the utility's ordinary course, day-to-day engagement with its residential, non-residential and very large customers. The schedule then discusses the various customer engagement activities that Toronto Hydro has undertaken specifically in connection with this application and the utility's 2015-2019 Distribution System Plan ("DSP"). The DSP has been filed as Exhibit 2B.

1. ORDINARY COURSE CUSTOMER ENGAGEMENT

Toronto Hydro serves a broad and diverse customer base, which it engages with in a variety of "ordinary course" interactions every year. This section describes the utility's customers and outlines some of the regular interactions that Toronto Hydro has with residential and non-residential customers.

The utility has approximately 730,000 customers, ranging from individual residential consumers up to large industrial and commercial businesses. Toronto is home to the country's largest banks, stock exchanges, major manufacturers, and other large customers that are sensitive to service interruptions. The utility powers non-residential customers from a wide variety of sectors, from data centres to large industrial and manufacturing facilities. The utility has over 80 hospital accounts, 280 healthcare and long-term care facility accounts, 690 schools accounts, and 140 college and university accounts. Toronto Hydro also supplies electricity to the Ontario's Provincial Legislature and Ministries, as well as Toronto's municipal government. Toronto has over 2,900 high-rise multi-residential condominium and apartment building accounts, many of which are "bulk-metered". Taking these behind-the-meters customers into account, Toronto Hydro's effective customer base exceeds 1 million customers.

The city of Toronto is one of North America's largest urban centers. Due to the scale and density of Toronto Hydro's franchise area, as well as the varied nature of the utility's customer base, the safe and reliable operation of the utility's distribution system affects a number of key economic drivers for the city, the province and the country.

1.1. Residential Customers

The utility has numerous "ordinary course" points of contact with its residential customers. The vast majority of such contacts occur in connection with billing matters: setting up, closing, paying, conservation and demand management ("CDM"), and otherwise relating to customer accounts.

Toronto Hydro also engages with customers when it carries out capital work. The utility's goal is to proactively mitigate customer and stakeholder concerns with Toronto Hydro's projects. To enable the effective delivery of planned capital projects while maintaining focus on customers, Toronto Hydro has a team dedicated to communication with customers in connection with planned capital projects and resolution of customer issues related to that work. These issues can range from repairs, outages, scheduling, installation of equipment, construction noise, safety, private property easements and the utility's staging areas.

Part of this engagement is driven by the City of Toronto's Municipal Consent Requirements ("MCR"), which requires that Toronto Hydro communicate with certain customers affected by capital work. Chapter 5 of the MCR states that:

> The Applicant [i.e., Toronto Hydro] shall provide written notification to all adjacent properties, and all properties that will face or will have a line of sight to the proposed plant. Such notification shall outline the nature of the work and clearly describe the size, appearance and location of the proposed

plant. The notice shall include the name and phone number of a contact person at the Applicant's office.

However, understanding customer needs and preferences on the execution of capital work goes beyond the City's MCR, Toronto Hydro also communicates with customers about capital projects through a variety of channels such as: letters, email, telephone, face-to-face meetings, newspapers, advertisements, newsletters, community meetings, and website. In 2013, Toronto Hydro's Customer Operations Communications Office ("COCO") distributed close to 60,000 customer letters, and communicated on over 270 projects. In 2015-2019, COCO plans to maintain its focus on communicating project information to customers who are affected by utility's capital projects, and to address their concerns.

1.2. Non-Residential Customers

Given the variety of Toronto Hydro's non-residential customers, the utility considers the needs of its larger customers[1] in terms of market segments. Broadly speaking, Toronto Hydro's customers fall into the major market segments set out in Table 1 below. The table also includes sub-categories, which provide examples of the types of businesses within each market segment:

Table 1: Major Market Segments

Major Market Segment	Illustrative Sub-Categories
Commercial	Offices
	Data Centre (Stand Alone)
	Banks
	Restaurants
	Hotels-Motels
	Retail

[1] Customers whose demand is between 50kW and 5,000kW.

Major Market Segment	Illustrative Sub-Categories
	Malls/Plazas
	Grocery Stores
	Entertainment
Institutional / Non-Municipal Government	Offices
	Colleges/Universities
	Religious
	Schools-Elementary/Secondary
	Hospitals
	Healthcare Facilities
	Community Service/Entertainment
	Public Works/Infrastructure/Transportation
Government – Federal, Provincial and Municipal	Civic Centres
	Parks and Recreation
	TTC
	Library
	Water and Waste Water
	Toronto Community Housing
	City Corporate Services
	Police
	Fire Hall
	EMS
	Exhibition Place
	Zoo
	Toronto Parking Authority
	Public Works
	Agencies/Boards/Commissions
Industrial / Manufacturing	Food & Beverage
	Plastics/Rubber
	Chemical/Pharmaceutical
	Raw Materials/Textiles
	Electronics
	Other Manufacturing

Major Market Segment	Illustrative Sub-Categories
	Warehouse
	Refrigerated Warehouse
Multi-Residential	Apartments
	Condominiums

One of the reasons that Toronto Hydro considers its larger non-residential customers in terms of market segments is that different industries may have vastly differing operating environments/regulations, sensitivities, needs and preferences. For example, industrial and manufacturing customers maybe very sensitive to the frequency of outages – the occurrence of an outage, regardless of its duration, may require an entire batch of a product to be scrapped and production equipment to be reset and inspected. This is typically a significant cost and concern to such customers, and something that Toronto Hydro considers as it plans operations and capital investments.

In contrast with industrial and manufacturing customers, multi-residential customers may be less concerned with the frequency of outages than their duration – a brief outage may inconvenience the residents of a 500-unit condominium, whereas a long outage may entail significant costs and potentially safety concerns.

Institutional customers' interest may extend to the broader social effects of service reliability. For hospitals and other healthcare providers, outages may affect the delivery of critical care to patients. Outages affecting schools may create extreme inconvenience to large numbers of people, and may give rise to significant costs and potential safety risks if schools are required to relocate students.

Toronto Hydro has approximately 81,000 non-residential customers whose demand is less than 5MW. The utility's ordinary course engagement with such customers is similar

to its contact with residential customers that it generally relates to account inquiries, billing information changes, follow-up on outage restoration, energy conservation incentives or specific customer requests such as new connections.

Toronto Hydro also engages in other forms of indirect communication with customers through its interactions with industry associations on conservation, reliability and infrastructure investment issues. Organizations such as the Building Owners and Managers Association ("BOMA") and the Toronto Board of Trade can help the utility effectively disseminate critical information to their large memberships.

In addition, Toronto Hydro collaborates with the City of Toronto Better Buildings Partnership within the Energy Efficiency Office to pursue conservation opportunities within the municipal sector as well as leveraging demand response programs to support the emergency generation and preparedness plans of city affiliates such as Toronto Community Housing. Toronto Hydro is also a member of Weatherwise, a partnership convened by the City and Civic Action consisted of public, private and Not-For-Profit organizations identifying the risks of extreme weather.

1.3. Very Large Customers

Finally, Toronto Hydro has an engagement program – the Key Account Management Services program – dedicated to its very large "key account" customers. The utility created this program to better understand and respond to the unique experiences, preferences and service needs of this type of customer. Key account customers are typically sophisticated commercial and institutional entities who have a strong grasp of their service requirements and a good working knowledge of the electricity sector.

In 2012, the initial scope of the key account management service program was to offer formal engagement meetings annually to customers with an electricity demand greater

/C

than 5 MW or with a large aggregate of multiple commercial accounts throughout the city. In 2013 , Toronto Hydro expanded its scope to include customers whose demand exceeds 1 MW and who are served by feeders that have been experiencing a high frequency of outages. Generally, Toronto Hydro prioritizes meeting with key account customers who are experiencing the worst reliability and/or that are most significantly affected by service quality issues (e.g., food processors and pharmaceutical companies who must dump product and re-sterilize equipment; health care facilities concerned with patient procedures; plastic moulding companies with equipment concerns; etc.).

Formal key account management meetings typically address the following topics:

- Review of the customer's annual reliability performance and customer experience;
- Toronto Hydro reliability investigations and root cause analysis reports;
- Improving Reliability and Services – Infrastructure Renewal Program;
- Regulatory environment, current filing, system reliability, capital plan and investments, rate impact;
- Available account management services, including single point of contact, 24/7 outage management service, energy data management, billing services; and
- Conservation and Demand Management ("CDM"), including incentive program opportunities, energy efficiency training and support, electricity savings verification.

Toronto Hydro endeavours to customize its key account management services to best suit individual customers' specific needs and preferences. This customization can occur regarding the form and frequency of how the customer prefers to be engaged. Accordingly, while Toronto Hydro aims to meet with this group of customers on a consistent basis, some may choose to forego a meeting, while others prefer multiple meetings over the course of a year in order to address specific needs and opportunities.

/C

As explained in more detail below, the information presented by Toronto Hydro is customized for each customer for their reliability experience, current and planned investments in their local area, conservation and demand programs and the rate impact of investments on their current bill.

1.3.1 Key account meeting structure and engagement materials

Toronto Hydro's key account management customer meetings are currently structured around a standardized presentation. The presentation has evolved over time, but typically addresses four main topic sections:

1. Overview: Includes an overview of the utility, historical system spending, historical system reliability measures (i.e. SAIDI/SAIFI), drivers of outages, future investment needs, investments to improve reliability, and from time-to-time, current information on the regulatory process, including a brief, high-level discussion of recently concluded rate applications and/or pending applications.
2. Customer Specific Details: Includes customer specific reliability performance, reliability investigations and cause of outages, and generally serves as an opportunity to discuss the customer's experience. This typically includes a discussion of planned capital projects that will address the customer's service.
3. Bill Information: Using a bill sample or the customer's bill, Toronto Hydro explains the various components of the electricity bill and explains how costs could potentially be reduced.
4. Conservation and Demand Management (CDM) programs: Includes a status review of past and current conservation projects. Toronto Hydro introduces possible CDM program opportunities that could help reduce electricity costs for the customer.

/C

The objective of these meetings is to give large, sophisticated and knowledgeable customers (typically senior management) an opportunity to discuss their specific needs in a timely and efficient format. Therefore, the level of focus given to each section of the presentation is ultimately dictated by customer-specific needs and preferences. Generally, Toronto Hydro finds that large customers are interested in discussing the details of their specific reliability experience, potential remedies to reliability issues, and how to manage their electricity costs.

To illustrate the range of content provided to key account customers, Appendix C includes a sample of a presentation deck provided to a customer during the development of the Application. These decks were subject to updates from time-to-time and included customer-specific information. The sample deck provided does not include any customer-specific information, but rather an explanation of the type of customer-specific information that may appear on a given deck.

/C

1.3.2 Outcomes of the Key Account Process

Toronto Hydro uses the input received from the Key Account Management Services program to plan CDM programs and to inform capital and maintenance program planning in areas such as the Worst Performing Feeder program (Exhibit 2B, Section E6.21) and the Vegetation Management maintenance segment (Exhibit 4A, Tab 2, Schedule 1, Section 5). Toronto Hydro also uses these meetings to better understand the impact of momentary interruptions and to inform the prioritization of longer-term capital investments as the work plan is executed. The following are examples of projects that were created and/or prioritized in response to feedback received through key account engagement:

- A backup feed for a large financial institution was found to be susceptible to moisture related outages. On those occasions when it was active, the customer's

sensitivity to power quality made the risk unacceptable to them. Based on this customer input, operations was able to connect to an alternate feeder.

- The causes of some outages are difficult to source. For the most sensitive key account customers, Toronto Hydro has installed sophisticated power quality meters to assist in diagnosing reliability issues, which could be utility or customer equipment related.
- The supply to a particular hospital is through a heavily treed area, making it more susceptible to outages. Following discussions with the customer, Toronto Hydro responded by intensifying its tree trimming program in that location.
- A large retail mall was susceptible to frequent outages due to the deterioration of its direct buried feeder cable. As of ongoing engagement, Toronto Hydro replaced the feeder as a prioritized renewal project.

The utility plans to continue to offer its Key Account Management Services program throughout the 2015-2019 planning period.

For further information on the utility's day-to-day customer contacts and forms of engagement see Toronto Hydro's Customer Relationship Management program.[3]

1.3.3 Letters Of Comment From Key Account Customers

During its regular meetings in 2013 and 2014, Toronto Hydro informed key account customers about the OEB's increasing focus on customer engagement as part of the renewed regulatory framework, and invited customers to submit letters of comment outlining their concerns and opinions on matters such as service quality, reliability, and cost of electricity, as well as the utility's ongoing, renewal-focused capital investment plans. Overall, Toronto Hydro received 15 letters of comment, copies of which are attached as Appendix A. Toronto Hydro notes that it previously submitted similar letters

[3] Exhibit 4A, Tab 2, Schedule 13.

of comment with the 2012-2014 ICM application (EB-2012-0064). These were filed as Appendix B in the response to undertaking JT2.2 (Phase 1 of the proceeding). /C

2. DSP-SPECIFIC CUSTOMER ENGAGEMENT

In addition to the utility's ordinary course customer engagement activities described above, Toronto Hydro has engaged with its customers specifically around this application and the utility's DSP for 2015-2019.

Toronto Hydro's DSP-specific customer engagement activities were guided by the Ontario Energy Board's ("OEB") expectations in the RRFE Report,[5] which states that distributors should provide services in a manner that responds to identified customer preferences,[6] and Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications ("Chapter 5").[7] Chapter 5 requires that a distributor describe its customer engagement activities to obtain information on their preferences and show how it considered those preferences in its plan.[8]

/C

[5] Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (October 18, 2012) [the "RRFE Report"].
[6] RRFE Report at page 2.
[7] Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, "Consolidated Distribution System Plan Filing Requirements," (March 28, 2013) ["Chapter 5"].
[8] Chapter 5 at section 5.0.4.

2.2. Residential and Non-Residential Customers

Toronto Hydro engaged Innovative Research Group Inc. ("Innovative"), a national consultancy with expertise in public opinion research, with particular experience in issues of public policy. Toronto Hydro asked Innovative to design and carry out a consultation process that would provide the utility with meaningful information to assist in preparing the DSP, as set out in Chapter 5. Initially, Toronto Hydro hopes that the results of Innovative's consultation will be valuable as the utility continues to carry out its proposed capital work over the term of this application. Innovative produced a detailed report documenting the process and findings of this consultation (the "Innovative Report"), a copy of which is included as Appendix B to this schedule.

Toronto Hydro asked Innovative to bring the major components of the utility's DSP to its most populous rate classes (Residential and General Service < 50 kW) as well as the utility's most populous larger customer market segments (Commercial and Industrial / Manufacturing), and to assess how customers' values and preferences align with the utility's proposed capital work. The consultation also included customers who live in condominiums or other multi-residential buildings. Toronto Hydro relied on Innovative's expertise to help determine how to effectively engage this diverse group of customers on the technical and often inaccessible topic of utility capital planning. Innovative ultimately used several methods to gauge the views of these customers:

1) an online workbook, accessible to any Toronto Hydro customer;
2) randomly recruited focus groups of residential and GS < 50 kW customers, facilitated by Innovative and based on a workbook describing the central pillars of Toronto Hydro's 2015-2019 DSP;
3) consultation with randomly recruited Commercial and Industrial / Manufacturing customers, including a panel discussion with Toronto Hydro staff moderated by Innovative, and focus groups using the same workbook;

4) a statistical telephone survey of 2016 Toronto Hydro customers from both residential and GS < 50 rate classes.

Figure 1 illustrates the process that Innovative used to develop this model of consultation.

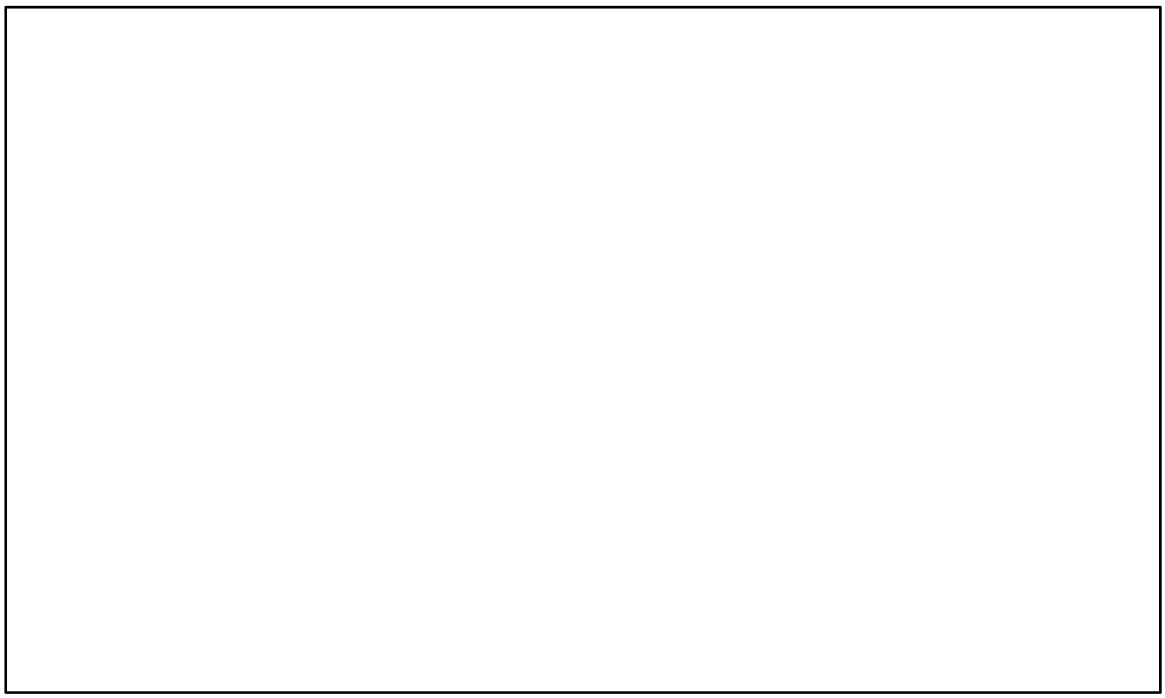


Figure 1: Innovative Research Group Consultation Structure

3. INNOVATIVE REPORT FINDINGS

The Innovative Report provides Toronto Hydro with valuable insight into its customers' perception of both the utility's priorities and those of the province's broader electricity sector. While the results of the consultation and the lessons drawn from it are addressed in more detail in the DSP, certain central themes can be briefly mentioned here:

- Customers' preferences align with central pillars of the utility's DSP. Toronto Hydro learned that, while its customers expect the utility to make prudent investment decisions, the majority accept the need for timely renewal of the

distribution system, while acknowledging that this will mean an increase in their monthly bills.

- Most customers would invest in the distribution system today in order to avoid paying more later.
- Customers believe they have an obligation to maintain the distribution system for future generations.
- While customers are generally satisfied with Toronto Hydro's response to major weather events, they would like to see enhanced communications.
- Most residential customers say that they are able to pay more for electricity, but are concerned about the potential effect that increased rates may have on vulnerable ratepayers.
- Customers also expect the utility to make prudent investments in new technologies, and that new technologies can make the distribution system more efficient and, ultimately, save ratepayers' money.
- Customers accept that Toronto Hydro should be making investment in IT systems, fleet and facilities.
- Interestingly, a large number of customers stated that Toronto Hydro should have increased rates more in the past to create a "reserve fund" to recover capital renewal investments required today.

The Innovative Report describes its methods and the results of the consultation in greater detail. For more detail on how customer values and preferences are reflected in Toronto Hydro's Asset Management Process and SPD programs, please see Exhibit 2B, E2.4.

Toronto Hydro is pleased to have received this more nuanced view of its customers' preferences on the utility's planned capital work. Toronto Hydro understands that its customers are sensitive to rate increases and expect the utility to be prudent in carrying

out its work. However, it is content to see that its customers accept the need to invest in Toronto's distribution system, despite the associated rate increases.

This is the first five-year rate application prepared by Toronto Hydro and one of the first Custom Incentive Rate-Setting ("CIR" or "Custom IR") applications prepared under the RRFE by any local distribution company (LDCs"). It also includes the most extensive and, necessarily, one of the first customer consultation exercises around any DSP. Toronto Hydro's customer engagement activities in connection with this application significantly exceed any past application-related consultation that it or any other Ontario LDC had previously undertaken. The results of this consultation will continue to inform the utility's capital work over the five-year term of the DSP, and provide an important starting point for subsequent customer consultations.

May 22, 2014

Dwight Cooke
Direct Line: (416) 644-4284
E-mail: dcooke@epicrealtypartners.com

Mr. Chris Tyrrell
VP, Customer Care & Chief Conservation Officer
Toronto Hydro-Electric System Limited
5800 Yonge St
Toronto, Ontario M2M 3T3

Dear Mr. Tyrrell,

We are writing to confirm that Epic Realty Partners very much supports Toronto Hydro's infrastructure renewal program.

We believe that continued investment in Toronto Hydro's electrical infrastructure is essential to maintaining overall levels of system reliability across the city.

Epic Realty Partners is committed to energy conservation initiatives and has implemented a number of projects in an effort to ease the demands on our buildings and on the electrical system. Epic Realty Partners manages 1.7 Million square feet of Commercial buildings across the city and the reliability of the electrical infrastructure is of paramount importance to EPIC and our tenants.

Toronto has been in growth for the last few years and this continued development will in no doubt place stresses on the existing systems.

We encourage careful consideration of any infrastructure renewal program to help ensure an outcome that is in the best interest of the City of Toronto's long term growth and development.

Yours truly,
Dwight Cooke
Regional Manager of Technical Services

EPIC Realty Partners Inc.

December 18, 2013

Mr. Chris Tyrrell
VP, Customer Care & Chief Conservation Officer
Toronto Hydro-Electric System Limited
5800 Yonge Street
Toronto, Ontario M2M 3T3

Dear Mr. Tyrrell,

Further to previous communications with you and your office, I would like to reiterate, on behalf of Cadillac Fairview and the Toronto-Dominion Centre, our unqualified support for what we believe to be essential and overdue infrastructure modernization initiatives needed to upgrade the delivery of hydro services to all parts of the property. As you can imagine, due to recent "brown-outs" and "black-outs", and too frequent power interruptions, our tenants have experienced unexpected and costly stress on their operations and their ability to conduct business. Our tenants rely on uninterrupted power 24 hours a day. We strongly believe that continued investment by Toronto Hydro in its power infrastructure is essential not just for Toronto-Dominion Centre, but for the systems reliability of the entire financial core.

Toronto-Dominion Centre has made it a priority to invest in energy smart capital projects and innovations to reduce the daily demands our buildings place on Toronto's power grid. We currently manage approximately 150 gigawatts of electricity consumption annually across our six towers, making the uninterrupted delivery of services a critical issue for the property as a whole as well as our individual tenants. We have long been a leader in promoting energy efficiencies in Toronto's downtown commercial sector and therefore believe we are in a unique position to comment on this matter and its potential impact on the long term health and viability of the core and its ability to provide the thousands of tenants that call it home with cost effective, reliable service.

The "new building" construction sector has been growing at an unprecedented rate for the last few years, making Toronto a global leader in construction activity. With this level of activity expected to continue for some time, it is not unreasonable to expect these new developments place added stress on an infrastructure system that has been unable to meet existing demands.

We encourage all concerned to carefully consider all reasonable infrastructure renewal programs designed to better serve the increasing energy requirements of the City of Toronto and specifically the downtown business community. Let's keep Toronto's financial core viable and dynamic.

Sincerely,

The Cadillac Fairview Corporation Limited,

David Hoffman
General Manager
Toronto-Dominion Centre

c.c. Victor da Rosa, CHM Technical Energy Consultant, Toronto Hydro-Electric System Limited
Christine Woon, Key Account Executive, Customer Care, Toronto Hydro-Electric System Limited

Toronto-Dominion Centre
The Cadillac Fairview Corporation Limited
P.O. Box 2, Suite 3800, TD Bank Tower, Toronto, ON M5K 1A1
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www.tdcentre.com

YORK
UNIVERSITÉ
UNIVERSITY

OFFICE OF THE
ASSISTANT
VICE-PRESIDENT

Campus Services &
Business Operations

4700 Keele St.
Toronto ON
Canada M3J 1P3
Tel 416 736 5789
Fax 416 736 5381

January 20, 2014

Mr. Chris Tyrrell
Vice-President, Customer Care & Chief Conservation Officer
Toronto Hydro-Electric System Limited
5800 Yonge Street
Toronto, Ontario M2M 3T3

Dear Chris,

York University is a leading interdisciplinary research and teaching university in Toronto. York offers a modern, academic experience at the undergraduate and graduate level. The third largest university in the country, York is host to a dynamic academic community of 55,000 students and 7,000 faculty and staff, as well as 250,000 alumni worldwide.

York's 11 faculties and 28 research centers conduct ambitious, groundbreaking research that is interdisciplinary, cutting across traditional academic boundaries. This distinctive and collaborative approach is preparing students for the future and bringing fresh insights and solutions to real-world challenges.

York relies on Toronto Hydro's services for a sprawling campus uptown, an intimate east-side campus, and downtown business centers. The Keele Campus is located at Keele Street and Steeles Avenue West on 550 acres. The Glendon Campus is located at Bayview and Lawrence Avenues on 85 acres. York has also established a Downtown Management Facility, the Miles S. Nadal Facility at King and Bay Streets, as part of the Seymour Schulich School of Business, and Osgoode Hall Law School Professional Development Centre at Yonge and Dundas Streets.

York acknowledges Toronto Hydro's electrical infrastructure capital investment application to the Ontario Energy Board. York University recognizes the need to upgrade outdated equipment for safety and reliability reasons, as York faces similar internal electrical infrastructure issues on a daily basis. World class ground breaking research requires 24/7 reliability, especially when working with the specialty research equipment in the physics and biology areas. York observes that the reliability issue goes beyond 24/7 power availability, and must include issues of voltage and frequency excursions, and transient short term interruptions.

York University observes that on average it experiences 1.5 grid related interruptions per month. Some of these interruptions result in service outages for students, residences, classroom activities and sensitive research facilities, as well as costly recall of maintenance staff.

York University supports initiatives to improve the reliability of the Toronto Hydro grid, and quality of the power supply.

Sincerely,

Richard Francki
Assistant Vice-President
Campus Services & Business Operations

MEDALLION
CORPORATION

970 Lawrence Ave. W., Suite 304, Toronto, Ontario M6A 3B6 Tel: 416-256-3900 Fax: 416-256-2827

E-Mail: cpandell@medallioncorp.com
Web Site: www.medallioncorp.com

Direct Telecopier: (416) 256-7010

June 11, 2014

Toronto Hydro-Electric System Limited
5800 Yonge Street
Toronto, Ontario.
M2M 3T3

Attention: Mr. Christopher Tyrell, Vice President,
Customer Care & Chief Conservation Officer

Dear Sirs:

Re: Power Interruption Concerns, Consumers Road, Toronto.

We recently met with Victor da Rosa and James Wei in order to learn more about Toronto Hydro's plans to ameliorate the high frequency of power interruptions being experienced at our 505 and 515 Consumers Road properties. It was confirmed by your team, that we continue to experience a *'higher than average'* frequency of power interruptions *(both 'momentary' and 'sustained' outages)*. These frequent outages are having a **severe** negative impact upon both our client population and on the marketing of the project to our customers. We have been advised that infrastructure improvement plans have been drafted and submitted for improvements to the Leslie TS and distribution network as part of a larger submission to the Ontario Energy Board. We are writing to confirm that Medallion Corporation supports Toronto Hydro's infrastructure renewal program.

We believe that continued investment in Toronto Hydro's electrical infrastructure is essential to maintaining overall levels of system reliability across the city.

Medallion Corporation owns and manages approximately two (2) million square feet of Commercial, Industrial and Retail properties in the City of Toronto and the reliability of the electrical infrastructure is of paramount importance to Medallion and our tenants. In addition to the Commercial portfolio, Medallion has approximately eight thousand (8,000) high-rise rental residential units in the City of Toronto with several new buildings under construction or in the planning stages.

We acknowledge that the Toronto market has been in a substantial growth mode for many years and this continued development will in no doubt place stresses on the existing infrastructure and systems. The successful continued growth in Toronto is directly linked to the ability of all of the essential service providers to both maintain and upgrade the necessary infrastructure to foster this growth.

We encourage careful consideration of any infrastructure renewal program to help ensure an outcome that is in the best interest of the City of Toronto's long term growth and development.

Yours very truly,

MEDALLION CORPORATION

Christopher A. Pandell, CSM., CMD.
Director, Commercial Leasing & Operations

Cc Victor da Rosa, Toronto Hydro-Electric System Limited
James Wei, Toronto Hydro-Electric System Limited
Joseph Cacciola, Medallion Corporation

May 16, 2014

Mr. Chris Tyrell
V.P., Customer Care and Chief Conservation Officer
Toronto Hydro-Electric System limited
14 Carlton Street
Toronto, ON M5B 1K5

Dear Mr. Tyrell,

Western Harbour Castle Hotel on One Harbour Square has implemented many conservation and electricity demand reduction projects and continues to coordinate with Toronto Hydro for the CDM incentive that makes it possible to pursue additional energy conservation and demand reduction opportunities.

On the other hand, we have recently struggled with an outage situation. The continued upgrade of old assets and electrical infrastructure is essential to maintain the reliability that we aspire. Therefore, we support any Toronto Hydro Infrastructure renewal programme that will positively affect the reliability of the distribution of electricity to our property.

We forward continued coordination and cooperation.
Kind regards

Mike Flint
Director of Finance

the westin harbour castle
one harbour square, toronto, ontario m5j 1a6
t 416.869.1600 f 416.869.1420
westin.com/harbourcastle

WESTIN
HOTELS & RESORTS

January 7, 2014

Chris Tyrrell
Vice President, Customer Care & Chief Conservation Officer
Toronto Hydro-Electric System Limited
5800 Yonge St.
Toronto, Ontario
M2M 3T3

Dear Mr. Tyrrell:

Consistent with our previous communication, our operation continues to be negatively impacted by the poor reliability of our power supply.

In 2013 we experienced 21 power supply quality events that caused 35 hours of equipment downtime. The direct financial impact to our operation last year was $380,000. Further the environmental and employee safety implications associated with the process disturbances caused by the power supply quality events are significant.

Owens Corning has been implementing measures to improve the resilience of our equipment to *voltage sags* including installing 3 phase line reactors on all our variable frequency drives, utilizing auto-restarts on equipment and uninterrupted power supply (UPS) devices on control systems as well as aggressively pursuing energy conservation initiatives to reduce demand on the system. However, the severity of the voltage sags continues to overwhelm some of our counter-measures.

As partners, we expect that Toronto Hydro will intensify their efforts to reduce the frequency of power supply quality events. We strongly urge you to reassess your Infrastructure Replacement/Management Strategy to provide 24/7 reliability. We acknowledge the need to improve your infrastructure and support your Capital Investment initiatives.

The Owens Corning 7 R U R Q W R 3 O D Q W ¶ V H P S O R \ H H V D U H F R Q W L Q X R X V O \ F R P in our network south of the border. It is becoming increasely difficult for us to offset the competitive advantage given to the US based plants by the superior reliability of their power utility.

We look forward to hearing from you and welcome your input to help us run efficiently and compete in the global market.

Sincerely,

Lucian Radut, P. Eng.
Maintenance Leader
OWENS CORNING CANADA LP
TORONTO PLANT

Wesley G. Co
Country Business Director
OWENS CORNING CANADA LP

Redpath Sugar Ltd.

4XHHQ·V 4XD\ (DVW
Toronto, ON M5E 1A3

January 2, 2014

Mr. Chris Tyrrell
Vice-President
Customer Care and Chief Conservation Offices
Toronto Hydro Electric System Limited
14 Carlton Street
Toronto ON.
M5B 1K5

Dear Mr. Tyrrell,

My name is Gary Porritt and I am the Chief Engineer at Redpath Sugar Limited. We are a Sugar Refining plant that generates most of our hydro requirements and purchases the difference from Toronto Hydro. We are synchronized to Toronto Hydro on one of the two feeders A38X or A39X, whichever is in service. We also have a new feed (2 years old) that is tapped off the same lines.

I have been working with your Save-On-Energy group over the last two years which has helped with projects and incentive money. This group has worked hard to help me complete the projects and ensure proper planning for each one was followed in order to successfully receive the incentives.

We are however looking at reliability of Toronto Hydro source and power quality for continuous VHUYLFH LQ WKLV DUHD ZKLFK , GRQ¶W VHH LPSURYLQJ DW SU Quality power causing our company some losses of equipment which I have had only the comments of the contract agreement conditions. This year we have experience 4 power interruption of minimum time, which has me concerned about what is going to happen in our area without some changes to your supply system. I would like to know how the reliability and power quality issues are being addressed. The frequency of Toronto Hydro outages at our site have increasing over the SDVW \HDU DQG , GRQ¶W VHH WKLV LPSURYLQJ waterfront area. I heard comments on the news about companies should have back-up generation installed at site (during this last ice storm) which has me concerned that improvements to present Toronto hydro system reliability are not being addressed. I want to know what is being done to address my concerns for future reliability.

I look forward to your comments and resolution on this item.

Yours very truly,

Redpath Sugar Ltd.

4XHHQ·V 4XD\ (DVW
Toronto, ONM5E 1A3

Gary E. Porritt

Cc Phil Guglielmi

Toronto Community Housing Corporation
931 Yonge Street
Toronto, ON M4W 2H2

Toronto Community Housing

June 23, 2014

Mr. Chris Tyrrell
Vice-President, Customer Care and Chief Conservation Officer
Toronto Hydro Electric System Ltd.
14 Carlton Street
Toronto ON M5B 1K5

Dear Mr. Tyrell,

I am writing to express Toronto Community Housing's support for Toronto Hydro's regulatory filing for its 2015 electricity rates. Toronto Community Housing is a not-for-profit corporation wholly owned by the City of Toronto, and Canada's largest provider of social housing. Our 1,600 employees work to deliver clean, safe, well-maintained and affordable homes for some 58,500 households with low and moderate incomes, and to build vibrant communities where people can thrive.

Toronto Community Housing, like many public-sector organizations including Toronto Hydro, has major capital repair needs. We are applying and pursuing innovative solutions to generate new funding to repair our aging buildings. In this light, we recognize Toronto Hydro's challenges and believe that your infrastructure renewal plan, which balances cost increases with ensuring a reliable supply of electricity for your customers, is a sound approach in the current fiscal environment.

As a landlord serving a large, diverse population that includes some of our city's most marginalized residents, our success depends in no small part on reliable and affordable electricity. We are one of Toronto Hydro's largest customers, and electricity cost increases affect our bottom line. However, we are also impacted by the social and economic costs of service disruptions caused by aging electricity system infrastructure, which can be significant as the December 2013 ice storm attests. Power outages have a disproportionate economic impact on low-income households and they pose increased safety and security risks in our communities.

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Furthermore, upgrades to Toronto Hydro's infrastructure will improve Toronto Community Housing's ability to participate in energy-savings programs offered by the Ontario Power Authority which can generate revenues for our own capital repair needs.

I hope that this statement of support is useful to Toronto Hydro as you bring forward your submission to the Ontario Energy Board later this year.

Sincerely,



Greg Spearn
Interim President and Chief Executive Officer
Chief Development Officer
Toronto Community Housing

cc: N.W. Bud Purves, Chair, Toronto Community Housing Board of Directors

Toronto Brewery
1 Carlingview Avenue
Toronto, Ontario
M9W 5E5

October 15th, 2013

Toronto Hydro Electric System Limited
14 Carlton Street Toronto ON, M5B 1K5

Attention: Mr. Chris Tyrrell, Vice-President, Customer Care and Chief Conservation Officer

Dear Mr. Tyrrell,

Molson Coors Canada's Toronto Brewery at 1 Carlingview Drive is one of GTA's top employers with approximately 3700 employees. The plant operates 24 hours per day and 7 days per week throughout the year. Reliability of electrical supply is a paramount concern for us as it directly impacts facility production.

Interruptions of any kind, even very short term voltage surges or sags cause product waste and lost production time directly impacting the profitability of our brewery.

We recognize that failure to invest in electrical infrastructure upgrades within the City of Toronto may directly or indirectly impact our own power quality even when work is not on our feeders but elsewhere on our supply bus. The reliability of the distribution grid is a serious concern for Molson Coors' Toronto Brewery.

Molson Coors recognizes that our continued success depends on a balanced plan that addresses the need for a reliable electricity supply grid coupled with competitive rates and supports the need for the planned electrical infrastructure renewal within the City of Toronto.

Sincerely,

Ed Dickhoff P.Eng.

Director of Engineering – Toronto Brewery
ed.dickhoff@molsoncoors.com | Office 416.675.8667 | Fax 416.675.8770 | Cell 416.986.7742

WRIGLEY
A Subsidiary of Mars, Incorporated

Wrigley Canada
1123 Leslie Street
Toronto, ON
M3C 2K1

D +1-416-449-8600
M +1-866-877-3577
F +1-416-449-1774

December 17, 2013

Mr. Chris Tyrrell
VP Customer Care & Chief Conservation Officer
Toronto Hydro-Electric System Limited
5800 Yonge Street
Toronto, Ontario M2M 3T3

Dear Mr. Tyrrell,

Wrigley is subsidiary of Mars Incorporated, leading food Manufacturing Corporation in the world.
Wrigley Canada is located at 1123 Leslie Street, Toronto.
Factory is built 1962; expended over time, most recent 2005, total area approximately 180,000 square feet.
On this location we have marketing and commercial team and gum manufacturing facility.
Total number of employees on site is approximately 450.
Facility is fed by 2x3MW transformers.

During last 12 months we have experienced close to 60 power interruption, majority been during summer months. In particular this summer, during hot and humid days, we had between 2 and 3 interruptions per day. Those interruptions have significant impact on our production process. Each interruption requires the reset of different systems that can take up to 1 hr downtime. In some instances we have to scrap product, which combined with idle labor cost, compromised quality and delivery time, is loss for our factory.

In addition, we recently had instances where power outage lasted few hours, where we had to send people home and delay product shipments.

We understand that Toronto Hydro has committed to improve service by investing in the electrical infrastructure in next few years and need to obtain funds to do that.

Wrigley Canada strongly supports this initiative, as we recognize that our continued success depends on a balanced plan that address the need for reliable electricity supply grid coupled with competitive rates.

Regards,

Milica Milovic, P.Eng.
Sr. Project Engineer
Wrigley Canada

HYMOPACK LTD.

41 MEDULLA AVE., TORONTO, ONTARIO, CANADA M8Z 5L6
TEL: (416) 232-1733 FAX: (416) 232-2194

December 10, 2013

Toronto Hydro Electric System Limited
14 Carlton Street
Toronto, Ontario
M5B 1K5

Attention: Mr. Chris Tyrrell
Vice President, Customer Care & Chief Conservation Officer

Dear Mr. Tyrrell:

Hymopack Ltd., is a retail packaging manufacturer located in the GTA area, employing over 160 employees. The plant operates 24 hours per day and 7 days per week throughout the year. Reliability of electrical supply is a paramount concern for us as it directly impacts facility production.

Interruptions of any kind, even very short term voltage surges or sags cause substantial product waste and lost production time directly impacting the profitability of our company.

We recognize that failure to invest in electrical infrastructure upgrades within the City of Toronto may directly or indirectly impact our own power quality. The reliability of the distribution grid is a serious concern for Hymopack.

Hymopack recognizes that our continued success depends on a balanced plan that addresses the need for a reliable electricity supply grid coupled with competitive rates and supports the need for the planned electrical infrastructure renewal within the City of Toronto.

Sincerely,

Gerry Maldoff

/jw

cc: Mr. Earl Provost
Mr. Michael Thompson

BROOKFIELD
Committed to Outstanding Service

December 17, 2013

Mr. Chris Tyrrell
VP, Customer Care & Chief Conservation Officer
Toronto Hydro-Electric System Limited
5800 Yonge St
Toronto, Ontario M2M 3T3

Dear Mr. Tyrrell,

Further to our various discussions, this is to confirm that Brookfield Residential Services Ltd. fully supports any Toronto Hydro infrastructure renewal program that will positively DIIHFW FRQGRPLQLXP RZQHUV DQG DQQXDO H[SHQVH EXGJ ³EODFN RXWV´ DQG ³GLUW\ HOHFWULFLW\ costs related to burned out circuit boards etc.. We believe that continued investment in 7RURQWR +\GUR¶V HOHFWULFDO LQIUDVWUXFWXUH LV HVVH reliability across the city.

We at Brookfield Residential Services Ltd. are committed to continually searching out and recommending capital projects and energy conservation initiatives in an effort to ease the demands from our buildings on the electrical system in Toronto. We currently manage approximately 60,000 condominium suites across the city and the reliability of the electrical infrastructure is of paramount importance to the tens of thousands of condominium owners who make up our portfolio. We are currently the leading promoter of energy efficiencies in the multi-residential sector in Toronto and as such we believe that we have the unique opportunity to see the negative impact the current infrastructure is having on our clients.

As you know, the condominium sector has been in growth for the last few years and Toronto is the global leader in new condominium construction developments and is forecast to continue at this pace for the next several years. This predicted continued development growth will in no doubt place excessive stresses on the existing systems.

We encourage careful consideration of any infrastructure renewal program to help HQVXUH DQ RXWFRPH WKDW LV LQ WKH EHVW LQWHUHVW R and development as well as the financial health of our many client condominiums.
Regards,

Murray Johnson
Vice President,
Client Service Development
Brookfield Residential Services Ltd.



Innovative Research Group, Inc.
Toronto • Vancouver

Customer Consultation Report

Distribution System Plan Review

July 2014

Prepared for:

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, ON, M5B 1K5

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Customer Consultation Report 1

Distribution System Plan Review 1

July2014

Thisreport hasbeenpreparedby InnovativeResearchGroupInc. (INNOVATIVE)for TorontoHydro r ElectricSystemsLimited(TorontoHydro).

Theconclusionsdrawn andopinionsexpressedare thoseof the authors.

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Introduction 1

About this Consultation 1

Innovative Research Group Inc. (INNOVATIVE) has been commissioned by Toronto Hydro to help the utility design, collect feedback and document its customer engagement and consultation process as part of the development of Toronto Hydro's Distribution System Plan[1] ("DSP") which was presented as the Grid Renewal Plan.

Toronto Hydro's Grid Renewal Plan is a key element of its next distribution rates application. The outcome of this application will determine Toronto Hydro's electricity distribution rates for a five year term beginning May 1, 2015 through to December 31, 2019.

The OEB's new "consumer-centric" approach to rate applications contained in the Renewed Regulatory Framework for Electricity (RRFE) requires LDCs to demonstrate services are provided in a manner that responds to identified customer needs and preferences[2]. Distributors are required to provide an overview of customer engagement activities that each distributor has undertaken with respect to its plans and how customer needs and preferences have been reflected in the distributor's application. While Toronto Hydro engages customers in a number of ways to explore their needs, it has not done so in the context of its capital plans. This initiative sought to bring customers directly into the process of finding the right balance between cost and reliability in Toronto Hydro's Grid Renewal Plan.

This process of identifying and reacting to customer needs and preferences as it pertains to their DSP development and execution is new to Ontario's LDCs. There is no established practices and there are a number of options available to engage with customers. The following section explains how we approached this engagement.

Approach to Meaningful Customer Engagement

It is our experience at INNOVATIVE that engaging customers in meaningful consultation can be a challenge. The reality of most consultation processes is they start out aiming to collect the views of the average person, but end up collecting the views of organized advocacy groups.

Many customers feel they don't know enough to contribute to a public consultation. Others fear the combative nature of some public processes or prefer not to risk offending friends and neighbours by taking firm positions on issues that are sometimes controversial. Moreover, many customers simply do not pay attention and remain unaware of particular consultations that they would participate in if they had been aware.

[1] In the workbook that was used for this consultation, the DSP was referred to as the "Grid Renewal Plan" as a more consumer friendly term. As such, the term "Grid Renewal Plan" appears throughout this report and is synonymous with DSP.

[2] OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.

Running a consultation on the Grid Renewal Plan has an additional challenge – the lack of awareness of the distribution system including how it is funded, regulated and the nature of its challenges. This is well documented in Ontario Energy Board research and in INNOVATIVE's own experience.

Considering both the challenge of engaging a representative group of customers and the challenge of lack of knowledge, we built a process built on six key principles:

1. Ensure customers from across Toronto Hydro's customer base have an opportunity to be heard.
2. Use random sampling research elements to ensure a representative sample of customers are engaged.
3. Create open voluntary processes to allow anyone who wants to be heard to be heard.
4. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
5. Create an opportunity for the public to learn the basics of the distribution system so they can provide a more informed point of view.
6. Test the consultation material ahead of time for clarity of language, appropriateness of questions, ability to respond to questions, and the right balance between comprehensiveness and simplicity.

Since this was the first time Toronto Hydro so explicitly engaged customers in the development of their DSP, a specific effort was made to collect participant comments on the process itself. While most customers felt this approach to engagement was effective at soliciting their feedback on Toronto Hydro's 5 Year Grid Renewal Plan, other ideas on how to improve upon the process were collected throughout the consultation. This is discussed in detail throughout the body of this report.

Customer Consultation Overview

Based on the principles outline above, INNOVATIVE worked with Toronto Hydro staff to design a multifaceted customer engagement program which included a combination of traditional consultation services as well as qualitative and quantitative research elements. This comprehensive consultation was designed to engage various rate classes and collect feedback on preferences and priorities as they relate Toronto Hydro's 5 Year DSP.

The consultation encompassed four core elements of customer engagement.

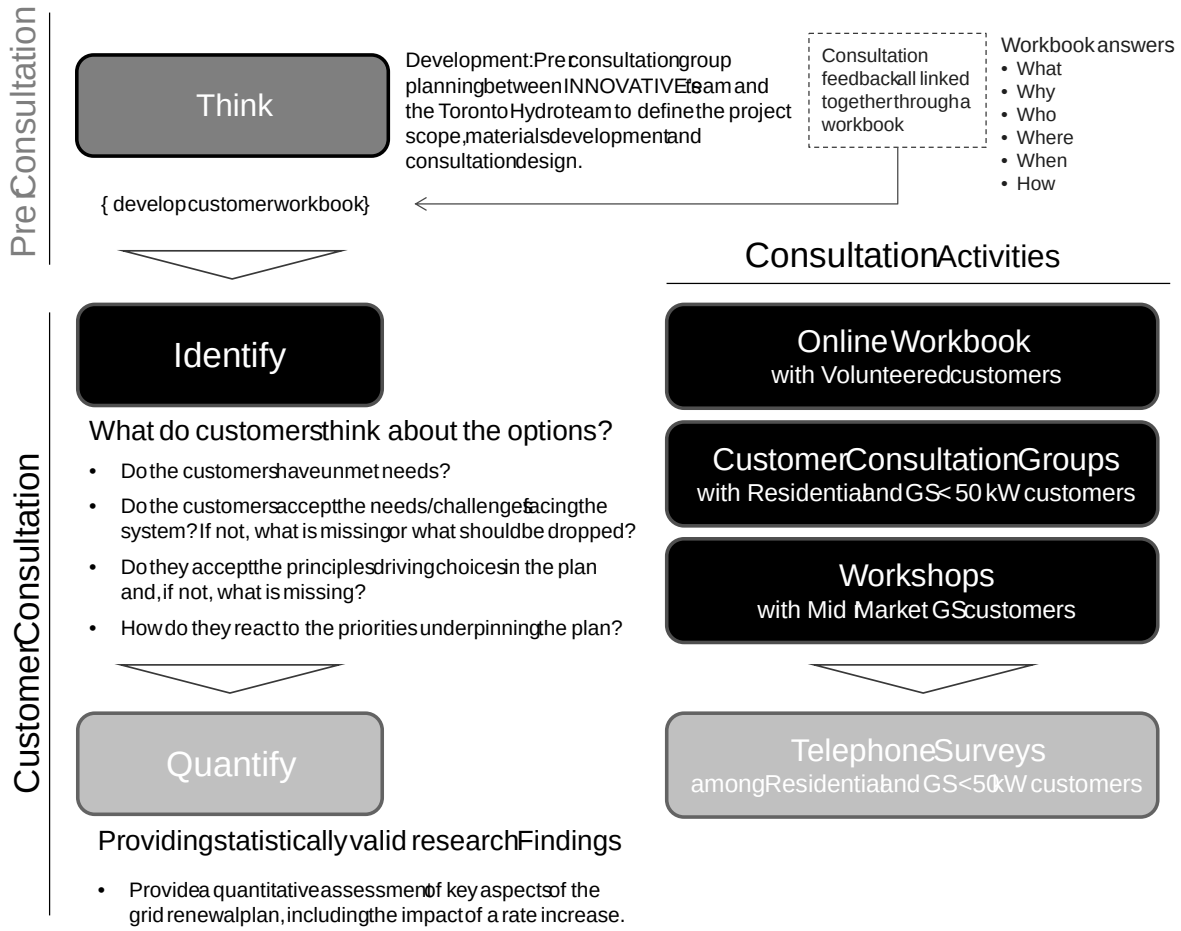
1. Online Workbook: The online workbook was promoted through traditional print advertising and social media as well as Toronto Hydro's website. This first phase of the consultation was available to all Toronto Hydro customers who wanted to participate.
2. General Service and Residential Consultation Groups: The General Service and Residential Customer phase of Toronto Hydro's multi faceted customer consultation was used as an engagement tool to educate customers, access customer preferences and priorities, gauge customer acceptance of rate increases, as well as inform subsequent phases of the consultation.

The groups were randomly recruited and held in different locations across the city. A workbook was used to provide the participants with core information about Ontario electricity system and Toronto Hydro's Grid Renewal Plan. They were provided incentives in recognition of their time commitment.

3. Mid Market General Service Workshops: General Service customers over 50 kW (GS > 50kW) were engaged through a series of randomly recruited workshops. They were provided incentives in recognition of their time commitment.
4. Random Telephone Surveys: INNOVATIVE conducted telephone surveys with residential and general service (GS < 50kW) customers to provide a quantitative assessment of key aspects of the grid renewal plan. Customer lists for both respondent groups were provided by Toronto Hydro and the sample was randomly selected by INNOVATIVE.

There were three stages in developing and implementing this consultation:

- Think: The first stage was developing the core background material and key questions for the workbook. INNOVATIVE and Toronto Hydro worked together to review the Grid Renewal Plan to identify potential questions that would allow customers to share their needs and preferences and then to develop a workbook that would provide the information needed to allow customers with different levels of initial knowledge to find answers to those questions.
- Identify: The second step was to find out the range of view in the public about the Grid Renewal Plan through the more qualitative elements of the process. This included an online workbook using a voluntary sample and a series customer discussion groups and workshops using randomly recruited samples of residential and GS customers. In parallel, Toronto Hydro continued its one on one meetings with major customers.
- Quantify: The third step was quantitative – randomly recruited telephone surveys of residential and GS customers. Randomly recruited surveys allow us to draw generalizable conclusions that can be applied to the broader population of Toronto Hydro customers. The surveys were developed based on the feedback from the qualitative research.



The consultation was designed so anyone who is interested would have an opportunity to participate in the process through the online workbook. However, in our approach, we distinguish between responses from the opinion research discipline (random recruits and scientific polls) and responses from an "open invitation" consultation discipline.

The small group results are presented as numeric counts to help readers remember that qualitative research only identifies points of view, it does not project the incidence of that point of view in the broader public.

The results from the workbook and random surveys are presented as percentages due to the larger numbers involved.

- Readers are cautioned that the workbook results represent the views of volunteers. The workbook sample is not randomly selected and cannot be generalised to the broader public.
- The telephone surveys are based on random samples so we can reliable project the incidence to the broader population of Toronto Hydro Customers.
- In some instances, the quantitative total may be greater than 100% due to rounding. This is in keeping with standard research practice.

It is important to note that these consultations occurred as Toronto Hydro was developing its plan. One critical change that occurred during the consultation is that the forecasted bill increase of the Toronto Hydro DSP changed between the qualitative and quantitative phase. Readers should bear this in mind when considering differences in results between the qualitative and quantitative phase.

Workbook Development 1

As we noted earlier, a key challenge in getting public feedback on Toronto Hydro's Grid Renewal Plan is the lack of knowledge of customers about the Ontario electricity system, and Toronto Hydro's role in the system and the local distribution system. The DSP itself is a very detailed and extensive document that uses technical language. Our challenge was to briefly cover these key issues and to frame meaningful questions about customer needs and preferences.

The process of developing the consultation workbook began in the fall of 2013. INNOVATIVE and Toronto Hydro staff began the process of reviewing Toronto Hydro's Grid Renewal Plan while INNOVATIVE conducted one night of exploratory groups on October 3rd, 2013 with randomly selected members of the general public asking who pay at least some attention to current events to ask what they were looking for in a consultation process and what they needed to know to make up their minds on whether Toronto Hydro's Grid Renewal Plan and associated rate plan was reasonable or not.

Based on the initial review of the plan, exploratory groups, and feedback from testing, the workbook was divided into key sections that explained Toronto Hydro' electric system, the challenges facing the system, and how Toronto Hydro intended to meet those challenges over time.

The final consultation workbook had six distinct chapters:

1. Introduction: the purpose of the discussion, where the discussion fits
2. Electricity 101: how the overall system works and the players involved in operating and regulating the system.
3. Toronto's Grid Today: a discussion of the structure and key elements of Toronto Hydro's distribution system.
4. Challenges Facing the Grid: a discussion of the various challenges facing the grid.
5. How We're Managing Grid Pressures an overview of recent and current initiatives to manage the challenges.
6. The Bottom Line: A section covering the level of planned spending for 2015 to 2019 by general Plant (described as Business Support), System Access, System Service and System Renewal; the expected impact on rates and reliability and feedback on priorities, pacing and overall reaction.

Although the sophistication of customers varied, the same basic workbook was used in all qualitative customer engagements – the online workbook, the residential and small GS discussion groups and the mid sized GS workshops. The key change between audiences is that the bill references were varied to reflect the details of that specific rate class. As the customer went through the consultation workbook – either independently or through a facilitated session – they were prompted with questions related to

system reliability, system challenges, and preferences on the direction of Toronto Hydro's proposed Grid Renewal Plan.

Another key element of the workbook were the questions. In developing the questions, we looked for questions that could work also on telephone without all the information in the workbook.

The needs questions were the easiest. We started with a basic satisfaction question and then asked an open ended question about how Toronto Hydro could improve its services. We let customers go to whatever topics they wanted to cover with no boundaries. Later in the workbook we probed satisfaction with the number and duration of routine outages and probed the impacts of those outages. We also zeroed in on major events by asking customers if they had experienced an outage during the ice storm or flooding, how satisfied they were with Toronto Hydro's response and how Toronto Hydro could improve its services during those events.

Preferences took a bit more thinking. We were looking for value choices rather than technical issues. Key topics for preferences included:

- Should the utility follow a run to failure or a pro active replacement strategy?
- What are acceptable outcomes for the number and duration of outages?
- Given the other major needs for investment, how important is it to invest in modernizing the Grid?
- Willingness to participate in centrally controlled demand response programs?
- Whether the overall Grid Renewal Plan was heading in the right or wrong direction and why?
- Whether Toronto Hydro had the balance right in its spending priorities and which areas should have more or less priority?
- Whether Toronto Hydro's goals are too high, too low or about right with probes for which are too high and which too low?

One challenging topic was system access. System access spending is mandated by legislation or other external obligations. There is little room for changes. In that area we simply asked how reasonable some of the major spending areas were to customers.

The final substantive question asked about the cost of the Plan and the outcomes it planned to receive. Sometimes this questions is asked with a simply support or oppose response scale, but we found that type of scale didn't effective capture customer responses. Instead, we gave customers four options as well as a not sure opt out:

- Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more.
- I am satisfied with the balance between outcomes and the proposed rate increase.
- I don't like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard.
- I think the bill impact is too high and Toronto Hydro needs to scale back its plans.

The workbook concluded with a final set of five questions to assess the workbook and process itself.

The workbooks can be found in the Appendix of this report.

Executive Summary 1

More than 300 customer participated in the qualitative stages of the consultation where we explored the range of responses, while another 1,200 customers responded to the quantitative stage where we documented the incidence of needs and preferences across the customer population.

The following section provides the detailed findings on the needs and the preferences of Toronto Hydro's General Service and residential customer base. In this section, we provide a high level overview of Toronto Hydro customers' needs and preferences.

Customer Needs 1

Most Toronto Hydro customers are generally satisfied with the job Toronto Hydro does running the electricity distribution system. This pattern was consistent across all forms of customer input.

Overall Satisfaction across Consultation Activities

	Directional				Generalizable	
	Residential Groups	GS under 50 kw Groups	Mid Market GS Workshop	Online Workbook	Residential Survey	GS Survey
Very Satisfied	6	5	9	26%	23%	19%
Somewhat satisfied	15	21	25	49%	50%	54%
Somewhat dissatisfied	9	4	7	12%	14%	13%
Very dissatisfied	3	1	0	9%	10%	8%
Don't know	0	0	0	4%	3%	7%

When we asked what Toronto Hydro can do better to improve services, comments focused on four major areas:

- Lower prices.
- A general desire for improved reliability or increased investment in infrastructure to improve reliability.
- Faster restoration times, particular during major outages such as the summer flooding or ice storm.
- Improved communications, again particularly during major outages.

This paradox of lower prices while seeking service improvements is the key dilemma the consultation sought to explore and better understand.

The consultation focused deeper on the question of outages. In the qualitative stage, the workbook shared information about the systems current average level of reliability and sought customer feedback on satisfaction with current levels of reliability and response to major events. With the flooding in the summer and the ice storm in December of 2013, major events were at the forefront of customer thoughts.

As the tables below illustrate, while a majority of customers are satisfied with the average frequency and duration of outages and with Toronto Hydro's management of recent major events, a significant minority are not satisfied.

Customer Satisfaction with Current Average Outage Frequency

	Directional			
	Residential Groups	GS under 50 kw Groups	Mid Market GS Workshop	Online Workbook
Very Satisfied	5	3	4	16%
Somewhat satisfied	12	14	13	37%
Somewhat dissatisfied	7	6	9	25%
Very dissatisfied	9	7	7	20%
Don't know	0	1	0	2%

Customer Satisfaction with Current Average Outage Duration

	Directional			
	Residential Groups	GS under 50 kw Groups	Mid Market GS Workshop	Online Workbook
Very Satisfied	4	4	9	17%
Somewhat satisfied	13	10	15	38%
Somewhat dissatisfied	9	7	12	24%
Very dissatisfied	7	10	4	19%
Don't know	0	0	1	2%

Customer Satisfaction with Management of Major Events

	Directional			
	Residential Groups	GS under 50 kw Groups	Mid Market GS Workshop	Online Workbook
Very Satisfied	3	4	10	27%
Somewhat satisfied	12	13	13	39%
Somewhat dissatisfied	7	4	10	15%
Very dissatisfied	9	6	4	14%
Don't know	0	3	3	5%
Refused / No response	2	1	1	N/A

The qualitative consultation activities spent additional time on exploring the impacts of outages on customers, acceptable frequencies and durations of outages as well as trade-offs between frequency and duration. Those findings are detailed in the following section.

The telephone survey built on the qualitative feedback and asked questions about customer preferences on the trade-off between cost and reliability.

Customer Preferences

Looking at the question of reliability performance, the residential and GS customer surveys asked respondents to choose between three options on how Toronto Hydro should respond to the frequency and duration of outages. Both residential and GS customers gave similar responses to both duration and frequency.

- Roughly 30% said Toronto Hydro should spend what is needed to reduce the number and frequencies of outages.
- Between 10 and 15% said Toronto Hydro accept more or longer outages to reduce costs.
- Between 34% and 41% said Toronto Hydro should spend what is needed to maintain the current number and frequencies of outages.

Although most spending in system access is mandated, most customers felt spending on connections, enabling other civic improvements and meters as reasonable with some reservations noted in the following qualitative sections of this report. The qualitative elements raised the topic of system access in an effort to help participants understand where Toronto Hydro's of the capital is spent.

The main focus for exploring customer preferences in the quantitative surveys was on system renewal, system service and general plant issues. The results from the qualitative elements were used to inform the customer surveys and the details are reported later, so for brevity we will focus on the generalizable survey results in this discussion.

On system renewal, the customer surveys asked respondents to pick between two points of view:

- Toronto Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years.
- Toronto Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.

A majority of both residential and retail customers believe Toronto Hydro should replace aging infrastructure, even if that means their bill will increase.

On system service, the surveys explored the issue of new technology. Again, the surveys asked respondents to pick between two points of view:

- In these tough economic times, investments in new technologies are more of a luxury than a necessity and will cost customers more than they are willing to pay.
- Investments in new technology will increase system reliability, make our local distribution system more efficient, and save us money in the long run.

This time, at least 60% of both residential and GS customers said they believe investments in new technology will deliver important benefits and did not see them as unaffordable luxuries.

The surveys took the same approach to general plant spending. The two points of view included:

- Toronto Hydro should find ways to make do with the buildings, equipment and IT systems it already has.
- While Toronto Hydro should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.

Again, a majority of both residential and GS customers say it is important that staff have the equipment and tools they need to manage the system efficiently and reliably.

Customer Reaction to Rate Impacts

As we found earlier in the needs discussion, Toronto Hydro's customers are conflicted when it comes to the DSP and the rate application.

Many customers are feeling a financial pinch. Others reacted to the latest stories in the newspapers about waste and mismanagement or perks and compensation in any part of the electricity system when considering Toronto Hydro's plan. As noted earlier, few customer welcome the idea of a rate increase.

Yet, reliable electricity service is critical to Toronto Hydro's customers. The recent major event outages reminded Torontonians that electricity is an indispensable necessity. It's not just about making do without lighting and television. Customers had to throw out spoiled food and do without showers or laundry. For others there was no heat and noted difficulty preparing food. Workplaces closed and had to send employees home for, in some cases, extended periods of time. Credit card systems and ATMs went down. Traffic signals, public transit and gas pumps were inoperable. There are few illusions about the need for reliable electricity in Toronto today.

Of course, coming into this process few customers had much understanding of what it takes to build and maintain their local distribution. Many participants in the qualitative exercises expressed appreciation for the opportunity to learn about some of those details. In the surveys we could not provide the same level of information but were able to raise awareness of the complexity through the choice and attitudinal questions.

At the end of each of these consultation processes, we concluded with a question to assess whether customers feel Toronto Hydro has found the right balance or not.

Customer Views on Cost and Outcomes of DSP

	Directional				Generalizable	
	Residential Groups	GS under 50 kw Groups	Mid r Market GS Workshop	Online Workbook	Residential Survey	GS Survey
Plan higher outcomes, even if rates go up	5	6	5	14%	4%	3%
Satisfied with balance	8	4	11	16%	15%	15%
Don't like increase but feel it is necessary	17	13	02	32%	39%	30%
Bill impact is too high, scale back plans	1	2	2	34%	34%	41%
Don't know / Refused	2	6	3	6%	8%	11%

In every consultation activity, the largest group is those who are either satisfied Toronto Hydro has found the right benefit of costs and outcomes or those who say they are unhappy with the price increase but feel it is necessary. While a significant minority say the price increase is too high and the plan should be scaled back, they are partially offset by a smaller group of customers that feel Toronto Hydro should aim for higher outcomes, even if their rates increase.

There is no simple answer to electricity utility spending in the public's view. Price increases are undesirable, but lower reliability is unacceptable and the need to invest in building and maintaining the distribution system is understood and accepted. As a result, Toronto Hydro customers reluctantly accept the proposed DSP and its accompanying price increase as an unfortunate necessity.

1

Online Workbook

Online Workbook
with Volunteered Customers

PURPOSE: To inform customers on the details of Toronto Hydro's proposed DSP and obtain feedback on the proposed plan

Summary

The following summary highlights key findings from residential customer feedback collected through an online workbook tool designed for Toronto Hydro.

Context: Familiarity & Satisfaction with the System

- More than three quarters (77%) have at least some understanding of the electricity distribution process; in fact, one in four (24%) say they could explain the details of the system to others. Almost all (95%) have at least somewhat of an understanding of how the parts of the system work together and which services Toronto Hydro is responsible for.
- Three quarters are either "very" (26%) or "somewhat" (49%) satisfied with the job Toronto Hydro is doing running their local distribution system. Suggested improvements include lower rates (25%) and eliminating/controlling power outages (16%).

System Reliability: Experiences and Perceptions

- Just over half of respondents feel that the current frequency (53%) and duration (55%) of power outages is acceptable. This leaves almost half who feel both are currently unacceptable.
- Almost all (91%) had experienced at least one power outage over the past two years, half of which lasted fewer than 12 hours. We see evidence of the two major storms of 2013 in the proportion reporting outages lasting longer than 12 hours.
- Almost three quarters (73%) were impacted by at least one of the major storms. Regardless of how long they were without power, most did not report any major inconveniences, and they were at least somewhat satisfied (66%) with how Toronto Hydro responded to these major storms. As heard in other research, respondents here feel there is a need for improvement when it comes to communicating the status and estimated length of outages.

Challenges Facing the System

- More than two thirds (68%) feel it is reasonable to prioritize connecting new customers over other investments. Slightly fewer feel it is reasonable to prioritize moving existing infrastructure to accommodate other projects (65%) or maintaining and upgrading grid customer meters to meet provincial standards (63%).
- The majority (73%) prefer a proactive approach over a run to failure strategy with aging equipment.

Modernizing the Grid

- Almost all (93%) feel they understand the challenges facing Toronto Hydro and what they are planning to do to meet those challenges.
- More than half (56%) feel it is "very important" for Toronto Hydro to invest now in modernizing the grid.
- Half (52%) say Toronto Hydro's investment plan is heading in the right direction, primarily because they feel it is necessary to upgrade for the future (57%). One in five (20%) say the plan is headed in the wrong direction.
- Just over half (53%) say the balance is right when it comes to how much Toronto Hydro is spending on each investment priority. Those who feel the priorities should be changed would like to see more spent on modernizing the grid (53%) and less spent on management salaries (20%) and construction projects (20%).
- Half (51%) feel that Toronto Hydro's goals are just right. One in four (24%) say they are aiming too high, while only one in ten (12%) say they are aiming too low. Rate increases (39%) are the primary concern among those who say the goals are too high.
- Overall, three in five (62%) approve of Toronto Hydro's plan. About half of this group (32%) don't like the rate increase but feel it is necessary. One third (34%) feel the bill impact is too high and plans should be scaled back.

Feedback on Workbook Approach

- Respondents deem the workbook "interesting" (35%) and "well done" (32%). The majority (56%) feel it contained the right amount of information, and more than one in four (27%) said there wasn't any content missing as far as they were concerned.
- Almost half (45%) say they prefer an online workbook for this type of consultation.

Methodology

About the Online Workbook

Throughout the fall and winter of 2013, Toronto Hydro and INNOVATIVE staff began developing an accessible customer workbook designed to both inform customers of the 5 year grid renewal plan and collect customer feedback.

The online workbook was divided into key sections that explained Toronto Hydro's electric system, the challenges facing the system, and how Toronto Hydro intended to meet those challenges over time. The online workbook had six distinct chapters:

1. Introduction
2. Electricity 101
3. Toronto's Grid Today
4. Challenges Facing the Grid
5. How We're Managing Grid Pressures
6. The Bottom Line

As the respondents went through the online workbook, they were prompted with questions related to system reliability, system challenges, and what the distribution system plan means to them. In total, the online workbook contained 35 questions, with opportunities for open-ended responses and additional comments. All responses were anonymous and kept strictly confidential.

For customers, this was an opportunity to learn more about Toronto Hydro's plan and to share their feedback. The ultimate goal was to ensure alignment between Toronto Hydro's operational plans and their customers' preferences and priorities.

Customer feedback was also incorporated into the design of subsequent consultation phases.

Field Dates:

The online workbook was available for Toronto Hydro customers to access for 37 days between February 21, 2014 and April 1, 2014.

Participation:

To ensure customer privacy, answers were grouped together with those of others who completed the same question and the information provided was used for statistical purposes only.

Responses to the online workbook are as follows:

- 1,233 unique visitors came to the online workbook's landing page.
- 485 customers moved beyond the online workbook's landing page and identified themselves as either residential customers or business customers (467 residential / 18 business customers).
- 300 qualified customers completed at least the profiling section of the online workbook (291 residential / 9 business customers).
- 209 customers completed the entire online workbook by answering all questions (202 residential / 7 business customers).

The results are based on completed answers to the online workbook questions by residential customers. Due to the small sample size, business customer responses are not reported in the body of this document, but rather recorded as footnotes below each chart.

Promoting the Online Workbook:

The online workbook was promoted by Toronto Hydro through traditional print advertising (the Toronto Star), Toronto Hydro's web site, customer bill inserts, and Toronto Hydro's social media accounts, including Facebook and Twitter.

Hosting the Online Workbook:

The online workbook was hosted by INNOVATIVE under the URL www.torontohydroworkbook.com.

The online workbook was designed to prevent respondents from completing the questions more than once and to save the progress of respondents in the event of survey mid-termination.

Cookies were used in the design of the online workbook to ensure that respondents only completed the online workbook once. Cookies are small amounts of data that attach to a user's computer hard drive when they visit a web site. When respondents reached the final web page, the survey was considered complete and the site was no longer accessible to the internet protocol (IP) address used to complete the online workbook.

At the same time, the site saved respondent answers if they left the online workbook or experienced a mid termination before reaching the final webpage of the workbook. When respondents returned to the online workbook, all previously entered answered were saved and appeared in the workbook linked to the user's internet protocol (IP) address.

We do not link the information we store in cookies to any personally identifiable information submitted on our site.

Respondent feedback data was only ever available to INNOVATIVE project team staff through a secure data retrieval portal.

Validating Customer Responses

Respondents who visited the online workbook were asked to self identify as either a residential or business customer of Toronto Hydro. Respondents were then asked to provide the postal code that corresponded to either their residence or business serviced by Toronto Hydro and answer the remaining questions from the perspective of the self identified customer type.

Only feedback from customers who provided a valid postal code were included in this report. In total, seven residential customers were removed from the dataset due to invalid postal codes that did not correspond with Toronto Hydro's service area.

Respondent Profile

The following details the demographic characteristics of qualified respondents who completed the profiling section of the Online Workbook [n=291 residential and n=9 business customers].

Figure 1.A: Residential Customer Profile

For business respondents, a total of nine respondents at least completed the profiling section of the online workbook. The total number of business respondents who completed the online workbook was seven.

Figure 1.B: Business Customer Profile 1

Respondent Feedback 1

A total of 202 residential customers completed Toronto Hydro's online workbook. However, 291 residential customers completed at least the profiling questions within the online workbook. Answers from the 89 semi-complete respondents have been included in the findings.

Responses provided by business customers are included in the following charts as footnotes because only nine business customers semi-completed the online workbook (seven business customer completed the entire online workbook).

Context: Familiarity & Satisfaction with the System 1

This section provides an introduction in terms of how familiar respondents are with the electricity system, how the different parts work together, and Toronto Hydro's role in the system.

1

Familiarity with the System

- More than three quarters (77%) of residential respondents report having at least some level of understanding when it comes to Toronto Hydro's electricity distribution system. One in four (24%) say they can explain the details of the system to others.
- Given what they already knew and what they had read in the online workbook, almost all (95%) respondents say they understand the important parts of the electricity system, how they work together and which services Toronto Hydro is responsible for. Half (50%) say they understand this "somewhat well", while almost as many (45%) say they understand this "very well".

Satisfaction with Toronto Hydro

- Three quarters of respondents are either "very" (26%) or "somewhat" (49%) satisfied with the job Toronto Hydro is doing running their local distribution system.
- Asked to suggest ways in which Toronto Hydro can improve its service, lower rates topped the list at 25%, followed by eliminating/controlling power outages (16%), and improving the infrastructure (13%).

Figure 1.1: Familiarity with Electricity Distribution System

Half of residential respondents say they can explain the details of Toronto Hydro's electricity distribution system to others (24%) or that they are generally familiar with it, but can't explain it to others (24%). An additional three in ten (28%) say they have some understanding of the system but are not sure of the details. The final quarter (23%) report having a very limited knowledge of Toronto Hydro's electricity distribution system.

Figure 1.2: Understanding Toronto Hydro's Role 1

Based on what they already knew, and what they had read in the online workbook, almost all (95%) residential respondents feel they understand the important parts of the electricity system, how they work together and which services Toronto Hydro is responsible for either "very well" (45%) or "somewhat well" (50%).

Of the 8 business respondents, 4 indicate they understand the system "very well" and the remaining 4 say they understand it "somewhat well".

Figure 1.3: Satisfaction with Toronto Hydro 1

Half (49%) of residential respondents are "somewhat" satisfied with the job Toronto Hydro is doing running the local distribution system, and a further one in four (26%) are "very" satisfied. About one in five are either "somewhat" (12%) or "very" (9%) dissatisfied.

Business respondents are also satisfied with the job Toronto Hydro is doing as 6 out of 8 respondents indicated they are either "very" or "somewhat" satisfied.

Figure 1.4: Improving Service 1

In particular, lowering rates and reducing power outages top the list of things residential respondents feel Toronto Hydro can do to improve their service. There were also suggestions for improving the infrastructure, better communication regarding outages, reducing salaries and tracking consumption.

For business respondents, only two provided an answer. One said "track consumption" and the other response did not fall into any of the above categories.

1

System Reliability

This section of the workbook explores experiences with power service interruptions and measures respondents' expectations of the frequency and length of these interruptions.

Experiences with Power Service Interruptions

- Half (53%) of residential respondents say the current average number of electricity outages is either "very" (16%) or "somewhat" (37%) acceptable.
- Results are very similar when it comes to average amount of outage time, with just over half (55%) finding the current average outage time either "very" (17%) or "somewhat" (38%) acceptable.
- Nine in ten (91%) residential respondents have experienced at least one power outage in the past two years, with some experiencing up to six or more. Half of these outages lasted for fewer than 12 hours.
- For one in five (19%), the power outage had little or no impact on them personally, but others were inconvenienced with issues like food spoilage (16%), having to relocate (15%), or having no heat (13%).
- There is no general consensus on what length of time leads to costs and consequences becoming serious as the result of a power outage, with answers ranging from one hour to more than three to five days.
- A plurality (33%) feel that two power outages per year are reasonable, although one in six (17%) feel no outages are reasonable. Over half (55%) think an hour or less is a reasonable duration for a service interruption, while one in ten (11%) maintain that no outage is acceptable.
- Almost three quarters (73%) were affected by at least one of 2013's major storms. One in ten (9%) were impacted by the flooding in July, while almost four times as many (35%) were hit by the ice storm in December. Three in ten (29%) were affected by both of these storms.
- Whether personally impacted or not, two thirds (66%) are satisfied with Toronto Hydro's management of these events. Despite being generally satisfied, some (31%) would have preferred better communication on the status of the outages.

Figure 1.5: Perception of Outage Frequency 1

Just over half (53%) of residential respondents find the current average number of electricity outages either "very" (16%) or "somewhat" (37%) acceptable. One in four (25%) find the number "not very acceptable" and slightly fewer (20%) say it is "not acceptable at all".

For the 7 business respondents who answered, 3 find the current level "very acceptable", 1 finds it "somewhat acceptable", 2 find it "not very acceptable", and the remaining 1 finds it "not acceptable at all".

Figure 1.6: Perception of Outage Duration 1

Similar to the responses noted for the frequency of outages, over half (55%) of residential respondents find the current average duration of outages either "very" (17%) or "somewhat" (38%) acceptable. One in four (24%) find the number "not very acceptable" and slightly fewer (19%) say it is "not acceptable at all".

For the 7 business respondents who answered, 3 find the current level "very acceptable", 1 finds it "somewhat acceptable", 1 finds it "not very acceptable", and the remaining 2 find it "not acceptable at all".

Figure 1.7: Power Service Interruption Experiences 1

Most residential respondents experienced a power service interruption in the past two years. Nine in ten (91%) indicated they had at least one power outage. One in five (19%) had only one outage in the past two years, while almost as many (17%) were hit by six or more.

Some outages (likely those related to one of the major storms of 2013) reportedly lasted two days or longer, but most lasted fewer than 12 hours. One in five (19%) service interruptions lasted less than an hour, with slightly more (22%) lasting between one and four hours.

Figure 1.8: Impact of Power Service Interruption

Concerning the impact of these service interruptions, one in five (19%) report little or no impact, followed by food spoilage/unable to cook (16%), had to relocate (15%), and having no heat (13%). Only one percent reported damages due to surges.

For business respondents, 3 out of the 8 respondents who answered the question experienced a service interruption. Two were left "unable to work", and one experienced "food spoilage/unable to cook".

Figure 1.9: Time at Which Costs and Consequences Become More Serious

There is no clear point beyond which residential respondents feel the costs and consequences of an outage become more serious for them. Equal proportions say it's more than 1 hour, 2 hours, 3 or 4 hours, 8 to 10 hours, 12 hours, or 2 to 3 days. For five percent, it depends on what time of year the outage occurs.

Concerning business respondents, 3 out of 4 responded "other" and the remaining respondents said 5 to 6 hours.

Figure 1.10: Reasonable Frequency of Power Service Interruptions

According to residential respondents, two power service interruptions a year is the most reasonable. One is seen as the next most reasonable (24%), followed by none (17%), followed by three outages (13%), then four outages (7%) and finally more than four (7%) outages per year.

Most business respondents indicated that one outage is acceptable (n=3), followed by none (n=2), then three (n=1) or four (n=1).

Figure 1.11: Reasonable Duration for Service Interruption 1

More than half (55%) of residential respondents feel that an outage lasting an hour or less is acceptable (29% say 1 hour, 26% say 30 minutes). One in five (19%) deem an outage of two hours to be reasonable. One in ten (11%) hold that no outage is acceptable.

Business respondents stated that 30 minutes (n=3) or 2 hours (n=1) is the most reasonable duration for a service interruption, although almost half (n=3) prefer no outages at all.

Figure 1.12: Impact of Major Storms in 2013

About three quarters (73%) of residential respondents were impacted by one or both of the two major storms of 2013. More than a third (35%) were affected by the ice storm, while one in ten (9%) were impacted by the flooding in July. Three in ten (29%) were affected by both storms.

Four business respondents were affected by December's ice storm, two were impacted by both, and one was not affected by either storm.

Figure 1.13: Satisfaction with Management of Storms 1

Two thirds (66%) are satisfied (27% "very" and 39% "somewhat") with Toronto Hydro's management of the major storms of 2013. About one in seven (15%) are "somewhat dissatisfied", and a similar proportion (14%) are "very dissatisfied".

Among business respondents, 2 were "very satisfied", 3 were "somewhat satisfied", and 1 was "very dissatisfied".

Figure 1.14: Improving Service During Major Storms 1

A plurality of residential respondents (31%) would have liked better communication on the status during the storms. Others would have liked their power restored faster (13%), or better updates on the outage maps (5%). Some suggested proactive measures like keeping trees trimmed (6%), hiring more staff (5%) and upgrading equipment (6%).

Among business respondents, 1 would like better communication on status, and 1 would like better updates on outage maps.

1

Challenges Facing the Distribution System

This section explores respondent views concerning service of the local distribution system. It focuses on the degree of satisfaction with the current system and means of improving the system in the future.

Understanding and Improving the Local Distribution System

- Overall, residential respondents agree it is reasonable to prioritize connecting new customers, moving existing infrastructure to enable other projects such as street widening or new developments, and maintain and upgrading grid customer meters to meet provincial standards over other investments.
- A solid majority (73%) of residential respondents prefer replacing equipment before it breaks down over running to failure.

Figure 1.15: Spending Priorities

Overall, residential respondents agree it is reasonable to give each of the three investments tested priority over other grid investments.

- 32% feel it is "very reasonable" to prioritize connecting new customers such as new housing, condominiums, or businesses. Another 36% find it "somewhat reasonable".

- 22% feel it is "very reasonable" and 43% feel it is "somewhat reasonable" to prioritize moving existing electricity infrastructure to enable other projects such as street widening or new developments.
- The result is very similar (22% "very", 41% "somewhat reasonable") for prioritizing maintaining and upgrading grid customer meters to meet provincial standards.

Figure 1.16: Running to Failure 1

Around three quarters of residential respondents (73%) would rather Toronto Hydro replace equipment before it breaks down to avoid power outages, rather than a run to failure approach (27%).

For business respondents, 7 out of 8 agreed with replacing equipment before breakdown.

1

Modernizing the Grid

This section touches on customer understanding of the challenges currently facing the Toronto Hydro grid and reaction to proposed investments into the system, including priorities, spending plans, and the balance between rate increases and investments into system improvements.

Understanding Toronto Hydro's Responsibility & Grid Challenges

- Based on what they already knew and had been exposed to in the online workbook, almost all (93%) feel they understand the challenges facing the Toronto Hydro grid and what they are planning to do to meet those challenges.
- More than half (56%) of residential respondents agree that it is "very important" for Toronto Hydro to invest now in modernizing the grid. An additional three in ten (30%) feel this is "somewhat important".
- Respondents are divided on whether or not they would participate in Demand Response (DR) programs. Three in ten (31%) say they are "not likely at all" to participate, while slightly fewer (27%) say they are "very likely" to participate. The remaining two in five are either "somewhat" (22%) or "not very" (19%) likely to take part in a DR program.

Reaction to Toronto Hydro's Investment Plan

- Half (52%) of residential respondents say it seems like Toronto Hydro's investment plan is headed in the right direction. One in five (20%) feel it is headed in the wrong direction, and the remaining 28% don't know. Those who feel Toronto Hydro is headed in the right direction tend to feel that way because they feel it is necessary to upgrade for the future (57%).
- A slim majority (53%) of residential respondents say the balance seems right when it comes to how much Toronto Hydro is spending on each of its investment priorities. Among those who feel the priorities should be changed, there is a desire for more spending on modernizing the grid (53%), and less spending on management salaries (20%) and construction projects (20%).
- Given the option of a proactive or reactive approach to maintaining the grid, half (51%) feel that Toronto Hydro's goals are about right. One in four (24%) say their goals are too high, and half as many (12%) say they are aiming too low. Those who feel the goals are too high are concerned about rate increases (39%), while those who say the goals are too low would like to see more effort put into replacing aging equipment (20%).
- Overall, three in five (62%) approve of Toronto Hydro's plan and the outcomes it is expected to achieve, even if half this group (32%) don't like the rate increase (but feel that it is necessary to maintain the grid to a reasonable standard). However, one third (34%) feel the bill impact is too high and Toronto Hydro needs to scale back its plans.

Figure 1.17: Understanding the Distribution System and Its Challenges 1

Given what they already knew and what they read in the online workbook, more than nine in ten (93%) respondents feel they understand the challenges facing the Toronto Hydro grid and what they are planning to do to meet those challenges. About half (48%) say they understand this "somewhat well", while almost as many (45%) say they understand it "very well".

Of the 7 business respondents who answered, 3 indicate they understand the challenges "very well" and the remaining 4 say they understand it "somewhat well".

Figure 1.18: Modernizing the Grid 1

A majority (56%) of residential respondents feel it is "very important" for Toronto Hydro to invest now in modernizing the grid. Another three in ten (30%) say this is "somewhat important". Only about one in ten (12%) feel it is either "not very" or "not at all" important to invest in the grid now.

Of the 7 business respondents who answered, 4 feel it is "very important" to invest in the grid now, 2 feel it is "somewhat important", and only 1 feels it is "not very important"

Figure 1.19: Demand Response Programs 1

1

Residential respondents are divided on whether or not they would participate in Demand Response programs. Half are either "very" (27%) or "somewhat" (22%) likely to participate in a DR program, while the other half are "not very likely" (19%) or "not likely at all" (31%) to do so.

Business respondents are also split on whether or not they would participate in DR programs. Of the 6 who responded, 1 said they were "very likely", 3 said "somewhat likely", 1 said "not very likely", and the remaining 2 said "not likely at all".

Figure 1.20: Reaction to Investment Plan 1

Just over half of residential respondents (52%) think Toronto Hydro's investment plan seems like it is going in the right direction. One in five (20%) say it is going in the wrong direction, and the remainder (28%) don't know.

Among business respondents, 4 say the plan is going in the right direction, 1 says wrong direction, and the other 2 don't know.

Figure 1.21: Reaction to Investment Plan (Reasons) 1

- Those who feel the plan is heading in the right direction primarily feel that way because they think it is necessary to upgrade for the future (57%).
- Among those who feel the plan is headed in the wrong direction, poor management/planning is the main reason (30%).
- Those who don't know are, for the most part, either concerned about communication regarding the plan (31%), or they feel that rates are already too high (22%).

Figure 1.22: Investment Priorities 1

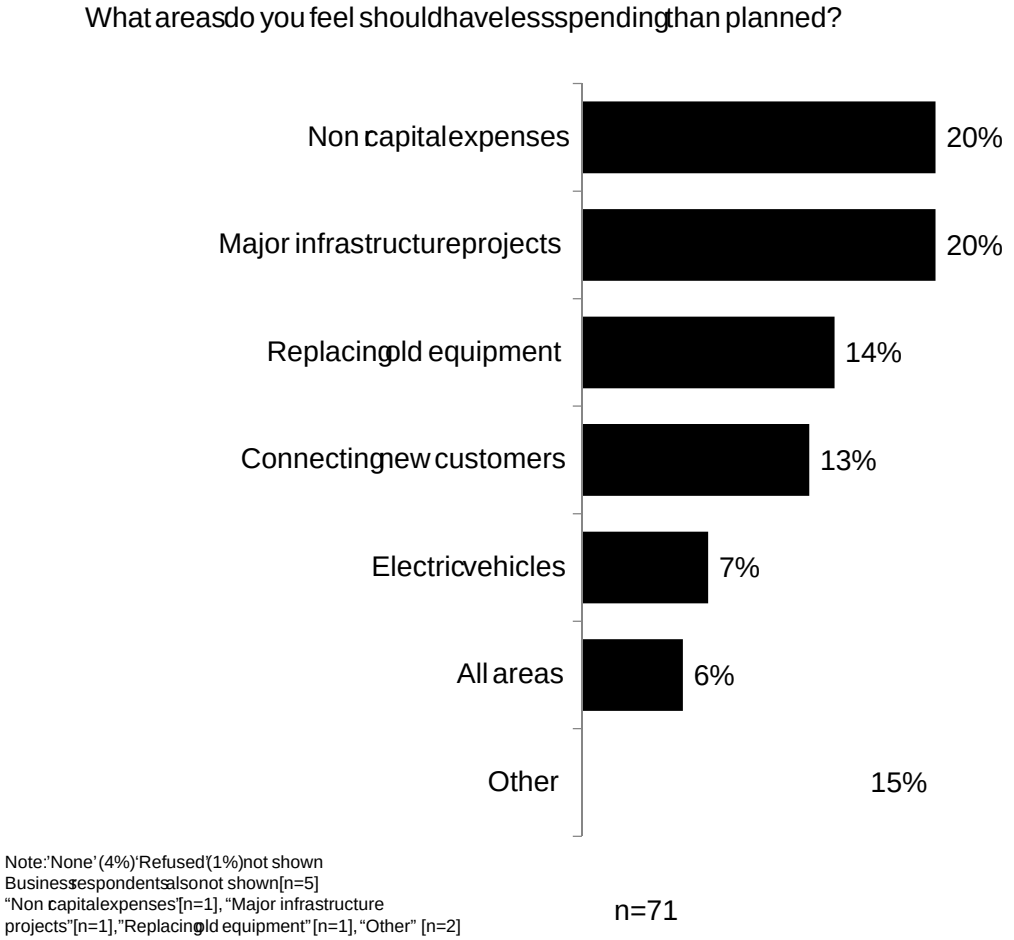
By a fairly slim margin (53% versus 47%), residential respondents feel Toronto Hydro has the balance right when it comes to how much they are spending on each of its investment priorities.

The result is similar among business respondents, with 4 saying the balance seems right and 3 saying they should change some of their priorities.

Figure 1.23: Investment Priorities (Where to Spend More)

Asked where they feel Toronto Hydro should be spending more than planned, more than half (53%) said they want more spent on modernizing the grid system.

Figure 1.24: Investment Priorities (Where to Spend Less)



Asked where Toronto Hydro should be spending less than planned, responses were more varied. One in five (20%) wanted to reduce spending on non-capital expenses[3] or major electric infrastructure projects (which often disrupt day to day life), while others wanted to cut back investment on replacing old equipment (14%) or connecting new customers (13%).

[3] Non-capital expenses include items related to Toronto Hydro's operating budget.

Figure 1.25: Spending Proposal 1 1

Half of residential respondents (51%) think (based on a table below which was shown in the online workbook) Toronto Hydro's goals are "about right". One in four (24%) feel their goals are too high, while half as many (12%) feel they are aiming too low. The remaining respondents (14%) are not sure.

Business respondents are more evenly divided on this question. Equal numbers feel the goals are "about right" (n=2) or "too high" (n=2). Another respondent feels the goals are "too low" and the remaining is not sure.

Note: forecasted rate increases were updated throughout the course of the consultation. This resulted in different forecasted rate increases used in the subsequent customer telephone surveys. For more information, please see Section 4: Customer Telephone Surveys

Figure 1.26: Reaction to Spending Proposal 1

Rate increases are the main reason (39%) that some feel Toronto Hydro's goals are too high, followed by the need for better communication or planning of their agenda (17%).

For those who feel the goals are too low, some says it's because they want to replace aging equipment (20%), while others say they want to reduce costs (13%) or outage times (13%). Still others feel the goals are too low because they want Toronto Hydro to pursue conservation solutions (7%), or they feel Toronto Hydro should be advocating for assistance from the government (4%).

Figure 1.27: Acceptance of Rate Increase 1 1

One third (34%) of residential respondents think the bill impact is too high and Toronto Hydro needs to scale back its plans. A similar proportion (32%) say they don't like the rate increase, but think it is necessary to maintain the grid to a reasonable standard. Half as many (16%) are satisfied with the balance between outcomes and the proposed rate increase, and slightly fewer (14%) say Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more.

Of the business respondents, 2 of 7 say Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more. Another 2 say they are satisfied with the balance between outcomes and the proposed rate increase. One doesn't like the rate increase but thinks it is necessary to maintain the grid, and one thinks the bill impact is too high and Toronto Hydro should scale back its plans. The remaining business respondent is not sure.

1

Feedback on Workbook Approach

This section provides respondent feedback on the online workbook itself and the research process.

In summary, respondents reacted favourably to the workbook, saying it was interesting (35%) and well done (32%). Most (56%) found it to contain the right amount of information, and over a quarter (27%) said there was not any content missing that they would have liked to have seen included. The primary outstanding questions were communication on costs/spending (21%), and improving system reliability (11%). For this type of consultation, an online workbook is the preferred format by almost half (45%).

Figure 1.28: General Feedback

Feedback on the workbook was generally positive, with about two thirds finding it interesting/ informative (35%) or well done (32%). There were a few who found the workbook too long or confusing (7%), biased (3%) or that it needed space for comments in each section (1%).

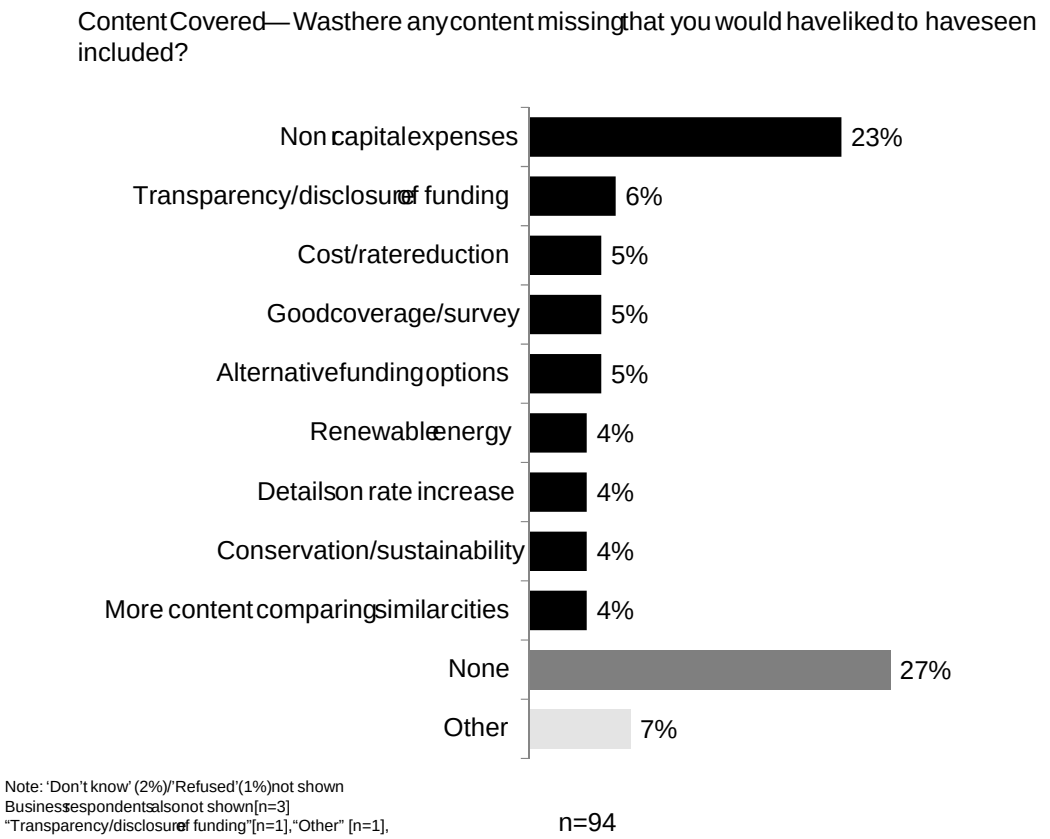
Figure 1.29: Volume of Information 1

Most (56%) residential respondents felt the workbook contained the right amount of information. One in four (25%) felt it was too much information, and about one in ten (12%) felt there was not enough information.

Business respondents were divided with 2 saying there was too much information, and 2 saying there wasn't enough information.

1

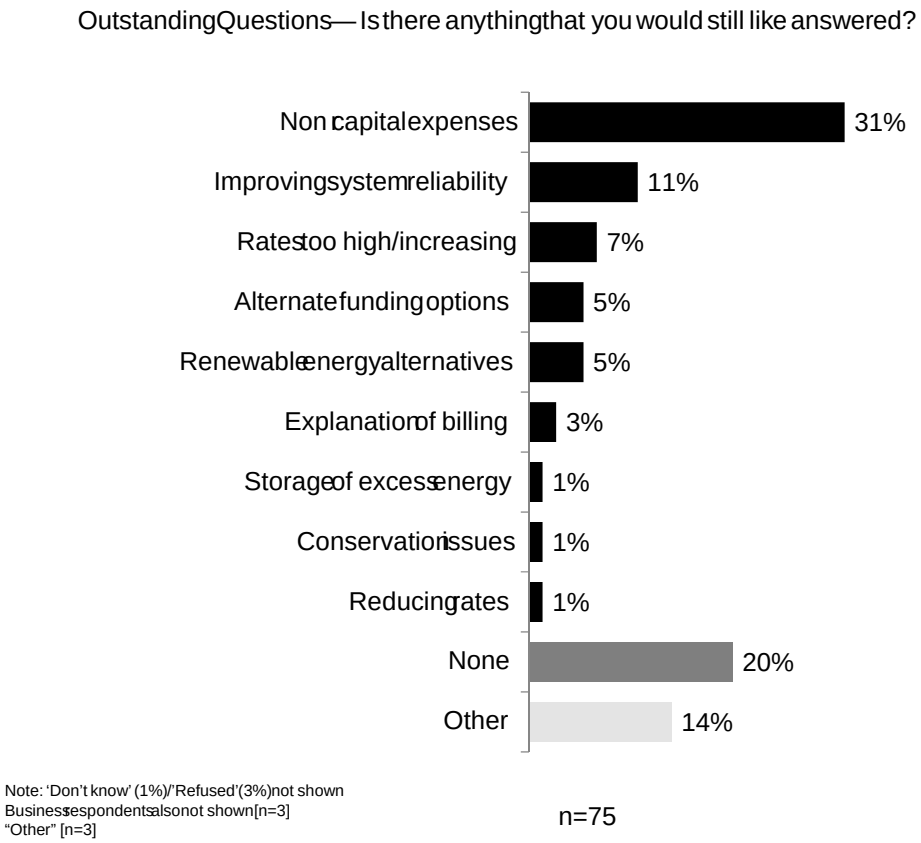
Figure 1.30: Content Covered 1



Note: 'Don't know' (2%)/'Refused'(1%) not shown
Business respondents also not shown [n=3]
"Transparency/disclosure of funding" [n=1], "Other" [n=1], "Don't know" [n=1]

A plurality (27%) didn't feel there was any content missing from the workbook. Areas were respondents would have liked to have seen additional information tended to focus on non-capital expenses (23%).

Figure 1.31: Outstanding Questions 1



Note: 'Don't know' (1%)/'Refused'(3%) not shown
Business respondents also not shown [n=3]
"Other" [n=3]

Nearly a third (31%) of residential respondents would like more details on non-capital expenses and spending. One in ten (11%) would like to know more about improving system reliability. Fewer had outstanding questions about rates being too high (7%), alternative funding options (5%), and renewable energy alternatives (5%).

One in five (20%) respondents had no outstanding questions.

Figure 1.32: Suggestions for Future Customer Engagement 1

An online format seems to be the favoured approach to this type of consultation among online respondents, with almost half (45%) saying they prefer an email/online/workbook format. Significantly fewer prefer a survey (16%), or an in person forum (13%).

Workbook Based Facilitated Discussion 1

Customer Consultation Groups
with RS and GS Customers

PURPOSE: To gain qualitative input/ response to proposed DSP from RS and GS < 50 kW customers and to feed into survey design

Summary 1

The following summary highlights key findings from the general service (under 50 kW) and residential consultation sessions held in North York, Central Toronto, Etobicoke, and Scarborough.

System Reliability: Customer Experience and Expectation 1

Most participants in the consultation groups had experienced an average of two to four power service interruptions at their businesses and/or homes in the past twelve months. The duration of the service interruption lasted from a few minutes to many hours in some cases. Both general service and residential customers reported losses of revenue and productivity within their respective businesses and households due to outages.

All of the participants in the group stated that they wanted better customer service from Toronto Hydro and its staff. Specifically, several participants in the group stated Toronto Hydro should improve its communication with customers especially when outages and other similar power service interruptions occur.

Improving Service of the Local Distribution System 1

Residential customers are concerned about both the frequency and duration of the outages and would prefer less of both. The general service users stated that depending on the type of business, both frequency and duration of outages can have major consequences.

Most participants in the consultations were unfavourable towards conservation and demand management programs because they did not want to lose control over their electrical equipment.

For the most part, general service and residential customers are satisfied with the job Toronto Hydro is doing running the local distribution system. When asked about improvements, the main suggestions concerned limiting rate increases, reducing power service interruptions, and having better communication with customers regarding and during power outages. Further, participants stated that Toronto Hydro should have saved up and created a reserve capital fund to use in case of emergencies and to replace aging equipment.

Coverage of Distribution System Topics

Most of the participants in both groups found the workbook to be very informative, providing the group with the right amount of information needed to discuss the issues at hand.

Many stated that they wanted to have more information on Toronto Hydro's operating budget, revenues, expenses and their profits and losses reports. Several wondered what other options there were for system investment besides the run to failure approach and Toronto Hydro's grid renewal plan.

A few of the participants thought the workbook consisted of too much technical information and they felt they were not qualified to answer some of the questions regarding reasonable investments, measures on connection issues, maintaining smart meters, and moving of electricity infrastructure.

Lastly, some of the participants stated that they wanted more time both to prepare and read through the workbook, and to express their views on the proposed plan during the consultation discussions.

System Renewal

Most participants support the policy of replacing equipment before it breaks down, and see this as a fiscally prudent approach to controlling system costs in the long term. When it comes to Toronto Hydro's overall grid investment plan, most felt they are heading in the right direction, but they would have preferred a "gradual cost increase".

Most stated that Toronto Hydro should spend and prepare more rigorously to cover major issues which in the long term would save money. In contrast, a few stated that they wanted an updated grid that would bring costs down in the long term. Others felt that Toronto Hydro should find effective and better ways to maintain and upkeep the current aging infrastructure.

Many within the residential groups felt that Toronto Hydro should invest more in renewable generation and renewable energy. Additionally, a few felt they did not have enough information or knowledge to comment on Toronto Hydro's planned spending.

Response During Major Weather Events

Almost everyone mentioned wanting better communication from Toronto Hydro to its customers during major weather events. Specifically, they stated Toronto Hydro should have engaged and consulted with customers on emergency management fixes and updates during extreme weather events.

Participants stated that Toronto Hydro should review and modify its emergency plans and make it a more "hands on" approach. Further, they went on to state that during major events Toronto Hydro should hire help from other Canadian cities, provinces, and private contractors. Lastly, most seemed to agree that Toronto Hydro should advise and inform people when services are going to be restored during major events.

Many felt that major event catastrophes could have been avoided if Toronto Hydro better maintained its system by investing in new equipment and/or had been proactive about removing or pruning trees around wires.

Toronto Hydro's Proposed Plan and Rate Impact

Most participants (53 of 64) accepted Toronto Hydro's plan to increase customer rates by the proposed amount; with 23 saying they support the proposed rate increase and 30 saying they don't like it, but think it is necessary.

Most felt that Toronto Hydro's proposed plan was well researched and documented. Moreover, they felt that there was a balanced perspective on the risks, benefits, and overall cost effectiveness of the proposed plan. Further, participants in the consultation stated that the evidence given was satisfactory for the proposed plan to be effective. They went on to say that Toronto Hydro appears to be proactive and seemed to be putting money where it would have the highest and most effective return.

Some participants felt unsure about Toronto Hydro's proposed plan and whether or not it was headed in the right direction. These participants felt they didn't have enough information to effectively answer the questions, while some others felt a sense of distrust toward Toronto Hydro. Moreover, most were disappointed that Toronto Hydro had found itself caught up in the present situation of aging infrastructure equipment.

Some felt Toronto Hydro should invest more in preventative methods and be more proactive with its spending. Various participants also thought that Toronto Hydro should work in conjunction with the Province of Ontario and the City of Toronto to get funding, instead of raising prices for customers. Participants recommended that since all of the revenue and profits accumulated from Toronto Hydro electricity bills were going back into a municipal body, that public money should be used to subsidize the proposed rate increase for the ratepayers.

General Service and residential customer permission on Toronto Hydro's proposed rate increase:

Looking at the cost of the Toronto Hydro plan and the outcomes it is expected to achieve, which point of view is closest to your own? [based on 64 respondents]

Response	Sum Total
Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more	11
I am satisfied with the balance between outcomes and the proposed rate increase	12
I don't like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard	30
I think the bill impact is too high and Toronto Hydro needs to scale back its plans	3
Not sure	4
No response	4
Total	64

How Could the Consultation Process be Improved?

At the conclusion of the sessions, participants were asked what they thought of this approach to customer consultation and how it could be improved.

The majority of the participants in the groups felt that the consultation process was helpful, accountable, and transparent. There were a few who felt the purpose of the consultation was to highlight the accomplishments of Toronto Hydro.

Some liked the consultation process but wanted other sides of the argument to be present. Others wanted to know more about the role of other provincial players within the system. Finally, some participants wanted to know what would happen after the initial five years and what Toronto Hydro's long term plan was for the future.

Most liked the way the consultation was conducted and the round table format, which gave all a chance to share their opinions. Many of the participants in the consultation suggested an online survey to get more of a quantifiable and democratic response.

Some participants in the group felt that they needed to have more information to provide educated answers and substantive feedback. Some stated that they would have liked to see an expert panel discussion on the pros and cons of the proposed plan. Others agreed and thought that the pros and cons of modernizing the grid should have been laid out in the workbook and explained in further detail during the consultation.

Methodology

About the General Service and Residential Customer Consultation

Innovative Research Group (INNOVATIVE) was engaged by Toronto Hydro Electric System Limited (Toronto Hydro) to conduct a series of general service and residential customer consultation sessions designed to identify the needs and preferences of consumers as they relate to the proposed Five Year Grid Renewal Plan.

The consultation sessions were held in North York on February 3, 2014, Central Toronto on February 4, 2014, Etobicoke on February 6, 2014, and Scarborough on February 12, 2014. A total of 64 general service and residential customers participated in these consultation sessions.

North York: February 3, 2014

General Service under 50 kW Rate Class	7 participants
Residential Rate Class	6 participants

Central Toronto: February 4, 2014

General Service under 50 kW Rate Class	7 participants
Residential Rate Class	8 participants

Etobicoke February 6, 2014

General Service under 50 kW Rate Class	7 participants
Residential Rate Class	10 participants

Scarborough February 12, 2014

General Service under 50 kW Rate Class	10 participants
Residential Rate Class	9 participants

Recruiting Consultation Participants

General Service customers in the under 50 kW rate class were randomly selected by telephone from customer lists and screened for appropriateness as session participants. General Service customers qualified for the consultation if they managed or oversaw their business electricity bill. This was to ensure they were at least somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed rate increases.

Customer recruitment lists were randomly generated and provided to INNOVATIVE by Toronto Hydro.

An incentive of $100 was provided to all general service and residential customers who participated in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and quotes.

Consultation Session Structure

The consultation sessions were structured around the themes contained in the workbook, which was developed by INNOVATIVE and Toronto Hydro staff in the fall of 2013.

The workbook themes included the following:

1. What is this about?
2. Electricity 101
3. Toronto's Grid Today
4. Challenges Facing the Grid
5. How We're Managing Grid Pressures
6. The Bottom Line

All consultation participants were sent electronic copies of the workbook via email as part of a pre read package in advance of the sessions.

At the start of the sessions, the facilitator gave an overview explaining the purpose of the consultation and why Toronto Hydro is seeking feedback from general service and residential customers.

After explaining the purpose of the consultation, hard copy workbooks were distributed to act as a session guide and for participants to record their answers to the questions contained within.

The facilitator then led the participants through the workbook section by section to ensure they understood the information and to answer any questions they had about the content.

When it came to the questions within the workbook, participants were asked to fill in their answers independently. The facilitator then led a group discussion on the answers participants provided and what the various issues meant for them or their businesses.

Hard copy workbooks were collected from the participants at the conclusion of each consultation session.

Each consultation session ran for approximately 2.5 hours.

Informing the Consultation Process

In addition to identifying customer needs and preferences as they relate to the proposed DSP, feedback collected from this phase of the consultation was used to inform the design of the telephone survey and used in the subsequent online consultation phase of Toronto Hydro's customer engagement program as part of their rate application.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Participant Feedback

The following section highlights the general feedback from each consultation group.

North York Consultation Sessions

General Service Under 50 kW Rate Class (North York)

System Reliability: Customer Experience and Expectation

Communication was the biggest concern, particularly during outages when business owners and managers need to make decisions on how to run their daily operations. Another concern shared by many was the bills they receive. Bills were considered confusing and hard to read in terms of how much electricity they are consuming. Further, some would prefer monthly bills because every other financial aspect of their business is conducted on a monthly basis.

Improving Service of the Local Distribution System

The general service users stated that depending on the type of business, both frequency of outages and duration of outages can have major consequences. Some commented that the three hour mark is where they might do things differently, like sending staff home, closing their business for the day, etc. While it was generally felt that Toronto Hydro comes up short when it comes to communication during outages,

it then became apparent that most were not making much effort to get updates aside from perhaps making a phone call.

One outage per year lasting no longer than 30 minutes was generally agreed upon as reasonable, though there was one individual who maintained that no outages are acceptable.

There was some discussion about trees that may be older or damaged and which are located close to hydro wires. The feeling was that Toronto Hydro is not being adequately responsive to requests to deal with these trees.

System Renewal

Everyone felt they understood the challenges facing Toronto Hydro 'somewhat well', and felt that they had done a good job of conveying the information. It was agreed that getting to a 'very well' level of understanding was an unreasonable goal given all that is involved.

Initially participants strongly preferred that aging equipment be replaced before it fails. For one participant, it was considered to be an assumed part of running Toronto Hydro because their job is to keep the lights on. Upon further conversation, a few began to feel that it is more financially prudent to try to maximize the lifecycle of equipment, but to be prepared to replace it as soon as breakdown occurs.

Coverage of Distribution System Topics

At this point in the discussion, it was generally agreed that there was a steep learning curve in understanding the system to be able to answer some of the questions in the workbook effectively.

Response During Major Weather Events

There was group consensus that more information was needed during storms. Specifically, participants wanted to know the estimated duration of the outages so that they could take appropriate measures for their business.

Only a couple of participants reported having tried to contact Toronto Hydro during either of the storms, and they described being transferred from one person to another and ultimately not getting the information they were looking for.

Toronto Hydro's Proposed Plan and Rate Impact

Most felt the proposed plan was headed in the right direction, but there were a couple who weren't sure. One participant was unsure due to his current difficulties in getting an accurate bill from his smart meter readings. He felt that the technology needed to be fixed before moving forward. Another felt there was a lot of information to take in and he simply hadn't had time to give it any thought.

Among those who thought the plan was headed in the right direction, the priorities were fixing the billing and improving customer service.

When asked, only one participant suggested that the spending priorities needed to be adjusted. Specifically, he felt that it would be good to spend more on renewable generation if possible, as there may be some long term benefit. Most felt they didn't know enough about the subject matter to be able to give an opinion. One participant wondered about the actual amount of money being spent.

Everyone struggled to give an opinion on Toronto Hydro's outcome goals with the DSP, but most seemed to be supportive. One participant commented that he would be willing to pay for it if the system was more reliable and so he felt Toronto Hydro should be spending more.

How Could the Consultation Process be Improved?

Most felt the current process worked for them. Some suggested an online survey.

Residential Rate Class (North York)

System Reliability: Customer Experience and Expectation

Many of the residential participants from North York felt that Toronto Hydro should improve its communication with its customers, specifically regarding outage issues. Moreover, several stated that they wanted to be regularly updated on the overall development plan of Toronto Hydro and how their particular regions of the city would be impacted.

Several commented that replacing aging equipment before or after breakdown depends on how critical the equipment is and the extent and duration of the outage. For these participants, the decision was nuanced, as they thought seniors' residences, hospitals, and residential homes would have different priorities and thus a cost benefit analysis was required to properly assess the situation.

Improving Service of the Local Distribution System

As the discussion began, participants almost immediately wondered why Toronto Hydro hadn't been putting money aside to maintain the grid. It was agreed that grid upgrades are needed, but some think it could be done and should be done without the customer having to pay for it.

Participants spoke about having a high number of power outages and subsequent inconveniences and food spoilage. It was felt that such frequent outages (at least once per month for one individual) were entirely unacceptable.

Most felt that Toronto Hydro should better invest in aging infrastructure, in particular changing old overhead systems with the Canadian climate in mind. One individual thought that Toronto Hydro should better manage contractors to avoid extra costs.

There was a desire for more long term information, that is, what happens after the implementation of the five year plan.

Communication with customers was a common theme, particularly during power outages. It was felt that planned outages should be properly communicated, and that communication during major outages should be better.

System Renewal

Some participants stated that Toronto Hydro should prepare more rigorously to cover major issues, thereby allowing them to save money in the long term. Others stated that they wanted an updated grid that would bring costs down in the long term.

There was some suggestion that Toronto Hydro should find effective and better ways to maintain and upkeep aging infrastructure, or that the city of Toronto should be paying for system improvements rather than customers.

Participants were divided on "run to failure" versus extending equipment lifecycles. Ultimately, everyone favoured whichever option would cost the least overall – whether that means proactively replacing equipment to avoid failure or leaving equipment in place as long as possible was not agreed upon. One individual said a cost benefit analysis would be required in order to answer the question properly.

Coverage of Distribution System Topics

Most found the workbook to be very informative, providing the group with the right amount of information needed to discuss the issues at hand.

Some felt there were other issues that were not covered in the workbook, while others felt that they needed more time to cover all of the topics.

Response During Major Weather Events

Many of the participants felt that major event catastrophes could have been avoided if Toronto Hydro better maintained its system by investing in new equipment.

During the storms, it was felt that Toronto Hydro was not well organized and was lacking in efficiency.

Concerning communication during major weather events, many felt that Toronto Hydro should have relayed up to date information regarding power outages during both the flooding in July and the ice storm in December of 2013. Participants stated that if they had updated information from Toronto Hydro, they could have made informed decisions about their needs for accommodation, food, and so forth.

Many reported having tried to call Toronto Hydro during these major outages, but none were satisfied with the response they received and felt that no one was giving them any information. It was acknowledged by one pariticipant that Toronto Hydro has been proactive with her in the past in terms of warning her of planned outages.

Toronto Hydro's Proposed Plan and Rate Impact

Most participants were unable to answer whether Toronto Hydro's plan seemed to be going in the right or wrong direction because they felt they needed to have more information to answer the question effectively.

For those who thought that Toronto Hydro's Five Year Grid Renewal Plan was not headed in the right direction, a variety of reasons were provided as to why the felt this way. Some felt the plan didn't seem practical, while others felt they needed to know what would happen once the five year plan was over.

For a couple of participants there was the sense that the present situation could have been avoided with preventative planning in place. Finally, there were those who simply objected to customers having to pay to implement the plan.

How Could the Consultation Process be Improved?

Within the group, there was a general consensus among participants that the consultation process was both effective and engaging. One of the participants suggested that he would prefer a referendum amongst Toronto Hydro customers to make a decision on the proposed plan.

Presented with the option, participants liked the idea of a year long consumer advisory group.

Central Toronto Consultation Sessions

General Service Under 50 kW Rate Class (Central Toronto)

System Reliability: Customer Experience and Expectation

In the general service group, everyone felt that they understood the electricity system at least 'somewhat well', but some would have liked to see more financial information in the workbook.

The group struggled with regard to the current frequency and duration of power outages. While they realized it may not be a realistic goal, many would still prefer to see zero outages. One participant didn't believe the average numbers presented in the workbook as she felt they were inflated in order for Toronto Hydro to make their case for a rate increase. Two gentlemen didn't want to allow for any power outages, as a way of communicating to Toronto Hydro that striving for anything other than zero is not good enough.

It was agreed by all that reducing duration is more important than reducing frequency of outages because it is the duration that really impacts their businesses.

Improving Service of the Local Distribution System

Power interruptions were the main theme in terms of desired improvements. Participants would like to see fewer outages and better customer service during outages. One participant would like to see Toronto Hydro help businesses avoid difficulties during power outages by providing them with generators.

There was general agreement that shorter duration of outages is more important that reducing frequency.

Some felt that the customer service issue extended beyond the realm of outages and that improvement was needed overall. One participant commented that he finds the Toronto Hydro website difficult to use.

Coverage of Distribution System Topics

The group generally felt that the questions regarding required investment priorities (questions 4, 5 and 6) should have been left out of the workbook as there was nothing to be done about them. They found

the types of investments themselves to be reasonable, but most didn't feel there was much point in discussing them as part of the consultation.

System Renewal

Many participants in the group had thoughts on where Toronto Hydro's main priorities should lie, whether it is investing in underground infrastructure, working less with developers in favour of residential and business customers, or reducing spending on things like electric vehicles.

Everyone in the group felt that, from a business perspective, they cannot afford the time lost if hydro equipment breaks down, and so they prefer replacement before breakdown.

Response During Major Weather Events

The primary request was for information on when the power would be restored, although it was recognized that this may not be possible.

One participant wondered why the tree trimming budget had been reduced last year.

Toronto Hydro's Proposed Plan and Rate Impact

Modernizing the grid was considered to be very important because of the perception that it gets at the root of the problem and can prevent business losses due to outages. One participant felt she was unable to answer the question because she was skeptical about the entire process and the information she was being presented with in the workbook.

Interest in participating in CDM programs was minimal. There was the sense that business owners/managers would be losing control over their business equipment which could impact their business, revenue and customers. One participant didn't like the "Big Brother" feel of the program.

Many felt unable to gauge whether or not Toronto Hydro's plan seemed to be heading in the right direction in terms of spending priorities. One participant was confused and wondered why Toronto Hydro doesn't have money set aside for this situation. A couple of participants felt that more should be spent on modernizing the grid.

Asked about Toronto Hydro's goals, most feel that the change is necessary, but they don't want a rate increase. On the other hand, one individual would like to see Toronto Hydro aim higher, even if it means a bigger rate increase. Two participants felt they were not able to answer the question without having more time to consider all of the information.

How Could the Consultation Process be Improved?

An online approach was suggested as an optional approach to this consultation. Others said that more time was needed to be able to read the workbook.

A couple of participants felt that the decisions had already been made, so they weren't sure what the point of the consultation was.

A few participants had issues with the questions, but were unable to come up with suggestions for improving them.

Asked what further information they would like to have, a few participants said they would like to have been given more financial information.

Presented with the option, participants liked the idea of a year long consumer advisory group.

Residential Rate Class (Central Toronto)

System Reliability: Customer Experience and Expectation

Overall, most participants feel that the current average number and duration of outages was at least "somewhat acceptable". Some were willing to accept more and longer outages, but there were a couple who felt that no outages are acceptable. One participant suggested that "understandable" may be a more appropriate term than "acceptable".

When discussing the consequences of power outages, participants mentioned medical equipment, elevators, food spoilage, gas pumps, public transportation and those who work from home being unable to work.

All of the participants in the group stated that they want better customer service from Toronto Hydro and its staff. Specifically, several said Toronto Hydro should improve its communication measures with its customers, especially when outages and other similar incidents occur.

Participants also stated that Toronto Hydro should focus on replacing aging infrastructure for safety concerns. They went on to say that old distribution units can be fire hazards to communities. One of the participants said that he would like Toronto Hydro to invest more in upgrading infrastructure and to replace overhead lines to avoid future outages.

Improving Service of the Local Distribution System

Several participants stated that Toronto Hydro should continue to concentrate on reducing the number and duration of outages. A couple of participants said that more money should be spent on preventative maintenance of equipment. One specifically stated that he would like Toronto Hydro to invest more capital into sophisticated infrastructure and solar panels.

Generally, participants would like to see an improvement in customer service, specifically, they would like Toronto Hydro to be more responsive when they call with issues or concerns. Communication during major outages was also raised, as well as during more minor outages. One participant who expressed having frequent summer "pop offs" shared her frustration with not being able to get an explanation. Door to door or automated dialing were suggested as means of communication during major outages.

Several would like either a more granular breakdown of their bill, or some other type of adjustments that would make their bill easier to understand.

Coverage of Distribution System Topics

Some of the participants stated they would have liked the workbook to tell a better story on how electricity reaches users and how much work goes on behind the scenes to keep Toronto lit up.

Several said they were not sure whether they were qualified to answer questions 4, 5, and 6 on page 11 regarding reasonable investment measures on connection issues, maintaining smart meters, and moving electricity infrastructure.

System Renewal

Participants in this group did not have much to say about system renewal during the majority of the discussion. Many felt that Toronto Hydro should have planned and saved ahead for the infrastructure maintenance and replacement costs. One of the participants in particular said that he wanted Toronto Hydro to do a better job with the upkeep of transmission wires.

Response During Major Weather Events

Many participants said that Toronto Hydro should have had better communication with its customers during the flooding and ice storm. Some went on to say that Toronto Hydro should not label these major storm events as "unusual" since Toronto Hydro should be ready for these types of situations to arise due to changing climate patterns.

Toronto Hydro's Proposed Plan and Rate Impact

Many felt unable to comment on whether they felt the balance of the spending plan looks right. The workbook was described as a good primer, but lacked the details required to make a judgment on the plan. Participants wanted more information behind the numbers – where do they come from and what exactly will the impact of the relative spending amounts be in the longer term. Conversely, some wondered what the future would look like if these investments were not made.

There were several questions about the various proportions indicated throughout the workbook in terms of the proportion of equipment over a certain age, etc.

As the discussion progressed, many wondered why Toronto Hydro hadn't planned on and budgeted for replacing aging equipment.

Almost everyone felt that the goals set by Toronto Hydro are too low and that more should be spent in order to do more and do it sooner. One participant felt it is their duty as citizens to undertake something like this for the sake of future generations. One participant felt there was a significant infrastructure deficit and he was not sure that the plan in its current form addressed it sufficiently.

Some participants wanted to know what the situation would look like in 2019 after the plan has been implemented. It was generally agreed that five years wasn't going to solve the problem. There were some who wondered about the layoffs referred to in the workbook, given the amount of work about to be undertaken.

How Could the Consultation Process be Improved?

One of the participants questioned why this type of consultation was not carried out by Toronto Hydro before and why it was not mandated by the OEB in previous years. Another participant, while liking the information, wanted Toronto Hydro to spend less on the workbooks (e.g. less glossy photos).

Some thought that the workbook should have had more choices laid out for participants to choose from instead of just two. In particular, one participant stated that some of the examples and comparative case studies did not help explain which plan was better. Another said that more information is needed as questions are raised (e.g. one fourth of the electricity bill goes to Toronto Hydro, but where does the rest go?).

Others were basically fine with the workbook, but wished they had had more time in advance to read it so that they could come to the group prepared to discuss it.

Several participants wanted to have more information in the workbook. One individual felt that the workbook seemed incomplete, especially when it came to fully disclosing the numbers and price of choices. Further, he stated that up to page 30 the workbook was effective, but after page 30, the workbook became uninformative.

As for specific information, some participants requested information on Toronto Hydro's operating budget while others stated that they would have liked more information on alternative forms of energy (e.g. wind farms and solar panels) that Toronto Hydro was currently investing in. They also wanted to know more about the role of other provincial players within the system. Another also requested information regarding excess power and where it goes.

Presented with the option, participants liked the idea of a year long consumer advisory group.

Etobicoke Consultation Sessions

General Service Under 50 kW Rate Class (Etobicoke)

System Reliability: Customer Experience and Expectation

Several participants in the group stated that Toronto Hydro's service was great because power outages were few in frequency and short in duration. One of the participants who runs a service based business stated that she would like Toronto Hydro to provide some type of notification as to when an outage might occur so that she can inform her customers and close the store to avoid any revenue shortfalls.

One participant felt that Toronto Hydro's prices have increased too fast, and service has not improved in terms of reliability. He went on say that communication during outages should be more open and transparent.

About half of the group felt that the current average number and duration of outages is acceptable. There were a few in the group who said that no outages are acceptable, and while they recognized that this may not be achievable, they still feel that in terms of goal setting, Toronto Hydro should be aiming for zero. One participant said she would like to have no outages but not if it was going to cost her significantly more.

There were two participants who reported experiencing many more outages than the average range, but they felt the duration of their outages was reasonable.

Two hours was agreed upon as the limit after which there would business implications such as food that would need to be thrown out, or businesses closed and staff sent home.

Improving Service of the Local Distribution System

Several participants agreed they want Toronto Hydro to clear out the trees that are currently blocking or interfering with the distribution lines.

A widely supported suggestion for improvement was communication during outages. One participant commented that the technology is there to use social media to provide updates and that in a place like Toronto Hydro they could have someone dedicated to that type of communication.

A couple of participants spoke of frequent outages and said they would like to see improvement in that regard.

Coverage of Distribution System Topics

Most of the participants in the group thought that the workbook was effective in explaining the proposed Toronto Hydro plan and that the consultation process was an effective approach for hearing the concerns of the general service users. One participant felt that the workbook was informative but too general.

Participants for the most part struggled to answer the questions about investment priorities (4, 5 and 6), but didn't necessarily feel the questions should have been left out. One participant described them as impossible to answer based on the information she had in front of her.

System Renewal

Several participants in the group said that although Toronto Hydro's plan is headed in the right direction, there should be more transparency Further, they felt that Toronto Hydro should let customers know the full costs of upgrading the system and the challenges Toronto Hydro faces in both the long and short term in modernizing the grid.

Many stated that Toronto Hydro should invest more in renewable generation and renewable energy. A few felt that they did not have enough information or knowledge to comment on Toronto Hydro's planned spending.

In response to CDM programs, most were in favour and said they would participate as long as they are made aware of planned outages in advance. However, there were a few who simply wouldn't trust anyone to put a meter on their equipment. One individual said he didn't feel the program is even necessary because there hasn't been a brownout due to lack of power in more than a decade.

Response During Major Weather Events

Several participants stated that Toronto Hydro should have taken the time to cut trees before the storm so that the trees would not become a major problem after the storm. And, several felt that Toronto Hydro should generally be more prepared and proactive in their approach to dealing with major weather events.

Many wished Toronto Hydro had better communicated with its customers during both the flood and the ice storm. They specifically stated that they wanted to be notified as to when services would be restored in their businesses and neighbourhoods.

Toronto Hydro's Proposed Plan and Rate Impact

All agreed that modernizing the grid was at least "somewhat important" in order to keep businesses up and running. They didn't necessarily know where it fit in with other investment priorities though.

Based on what they knew already and what they read in the workbook, most participants felt they understood the challenges facing Toronto Hydro.

The majority felt that Toronto Hydro's plan was moving in the right direction and thought that replacing the aging infrastructure was vital in renewing the grid.

One participant stated that, although Toronto Hydro's plan is headed in the right direction, he feels as if Toronto Hydro has started to modernize the grid too late since the demand for electricity has been increasing substantially over the last fifty years.

A couple of participants felt Toronto Hydro generally had the right balance, but she wondered why modernizing the grid was separate from replacing aging and obsolete equipment. And, if the items were to be separate, they wondered why modernizing the grid was such a low priority or even why it was part of a general capital upgrade.

While a couple in the group were satisfied with the balance between outcomes and the proposed rate increase, most don't like the rate increase, even if they feel it is necessary in order to maintain the grid to a reasonable standard. One participant wanted to know why the dividend being paid to the city of Toronto isn't being used to fund the plan.

One participant felt he didn't know enough to make a judgment on the plan, but he felt that the public cannot afford any more rate increases.

How Could the Consultation Process be Improved?

For the most part, participants found the consultation enjoyable and informative. One participant said she was intrigued when she got the recruitment call, and she enjoyed the process. On the other hand another participant, felt the process was about trying to convince customers that Toronto Hydro's rate increase is justified.

When asked, most said they would be interested in an advisory panel, but one participant added the caveat that such a panel would need to have some kind of "power" or ability to enforce decisions.

Residential Rate Class (Etobicoke)

System Reliability: Customer Experience and Expectation

Outages were mentioned as the primary area of concern. A few participants in the group mentioned experiencing frequent outages and not being able to communicate with Toronto Hydro about it. Two participants expressed frustration in not being able to get a response from Toronto Hydro in spite of calling them multiple times.

Several participants mentioned more communication of information during outages. Further, a couple of respondents said they wanted Toronto Hydro to minimize the number and duration of power outages. Another participant mentioned faster response times by Toronto Hydro when there is a blackout.

A couple of participants wondered why Toronto Hydro isn't being more proactive about either removing or pruning trees or burying lines underground.

Others said they were generally satisfied with Toronto Hydro and had no suggestions for improvements.

In terms of the average frequency and duration of outages, participants were generally accepting. In their own lives, they would find an outage lasting longer than a day to be problematic.

Improving Service of the Local Distribution System

Multiple participants said that replacing equipment is a priority, especially modernizing the grid and replacing old equipment. A few mentioned spending more money on knowledgeable employees. A couple of participants said that connecting renewable generation needs to be a higher priority. And one individual said that money needs to be spent on improving reliability.

Coverage of Distribution System Topics

Several participants said that the workbook was very informative and appeared to be filled with valuable information. One member of the group stated that both the workbook and consultation overall was very easy to follow. One added that although it was the right length, the information in the workbook was more technically oriented than needed. Mostly, participants in the group asked for more time to be able to read and evaluate the information presented in the workbook.

One participant thought that the workbook was interesting but very self-serving. Another participant said the workbook was too simple to be able to accurately assess the plan. Several said there was not enough information as the workbook seemed to present too narrow of a scope to be able to properly assess Toronto Hydro's plan. One individual also commented that they would have liked to know more about Toronto Hydro's communication and engagement plans.

System Renewal

Several of the participants thought that Toronto Hydro and its customers have no choice but to deal with a rate increase because at this point, customers need to deal with the "growing pains" of modernization. In contrast, others felt that the proposed plan was just a way for Toronto Hydro to raise the rates but that nothing would really improve.

Everyone preferred the strategy of replacing equipment before it breaks down as being more cost-effective than the run-to-failure option. One participant compared it fixing a problem with his car, saying it's always more if he waits.

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Response During Major Events

Many participants said they would like better communication during major outages, especially with regards to when service will resume, so that they can plan accordingly.

One participant gave Toronto Hydro kudos for handling both major storms as well as possible under the circumstances.

Overall, for every person who had a complaint about how Toronto Hydro responded to the major storms, there was someone else defending them for doing the best they could do when dealing with an "act of God".

Toronto Hydro's Proposed Plan and Rate Impact

With only two exceptions, everyone said they don't like the rate increase but they feel it is necessary to maintain the grid to an acceptable standard. One individual wondered why the provincial government wasn't stepping in to ease the burden on customers.

One participant said that the plan is presented in isolation and that there are no contrasting views or other pertinent information. Further, many of the participants said they needed more information before they made up their mind.

When asked about improvements to the system, several said less money should be spent on upgrading customer meters and connecting customers. Another mentioned that Toronto Hydro should stop focussing its energy on debt reduction and delivery charges. One participant also stated that updating IT structure should be less of a priority while others thought that renewable generation and reliability goals should be more of a priority.

How Could the Consultation Process be Improved?

When asked about the consultation process, one participant commented that it feels like Toronto Hydro has already made up its mind and that the consultations are too late. A couple of other participants thought the process should be more inclusive and include Toronto Hydro staff who can answer any outstanding questions. There was also a suggestion that the workbook should have been written by a third party.

When asked about specific topics and questions, one participant mentioned that information about operating costs including administration costs, benefits, and salaries were not properly explained. Another participant said that rebates should have been discussed. One person also asked how Toronto Hydro will be improving their communications systems going forward.

Scarborough Consultation Sessions

General Service under 50 kW Rate Class (Scarborough)

System Reliability: Customer Experience and Expectation

Most of the participants in the group said Toronto Hydro should reduce outages. One in particular added that Toronto Hydro could offer business customers credit or a rebate for time and revenue lost when power is out.

Further, communications seemed to be a prevalent issue with most participants. Some said that there needs to be more communication with the public as well as improved customer service.

Improving Service of the Local Distribution System

A couple of participants mentioned upgrading equipment and the grid with more modern technology. And, as noted above there was a desire for better communication.

Coverage of Distribution System Topics

A few participants said that the workbook was long but straightforward. On the other hand, a couple of participants said they felt like information had been left out. Another said that the workbook does a reasonable job of explaining a very complex set of systems.

Many said there was too much information in the workbook. One said there was too much on technological systems and there was too much jargon. On the other hand, another participant said they wished there was more information on the technological side. A couple of participants thought the workbook covered the relevant areas sufficiently. However, one in the group wished there was more detail on where the money is being spent.

Response During Major Weather Events

Some participants expressed a need for improvement and for priority to be given to schools and seniors' residences during major weather events. Participants suggested that more workers from other areas should be brought in to help with large scale power outages or during major weather events. The lack of information or ability to reach someone at Toronto Hydro was also mentioned.

Lastly, several participants felt that during major weather events power should be restored to businesses and larger buildings before restoring power to single houses.

Toronto Hydro's Proposed Plan and Rate Impact

Two participants said they thought the proposed plan was headed in the right direction as aging equipment needs to be updated in order to prepare for the future. One participant said it was headed in the right direction because Toronto Hydro is building an effective system for the good of users.

When asked about how Toronto Hydro spends its money, a few said more money should be spent on improving the grid and more money for micro generators that can keep vital equipment functioning in the event of a power outage longer than 30 minutes. Another participant commented that more money should be spent on employee talent and recruitment.

An individual who was unsure about the direction said they don't have enough information and don't know if Toronto Hydro's priority is making money or serving Torontonians.

One participant said there should be a realistic assessment of costs for the "unusual costs" that were referred to in one part of the workbook. Another participant said there should be less spent at the top level of execution planning. Still another said the real benefits do not seem to justify the costs. Construction also seemed to be an issue of contention. A couple of participants mentioned a lot of Toronto Hydro money and resources were being wasted in supporting new developments and construction projects.

When it comes to goals and priorities, some said the goals were reasonable but that the city should be able to handle more of the expenses without the consumers picking up the costs. One participant said the priority should be with replacing aging and obsolete equipment. Another participant felt there should be more of a focus on training and retention of employees.

How Could the Consultation Process be Improved?

At the end of the session, there were two questions for which participants wanted answers. The first was "if we don`t have to answer technical stuff on the grid, why is there so much complex technical stuff in this booklet?" and the second was "how does Toronto Hydro compare to other service providers?"

When discussing improvements to the consultation process, one participant said that perhaps Skype or email could be used while another participant said that there should be more lead time for reading the information provided. Two suggested making the focus groups shorter. And one participant wanted more information on renewable energy sources.

Residential Rate Class (Scarborough)

System Reliability: Customer Experience and Expectation

Several participants mentioned improving communications especially when there are power outages. One individual suggested that there should be an option to call someone at Toronto Hydro when there is an emergency. Another said that improvements to the website would also be helpful.

Many participants mentioned that the number of power outages should be reduced and one in particular felt that rebates should be given in the event of outages. There was also a request for more realistic estimates on times needed for repairs. One of the participants in the group wanted underground cables to be put in. Another suggested eliminating peak use times.

Improving Service of the Local Distribution System

Several participants stated that Toronto Hydro should replace aging infrastructure and not wait until the equipment fails to replace it.

Coverage of Distribution System Topics

Most of the participants found the workbook to be very informative, and that it covered all of the necessary topics sufficiently. Specifically, one participant commented that the workbook was helpful and the language and content were easy to understand.

A few said that the workbook consisted of too much information at once. However, at the same time they realized that to explain everything clearly, the workbook needed to include a great deal of information. One of the participants felt there needed to be more on costs for improvements but less on other things.

System Renewal

Many mentioned spending more on modernizing the grid. A couple of these participants said that more money should be spent on preventative maintenance of equipment. In particular, one participant said that more spending needs to be spent on underground cables.

Most didn't seem to know what should be prioritized with regards to spending. One individual said that less money should be spent on expanding capacity and accommodating construction projects in the city. Some wondered why Toronto Hydro couldn't set money aside for future expenses/costs.

Response During Major Weather Events

Almost everyone mentioned that communication from Toronto Hydro could be improved during major weather events. One participant suggested a real person instead of a recording on the phone. Others said there needs to be a better system for giving updates on the state of repairs during these major weather events. One participant suggested that until the power came back on Toronto Hydro could have provided temporary generators.

Toronto Hydro's Proposed Plan and Rate Impact

None of the participants in the group said Toronto Hydro was headed in the "wrong direction" and most participants who said "not sure" provided no further comments concerning why they said that. However, one participant who thought Toronto Hydro was headed in the right direction said that renewing equipment must be a priority. Another who agreed that Toronto Hydro was heading in the right direction thought that more money should be spent on preventative maintenance of equipment.

Most didn't seem to know what should receive less spending. However, one participant said that less money should be spent on expanding capacity and accommodating construction projects in the city.

How Could the Consultation Process be Improved?

All of the participants in the group agreed that the consultation was well put together. Further, most thought there was just enough information in the consultation to be an informative and accountable discussion. Another wanted to hear more about costs for modernization. Smart meters were also raised as a potential discussion topic.

Questionnaire Results 1

The following tables are the tabulations of participant feedback to questions in the hard copy workbooks, which were returned at the end of each consultation session.

Note: "GS" = general service less than 50 kW customers, while "RS" = residential customers. Due to the high occurrence of non-response to open-ended questions and subsequent small sample size, these results are not segmented by region, but rather only between general service and residential customers.

Blue tallies denote feedback from North York Customers (GS and RS)
Orange tallies denote feedback from Toronto Customers (GS and RS)
Green tallies denote feedback from Etobicoke Customers (GS and RS).
Purple tallies denote feedback from Scarborough Customers (GS and RS)
Numbers in red denote the sum of all participant feedback tallies.

1. How well do you feel you understand the important parts of the electricity system, how they work together and which services Toronto Hydro is responsible for?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very well	3	0	3	1	4	5	3	3	6	3	3	6	20
Somewhat well	4	5	9	6	4	10	4	6	10	6	6	12	41
Not very well	0	1	1	0	0	0	0	1	1	1	0	1	3
I don't understand at all	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

2. How satisfied are you with the job Toronto Hydro is doing running your local distribution system?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very satisfied	0	0	0	1	3	4	1	2	3	3	1	4	11
Somewhat satisfied	6	1	7	5	3	8	4	4	8	6	7	13	36
Somewhat dissatisfied	1	2	3	0	2	2	2	4	6	1	1	2	13
Very dissatisfied	0	3	3	1	0	1	0	0	0	0	0	0	4
Don't know	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

3: Is there anything in particular that Toronto Hydro can do to improve its service to you? (OPEN ENDED)

Response	General Service	Residential	Sum Total
Better communication with customers/improved customer service	6	8	14
Improve and invest more in electricity system to make it more reliable to make it more reliable	6	5	11
Lower costs of electricity rate	4	6	10
Faster/better response times during power outages	3	2	5
Service is good	3	0	3
Cut trees where overhead wires to avoid entanglement	2	0	2
Better and accurate smart meter readings	1	0	1
Simpler invoices	1	0	1
Safety	1	0	1
Improve and invest more in electricity system to make it more reliable	0	1	1
Other	0	3	3
Don't know	1	0	1
No response/ refused	3	8	11
Total	31	33	64

4. Under provincial legislation, there are several types of investments Toronto Hydro must make when the need presents itself. How reasonable do you feel it is to give each of these investments priority over other investments (for example, replacing aging equipment)? Connecting new customers such as new housing, condominiums or businesses.

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very reasonable	4	1	5	4	6	10	3	5	8	3	3	6	29
Somewhat reasonable	3	2	5	2	2	4	3	4	7	6	5	11	27
Not very reasonable	0	0	0	0	0	0	0	0	0	0	1	1	1
Not reasonable at all	0	1	1	0	0	0	0	0	0	0	0	0	1
Don't know	0	1	1	1	0	1	1	0	1	1	0	1	4
No response/ refused	0	1	1	0	0	0	0	1	1	0	0	0	2
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

5. Under provincial legislation, there are several types of investments Toronto Hydro must make when the need presents itself. How reasonable do you feel it is to give each of these investments priority over other investments (for example, replacing aging equipment)? Maintaining and upgrading customer meters to meet provincial standards.

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very reasonable	2	1	3	1	2	3	1	3	4	2	4	6	16
Somewhat reasonable	4	2	6	2	4	6	2	4	6	5	3	8	26
Not very reasonable	0	1	1	3	0	3	1	0	1	1	1	2	7
Not reasonable at all	1	1	2	0	2	2	2	1	3	1	0	1	8
Don't know	0	0	0	1	0	1	1	0	1	1	0	1	3
No response/ refused	0	1	1	0	0	0	0	2	2	0	1	1	4
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

6. Under provincial legislation, there are several types of investments Toronto Hydro must make when the need presents itself. How reasonable do you feel it is to give each of these investments priority over other investments (for example, replacing aging equipment)? Moving existing electricity infrastructure such as poles and transformers to enable other projects such as street widening or new developments.

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very reasonable	4	0	4	1	2	3	3	4	7	3	2	5	19
Somewhat reasonable	3	3	6	3	4	7	2	2	4	4	3	7	24
Not very reasonable	0	0	0	0	0	0	0	1	1	1	3	4	5
Not reasonable at all	0	2	2	0	1	1	1	1	2	0	0	0	5
Don't know	0	0	0	2	1	3	1	0	1	2	1	3	7
No response/ refused	0	1	1	1	0	1	0	2	2	0	0	0	4
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

7. Wait until equipment breaks down or replace equipment before it breaks down?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Wait until breakdown	2	0	2	2	0	2	1	0	1	5	0	5	10
Replace before breakdown	5	5	10	5	7	12	3	8	11	4	9	13	46
No response/ refused	0	1	1	0	1	1	3	2	5	1	0	1	8
Total	7	6	13	7	7	15	7	10	17	10	9	19	64

8. Do you feel the current average number of electricity outages is acceptable or not acceptable?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very acceptable	1	0	1	0	2	2	1	2	3	1	1	2	8
Somewhat acceptable	2	1	3	1	3	4	4	4	8	7	4	11	26
Not very acceptable	3	2	5	1	2	3	1	1	2	1	2	3	13
Not acceptable at all	1	3	4	4	1	5	1	3	4	1	2	3	16
Don't know	0	0	0	1	0	1	0	0	0	0	0	0	1
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

9. Do you feel the current average amount of outage time is acceptable or not acceptable?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very acceptable	1	0	1	0	2	2	1	1	2	2	1	3	8
Somewhat acceptable	0	3	3	1	3	4	3	3	6	6	4	10	23
Not very acceptable	3	1	4	3	1	4	1	5	6	0	2	2	16
Not acceptable at all	3	2	5	3	2	5	2	1	3	2	2	4	17
Don't know	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

(Questions 10 and 11 asked about the number of outages experienced in the past two years and duration of the most recent outage).

12: How did the power outage affect your business or you personally? (OPEN ENDED)

Response	General Service	Residential	Sum Total
Closed business due to outage	5	0	5
Had to use back up generator Increased production costs	1	0	1
Negatively affected business (loss of production, loss of revenue)	14	1	15
No heat	0	1	1
Not affected	5	8	13
Personal loss	0	12	12
Safety Concern	1	0	1
Spoiled goods and loss of money	0	7	7
Other	0	2	2
Don't Know	3	0	3
No response / refused	2	2	4
Total	31	33	64

13: Is there a certain length of time at which the costs/consequences of an outage become more serious for you or your business? (OPEN ENDED)

Response	General Service	Residential	Sum Total
0 to 1 hours	6	4	10
1 to 4 hours	8	4	12
6 to 12 hours	3	8	11
More than 24 hours	4	9	13
More than a week	0	1	1
Other	3	1	4
Don't know	2	0	2
No response / refused	5	6	11
Total	31	33	64

14. How many power service interruptions are reasonable in a year?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
No outage is acceptable	3	3	6	2	0	2	1	1	2	2	2	4	14
One	1	1	2	2	2	4	3	3	6	2	1	3	15
Two	2	2	4	1	4	5	0	2	2	3	2	5	16
Three	0	0	0	1	1	2	2	1	3	2	3	5	10
Four	0	0	0	0	1	1	0	1	1	1	0	1	3
More than four	1	0	1	0	0	0	0	0	0	0	1	1	2
No response / refused	0	0	0	1	0	1	1	2	3	0	0	0	4
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

15. What is a reasonable duration for a service interruption?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
No outage is acceptable	1	3	4	1	0	1	0	0	0	2	2	4	9
30 minutes	5	1	6	4	1	5	2	2	4	4	4	8	23
1 hour	0	0	0	0	2	2	0	1	1	1	2	3	6
2 hours	1	1	2	1	5	6	4	1	5	1	0	1	14
3 hours	0	1	1	1	0	1	0	2	2	1	1	2	6
4 hours or more	0	0	0	0	0	0	0	2	2	1	0	1	3
No response / refused	0	0	0	0	0	0	1	2	3	0	0	0	3
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

16. Thinking back to the two major storm events of 2013, were you affected by either or both of these events?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Yes – the flooding in July	0	0	0	2	2	4	1	0	1	0	0	0	5
Yes – the ice storm in December	0	2	2	4	4	8	2	2	4	4	6	10	24
Yes – both	6	3	9	0	0	0	2	6	8	0	1	1	18
No – neither weather events	1	1	2	1	2	3	2	1	3	6	2	8	16
No response / refused	0	0	0	0	0	0	0	1	1	0	0	0	1
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

17. Whether you were personally affected or not, how satisfied are you with Toronto Hydro's management of these events?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very satisfied	0	0	0	0	1	1	3	2	5	1	0	1	7
Somewhat satisfied	2	0	2	3	6	9	3	3	6	5	3	8	25
Somewhat dissatisfied	2	2	4	1	1	2	0	1	1	1	3	4	11
Very dissatisfied	2	4	6	2	0	2	0	2	2	2	3	5	15
Don't know	0	0	0	1	0	1	1	0	1	1	0	1	3
No response / refused	1	0	1	0	0	0	0	2	2	0	0	0	3
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

18: Is there anything in particular that Toronto Hydro could have done to improve its service to you or your business during these events?

Response	General Service	Residential	Sum Total
Better communication	8	17	25
Better customer service	2	1	3
Better maintenance of aging equipment	1	1	2
Contingency plans in place	4	0	4
Invest more in electricity system	1	1	2
Pruning of trees	1	0	1
Resolve outage issues faster	3	2	5
Other	2	0	2
No response / refused	9	11	20
Total	31	33	64

19. How important do you feel it is for Toronto Hydro to invest now in modernizing the grid?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very important	5	3	8	4	7	11	4	5	9	5	8	13	41
Somewhat important	2	2	4	1	0	1	3	1	4	4	1	5	14
Not very important	0	1	1	0	0	0	0	0	0	1	0	1	2
Not important at all	0	0	0	0	0	0	0	0	0	0	0	0	0
Don't know	0	0	0	0	0	0	0	0	0	0	0	0	0
No response / refused	0	0	0	2	1	3	0	4	4	0	0	0	7
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

20. How likely is that you would participate in Demand Response programs that would allow electricity system managers to turn off equipment you are using?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very likely	1	1	2	1	4	5	4	2	6	1	2	3	16
Somewhat likely	0	2	2	3	1	4	1	2	3	1	0	1	10
Not very likely	3	3	6	0	1	1	0	3	3	4	1	5	15
Not at all likely	3	0	3	1	1	2	1	2	3	2	2	4	12
No response / refused	0	0	0	2	1	3	1	1	2	2	4	6	11
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

21. How well do you feel you understand the challenges facing the Toronto hydro grid and what they are planning to do to meet those challenges?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Very well	1	1	2	4	4	8	2	1	3	0	0	0	13
Somewhat well	6	2	8	3	4	7	3	7	10	9	7	16	41
Not very well	0	3	3	0	0	0	1	1	2	0	0	0	5
I don't understand at all	0	0	0	0	0	0	0	0	0	0	0	0	0
No response / refused	0	0	0	0	0	0	1	1	2	1	2	3	5
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

22. Does Toronto Hydro's investment plan seem like it is going in the right direction or the wrong direction?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Right direction	4	0	4	3	5	8	5	4	9	7	5	12	33
Wrong direction	3	1	4	2	0	2	0	1	1	1	0	1	8
Not sure	0	5	5	2	3	5	1	4	5	1	2	3	18
No response / refused	0	0	0	0	0	0	1	1	2	1	2	3	5
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

23: Right/Wrong/Unsure Direction: And why do you feel that way? (In relation to Q22) (OPEN ENDED)

Response	General Service	Residential	Sum Total
Right direction - Investment plan and replace before breakdown makes sense	13	10	23
Unsure - Not enough information	7	6	13
Wrong direction - mistrust/previous plans failed	3	1	4
Wrong direction - More investment needed	0	1	1
Wrong direction - previous plans failed	0	1	1
Wrong Direction - Problems still persist in electricity system	1	0	1
Wrong direction - too costly	0	4	4
Wrong direction r - Previous plans failed	0	1	1
No response / refused	7	9	16
Total	31	33	64

24. When you look at how much Toronto Hydro is spending on each of its investment priorities, do you think they have the balance right or would you change the relative priorities?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
The balance looks right	7	0	7	2	5	7	3	3	6	7	6	13	33
They should change some of the priorities	0	6	6	4	3	7	3	5	8	2	3	5	26
No response / refused	0	0	0	1	0	1	1	2	3	1	0	1	5
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

25: What areas do you feel need MORE spending than planned? (OPEN ENDED)

Response	General Service	Residential	Sum Total
Good balance in budget	2	1	3
Modernize the grid	7	9	16
More information needed	2	4	6
Plan ahead - proactive approach	1	0	1
Provide better reliability	0	1	1
Renewable Generation	2	5	7
Replacing aging equipment	1	1	2
Other	1	3	4
Don't know	3	3	6
No response / refused	12	6	18
Total	31	33	64

26: What areas do you feel need LESS Spending than planned? (OPEN ENDED)

Response	General Service	Residential	Sum Total
Accommodating construction projects	1	5	6
Debt reduction	1	1	2
Good balance in budget	2	0	2
Not enough information	3	1	4
Spend less on burying cables	1	0	1
Spend less on renewable generation	1	0	1
Stop accommodating electric vehicles	1	1	2
Stop spending money to connect new customers	0	4	4
Other	1	2	3
Don't know	3	3	6
No response / refused	17	16	33
Total	31	33	64

27. When you consider the options outlined in the table on the previous page, do you think Toronto Hydro's goals are too high, too low or about right?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Too high	0	2	2	1	0	1	1	1	2	1	1	2	7
About right	3	2	5	3	3	6	4	5	9	5	5	10	30
Too low	1	1	2	1	3	4	0	0	0	1	0	1	7
Not sure	3	1	4	0	2	2	1	2	3	1	2	3	12
No response / refused	0	0	0	2	0	2	1	2	3	2	1	3	8
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

28: What are the goals you feel are too HIGH? (OPEN ENDED)

Response	General Service	Residential	Sum Total
Funding for new equipment	2	2	4
More information needed	0	5	5
Plan is too costly overall	1	1	2
Reduce power outages	0	1	1
Run to Failure approach	1	0	1
Other	2	0	2
Don't know	1	1	2
No response / refused	24	23	47
Total	31	33	64

29: What are the goals you feel are too LOW? (OPEN ENDED)

Response	General Service	Residential	Sum Total
Better reliability	1	0	1
Hiring better workers and staff	1	0	1
Infrastructure renewal	1	4	5
More information needed	0	1	1
Reducing costs for consumers	0	2	2
Reducing power interruptions	1	0	1
Renewable Energy	2	1	3
Don't know	1	4	5
No response / refused	24	21	45
Total	31	33	64

30. Looking at the cost of the Toronto Hydro plan and the outcomes it is expected to achieve, which point of view is closest to your own?

Response	GS	RS	Total	GS	RS	Total	GS	RS	Total	GS	RS	Total	Sum Total
Achieve higher outcomes	3	0	3	1	3	4	1	1	2	1	1	2	11
Satisfied with the rate increase	1	0	1	0	2	2	1	3	4	2	3	5	12
Rate increase is necessary	2	5	7	3	2	5	3	5	8	5	5	10	30
Scale back plans	0	1	1	0	0	0	0	0	0	2	0	2	3
Not sure	1	0	1	1	1	2	1	0	1	0	0	0	4
No response / refused	0	0	0	2	0	2	1	1	2	0	0	0	4
Total	7	6	13	7	8	15	7	10	17	10	9	19	64

31: What did you think about the workbook? (OPEN ENDED)

Response	General Service	Residential	Sum Total
Biased Information	2	2	4
Clear and easy to understand	2	2	4
Effective form of engagement	5	5	10
Informative	10	11	21
Not clear	0	1	1
Not enough information	1	5	6
Too much information	1	2	3
Other	0	1	1
No response / refused	10	4	14
Total	31	33	64

32: Volume of information – Did Toronto Hydro provide too much information, not enough, or just the right amount? (OPEN-ENDED)

Response	General Service	Residential	Sum Total
Enough information	23	19	42
Not enough information	4	6	10
Too much information	4	6	10
No response / refused	0	2	2
Total	31	33	64

33: Content covered – Was there any content missing that you would have liked to have seen included? (OPEN-ENDED)

Response	General Service	Residential	Sum Total
Better breakdown of bill	2	1	3
Cost analysis	0	1	1
Costs cutting measures	0	1	1
Customer service	1	0	1
Financial reports	2	3	5
Financial Reports (operating budget, etc.)	1	0	1
More information	1	1	2
Not enough information	1	1	2
Other available options	0	2	2
Renewable Energy	2	1	3
Smart Meters	0	1	1
Waste management	1	0	1
Other	3	5	8
Don't know	1	1	2
No response / refused	16	15	31
Total	31	33	64

34: Outstanding Questions – Is there anything that you would still like answered? (OPEN-ENDED)

Response	General Service	Residential	Sum Total
Better explanation of bill	1	1	2
Clarification on increase	0	1	1
Communication plan	0	1	1
Comparison study	1	0	1
Contingency plans	1	1	2
History of Toronto Hydro	1	0	1
Impact of plan on costs for consumers	1	0	1
More engagement	0	1	1
More information on long-term energy plan	1	2	3
Renewable energy technologies	0	1	1
Time of Use question	0	1	1
Tree pruning clarification	1	1	2
Other	3	4	7
No response / refused	21	19	40
Total	31	33	64

35: Suggestions for future consultations – How would you prefer to participate in these consultations? (OPEN-ENDED)

Response	General Service	Residential	Sum Total
Focus group – was effective	6	8	14
More information	1	1	2
More time to prepare	2	1	3
Online engagement	4	1	5
Online survey	1	1	2
Process should be more engaging and comprehensive	0	2	2
Referendum vote	0	1	1
Shorter	0	1	1
Shorter session	2	0	2
Telephone interview	0	1	1
Other	2	3	4
Don't know	1	0	1
No response / refused	12	13	25
Total	31	33	64

Mid-Market GS 1-4 Workshops

Workshop Presentations and Discussion Groups
with Mid-market GS Customers

PURPOSE: To gain qualitative input/ response to proposed DSP from GS> 50 kW customers and to feed into survey design

Summary

The following summary highlights key findings from the commercial and industrial customer consultation sessions held in the Toronto area on March 31st and April 2nd of 2014.

System Reliability: Customer Experience and Expectation

- Most participants in the consultation groups have experienced power service interruptions at their businesses in the past twelve months. The duration of the service interruption lasted from a few minutes to many days in some cases. The frequency of outages averaged around two to three power service interruptions per year.
- Both commercial and industrial users reported losses of revenue and productivity within their respective businesses due to power service interruptions.
- Service-based commercial users would like Toronto Hydro to concentrate on limiting the duration of outages. Similarly, larger industrial businesses in the manufacturing sector wanted Toronto Hydro to focus on limiting the duration or length of power service interruptions per year. They stated that longer outages can have a serious consequence to productivity, as production cannot continue for long periods of time and can cause a "logistical nightmare" with workers.
- Alternatively, other manufacturing businesses stated that they would want Toronto Hydro to concentrate on limiting the frequency of outages as every time there is an outage their production equipment is forced to shut down, and that the time required to reset their production equipment could lead to significant loss of productivity.
- A number of participants stated that with a rate increase should come an obligation on behalf of Toronto Hydro to proactively communicate with customers on how the additional funds are being spent and to provide on-going status updates on the grid renewal plan.
- Both commercial and industrial customers stated that they wanted better customer service from Toronto Hydro staff. Specifically, many suggested better customer communications around power outages. Participants in the group stated that they wanted to know how long outages would last so they could prepare for a "contingency plan" and not suffer losses in productivity.

Improving Service of the Local Distribution System

- Overall, both commercial and industrial customers are satisfied with the work Toronto Hydro is doing maintaining the local distribution system. As stated above, when participants in the groups

were asked about improvements, the main suggestions concerned limiting rate increases, reducing power service interruptions and better customer communications around power outages.

- Participants in the groups were impressed overall by Toronto Hydro's accomplishments in reducing employee headcount, keeping absenteeism low, working safely, and improving the coordination of capital projects.
- Large-scale industrial customers expressed concerns about electricity costs. They stated that, unlike commercial service-based businesses that can more readily pass costs onto their customers, many industrial manufacturers operating within the Toronto Hydro grid are unable to pass on costs as their products are sold in competitive, international markets. A number of industrial customers suggested that rate increases could put them at a disadvantage with competing firms operating in jurisdictions with lower electricity costs.
- When it came to the choice between "running to failure" or replacing equipment before it breaks down, most participants prefer the more proactive approach of replacing equipment before it breaks.

Coverage of Distribution System Topics

- Overall, participants in the consultation sessions felt the workbook did an effective job of covering the topics they expected and allowed them to have a meaningful discussion about Toronto Hydro's grid renewal plan.

System Renewal

- Most participants felt the proposed pace of system renewal is "about right". That is, most agreed that the plan balanced the need to replace aging infrastructure with customer bill impacts.
- Most commercial and industrial participants (36 of 41) accepted the need to increase customer rates by the proposed amount; with 16 of 41 saying they support the proposed rate increase and 20 of 41 saying they don't like it, but think it is necessary. On the contrary, 2 of 41 participants believe the rate increase is unreasonable and opposed it.
- The main reasons for the opposition to the bill increase was because both commercial and industrial businesses are concerned about their ability to pay and the impact it will have on their competitiveness with other firms in lower cost jurisdictions.
- Those who accepted the proposed DSP believed the plan seemed reasonable and was necessary to maintain system reliability.

Response During Major Weather Events

- Participants in both the commercial and industrial groups stated that Toronto Hydro staff worked "tremendously hard" during the major weather events of 2013. All of the participants in the groups stated that they were both pleased by the service received and applauded the hard work Toronto Hydro did to repair the damages caused by both the flooding in July and the ice storm in December.
- Participants in both the commercial and industrial groups also understood that Toronto Hydro's hands were tied during the major events of 2013 and they did the best job "humanly possible" given the circumstances.

- Some of the participants in the group stated that they wanted Toronto Hydro to do a better job in updating their website and customer service call centres during the major weather events. Specifically, participants stated that Toronto Hydro could have had a better online format (e.g. "tell us areas where the outage is occurring, give us an ETA for fixing issues on the Toronto Hydro main page"). Participants went on to say that Toronto Hydro should better advertise its website and social media accounts to get people engaged and "in the know" of what's happening with electricity outages/issues in the Toronto area.

Toronto Hydro's Proposed Plan and Rate Impact

- A number of commercial and industrial customers expressed concern over what they saw as poor fiscal management at Toronto Hydro. Specifically, participants questioned why Toronto Hydro did not save money in anticipation of grid renewal requirements. As owners and managers, these groups of commercial and industrial participants explained that they have to budget and have some sort of reserve fund to replace their equipment and business tools – so why didn't Toronto Hydro have a contingency plan in place for grid renewal needs? However, after the moderators explained the OEB mandate, participants in both the commercial and industrial groups understood that Toronto Hydro's regulatory regime does not allow it to have a reserve fund.
- Overall, all of the participants understood the proposed "Grid Renewal Plan" and the process Toronto Hydro must go through to apply for a rate increase (e.g. through the OEB). Participants in both the commercial and industrial groups were generally intrigued by the role played by interveners and the OEB hearings and rate setting process. Most felt that these steps help keep the rate setting process fair, where different perspectives on the proposed rate increase would be represented, and ultimately assist the process in being more accountable.
- Participants in both the commercial and industrial groups were genuinely pleased and happy about Toronto Hydro's cost saving efforts and plans.
- Participants in both the commercial and industrial groups said that both the consultation and workbook only looked at 11% of the bill. They inquired about the rest of the 89% left over and if that portion of the bill would also have an increase. They understood that Toronto Hydro was only responsible for distribution of electricity (11% of the bill), but irrespectively stated they would have a hard time budgeting their total costs spent on electricity if they were "left in the dark" about the undiscussed 89% of the bill (e.g. transmission and generation costs as well as global adjustment, regulatory costs and debt retirement).
- Furthermore, participants wondered how much of an increase they can afford by stating that "if there is increase in all sectors of the bill, then it will have a negative effect on our business bottom line". Participants in both the commercial and industrial groups stated they could live with a rate increase – but said that they would have to consider the other parts of the bill (e.g. transmission and generation costs) to come to a final decision on whether to support a rate increase or not. However, they went on to state within the context of Toronto Hydro's proposed plan they were willing to live with the rate increase if it is a necessary course of action to maintain reliability within the distribution system.

Mid-Market Opinion on Toronto Hydro's Proposed DSP

Looking at the cost of the Toronto Hydro plan and the outcomes it is expected to achieve, which point of view is closest to your own? [Based on 41 responses]

Response	Sum Total
Toronto Hydro should plan to achieve higher outcomes, even if the rates need to up even more;	5
I am satisfied with the balance between outcomes and the proposed rate increase;	11
I don't like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard;	20
I think the bill impact is too high and Toronto Hydro needs to scale back its plans	2
Not sure	0
No response / Refused	3
Total	41

How Could the Consultation Process be Improved?

- At the conclusion of the sessions, participants were asked what they thought of this approach to commercial and industrial consultation and how it could be improved.
- Some of the participants in the commercial and industrial groups wanted to know why Toronto Hydro did not address these problems related to grid renewal before as well as why this type of customer consultation was only happening now, and not on an on-going basis. Participants stated that they would have liked Toronto Hydro to take a more pro-active approach in discussing the proposed plans with its customers.
- The vast majority stated they very much liked this approach to customer consultation. They felt the workbook-led format allowed them to have a meaningful discussion on what is often seen as a confusing and complex topic.
- Participants went on to say that they appreciated Toronto Hydro for actively seeking feedback from its commercial and industrial customers and that they would like to see this approach incorporated into on-going policy decision-making.

- Participants had very little to suggest in terms of ways in which the process could be improved. One suggestion was to have even more specific and relevant information in the workbook about the rate proposal process.

Methodology 1

About the Mid-Market GS>50 Workshop Consultation 1

INNOVATIVE conducted a series of commercial and industrial customer consultation sessions designed to identify the needs and preferences of Toronto Hydro's mid-market consumers as they relate to the proposed 5-Year DSP.

Two evening workshops were conducted at a rented hotel space between 5:30 pm and 9:00 pm. Each 3.5 hour session was customized for either COMMERCIAL or INDUSTRIAL customers. The workshops were divided between a presentation and question and answer session managed by Toronto Hydro staff and a facilitated discussion session lead by moderators from INNOVATIVE.

- Presentation and Q&A: approximately 1.25 hours
- Break: 15 minutes.
- Facilitated discussion approximately 2 hours

GS>50 kW customers were recruited for each the commercial and industrial workshops to participate in the group presentation and Q&A. After the group presentation, three smaller facilitated breakout discussion sessions were scheduled for the second half of the evening.

Both workshops were located off of Hwy 401 in Toronto. The commercial customer workshop was held in North York on March 31st, 2014, while the industrial customer workshop was held in Etobicoke on April 2nd, 2014.

A total of 41 commercial and industrial customers participated in these consultation sessions:

Commercial Workshop (21 Commercial Customers): March 31, 2014	
Group One	5 participants
Group Two	8 participants
Group Three	8 participants
Industrial Workshop (20 Industrial Customers): April 2, 2014	
Group One	8 participants
Group Two	6 participants
Group Three	6 participants

Recruiting Consultation Participants

Commercial and industrial users were randomly selected by telephone from customer lists and screened for appropriateness as session participants. Users qualified for the consultation if they managed or oversaw their commercial or industrial business' electricity bill. This was to ensure they were at least somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed rate increases.

The customer screening process ensured that only customers who met the following criteria qualified to participate in the workshops:

- Participants must work at businesses that receive an electricity bill from Toronto Hydro.
- Participants must be in charge of managing or overseeing their business' Toronto Hydro electricity bill(s).
- Participants had to be willing participate in a Toronto Hydro presentation and read through a 30 page workbook. Furthermore, participants were required to write out answers to a series of questions and carry on a discussion in English.

A list of mid market customers was provided to INNOVATIVE by Toronto Hydro. In terms of consumption, customers included in this list ranged from over 50 kW to 1 MW in size. Approximately 3,000 mid market customer contacts were provided.

Given the longer time commitment required of workshop participant than in previous customer consultation sessions, a larger incentive of $150 was provided to all commercial and industrial customers who participated in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and quotes.

Facilitated Discussion Session Structure

The consultation sessions were structured around the themes contained in the workbook. The workbook themes included the following:

1. Introduction
2. Electricity 101
3. Toronto's Grid Today
4. Challenges Facing the Grid
5. How We're Managing Grid Pressures
6. The Bottom Line

- All mid market participants were sent electronic copies of the workbook via email as part of a pre r read package in advance of the workshops.
- At the start of the sessions, the facilitator gave an overview explaining the purpose of consultation and why Toronto Hydro is seeking feedback from business users.
- After explaining the purpose of the consultation, hard copy workbooks were distributed to act as a session guide and for participants to record their answers to the questions contained within.

- The facilitator then led the participants through the workbook section by section to ensure they understood the information and to answer any questions they had about the content.
- When it came to the questions within the workbook, participants were asked to fill in their answers independently. The facilitator then led a group discussion on the answers participants provided and the implications for their commercial or industrial businesses.
- Hard copy workbooks were collected from the participants at the conclusion of each consultation session.
- Each consultation session ran for approximately 2 hours.

Informing the Consultation Process: 1

In addition to identifying customer needs and preferences as they relate to the proposed DSP, feedback collected from this phase of the consultation was used to inform the design of the telephone survey.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Participant Feedback 1

The following section highlights the general feedback from each night of the consultation discussion group.

Commercial Workshop Session 1

General Overview 1

Generally, participants in the commercial consultation group felt that the proposed Grid Renewal Plan was reasonable, effective, and representative of the electrical power needs of the businesses in the Toronto region.

Some of the participants in the group thought that Toronto Hydro should spend more in the grid renewal plan to achieve higher outcomes. Two of the participants in the group stated that they were satisfied with the present balance between the bill and reliability of services. No one was opposed to a bill increase, as they all thought that it was necessary.

Generally participants within this commercial group agreed that the rate increase was necessary to replace aging infrastructure. In particular, some participants felt that the Grid Renewal Plan was reasonable and not an "easy fix" to a complex problem.

System Reliability: Customer Experience and Expectation

Most participants in the consultation groups have experienced power service interruptions at their commercial businesses in the past twelve months. The duration of the service interruption lasted from a few minutes to many days in some cases. The frequency of outages averaged around one to three power service interruptions per year. Further, commercial users reported loss of both revenue and productivity within their respective businesses due to outages.

Most of the participants in the groups stated that they wanted better customer service from Toronto Hydro and its staff. Specifically, several stated that Toronto Hydro should improve its communication measures with its customers especially when outages and other similar power service interruptions occur.

Several participants stated that the problem with outages is that they didn't know how long the outages would last. They thought that better communication is needed from Toronto Hydro so that businesses can figure out how to mitigate the impact of power outages.

Participants also wanted Toronto Hydro to regularly update them on how their money is being spent and the state of the grid renewal.

Improving Service of the Local Distribution System

Some of the participants in the industrial groups wanted Toronto Hydro to let them know of any planned outages and when power would be coming back on. "Let us know how long outages will be, so we can plan accordingly".

Commercial users stated that depending on the type of business, both frequency and duration of outages can have major consequences. Further, one of the participants recommended that Toronto Hydro give higher priority to larger businesses during outages since they employ a large part of the community and have a greater impact on the local economy.

System Renewal

While most commercial participants stated that their businesses could afford the proposed rate increase and believed it was necessary to maintain system reliability, a few voiced concerned about the impact it could have on some their suppliers and customers who struggle financially.

Most participants in the commercial workshop believe they would likely be able to pass on any rate increase to their customers as this would be a common cost borne by similar businesses and the competition.

Coverage of Distribution System Topics

Most of the commercial users found the workbook to be very informative, providing the group with the right amount of information needed to discuss the issues at hand.

Many of the participants in the consultation groups stated that they wanted to have more information on "Toronto Hydro's operating budget and their corporate structure". In particular, some of the participants stated that they wanted more time to prepare and read through the workbook, and also be given more discussion time during the consultation to express their views on the proposed plan.

Further, other participants in the groups felt that the workbook did not contain enough information, as they would have liked to see the operating budget, revenues, expenses, and profits and losses reports.

Lastly, participants also felt that both the workbook and the consultation process did not have a wide array of choices when it came to the investment plans Toronto Hydro was proposing.

Several participants stated that they would want Toronto Hydro to make commercial users more aware about conservation efforts and how to be more energy efficient (e.g. shutting down of extra equipment). Further, participants in the commercial groups also stated they wanted Toronto Hydro to install more accurate smart meters within businesses.

A few of the participants in the commercial user groups stated that Toronto Hydro should invest more in renewable generation and renewable energy.

Most stated that Toronto Hydro should spend and prepare more "rigorously" to cover major issues which in the long term "save money". A select few stated that they wanted an updated grid that would bring costs down in the long term. One of the participants felt that Toronto Hydro should find effective and better ways to maintain and upkeep aging and old infrastructure.

Response During Major Weather Events

Almost every participant in the commercial groups mentioned better communication from Toronto Hydro to its customers during major weather events. Several of these participants also said there needs to be a better system of updating on the state of repairs during these major weather events.

Many stated that events such as the two major storms of 2013 could have been avoided if Toronto Hydro better maintained its system by investing in new equipment.

Overall, participants in the commercial groups felt that Toronto Hydro should have relayed better, up to date information regarding power outages during both the flooding in July and the ice storm in December of 2013. The participants said that if they had more accurate information from Toronto Hydro, they could have made better decisions concerning staffing.

Participants in the commercial sessions stated that they hoped Toronto Hydro could have restored service sooner during the major storms. Further, some participants stated that Toronto Hydro should have engaged and consulted with customers on emergency management fixes and updates.

Some pointed out that the widespread outages were the result of things that happened due to adverse weather and that there was little Toronto Hydro could do prevent such outages.

Toronto Hydro's Proposed Plan and Rate Impact

Some voiced concern over "the other 89 percent" of their bill because it represents a much larger proportion of their expense than the distribution portion. At the same time, they expressed relief that the rate increase applied only to the small portion of their bill that goes to Toronto Hydro.

As an alternative to a rate increase, some suggested moving the cost of required investments from ratepayers to taxpayers. Various participants in the groups suggested that Toronto Hydro work in conjunction with the Province of Ontario and the City of Toronto to get funding, instead of asking business customers to pay more.

A number of participants suggested that since all of the profits accumulated from Toronto Hydro electricity bills were going back into a municipal body, that public money should be used to subsidize the proposed rate increase for the ratepayers.

Further, a few participants were also critical of what they believed was mismanagement at Toronto Hydro and the Ontario Energy Board, blaming them for the present situation where Toronto Hydro is requesting a rate increase.

Some participants felt Toronto Hydro should invest more in preventative methods and be more proactive with its spending. Further, one of the participants stated Toronto Hydro should subsidize its large scale commercial customers with the cost and installation of backup generators.

However, after much concern voiced over a proposed rate increase, most of the commercial participants in the group accept the proposed rate increase, so long as it meant better and more reliable service for their businesses.

How Could the Consultation Process be Improved?

The commercial users within the group enjoyed the consultation process, as they thought it was an effective way to engage people and get them to start talking about electrical distribution issues, which many felt are often taken for granted.

Generally, participants in the commercial consultation group felt that the proposed Grid Renewal Plan was reasonable, effective, and representative of the electrical power needs of the businesses in the Toronto region.

However, a number of the participants in the commercial groups stated that they wanted access to progress reports that would update them on system renewal projects and that this in turn would make Toronto Hydro seem more accountable and transparent.

Industrial Workshop Session 1

General Overview

As seen in other Toronto Hydro consultations, most industrial customers do not like the idea of a price increase over the next 5 years, but generally feel it's necessary to maintain the system reliability.

In terms of the Toronto Hydro's workshop consultation materials, most participants felt the information presented made a compelling case to justify the need for increased investments in system renewal and new technologies that would support system reliability.

System Reliability: Customer Experience and Expectation

From the perspective of industrial customers, most were relatively satisfied with the level of system reliability their businesses receive from Toronto Hydro.

However, it's important to note that most participants in this group largely agreed that poor system reliability far outweighed the costs of Toronto Hydro's proposed rate increase for their rate class.

Improving Service of the Local Distribution System

While most accept the proposed rate increase, a number of the participants wanted Toronto Hydro to increase their efforts to help businesses find ways to reduce their electricity consumption to offset the impact of the proposed rate increase. Specifically, a number of participants cited that Conservation Demand Management (CDM) measures did not save their businesses much money. These participants found that the CDM measures were "not worth their time, service, or effort" and largely found it to be an inconvenience.

Overall, a common theme cited by participants within the industrial group was better communication from Toronto Hydro (e.g. customer service, better updates, and quicker repairs). Specifically, a number of participants in the industrial groups felt that Toronto Hydro could improve their customer services by better providing businesses with accessible information on the status of power outages and the length of time it will take to restore it. Participants suggested more timely and accurate web site updates on power service interruptions as well as mobile apps that would provide updates to customer account contacts.

Coverage of Distribution System Topics

Most participants in this group felt that the workbook helped them better understand the challenges facing their local distribution system and that a proactive approach to system renewal is better than a reactive one.

While out of scope for this consultation a few participants wanted more information on the other 89% of their electricity bill, outside of their distribution costs. Overall, the participants thought the workbook was easy to read, well put together, and comprehensive.

System Renewal and Rate Impact

While most participants in this group thought that Toronto Hydro's plan was headed the right direction, a few were not sure, as they thought they needed more information to come to a full conclusion on what the rate increase would mean for their businesses.

Customers who did not accept the price increase generally cited that they were not convinced that Toronto Hydro had made enough efforts to cut costs elsewhere or find operational efficiencies that could help pay for the increased in required capital expenditures. Although these concerns were shared by other industrial customers, most participant in these workshops accepted the proposed price increase.

When given the pacing option between "invest now" or "pay more later", most participants felt that Toronto Hydro should begin investing in system renewal now in order to avoid ratepayers from paying more in the future to fund delayed system renewal investments.

As heard in other consultations with business owners and managers, a number of participants in the industrial groups felt that Toronto Hydro should have created a reserve fund in anticipation of required capital expenditures required for system renewal.

Finally, some of the participants in the industrial group said that they would like to see a line on the bill (e.g. "system renewal investment") – which makes both the proposed plan and bill increase seem more accountable and transparent.

How Could the Consultation Process be Improved?

Participants in the group stated one way to improve the consultative process was to have less of a presentation element and more of an open dialogue process. Some participants also thought the consultation was rushed through and wanted to be given more of an opportunity to express their concerns and opinions.

On the other hand, some of the participants in the industrial groups stated the consultation process made them understand the issues facing the distribution system at a level where they could have a meaningful and informed discussion about system priorities and challenges. One of the participants felt that consultation on system renewal and capital investing should be an ongoing and regular customer engagement process, as opposed to only part of Toronto Hydro's rate application process.

Questionnaire Results

The following tables are the tabulations of participant feedback to questions in the hard copy workbooks which were returned at the end of each consultation session.

Due to the high occurrence of non response to open ended questions and subsequent small sample size, these results are not segmented by region, but rather only between commercial and industrial customers.

Blue tallies denote feedback from Commercial (Co) customers.
Red tallies denote feedback from Industrial (Ind) customers.
Numbers in green denote the sum of both Commercial and Industrial participant feedback tallies

Missing values are recorded beneath each table to indicate the number of participants who left a particular question unanswered.

Q1. How well do you feel you understand the important parts of the electricity system, how they work together and which services Toronto Hydro is responsible for?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very well	2	1	3	6	5	4	4	11	19
Somewhat well	5	4	4	13	3	1	2	6	19
Not very well	0	2	0	2	0	1	0	1	3
I don't understand at all	0	0	0	0	0	0	0	0	0
Total	7	7	7	21	8	6	6	20	41

Q2. How satisfied are you with the job Toronto Hydro is doing running your local distribution system?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very satisfied	1	0	3	4	1	3	1	5	9
Somewhat satisfied	4	4	4	12	6	3	4	13	25
Somewhat dissatisfied	2	3	0	5	1	0	1	2	7
Very dissatisfied	0	0	0	0	0	0	0	0	0
Don't know	0	0	0	0	0	0	0	0	0
Total	7	7	7	21	8	6	6	20	41

Q3: Is there anything in particular that Toronto Hydro can do to improve its service to you? (OPEN ENDED)

Response	Co	Ind	Sum Total
Better communication during emergencies	3	11	14
Explanation of billing/breakdown of usage	1	1	2
Better customer service	0	2	2
Faster service regarding outages/eliminate	7	2	9
Reduce rates	2	0	2
Upgrade system	2	1	3
Updates on system status/progress	1	0	1
Other	4	1	5
No response/ Refused	1	2	3
Total	21	20	41

Q4. Under provincial legislation, there are several types of investments Toronto Hydro must make when the need presents itself. How reasonable do you feel it is to give each of these investments a priority over other investments (for example, replacing aging equipment)?

Connecting new customers such as new housing, condominiums or businesses.

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very reasonable	0	4	3	7	1	3	2	6	13
Somewhat reasonable	6	3	3	12	4	1	4	9	21
Not very reasonable	1	0	0	1	1	1	0	2	3
Not reasonable at all	0	0	0	0	1	0	0	1	1
Don't know	0	0	1	1	0	0	0	0	1
No response/ Refused	0	0	0	0	1	1	0	20	2
Total	7	7	7	21	8	6	6	20	41

Q5. Under provincial legislation, there are several types of investments Toronto Hydro must make when the need presents itself. How reasonable do you feel it is to give each of these investments a priority over other investments (for example, replacing aging equipment)? Maintaining and upgrading customer meters to meet provincial standards.

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very reasonable	1	3	3	7	4	2	2	8	15
Somewhat reasonable	6	3	2	11	2	2	2	6	17
Not very reasonable	0	1	1	2	1	1	1	3	5
Not reasonable at all	0	0	1	1	0	0	1	1	2
Don't know	0	0	0	0	0	0	0	0	0
No response/ Refused	0	0	0	0	1	1	0	2	2
Total	7	7	7	21	8	6	6	20	41

Q6. Under provincial legislation, there are several types of investments Toronto Hydro must make when the need presents itself. How reasonable do you feel it is to give each of these investments a priority over other investments (for example, replacing aging equipment)? Moving existing electricity infrastructure such as poles and transformers to enable other projects such as street widening or new developments.

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very reasonable	3	2	3	8	2	1	4	7	15
Somewhat reasonable	2	3	3	8	4	4	1	9	17
Not very reasonable	2	2	0	4	1	0	1	2	6
Not reasonable at all	0	0	0	1	1	0	0	1	1
Don't know	0	0	1	0	0	0	0	0	1
Total	7	7	7	21	8	5	6	20	41

Q7. Wait until equipment breaks down or replace equipment before it breaks down?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Wait until breakdown	2	2	4	8	0	0	2	2	10
Replace before breakdown	5	5	3	13	7	4	4	15	28
No response/ Refused	0	0	0	0	1	2	0	3	3
Total	7	7	7	21	8	6	6	20	41

Q8. Do you feel the current average number of electricity outages is acceptable or not acceptable?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very acceptable	2	0	3	5	1	0	1	2	7
Somewhat acceptable	2	4	2	8	6	5	3	14	22
Not very acceptable	1	2	1	4	0	1	1	2	6
Not acceptable at all	2	1	0	3	1	0	0	1	4
Don't know	0	0	1	1	0	0	1	1	2
Total	7	7	7	21	8	6	6	20	41

Q9. Do you feel the current average amount of outage time is acceptable or not acceptable?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very acceptable	2	0	3	5	1	1	2	4	9
Somewhat acceptable	0	3	3	6	4	3	2	9	15
Not very acceptable	4	2	1	7	1	2	2	5	12
Not acceptable at all	1	2	0	3	1	0	0	1	4
Don't know	0	0	0	0	1	0	0	1	1
Total	7	7	7	21	8	6	6	20	41

Q12: How did the outage affect your business? (OPEN ENDED)

Response	Co	Ind	Sum Total
Loss of sales/revenue/productivity	7	7	14
Closed	3	2	5
Food/product spoilage	1	2	3
Not affected/not during business hours	1	3	4
Had a generator	2	2	4
Other	5	1	6
No response/ Refused	2	3	5
Total	21	20	41

Q13: Is there a certain length of time at which the costs/consequences of an outage become more serious for your business? (OPEN ENDED)

Response	Co	Ind	Sum Total
Every minute	3	1	4
30 - 60 minutes	1	1	2
1 hour +	4	2	6
2 hours +	2	5	7
One day	1	3	4
36 - 48 hours +	2	1	3
Depends on the season/time of year	1	2	3
Other	6	4	10
No response / Refused	1	1	2
Total	21	20	41

Q14. How many power service interruptions are reasonable in a year?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
No outage is acceptable	3	3	3	9	1	0	1	2	11
One	2	3	1	6	2	2	0	4	10
Two	2	1	3	6	4	4	3	11	17
Three	0	0	0	0	1	0	1	2	2
Four	0	0	0	0	0	0	1	1	1
More than four	0	0	0	0	0	0	0	0	0
Total	7	7	7	21	8	6	6	20	41

Q15. What is a reasonable duration for a service interruption?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
No outage is acceptable	4	3	2	9	1	0	2	1	12
30 minutes	2	3	5	10	4	2	2	8	18
1 hour	1	0	0	1	0	2	1	4	4
2 hours	0	0	0	0	2	1	0	4	3
3 hours	0	0	0	0	1	0	0	1	1
4 hours or more	0	1	0	1	0	0	1	1	2
No response / Refused	0	0	0	0	0	1	0	1	1
Total	7	7	7	21	8	6	6	20	41

Q16. Thinking back to the two major storm events of 2013, were you affected by either or both of these events?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Yes – the flooding in July	1	0	0	1	3	1	1	5	6
Yes – the ice storm in December	0	4	3	7	2	0	3	5	12
Yes – both	2	3	2	7	2	2	0	4	11
No – neither weather event affected my electricity	4	0	2	6	1	3	2	6	12
Total	7	7	7	21	8	6	6	20	41

Q17. Whether you were personally affected or not, how satisfied are you with Toronto Hydro's management of these events?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very satisfied	2	0	1	3	3	4	0	7	10
Somewhat satisfied	3	2	2	7	2	1	3	6	13
Somewhat dissatisfied	2	3	0	5	2	0	3	5	10
Very dissatisfied	0	2	1	3	1	0	0	1	4
Don't know	0	0	2	2	0	1	0	1	3
No response / Refused	0	0	1	1	0	0	0	0	1
Total	7	7	7	21	8	6	6	20	41

Q18: Is there anything in particular that Toronto Hydro could have done to improve its service to your business during these events? (OPEN ENDED)

Response	Co	Ind	Sum Total
Better communication	3	7	10
Did their best/good job	2	2	4
Upgrade system	5	2	7
None	1	1	2
Other	3	2	5
No response/ Refused	7	6	13
Total	21	20	41

Q19. How important do you feel it is for Toronto Hydro to invest now in modernizing the grid?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very important	6	6	1	13	5	4	5	14	27
Somewhat important	1	1	6	8	3	2	1	6	14
Not very important	0	0	0	0	0	0	0	0	0
Not important at all	0	0	0	0	0	0	0	0	0
Don't know	0	0	0	0	0	0	0	0	0
Total	7	7	7	21	8	6	6	20	41

Q20. How likely is that you would participate in Demand Response programs that would allow electricity system managers to turn off equipment you are using?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very likely	5	5	0	10	2	3	3	8	18
Somewhat likely	1	2	5	8	2	2	2	6	14
Not very likely	0	0	1	1	1	0	0	1	2
Not at all likely	1	0	1	2	1	1	1	3	5
No response/ Refused	0	0	0	0	2	0	0	2	2
Total	7	7	7	21	8	6	6	20	41

Q21. How well do you feel you understand the challenges facing the Toronto hydro grid and what they are planning to do to meet those challenges?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Very well	1	2	2	5	3	4	2	9	14
Somewhat well	6	5	5	16	4	2	4	10	26
Not very well	0	0	0	0	0	0	0	0	0
I don't understand at all	0	0	0	0	0	0	0	0	0
No response/ Refused	0	0	0	0	1	0	0	1	1
Total	7	7	7	21	8	6	6	20	41

Q22. Does Toronto Hydro's investment plan seem like it is going in the right direction or the wrong direction?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Right direction	6	4	4	14	3	6	5	14	28
Wrong direction	0	0	1	1	0	0	0	0	1
Not sure	1	3	2	6	4	0	1	5	11
No response/ Refused	0	0	0	0	1	0	0	1	1
Total	7	7	7	21	8	6	6	20	41

Q23: And why do you feel that way? (OPEN-ENDED)

Response	Co	Ind	Sum Total
Aging infrastructure must be upgraded	6	7	13
A proactive approach	4	2	6
Need to know more	1	2	3
Cost concerns	2	2	4
Don't know	0	3	3
Other	7	1	8
No response/ Refused	1	3	4
Total	21	20	41

Q24: What areas do you feel need more spending than planned? (OPEN-ENDED)

Response	Co	Ind	Sum Total
Aging equipment/infrastructure	9	5	14
Renewable energy	1	2	3
Other	5	7	12
No response/ Refused	6	6	12
Total	21	20	41

Q25. When you look at how much Toronto Hydro is spending on each of its investment priorities, do you think they have the balance right or would you change the relative priorities?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	SumTotal
The balance looks right	4	5	5	14	3	6	4	13	27
They should change some of the priorities	3	2	1	6	3	0	2	5	11
No response/ Refused	0	0	1	1	2	0	0	2	3
Total	7	7	7	21	8	6	6	20	41

Q26: What areas do you feel should have less spending than planned? (OPEN-ENDED)

Response	Co	Ind	SumTotal
Electric vehicles	3	1	4
Connecting new customers	1	1	2
Upgrading customer meters	1	2	3
Other	4	2	6
No response/ Refused	12	14	26
Total	21	20	41

Q27. When you consider the options outlined in the table on the previous page, do you think Toronto Hydro's goals are too high, too low or about right?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	SumTotal
Too high	0	0	1	1	0	0	1	1	2
About right	3	5	5	13	5	6	4	15	28
Too low	0	1	0	1	2	0	0	2	3
Not sure	4	1	1	6	0	0	0	0	6
No response/ Refused	0	0	0	0	1	0	1	2	2
Total	7	7	7	21	8	6	6	20	41

Q28: What are the goals you feel are too high? (OPEN-ENDED)

Response	Co	Ind	Sum Total
Cost	2	1	3
Equipment upgrade	1	1	2
Other	3	3	6
Don't Know	1	0	1
No response/ Refused	14	15	29
Total	21	20	41

Q29: What are the goals you feel are too low? (OPEN-ENDED)

Response	Co	Ind	Sum Total
Aging infrastructure	3	6	9
Rates concerns	3	0	3
Don't Know	1	0	1
No response/ Refused	14	14	28
Total	21	20	41

Q30. Looking at the cost of the Toronto Hydro plan and the outcomes it is expected to achieve, which point of view is closest to your own?

Response	Co1	Co2	Co3	Total	Ind1	Ind2	Ind3	Total	Sum Total
Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more	0	0	0	0	4	0	1	5	5
I am satisfied with the balance between outcomes and the proposed rate increase.	2	1	1	4	4	2	1	7	11
I don't like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard	5	4	5	14	0	3	3	6	20
I think the bill impact is too high and Toronto Hydro needs to scale back its plans	0	0	1	1	0	0	1	1	2
Not sure	0	0	0	0	0	0	0	0	0
No response/ Refused	0	2	0	2	0	1	0	1	3
Total	7	7	7	21	8	6	6	20	41

S1: Toronto Hydro values your feedback. This is the first time the utility has conducted a review about its upcoming

investment plan in this type of format. What did you think about the workbook? (OPEN ENDED)

Response	Co	Ind	Sum Total
Good	7	9	16
Informative	4	7	11
Biased	2	0	2
Other	4	0	4
No response/ Refused	4	4	8
Total	21	20	41

S2: Volume of Information — Did Toronto Hydro provide too much information, not enough, or just the right amount?

Response	Co	Ind	Sum Total
Too much, use more simple examples	1	1	2
Needed more information	5	7	12
Right amount of information	11	9	20
Other	2	0	2
No response/ Refused	2	3	5
Total	21	20	41

S3: Content Covered — Was there any content missing that you would have liked to have seen included? (OPEN ENDED)

Response	Co	Ind	Sum Total
Well covered	3	1	4
None	8	6	14
Other	5	2	7
Don't Know	1	1	2
No response/ Refused	4	10	14
Total	21	20	41

S4: Outstanding Questions — Is there anything that you would still like answered? (OPEN-ENDED)

Response	Co	Ind	Sum Total
Bill breakdown	2	1	3
None	10	3	13
Other	3	3	6
No response / Refused	6	13	19
Total	21	20	41

S5: Suggestions for Future Consultations — How would you prefer to participate in these consultations? (OPEN-ENDED)

Response	Co	Ind	Sum Total
Same face to face discussion / focus groups	6	6	12
Other	6	2	8
No response / Refused	9	12	21
Total	21	20	41

Customer Telephone Surveys

Telephone Surveys among Residential and GS Customers

PURPOSE: To obtain statistically significant quantitative feedback on the proposed DSP and assess reaction to customer opinions obtained from the previous research phases

Summary

The following summary highlights the key findings from two telephone surveys of 1,006 Toronto Hydro residential customers and 200 General Service <50 kW customers:

General Satisfaction

- About half (48%) of residential customers are familiar with their local distribution system, while General Service customers are slightly less familiar (43%). High volume electricity consumers are more familiar than those who consume less.
- Three quarters (73%) of residential and General Service customers are satisfied with Toronto Hydro. Residents consuming the least power are most satisfied, while General Service customers using the highest volume of electricity (84%) are the most satisfied.
- When asked how to improve service, four in ten want cheaper (39% RS; 40% GS) and more consistent service/less power outages (12% RS; 6% GS). A quarter (26%) of residential customers and nearly three in ten (28%) GS customers said Toronto Hydro could do "nothing/already satisfied".

System Reliability

- Two thirds (66%) of residents and more than half (55%) of General Service customers experienced power outages during extreme weather. Not including extreme weather, six in ten (57%) residential customers and about half (49%) of General Service customers experienced "other" power outages in the last twelve months.
- Roughly two thirds (64%) of General Service customers report costs to their business during "other" power outages.
- Regarding the frequency of outages, seven in ten (70%) residential customers think Toronto Hydro should spend what is needed to either reduce (31%) or maintain (39%) the level of power outages. General Service numbers are similar (67%) on the frequency of outages.
- Three quarters (74%) of residential and two thirds (67%) of General Service customers think Toronto Hydro should spend what is needed to either reduce (33% RS; 30% GS) or maintain (41% RS; 37% GS) the length of power outages.

System Challenges & Priorities

- On infrastructure investment, six in ten (60%) residential customers and half (51%) of General Service customers believe that Toronto Hydro should invest in its aging infrastructure to reduce future outages, even if it means higher bills. Highest support for infrastructure investment among residential customers is in Central Toronto (68%).

- On investment in new technologies, two thirds (67%) of residential customers and six in ten (61%) General Service customers agree that investments in new technology will increase system reliability, make local distribution system more efficient and save money in the long run. About two in ten (RS 19%; GS 20%) preferred the argument against investment in new technologies. Again, residents in Central Toronto region (73%) are most likely to agree to investment in new technologies.
- Two thirds (66%) of residential customers and over half (56%) of General Service customers believe that Toronto Hydro should be wise with its spending on equipment and tools, but they also think it is important that staff have the equipment and tools needed to manage the system efficiently and reliably.

Overall Assessment of Plan 1

Residential Acceptance Nearly six in ten residential (58%) customers accept the rate increase. Most of that support appears reluctant (39%): they "don't like the increase, but feel it's necessary to maintain the grid". However, only a third (34%) thinks the rate increase is unreasonable and would not support it.

Q: Looking at the cost of the Toronto Hydro plan and outcomes it is expected to achieve, which point of view is closest to your own? Would you say…?	
Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more	4%
I am satisfied with the balance between outcomes and the proposed rate increase	15%
I don't like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard	39%
I think the bill impact is too high and Toronto Hydro needs to scale back its plans	34%
No response	8%

General Service Acceptance General Service customers are less supportive of rate increases than residential customers; just under half (48%) of organizational customers support the proposed Toronto Hydro plan and about four in ten (41%) think the bill impact would be too high.

Q: Looking at the cost of the Toronto Hydro plan and outcomes it is expected to achieve, which point of view is closest to your own? Would you say…?	
Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more	3%
I am satisfied with the balance between outcomes and the proposed rate increase	15%
I don't like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard	30%
I think the bill impact is too high and Toronto Hydro needs to scale back its plans	41%
No response	11%

1

Methodology 1

INNOVATIVE conducted two customer surveys by telephone for Toronto Hydro:

1. A residential customer survey conducted among 1,006 respondents between June 10 and 25, 2014; and
2. A general service customer (GS < 50 kW) survey conducted among 200 respondents between June 10 and 25, 2014.

Note: No calls were made on June 12, 2014 – the date of the Ontario provincial election – given the increased likelihood of customers being out of their homes or offices, as well as a potential preoccupation with provincial policy issues which could bias survey responses.

Participants were randomly selected from customer lists provided by Toronto Hydro (30,000 residential records and 6,000 GS records).

- A sample of 1,006 residential customers is considered accurate to within ±3.1 percentage points, 19 times out of 20.
- A sample of 200 General Service customers is considered accurate to within ±6.9 percentage points, 19 times out of 20.

The margin of error in both surveys will be larger within each sub grouping of the samples.

Questionnaire Design 1

The questionnaires were designed to simulate the journey that respondents in the Online Workbook and Workbook led Consultation Sessions experienced. This included a combination of educating the customer, having customers reflect on their personal experience with their distribution system, and having them make value judgments on trade offs between system reliability and bill impact.

As part of simulating the "workbook journey", the questionnaires were informed by and incorporated feedback from the previous phases of Toronto Hydro's customer engagement. This included sharing both supportive and non supportive feedback in the survey from previous phases of Toronto Hydro's customer consultation as it related to Toronto Hydro's proposed capital work and the associated rate increase. Wording of questions differed slightly between the Residential and General Service survey – for example, in the preambles the size of monthly bills differed between residential and general service customers – but otherwise remained generally consistent.

One notable difference between surveys is an additional question on service reliability and cost that was added to the General Service survey: "Thinking back to the most recent power outage – which was caused by something other than last year's floods or ice storm – how did it affect your organization in terms of cost?..."

The average survey ran at approximately 10 minutes. Both survey instruments can be found at the end of this section of the report.

Fielding the Survey 1

Residential (RS) Customer Survey:

For the purposes of executing the residential survey, Toronto Hydro provided INNOVATIVE with a confidential list containing 30,000 of their residential customers' contact information. Toronto Hydro built this contact list by randomly selecting records from among approximately 700,000 residential contact records on file in their customer database.

The contact list included only residential customers with residential landline contact information on file and who had been a customer of Toronto Hydro since at least January 1, 2013. The information contained in the contact list included customer name, home telephone number, home address, service area, and total annual usage between January 1 and December 31, 2013.

Only one customer per household was eligible to complete the residential survey. Survey respondents were screened to certify that only the resident primarily responsible for paying their Toronto Hydro electricity bill was interviewed. This step was taken to ensure that survey respondents represented the most qualified person within a household to answer questions about their electricity bill and how Toronto Hydro's proposed rate increase would have a relative impact on their bill.

Before retiring any randomly selected telephone number from the contact list, 12 attempts were made to reach a potential respondent for each unique telephone number, or until an interviewer received a hard refusal. Each number was called twice a day for the first four days and once a day for the final four. Each night – from June 10th to June 25th, new sample was released from the contact list to replace completed or retired numbers.

Toronto Hydro's residential customers were contacted at their home by telephone between 4pm and 9pm on weekdays, between 10am and 8pm on Saturdays, and between 11am and 8pm on Sundays.

General Service (GS) Customer Survey:

The GS survey consisted of 200 customers drawn from a confidential list provided to INNOVATIVE by Toronto Hydro. Toronto Hydro provided a list of approximately 6,000 GS < 50 kW contact records, randomly selected from its customer database.

GS customers were contacted on weekdays between 9am to 4pm. In addition, customers were screened to ensure they were in charge of managing the electricity bill at their organization.

All fieldwork was conducted using INNOVATIVE's computer assisted telephone interviewing (CATI) system.

Sample Design 1

The two surveys followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, customer service area or electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In the first survey, residential customers were initially divided into strata based on service area populations. Within service area populations, residential customers were then divided into quartiles based on annual electricity usage to ensure the sample had a proportionate mix of customers from low, medium low, medium high, and high electricity usage households.

Residential Sample Design:

The following table illustrates the segmentation of the residential survey sample by Toronto Hydro's customer service areas.

Service Area	Customer Distribution	Target Sample	Actual Sample	Difference
East York	4.0%	40	41	+1
Etobicoke	14.7%	147	147	0
North York	21.9%	219	220	+1
Scarborough	21.7%	217	220	+3
Central Toronto	32.3%	323	324	+1
York	5.4%	54	54	0
TOTAL	100.0%	1,000	1,006	+6

Within service area populations, customers were divided into quartiles based on annual electricity usage. The table below illustrates the actual survey interviews by usage quartile within Toronto Hydro's six customer service areas.

Service Area	Low Usage	Medium-Low Usage	Medium-High Usage	High Usage	Total
East York	10	10	10	11	41
Etobicoke	37	37	36	37	147
North York	55	55	55	55	220
Scarborough	54	56	55	55	220
Central Toronto	81	81	81	81	324
York	13	14	13	14	54
TOTAL	250	253	250	253	1,006

GS Sample Design:[4]

The survey of General Service customers also divided the respondents by region and annual electricity usage to reflect the actual distribution of Toronto Hydro GS customers:

Service Area	Customer Distribution	Target Sample	Actual Sample	Difference
East York	4.1%	8	8	0
Etobicoke	8.2%	16	16	0
North York	20.2%	40	43	+3
Scarborough	10.4%	21	22	+1
Central Toronto	47.0%	94	96	+2
York	10.1%	20	15	5
TOTAL	100.0%	199	200	+1

[4] Throughout this section, the term Outer Toronto is used to reference the regions of Etobicoke, North York, Scarborough and York.

Again, within service area populations, GS customers were divided into quartiles based on annual electricity usage. The table below illustrates the actual survey interviews by usage quartile within Toronto Hydro's six customer service areas.

Service Area	Low Usage	Medium-Low Usage	Medium-High Usage	High Usage	Total
East York	2	2	2	2	8
Etobicoke	4	4	4	4	16
North York	11	10	11	11	43
Scarborough	6	5	6	5	22
Central Toronto	25	25	19	27	96
York	5	5	4	1	15
TOTAL	53	51	46	50	200

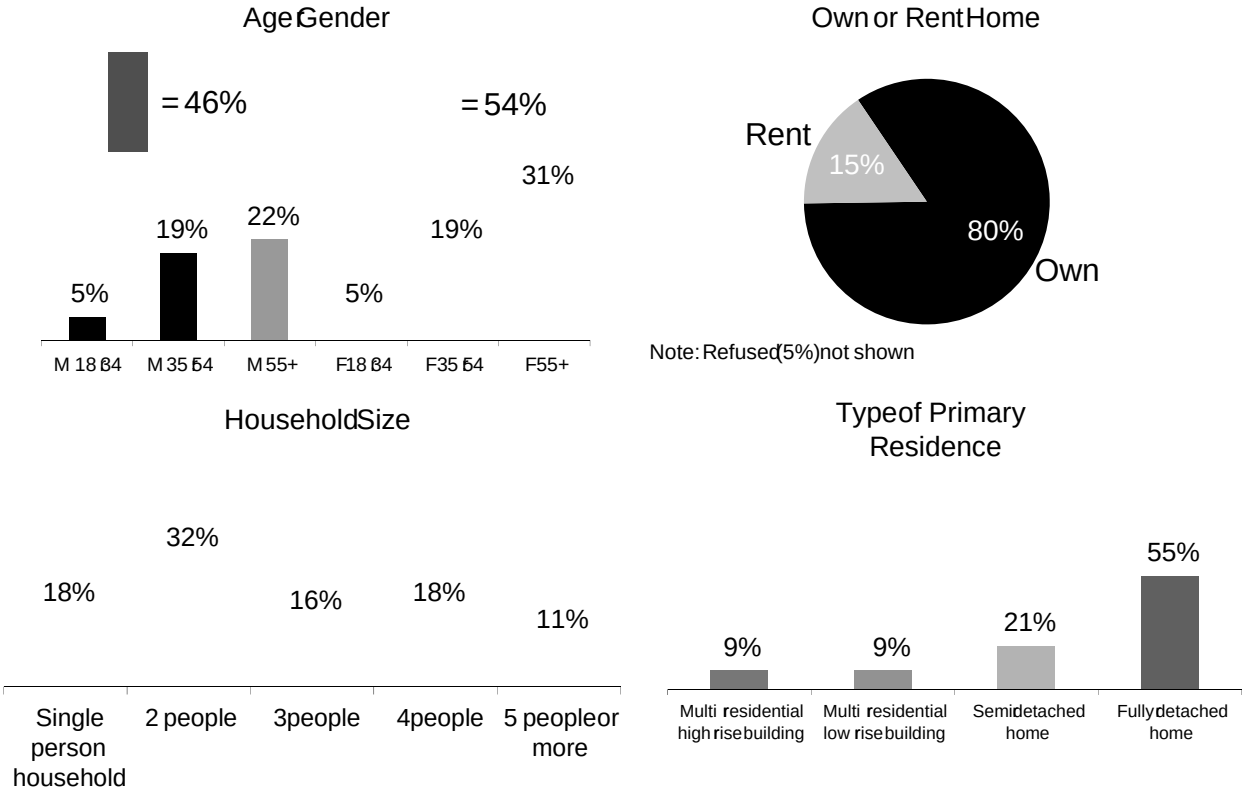
Sample Weights

Weights have not been applied to either the residential or GS data as the stratified random samples are accurate representations of Toronto Hydro's actual customer distribution and type.

Demographic Profiles

The following details the demographic characteristics of respondents who completed the Residential Ratepayer Survey [n=1,006].

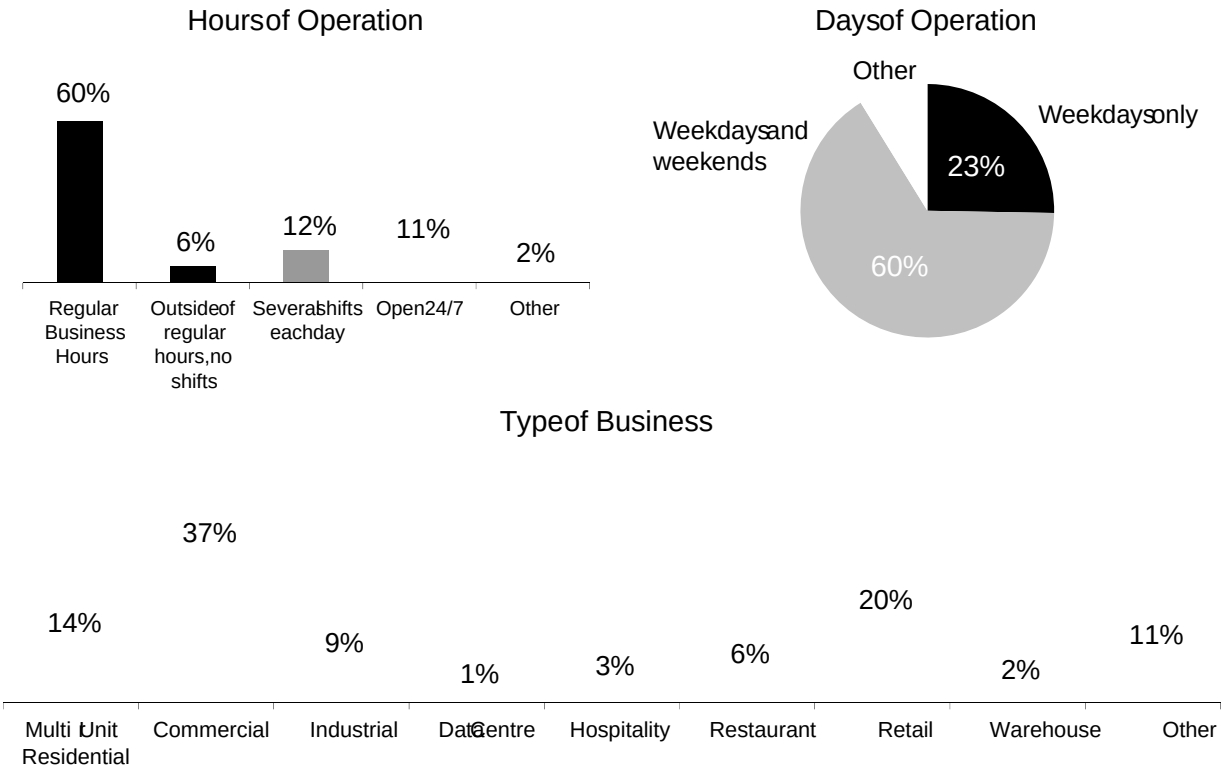
Figure 4.A: Residential Customer Profile



Firmographic Profiles 1

Below are the firmographics of respondents who completed the General Service Ratepayer Survey [n=200].

Figure 4.B: GS Customer Profile 1



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Respondent Feedback 1

Familiarity and Satisfaction 1

This section of the workbook explores familiarity and experiences with the local distribution system and satisfaction with Toronto Hydro in running that system. The results for residential customers will be presented first, followed by general service (GS) customers.

Familiarity and Satisfaction Summary 1

- Almost half of residential customers (48%) are familiar with the local distribution system, while General Service customers are slightly less familiar (43%).
    - Residential consumers in East York (59%) and York (54%) are the most familiar with the system.
    - High consumption consumers (55% RS; 44% GS) are more familiar with the system than low (45% RS; 36% GS) level consumers.
    - General Service respondents in Central Toronto/East York (49%) are much more familiar with the system than those in the Golden Horseshoe (36%).
- Three quarters (73%) of residential and General Service customers are satisfied with the job Toronto Hydro is doing.
    - The highest consumption residential customers (84%) are the most satisfied.
- When asked how to improve service, a plurality (39% RS; 40% GS) want reduced rates and charges, followed by more consistent service/less power outages (12%).
- A quarter (26%) of residential customers and nearly three in ten (28%) GS customers say Toronto Hydro could do "nothing/already satisfied".

Preamble for Familiarity and Satisfaction Section 1

Prior to answering the questions in the General Satisfaction Section, respondents were presented with a preamble concerning key components of Ontario's electricity system. The preamble read as follows:

"To start, I'd like to ask you a few questions about the electricity system…

As you may know, Ontario's electricity system has three key components generation, transmission and distribution.

- Generating stations convert various forms of energy into electric power;
- Transmission lines connect the power produced at generating stations to where it is needed across the province; and
- Distribution lines carry electricity to the homes and businesses in our communities.

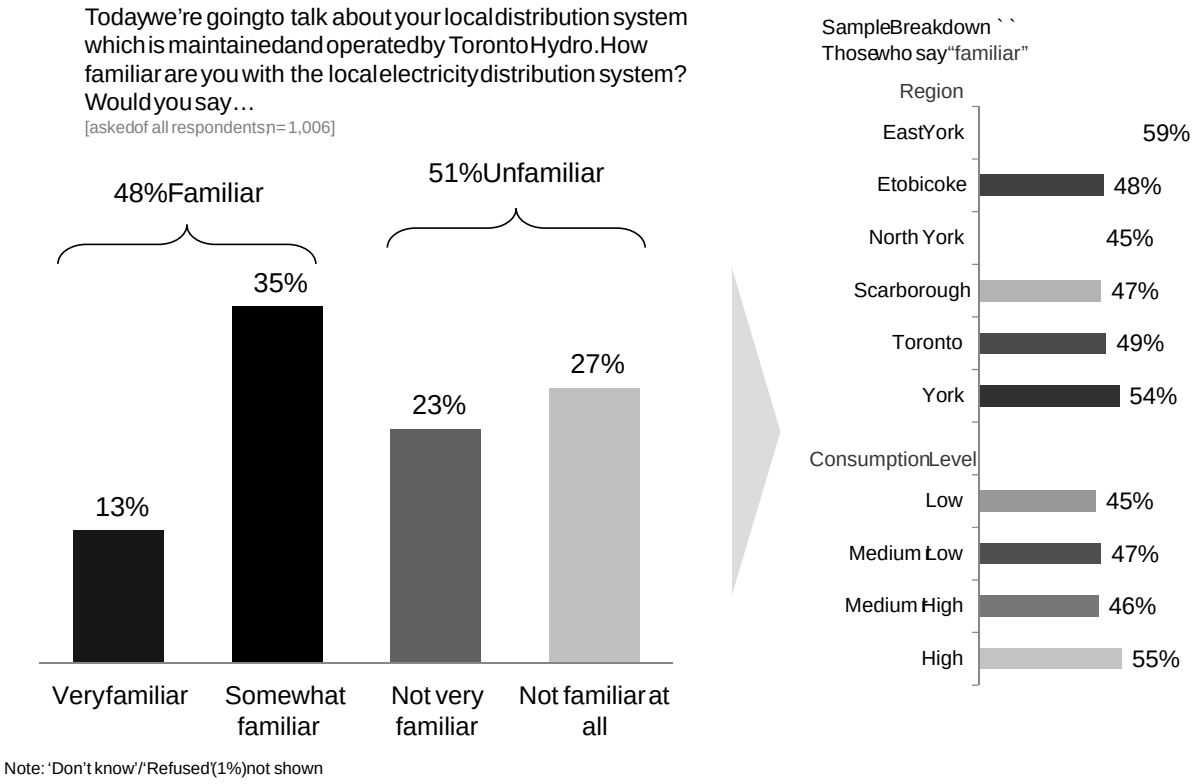
Today we're going to talk about your local distribution system which is maintained and operated by Toronto Hydro."

Familiarity with Local Electricity Distribution System

Almost half of residential respondents (48%) are familiar with their local distribution system. Of those who indicated they are familiar, 13% say they are very familiar with the system.

- The East York (59%) and York (54%) Regions have the highest level of familiarity with the local system.
- Differences in consumption level are also related to familiarity. High (55%) levels of consumption are associated with greater familiarity than low (45%) level consumption.
- Single person households (40%) are the least familiar with their local electricity distribution system (2: 50%; 3 or 4: 49%; 5 or more: 57%). And owners (50%) are more familiar than renters (39%).

Figure 4.1 RS: Familiarity with the Local Distribution System

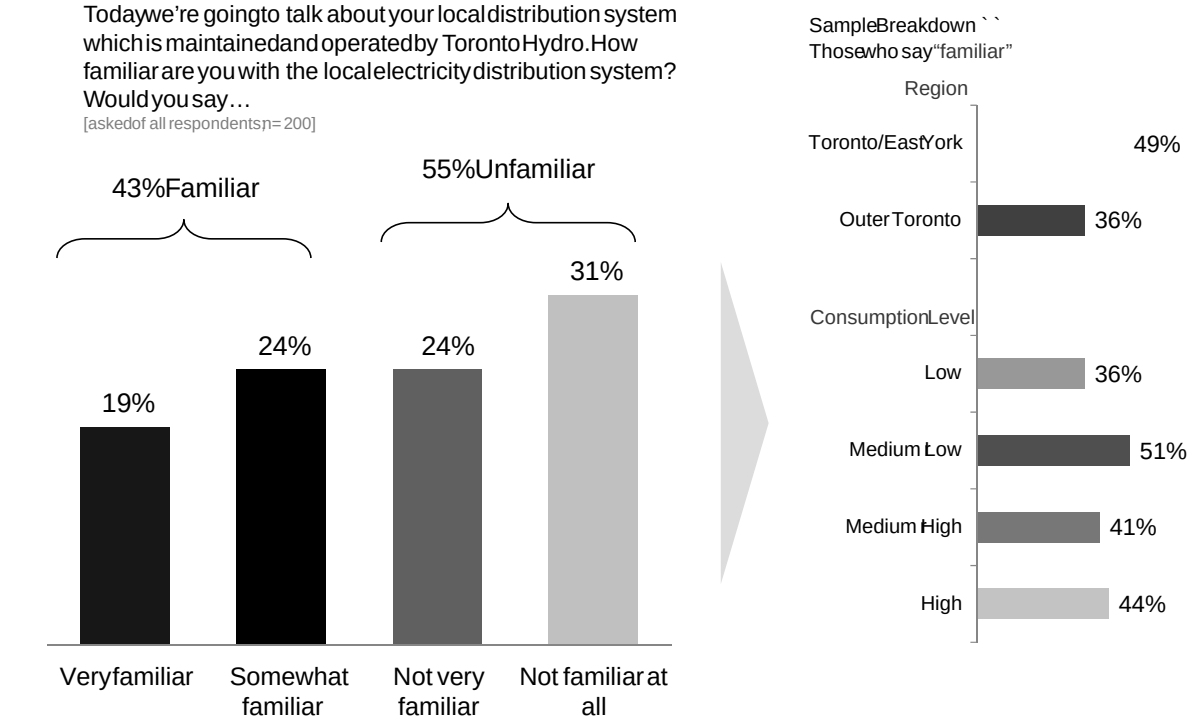


Note: 'Don't know'/'Refused' (1%) not shown

Of the General Service respondents, more than four in ten (43%) are familiar with their local distribution system. Of those who indicated they are familiar, 19% say they are very familiar with the system.

- Half (49%) of General Service customers in Central Toronto/East York are familiar, while only 36% of Golden Horseshoe customers state the same.
- Low (36%) consumption organizations are the least familiar with their local distribution system.
- Bill size appears to affect familiarity: those organizations with larger bills are more familiar with the system (<$500/month: 37%; between $500 and $1000: 46%; $1000+/month: 54%)

Figure 4.1 GS: Familiarity with the Local Distribution System 1



Note: 'Don't know'/'Refused' (3%) not shown

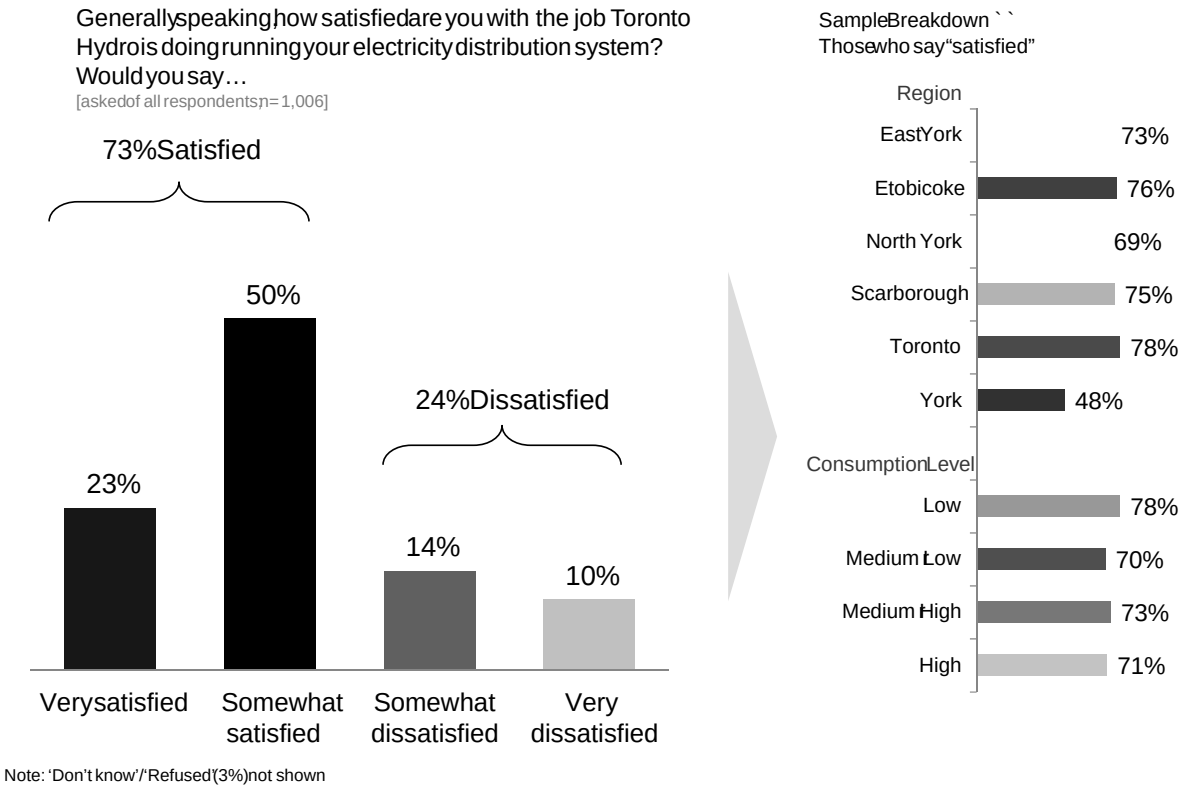
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Satisfaction with Toronto Hydro Running the Distribution System

Almost three quarters (73%) of residential customers are satisfied with the job Toronto Hydro is doing running their electricity distribution system, with nearly a quarter (24%) of residential customers responding "very satisfied".

- All regions but one are mostly satisfied with Toronto Hydro: North York (69%), East York (73%), Scarborough (75%), Etobicoke (76%) and Central Toronto (78%) all range between seven in ten and three quarters satisfied. However, in York, just under half (48%) of residential customers are satisfied with the job Toronto Hydro is doing.
- Those residents consuming the lowest amount (78%) of power are most satisfied with Toronto Hydro, between five and eight percent higher than respondents with higher consumption levels (70 to 73%).
- Residents of houses (fully detached: 72%; semi detached: 73%) are a bit less satisfied with Toronto Hydro than those in multi residential buildings (less than five stories: 81%; greater than five stories: 76%)
- Single and two person households (77%) are slightly more satisfied with Toronto Hydro than respondents in larger households (three: 72%; four: 66%; five or more: 72%).
- Residents who agree that their electricity bill "has a major impact on my finances" are less satisfied (68%) with Toronto Hydro than those who do not feel their bill has a major impact on their finances (82%).

Figure 4.2 RS: Satisfaction with Toronto Hydro

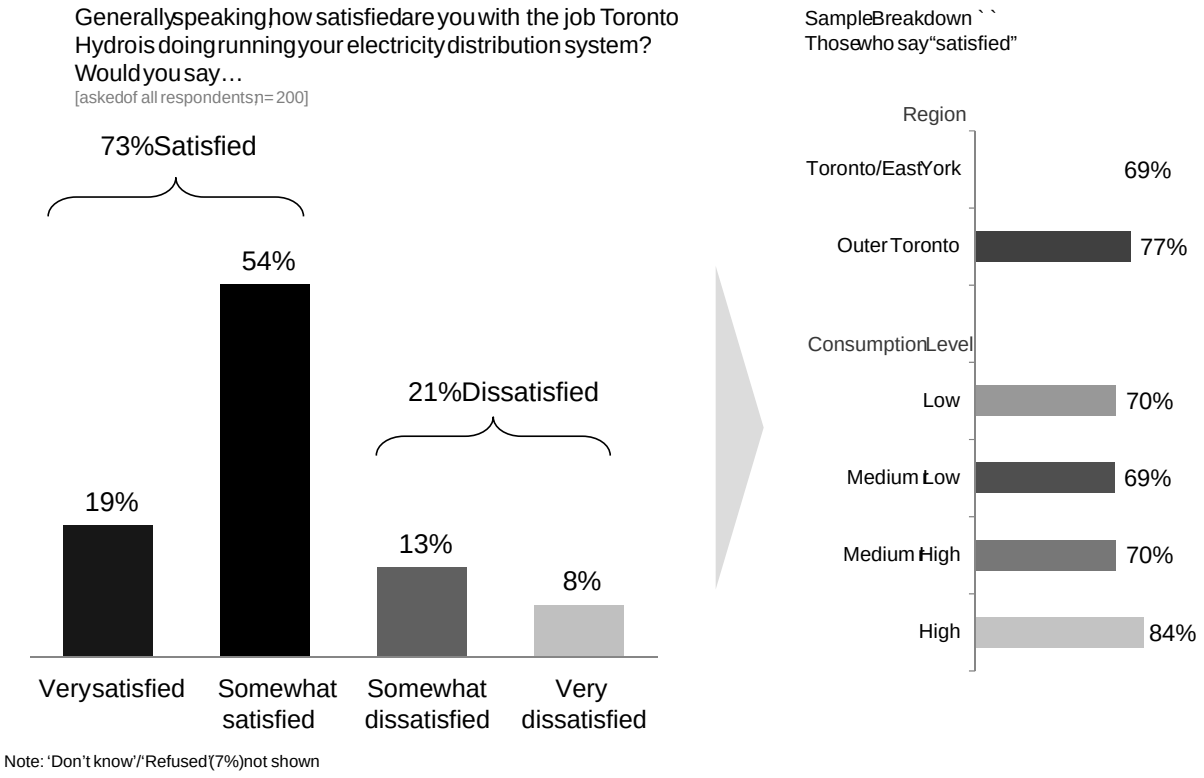


Note: 'Don't know'/'Refused' (3%) not shown

Like residential customers, almost three quarters (73%) of General Service customers are satisfied with the job Toronto Hydro is doing running the distribution system. About two in ten (19%) General Service customers are very satisfied with Toronto Hydro.

- The highest consumption volume (84%) General Service consumers are the most satisfied with Toronto Hydro.
- Organizations who feel their electricity bill has "a major impact on their bottom line" (76%) are slightly less satisfied with Toronto Hydro than those who do not feel it has a major impact on their finances (86%).

Figure 4.2 GS: Satisfaction with Toronto Hydro 1



Note: 'Don't know'/'Refused' (7%) not shown

1

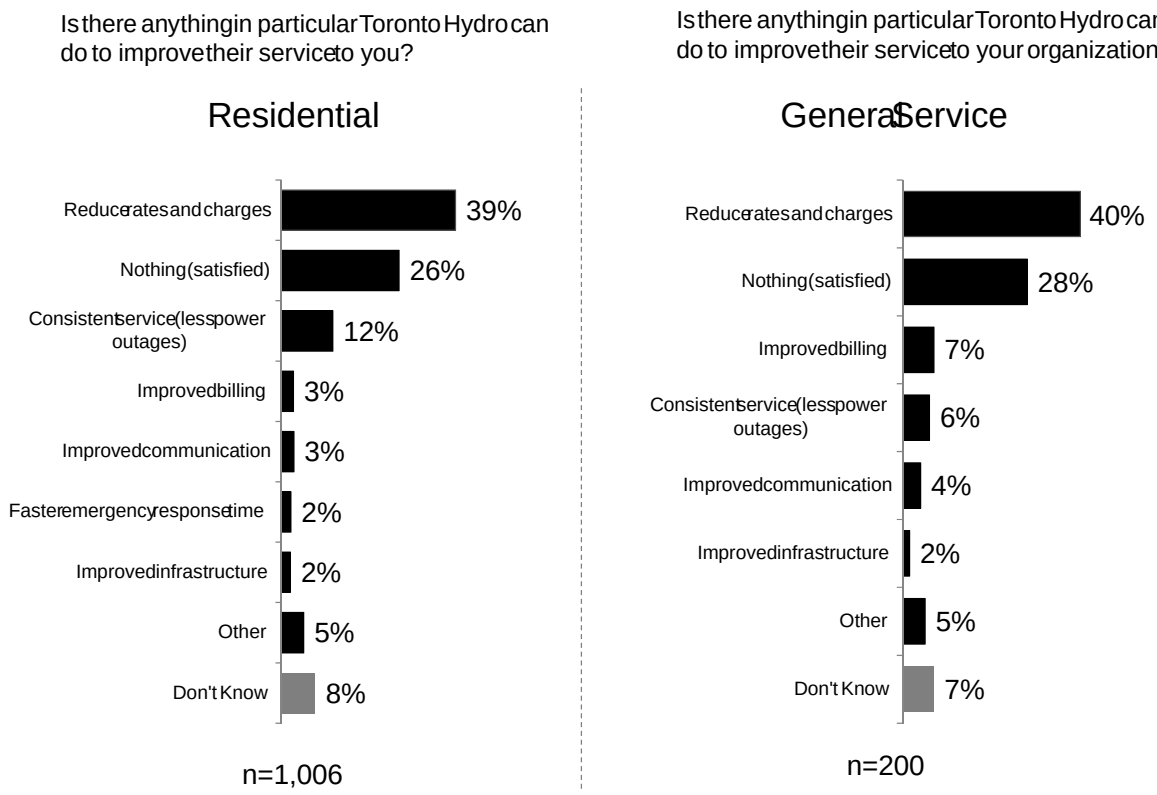
How to Improve Service

When asked how Toronto Hydro could improve service, a plurality of residential (39%) and General Service (40%) customers suggest that Toronto Hydro could "reduce rates and charges".

Other areas for improvement mentioned by residential respondents include "more consistent service/less power outages" (12%), "improved billing" (3%), "improved communication" (3%), "faster emergency response time" (2%), and "improved infrastructure" (2%).

A quarter (26%) of residential customers and nearly three in ten (28%) General Service customers say Toronto Hydro could do "nothing to improve their service".

Figure 4.3 RS/GS: How to Improve Service



Electricity Bill Knowledge

This section explores Residential and General Service respondent perceptions and knowledge of their electricity bill. It specifically focuses on the breakdown of the bill and what portion respondents estimate goes to Toronto Hydro.

Electricity Bill Knowledge Summary

- Most residential (35% familiar) and General Service (36%) respondents are not overly familiar with the breakdown of their electricity bill.
- In the Residential survey, East York (44%) and York (43%) prove the most familiar with their billing; highest consumption (40%) customers are more familiar than lowest (31%).

Preamble for Bill Knowledge & Impact Section

For this component of the survey, respondents were presented with a preamble concerning the breakdown of costs of an electricity bill. The two surveys provided different preambles based on targeted respondents.

The preamble for residential customers read as follows:

"I'd now like to talk with you about your electricity bill …

While some customers pay more and others pay less, the average residential customer pays about $132 a month for electricity of which $33 or approximately 25% goes to Toronto Hydro. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."

The General Service preamble explained it slightly differently:

"I'd now like to talk with you about your electricity bill …

While some customers pay more and others pay less, the average small and medium sized business pays about $330 a month for electricity of which $80 or approximately 25% goes to Toronto Hydro. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."

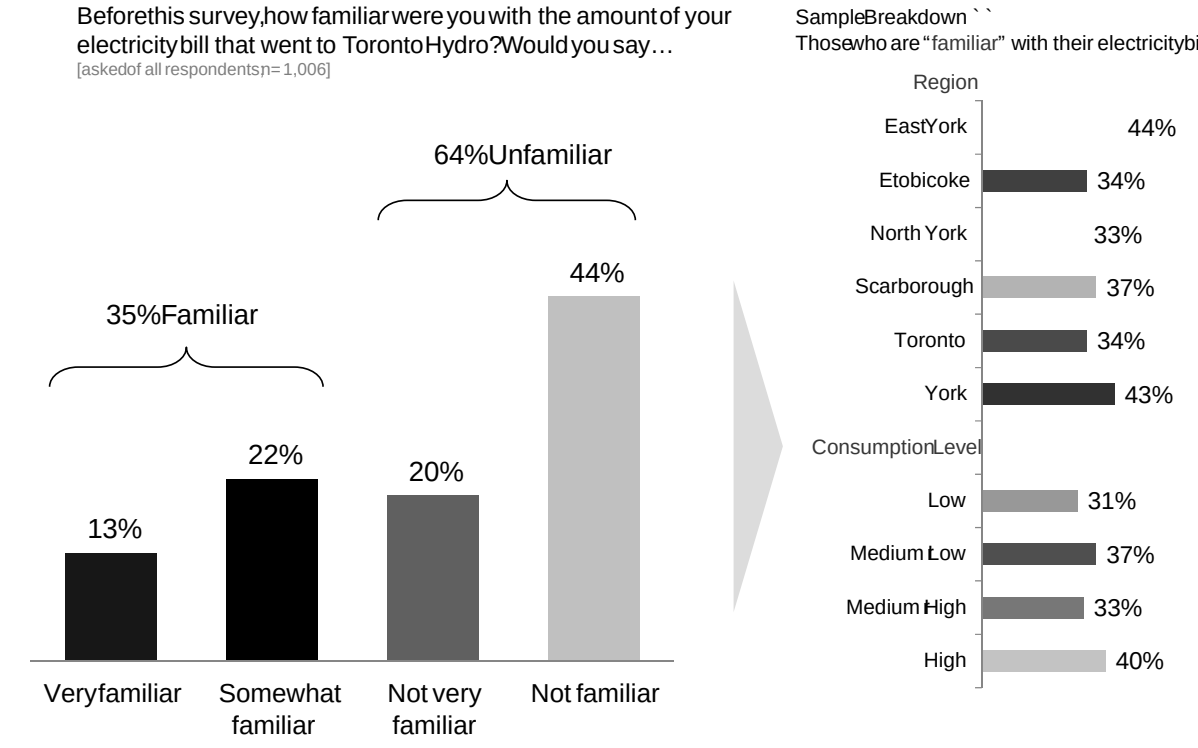
1

Familiarity with Share of Bill Going to Toronto Hydro

After the preamble, when asked about the breakdown of their electricity bill, 35% state they were familiar with the amount of their electricity bill that went to Toronto Hydro. In contrast, nearly two r thirds (64%) indicate they are not familiar with the breakdown of their bill.

- Regionally, East York (44%) and York (43%) are the most familiar with their electrical bill, with all other regions (33 r 37%) close to the mean (35%).
- Those with the highest consumption (40%) prove more familiar with their bill than the lowest (31%).
- Single detached home owners (39%) are more familiar with their bill than other residents (Semi r detached home: 31%; Multi less than five stories: 25%; Multi more than five stories: 33%).

Figure 4.4 RS: Familiarity with Share of Bill Going to Toronto Hydro



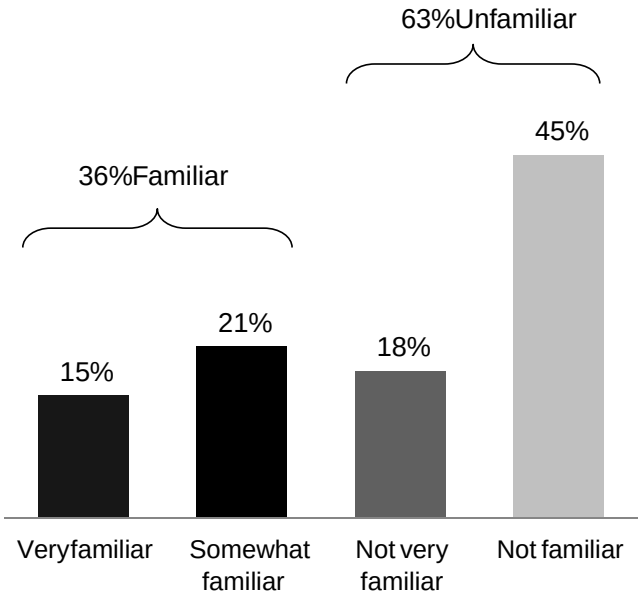
Note: 'Don't know'/'Refused' (0%) not shown

Similar levels of familiarity occur in the GS survey: 36% of respondents say they are familiar with the amount of their bill going to Toronto Hydro, while 63% indicate they are not familiar with how their bill is broken down.

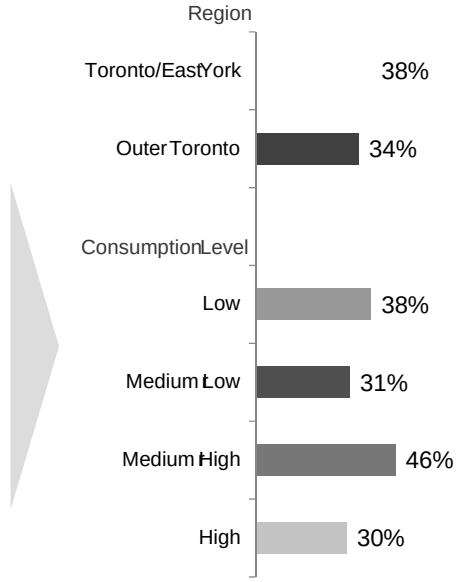
- By region (Central Toronto/East York: 38%; Outer Toronto: 34%) and at all consumption levels, there tends to be low knowledge concerning the breakdown of electricity bills.
- Organizations paying the lowest amount for electricity are the least familiar with their electricity bill (<$500/month: 24%; $500 to <$1000/month: 41%; >$1000/month: 46%).

Figure 4.4 GS: Familiarity with Share of Bill Going to Toronto Hydro

Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Toronto Hydro? Would you say…
[asked of all respondents, n = 200]



Sample Breakdown
Those who are "familiar" with their electricity bill



Note: 'Don't know'/'Refused' (2%) not shown

1

System Reliability

This section covers the feedback provided by respondents on previous power service interruptions, due to weather and non-weather related events, as well as the cost of service interruption to General Service respondents. It also discusses perceptions surrounding spending and reducing the number and length of power service interruptions.

System Reliability Summary

- Two-thirds (66%) of residents and just over half of organizations (55%) experienced power service interruptions during extreme weather.
- Not including unusual weather events, six in ten (57%) residential customers experienced "other" power outages in the last twelve months. About half (49%) of General Service customers report the same.
- When asked how much the "other" power outages cost their organization, almost two-thirds (64%) of General Service customers report at least some cost to their business.
- To address the number of outages, three in ten (31%) residential customers think Toronto Hydro should spend what is needed to reduce the number of power outages and four in ten (39%) think it should spend what is needed to maintain the current level.
- Two-thirds (67%) of GS customers think Toronto Hydro should spend what is needed to either reduce (30%) or maintain (37%) the length of power outages.

Preamble for Power Service Interruptions

Prior to the question being asked in this section, a preamble concerning power interruptions and extreme weather was provided. The preamble read as follows:

"This past year Toronto Hydro customers experienced unusually extreme weather – a wind storm in July and an ice storm in December. These storms caused power outages across the Toronto Hydro service area."

Power Service Interruptions

Two-thirds (66%) of residential customers experienced power outages in their homes during the extreme weather last year. The ice storm caused four in ten (41%) to lose power and five percent lost power due solely to the flooding; one in five (20%) lost power due to both. A third (32%) of Residential customers did not have an interruption in service due extreme weather.

- Central Toronto residents (44%) are much less likely to report outages during the extreme weather than other regions (Scarborough 72%; Etobicoke 73%; York 79%; North York 80%; East York 93%).
- Low consumption residential consumers (62%) are a bit less likely to report outages during the extreme weather than higher consumers (68-69%).
- Single-detached (74%) and semi-detached (64%) homes are the most likely to report power outages during the extreme weather and high rises (5+ stories: 42%) the least likely.
- Owners (69%) experienced power outages more frequently than renters (55%).

Among the General Service customers, 55% experienced outages and more about four in ten (42%) did not have weather events affect their power service. One in four (25%) lost power due to the ice storm and nearly three in ten (28%) lost power due to both the ice storm and the flooding. Only two percent lost power during the Toronto flooding.

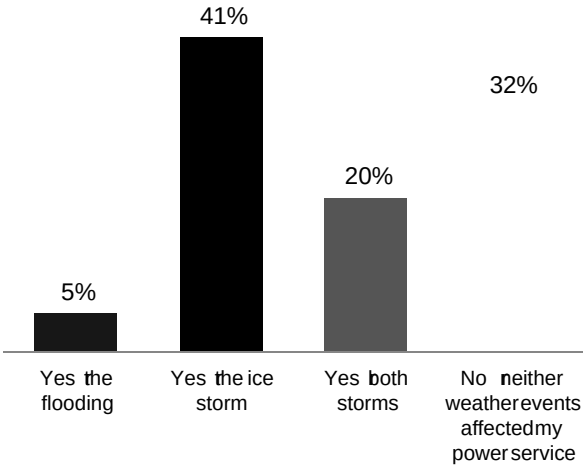
- For General Service, no statistically significant differences by region.
- Low (47%) consumers report slightly fewer outages during the extreme weather than higher energy consumers (60%: Medium low; 54%: Medium High; 54%: High).
- Organizations with a monthly bill of over $1000/month are much more likely to lose power during extreme weather than those paying less than $500/month (41%) or $500 to $1000/month (56%).
- Of the GS respondents who agree that their electricity bill "has a major impact on the bottom line" of their organizations, 65% report an outage during extreme weather, compared to just 41% who disagree with the statement.

Figure 4.5 RS/GS: Power Service Interruptions [1]

This past year Toronto Hydro customers experienced unusually extreme weather – flooding last July and an ice storm in December. These major weather events caused power outages across the Toronto Hydro service area.

Residential

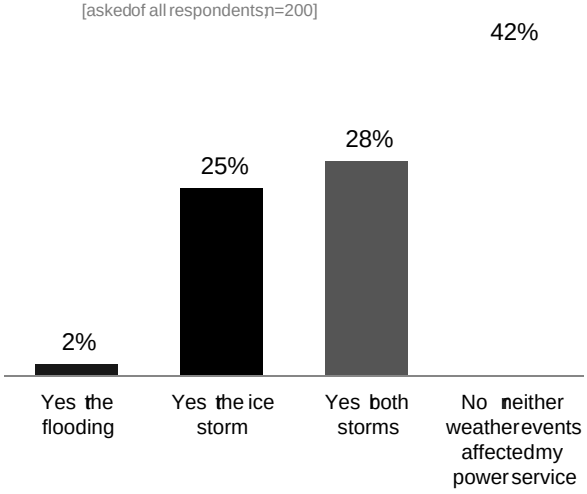
Did either of these major weather events cause a power outage at your home?
[asked of all respondents; n=1,006]



Note: 'Don't know'/'Refused' (1%) not shown

General Service

Did either of these major weather events cause a power outage at your home?
[asked of all respondents; n=200]



Note: 'Don't know'/'Refused' (5%) not shown

[1]

Other Power Outages

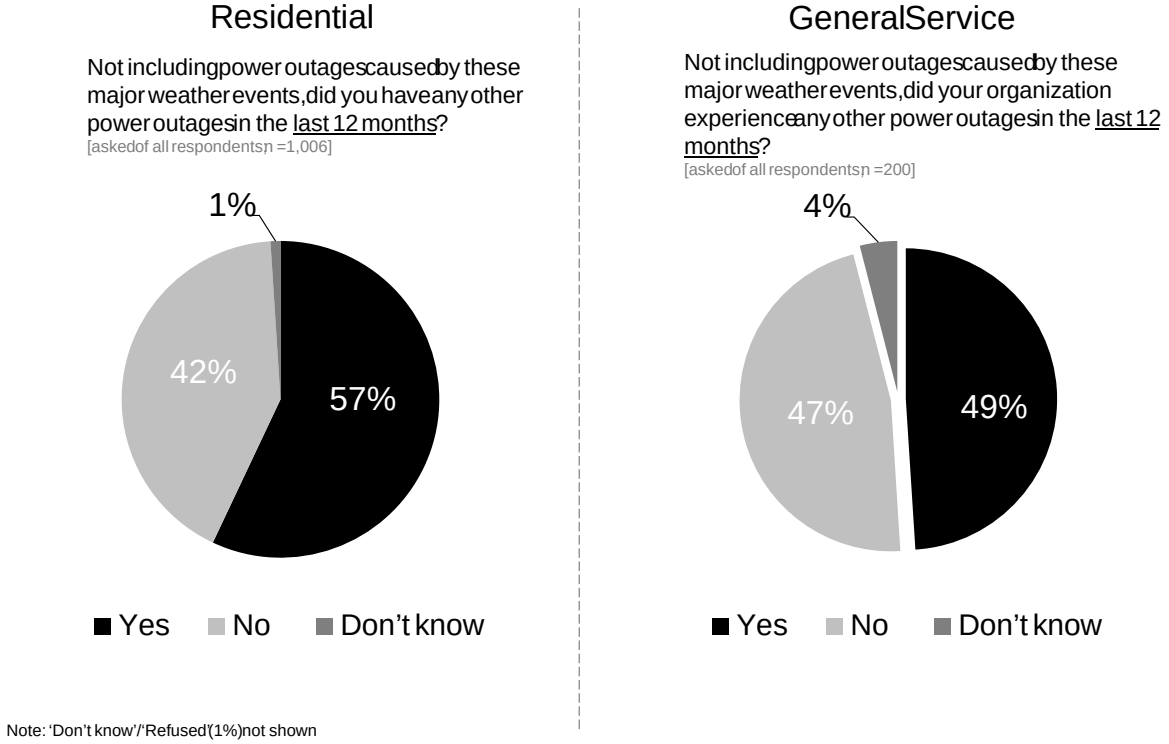
Not including power outages caused by major weather events, nearly six in ten (57%) residential customers say they experienced "other" power outages in the last twelve months. Only about four in ten (42%) residential customers did not experience such an outage.

- Looking by region, residential customers in York (81%) and East York (73%) are the most likely to report "other" power outages, while those in North York (66%), Etobicoke (47%) and Scarborough (45%) are less likely to report them.
- Residents living in houses (single detached: 61%; semi detached: 62%) and low rise buildings (53%) are much more likely to report "other" outages than those living in 5+ story buildings (35%).
- More residence owners (59%) report "other" outages than do renters (48%).

General Service reports slightly better service during normal weather with roughly a 50/50 split (49% experienced outages; 47% did not; 4% don't know).

- Outer Toronto GS customers (57%) are slightly more likely to report an "other" power outage than those organizations based in Central Toronto and East York (41%).
- Commercial businesses (52%) are slightly more likely to report "other" power outages than Retail and Restaurants (42%).

Figure 4.6 RS/GS: Other Power Outages



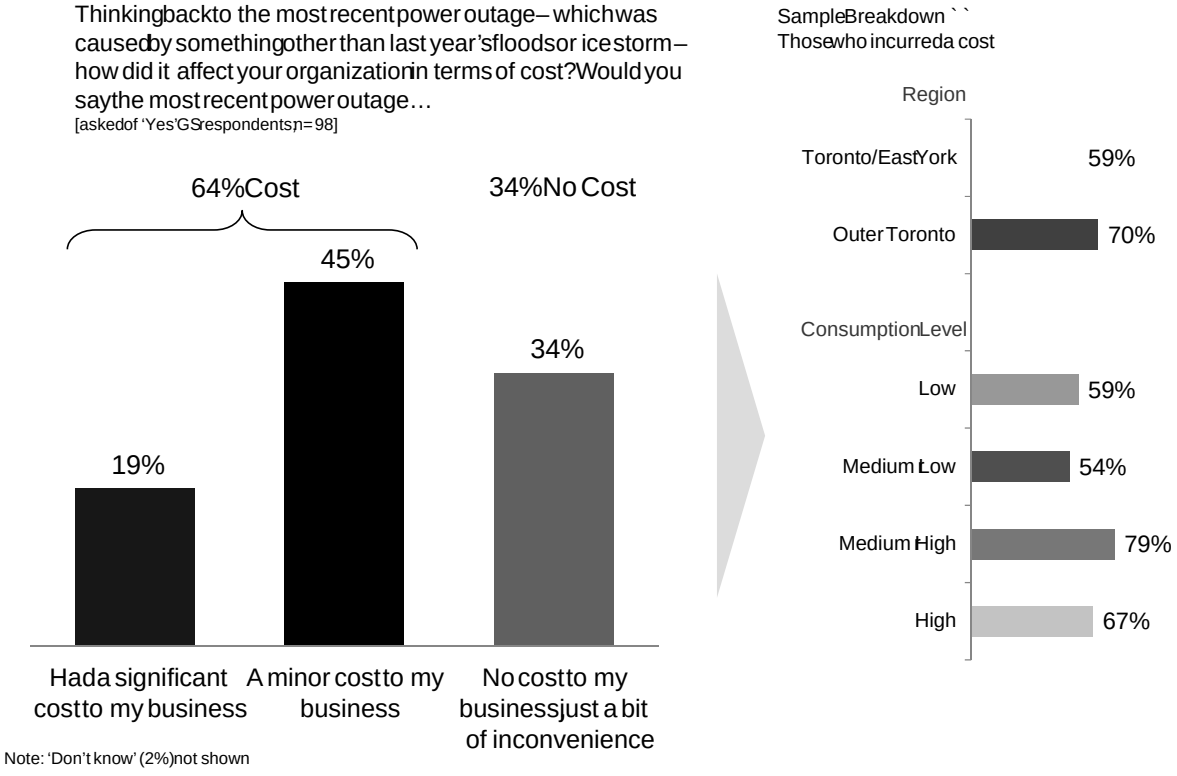
Note: 'Don't know'/'Refused' (1%) not shown

Only General Service respondents who responded "Yes" were asked an additional question on the cost of other (i.e. not caused by extreme weather) power outages: "how did it affect your organization in terms of cost?"

Almost two thirds (64%) of General Service customers report that the most recent power outage cost their business. For two in ten (19%) organizational customers, it had a significant cost to their business. About one third (34%) of respondents respond it had "no cost to their business just a bit of inconvenience".

- Of GS respondents who state that their electricity bill "has a major impact on the bottom line" of their organizations, 74% report a business cost to the recent outage with 24% dealt a significant cost.
- By region, seven in ten (70%) of Outer Toronto GS customers report a cost to their business, compared with six in ten (59%) in Toronto and East York. However, the cost impact appears to be more significant among respondents in Toronto/East York: a quarter (26%) of Toronto/East York customers had a significant cost to their business, compared with just 15% of Outer Toronto GS customers.
- Higher consumption organizations (High (67%); Medium high (79%) are more likely to report a cost to the power outage than lower consumption customers (Medium Low: 54%; Low: 59%).

Figure 4.7 GS: Commercial Cost of Outages 1



Note: 'Don't know' (2%) not shown

Preamble for Addressing the Frequency of Service Outages

The next question focused on how, according to the respondent, Toronto Hydro should address the number of outages financially. A preamble concerning the average number of power interruptions was provided before the question concerning addressing the number of outages. The preamble read as follows:

"Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

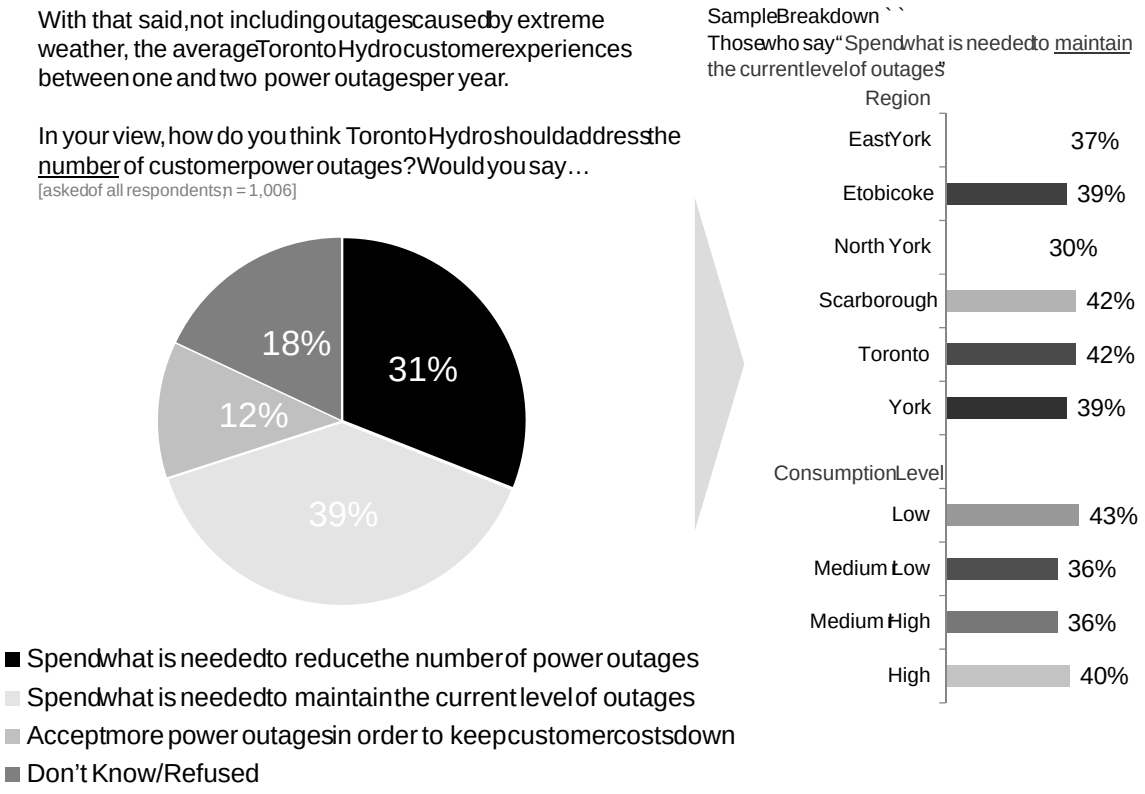
With that said – not including outages caused by extreme weather – the average Toronto Hydro customer experiences between one and two power outages per year."

Addressing the Frequency of Service Outages

Three in ten (31%) residential customers think Toronto Hydro should spend what is needed to reduce the number of power outages and four in ten (39%) think it should spend what is needed to maintain the current level. Just 12% state that Toronto Hydro should accept more power outages in order to keep customer costs down. Under two in ten (18%) don't know or refused to answer.

- Regionally, the only difference is that North York (30%) residents are less likely to want to "spend to maintain" than the rest of the GTA.
- There is little difference on this question when looking at consumption levels.
- Residents who agree that their electricity bill "has a major impact on their bottom line" are much less likely to want to "spend to maintain" (33%) than those who do not feel their bill has a major impact on their bottom line (48%).

Figure 4.8 RS: Addressing the Frequency of Service Outages



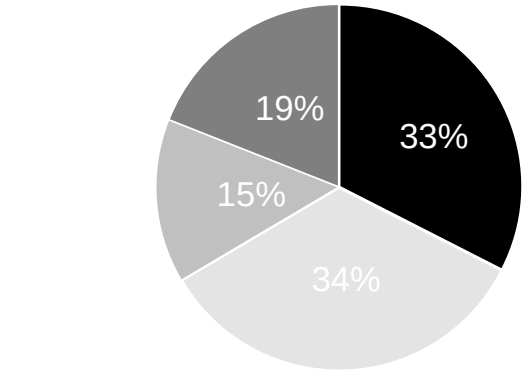
General Service customers respond likewise on how to address the number of outages: a third (33%) think that Toronto Hydro should spend what is needed to reduce the number of power outages and a third (34%) say it should spend what is needed to maintain the current level.

- Across region and consumption patterns there are no significant differences in opinion. Those with larger bills are less likely to want to "spend to maintain" ($1000+/month: 22% vs. 39% <$1000/month).

Figure 4.8 GS: Addressing the Frequency of Service Outages 1

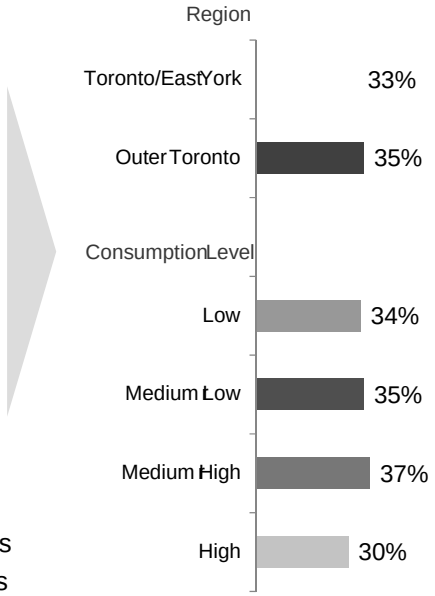
With that said, not including outages caused by extreme weather, the average Toronto Hydro customer experiences between one and two power outages per year.

In your view, how do you think Toronto Hydro should address the number of customer power outages? Would you say…
[asked of all respondents; n = 200]



- Spend what is needed to reduce the number of power outages
- Spend what is needed to maintain the current level of outages
- Accept more power outages in order to keep customer costs down
- Don't Know/Refused

Sample Breakdown
Those who say "Spend what is needed to maintain the current level of outages"



1

Preamble for Addressing the Duration of Service Outages

Before the follow-up question on how Toronto Hydro should address the length of time without power, respondents were read the following preamble:

"Again, not including outages caused by extreme weather, the average Toronto Hydro customer is without power for <u>one to one and a half hours</u> per year."

Addressing the Duration of Service Outages

Three-quarters (74%) of residential customers think Toronto Hydro should spend what is needed to either reduce (33%) or maintain (41%) the length of power outages. Only one in ten (11%) think that Toronto Hydro should accept longer power outages to keep costs down.

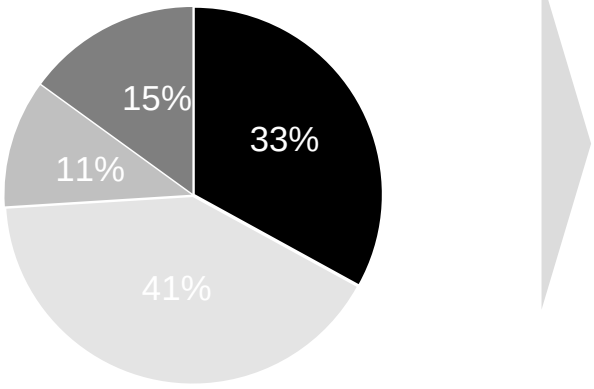
- Residents of East York (49%) and Central Toronto (47%) are the most likely to say "spend to maintain" the length of outages.
- No significant patterns by consumption level.
- Residents who say that their electricity bill "has a major impact on their bottom line" are less likely to want Toronto Hydro to "spend to maintain" (37%) than those unaffected financially by their bill (48%).

Figure 4.9 RS: Addressing the Duration of Service Outages

Again, not including outages caused by extreme weather, the average Toronto Hydro customer is without power for one to one and a half hours per year.

In your view, how do you think Toronto Hydro should address the <u>length of time</u> customers are without power? Would you say…

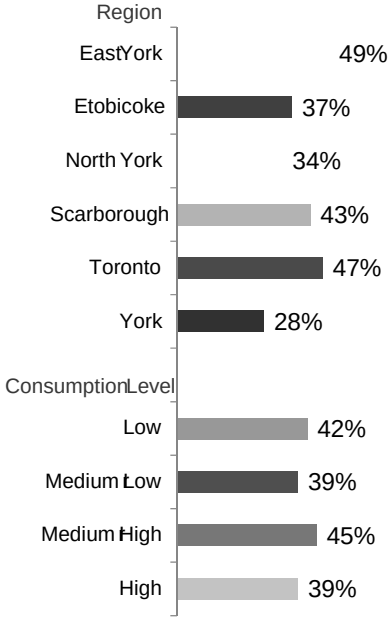
[asked of all respondents; n = 1,006]



- Spend what is needed to reduce the length of power outages
- Spend what is needed to maintain the current length of outages
- Accept longer power outages in order to keep customer costs down
- Don't Know/Refused

Sample Breakdown

Those who say "Spend what is needed to <u>maintain</u> the current length of outages"

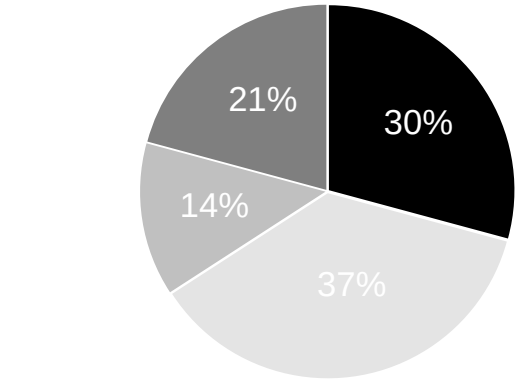


General Service customers are slightly less likely to think Toronto Hydro should spend what is needed to reduce (30%) or maintain (37%) the length of power outages. No significant differences arise within region or consumption.

Figure 4.9 GS: Addressing the Duration of Service Outages 1

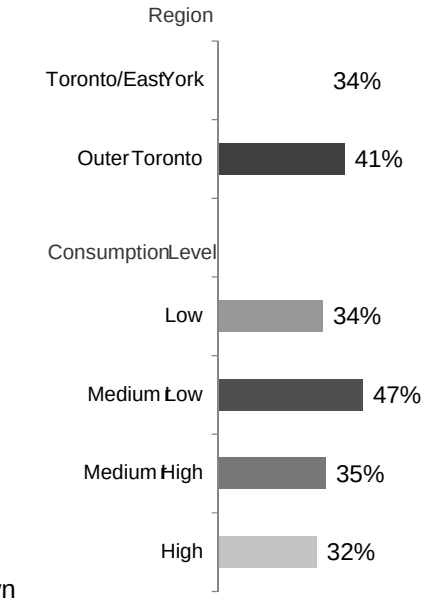
Again, not including outages caused by extreme weather, the average Toronto Hydro customer is without power for one to on r and a half hours per year.

In your view, how do you think Toronto Hydro should address the length of time customers are without power? Would you say…
[asked of all respondents; n = 200]



- Spend what is needed to reduce the length of power outages
- Spend what is needed to maintain the current length of outages
- Accept longer power outages in order to keep customer costs down
- Don't Know/Refused

Sample Breakdown
Those who say "Spend what is needed to maintain the current length of outages"



System Challenges & Priorities 1

This section explores respondents' support for various types of investment including infrastructure, technology and tools and equipment.

System Challenges & Priorities Summary 1

Investment in Aging Infrastructure

Six in ten (60%) residential customers and half (51%) of General Service customers believe that Toronto Hydro should invest in aging infrastructure to reduce future power outages, even if it means their bills may increase.

- Highest support among residential customers for infrastructure investment lies in Central Toronto (68%).

Investment in New Technologies

Two thirds (67%) of residential customers and six in ten (61%) General Service customers agree that investments in new technology will increase system reliability, make the local distribution system more efficient and save money in the long run. About two in ten (RS 19%; GS 20%) prefer the view that the utility should not invest in new technologies.

- Residents in the Toronto region (73%) are most likely to agree to investment in new technologies.

Investment in Equipment and Tools

Two thirds (66%) of Residential customers believe that Toronto Hydro should be wise with its spending, but they also think it is important that staff have the equipment and tools needed to manage the system efficiently and reliably.

- Residential customers struggling with the cost of their electricity bill (63%) are less likely to believe it is important that Toronto Hydro has proper equipment and tools than those who are unaffected financially by the electricity bill (74%).

Preamble for System Challenges & Priorities Section 1

At this point in the survey, respondents were presented with a preamble concerning the status of current electricity infrastructure and the need to rebuild it to prevent future service disruptions:

"As you may be aware, much of your local electricity system is aging and needs to be replaced in the near future. The time lost to power service interruptions caused by aging equipment has been growing steadily over the past decade.

According to Toronto Hydro's engineers, almost 60% of Toronto's electricity distribution infrastructure needs to be rebuilt over the next two decades. The price of these upgrades is approximately $5.6 billion overall.

As part of its 5 year plan, Toronto Hydro is proposing to continue its significant annual infrastructure renewal investment program. Although this plan will allow Toronto Hydro to make necessary investments it will have an impact on customer bills."

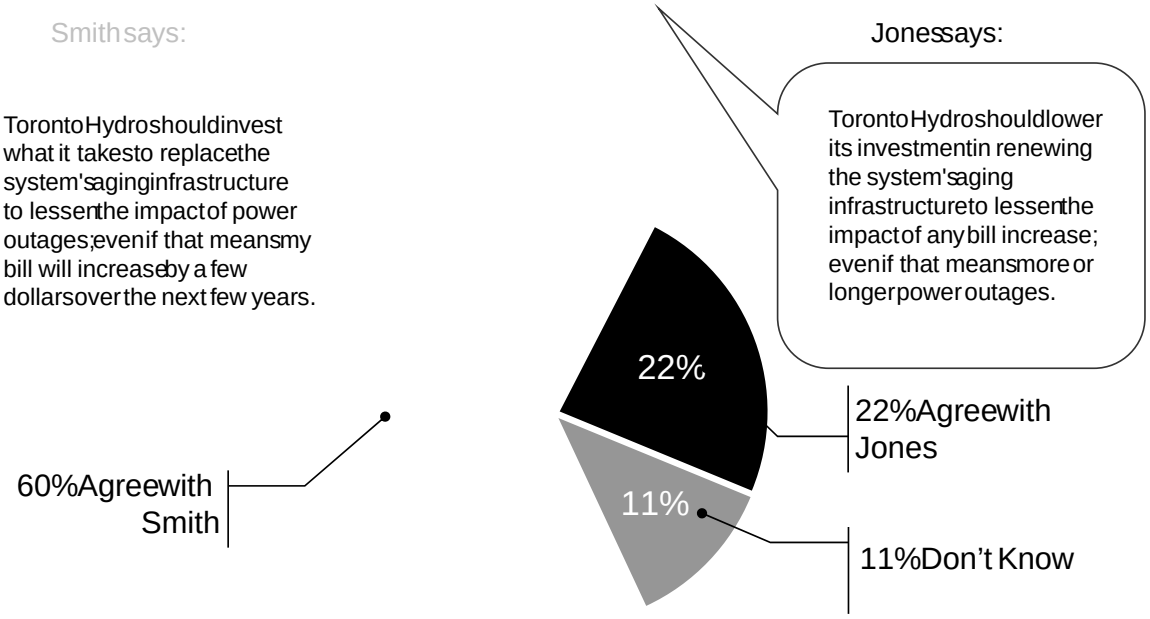
Investment in Aging Infrastructure

Six in ten (60%) residential customers believe that Toronto Hydro should invest what it takes to replace the system's aging infrastructure to lessen the impact of power outages, even if it means their bills will increase. In opposition, 22% of respondents think Toronto Hydro should lower its investment in renewing the system's aging infrastructure even if it means there will be more or longer outages.

- Highest support for infrastructure investment lies in Central Toronto (68%), with the lowest in Etobicoke (55%) and Scarborough (54%).
- There are no significant differences across consumption or residence type for investing in aging infrastructure.
- Residents who claim that their electricity bill "has a major impact on their bottom line" (51%) are much less likely to support investment in aging infrastructure than those who are unaffected financially by the electricity bill.

Figure 4.10 RS: Investment in Aging Infrastructure

Throughout Toronto Hydro's consultation process, customers have made a number of statements about the proposed increased investment. Which of the following statements best represents your point of view?
[asked of all respondents; n=1,006]



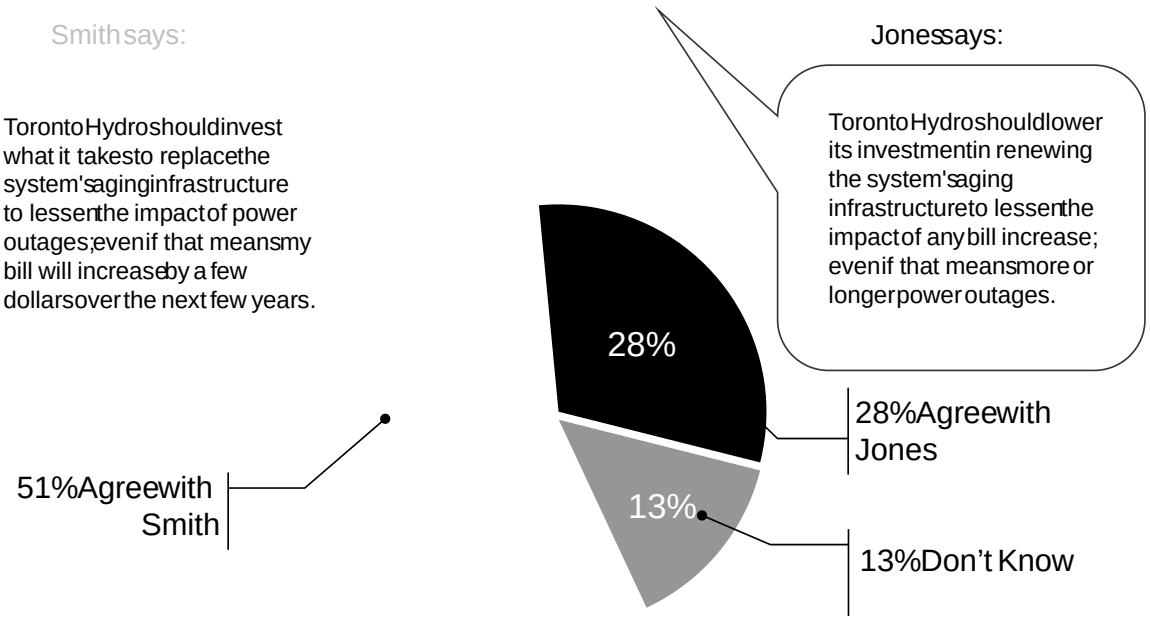
Note: 'Refused' (6%) not shown

As for General Service customers, half (51%) think Toronto Hydro should invest what it takes to replace the system's aging infrastructure to lessen the impact of power outages, despite a possible bill increase. Less than three in ten (28%) think Toronto Hydro should lower its investment in aging infrastructure, even if that means more outages.

- Central Toronto and East York (57%) are somewhat more likely to support investment in aging infrastructure than Outer Toronto (45%).

Figure 4.10 GS: Investment in Aging Infrastructure [1]

Throughout Toronto Hydro's consultation process, customers have made a number of statements about the proposed increased investment. Which of the following statements best represents your point of view?
[asked of all respondents; n=200]



Note: 'Refused' (9%) not shown

[1]

Investment in New Technology

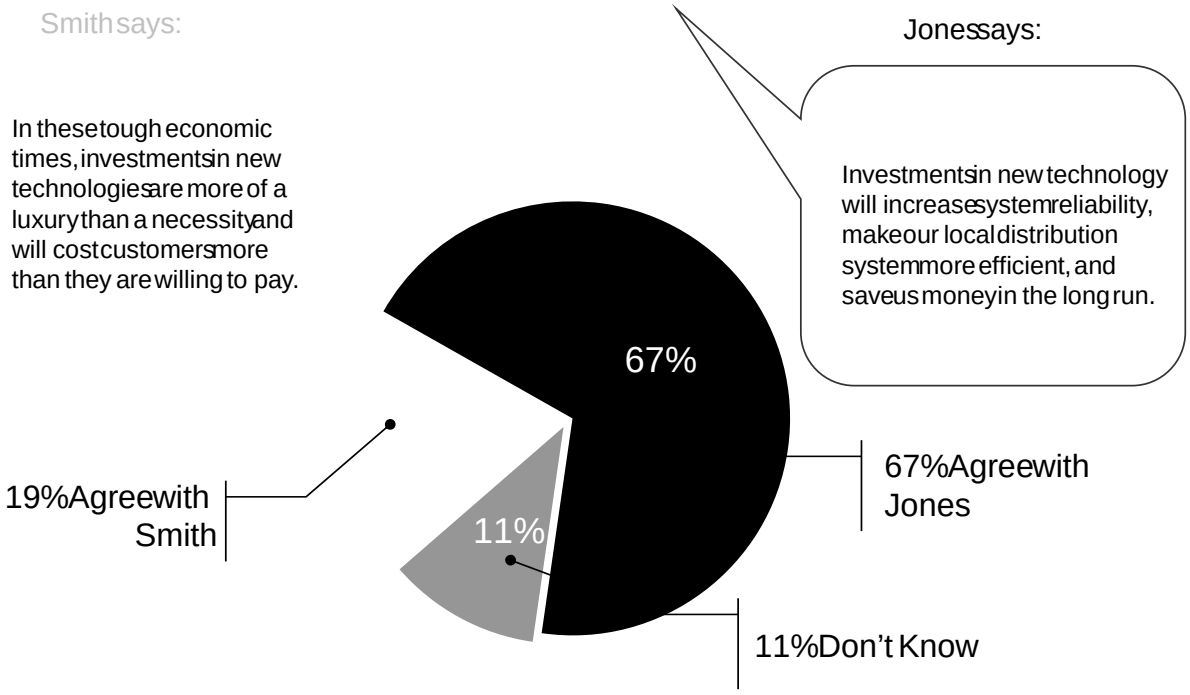
Following the questions on infrastructure investment, customers weighed in on investment in new technology.

Two thirds (67%) of residential customers agree that investments in new technology will increase system reliability, make local distribution system more efficient and save money in the long run. Just two in ten (19%) prefer the counter argument that new technologies are a luxury, not a necessity and would cost the customers more than they are willing to pay.

- Customers in Central Toronto (73%) are most likely to agree on the benefits of investment in new technology.
- Consumption rate does not appear to affect opinion on investment in new technology.
- Residential customers claiming that their electricity bill "has a major impact on their bottom line" (66%) are somewhat less likely to support investment in new technology than those who are unaffected financially by the electricity bill (75%).

Figure 4.11 RS: Investment in New Technology

Other Toronto Hydro customers have made a number of statements about aging infrastructure and future investments required to improve the reliability of the electricity system. Which of the following statements best represents your point of view?
[asked of all respondents; n=1,006]



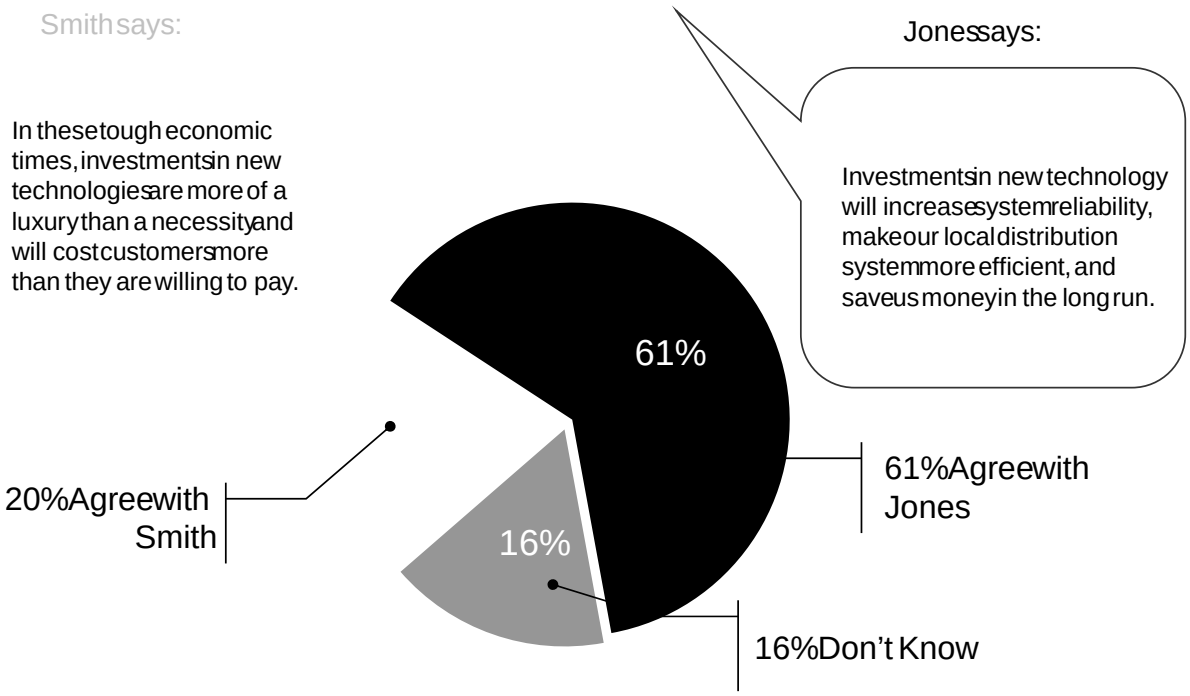
Note: 'Refused' (3%) not shown

Six in ten (61%) General Service customers agree with the statement praising investments in new technology, compared with just two in ten (20%) who prefer the counter argument

- No significant differences emerge by region or consumption.
- Those paying more on their monthly bill ($1000+: 50%) are less likely to agree that investment in new technology will increase reliability, efficiency and save money in the long run.

Figure 4.11 GS: Investment in New Technology 1

Other Toronto Hydro customers have made a number of statements about aging infrastructure and future investments required to improve the reliability of the electricity system. Which of the following statements best represents your point of view?
[asked of all respondents; n=200]



Note: 'Refused' (4%) not shown

1

Preamble for Investment in Equipment and Tools

For the following question on investment in equipment and tools, respondents were read this brief preamble:

"Toronto Hydro is not just the local electricity distribution system itself, but a company that operates the system. As a company, Toronto Hydro needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information." 1

Investment in Equipment and Tools

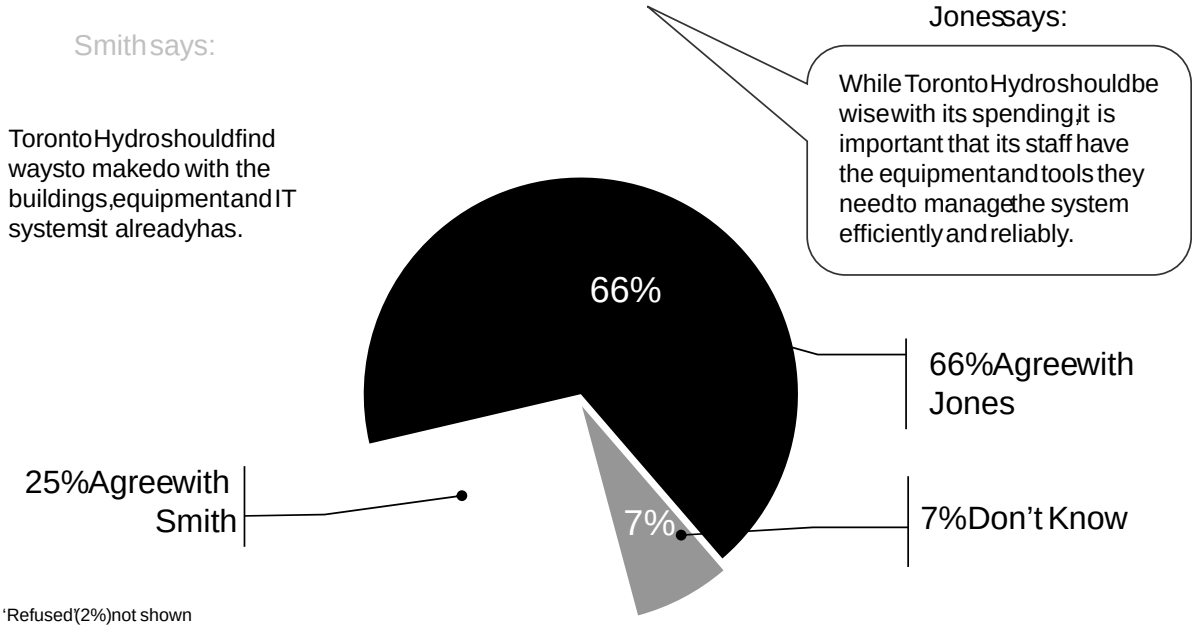
Two thirds (66%) of Residential customers believe that Toronto Hydro should be wise with its spending, but they also think it is important that staff have the equipment and tools needed to manage the system efficiently and reliably. One quarter (25%) of respondents think that Toronto Hydro should find ways to make do with the buildings, equipment and IT systems it already has.

- Across region and consumption patterns there is little change in belief on properly equipping Toronto Hydro to manage its system.
- Residential customers struggling with the cost of their electricity bill (63%) are less likely to believe it is important that Toronto Hydro has proper equipment and tools than those who are unaffected financially by the electricity bill (74%).

Figure 4.12 RS: Investment in Equipment and Tools

Toronto Hydro is not just the local electricity distribution system itself, but a company that operates the system. As a company Toronto Hydro needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information.

Customers have made number of statements about this sort of investment. Which of the following statements best represents your point of view?
[asked of all respondents; n=1,006]



Note: 'Refused' (2%) not shown

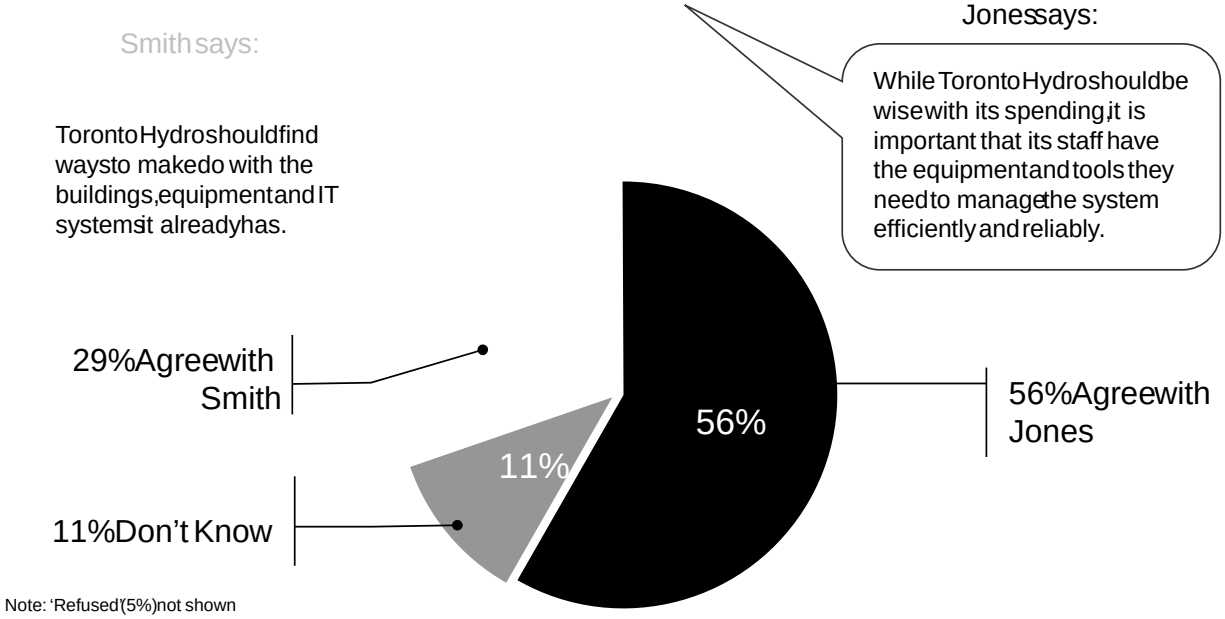
Less than six in ten (56%) General Service customers believe that, while Toronto Hydro should be wise with its spending, it is important that Toronto Hydro's staff have the equipment and tools they need to manage the system efficiently and reliably.

- Regionally, there is little difference among General Service customers.
- High consumption organizations (64%) are the most likely to agree with the positive statement on investing in Toronto Hydro equipment and tools.

Figure 4.12 GS: Investment in Equipment and Tools

Toronto Hydro is not just the local electricity distribution system itself, but a company that operates the system. As a company Toronto Hydro needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information.

Customers have made number of statements about this sort of investment. Which of the following statements best represents your point of view?
[asked of all respondents; n=200]



Note: 'Refused' (5%) not shown

Reaction to Previous Customer Consultation Input

This section measures agreement with some of the key opinion statements provided by Toronto Hydro's customers in previous phases of the consultation.

Customer Reaction Statements Summary

Of the thirteen customer input statements provided in the questionnaire, the statement with the most support among residential customers is "I think Toronto Hydro should do more to help customers find ways to reduce the electricity consumption and costs".

Similarly, among General Service customers, the most supported statement was the business version of the same question: "I think Toronto Hydro should do more to help business customers find ways to reduce their electricity consumption and costs."

The statement with the lowest level of agreement is "when it comes to reducing power outages and improving reliability, the first priority should be business customers, then residential customers."

Again, the statement with the lowest level of General Service agreement is "when it comes to reducing power outages and improving reliability, the first priority should be business customers."

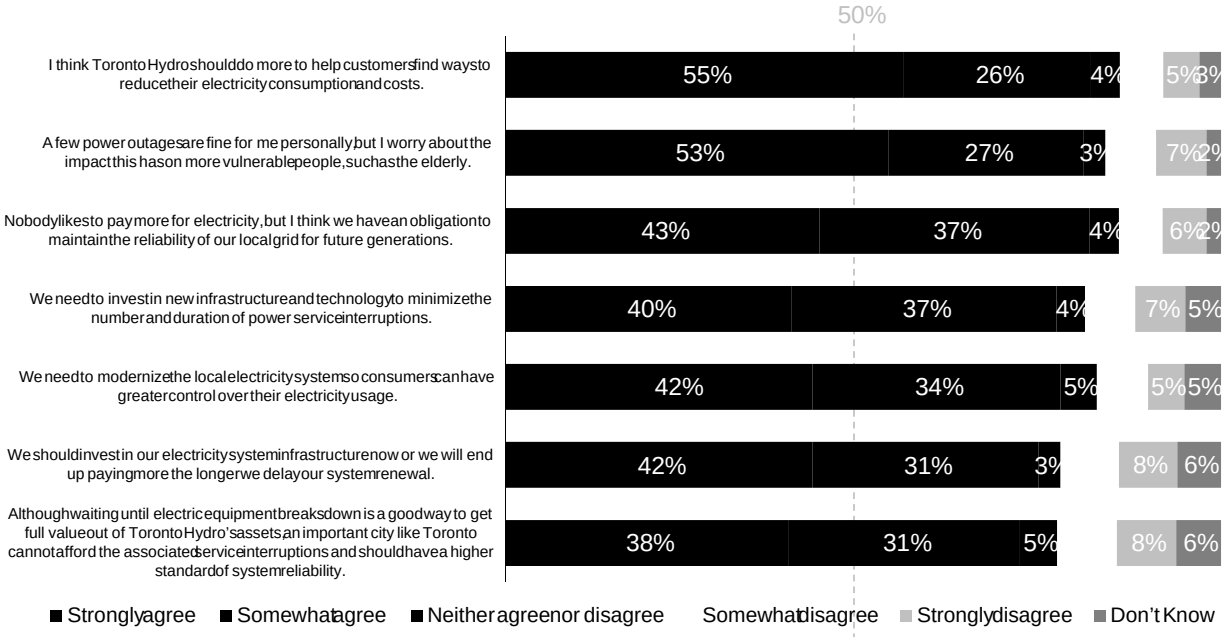
Residential Customer Reaction

A majority of residential respondents agree with all of the customer input statements provided in the questionnaire except one: "When it comes to reducing power outages and improving reliability, the first priority should be business customers, then residential customers." (31% agree; 57% disagree; 37% strongly disagree).

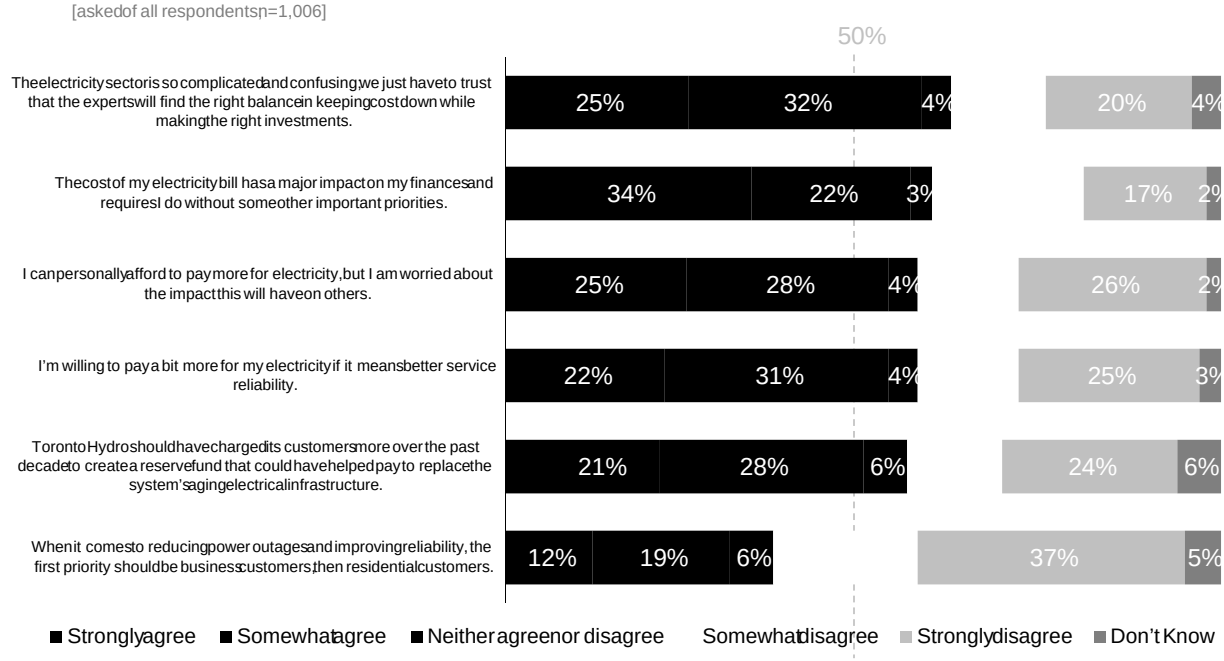
Of the thirteen statements put forth to residential customers, three of them have at least 80% support. These three statements focus on cost, the vulnerability of the elderly and the future of infrastructure. In the statement with the most support, eight in ten (81%) agree that "I think Toronto Hydro should do more to help customers find ways to reduce the electricity consumption and costs" and 55% of respondents strongly agree. Eight in ten (80%) residential customers also agree that "a few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly". This statement on the vulnerability of the elderly also has intense agreement: over half (53%) of residential customers strongly agree. Eight in ten (80%) of those surveyed also agree that "nobody likes to pay for more for electricity, but I think we have an obligation to maintain the reliability of our local grid for future generations". Again, this statement elicits strong intensity of agreement (43% strongly agree).

Figure 4.13: RS: Reaction to Customer Input 1

The following statements have been made by customers throughout Toronto Hydro's consultation process. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked of all respondents n=1,006]



The following statements have been made by customers throughout Toronto Hydro's consultation process. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked of all respondents n=1,006]



1

GS<10 Customer Reaction 1

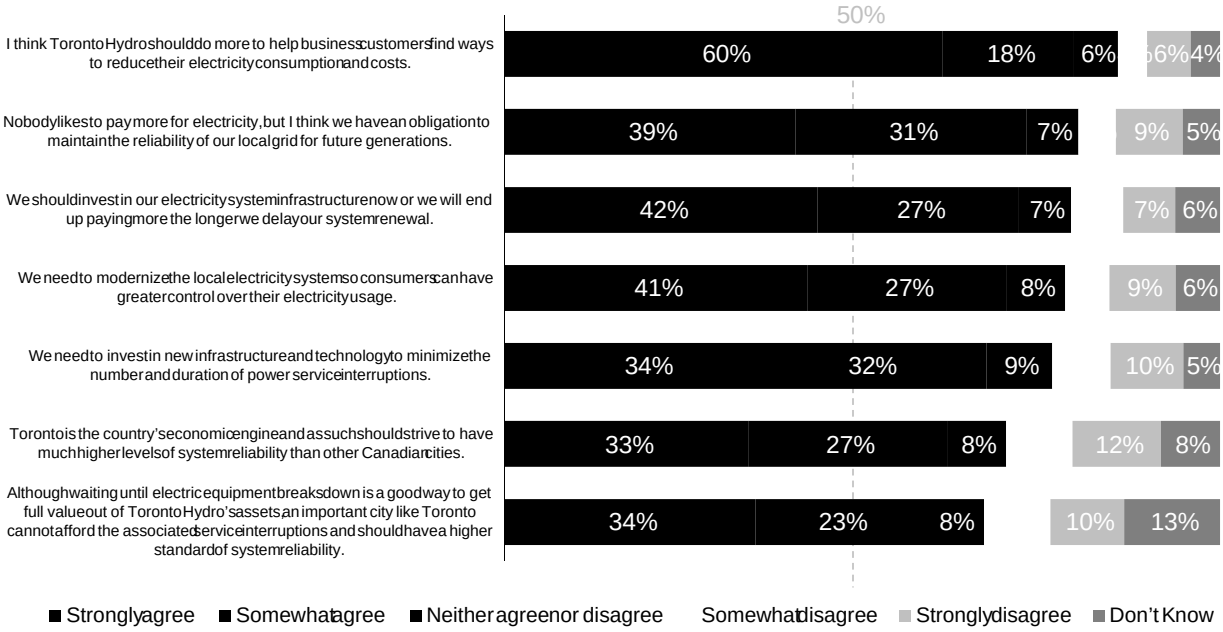
A majority of General Service agree with ten of the thirteen statements provided in the questionnaire. The strongest agreement is on cost savings: "I think Toronto Hydro should do more to help business customers find ways to reduce their electricity consumption and costs." Nearly eight in ten (78%) agree with that statement, with six in ten who strongly agree.

Less than half of General Service respondents agree with three of the thirteen statements:

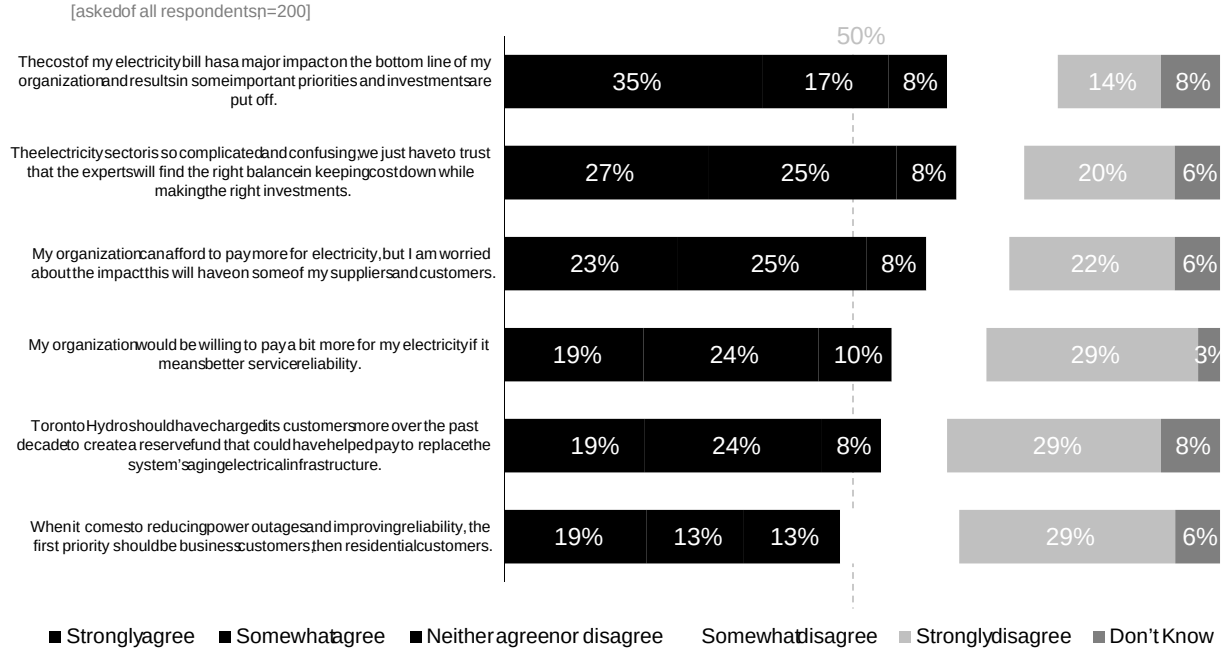
- Only 43% think that their organization would be willing to pay a bit more for electricity if it means better service reliability, with intense disagreement (29% strongly disagree).
- 43% also believe that Toronto Hydro should have charged its customers more over the past decade to create a reserve fund for infrastructure, with again 29% who strongly disagree.
- And just 32% agree that when it comes to reducing power outages and improving reliability, the first priority should be business customers.

Figure 4.13 GS: Reaction to Customer Input 1

The following statements have been made by customers throughout Toronto Hydro's consultation process. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked of all respondents n=200]



The following statements have been made by customers throughout Toronto Hydro's consultation process. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked of all respondents n=200]



Assessment of Plan

This section explores the degree of acceptance that Toronto Hydro's customers give for a rate increase. Acceptance is defined as either support for a rate increase or agreeing that it is necessary. This section also explores the underlying reasons for acceptance and opposition to a rate increase, probing more specifically through open-ended questions.

Acceptance of Rate Increase: Summary

Nearly six in ten residential (58%) customers accept the rate increase. However, most of these respondents offer reluctant acceptance (39%): they don't like the increase, but feel it's necessary to maintain the grid. Only a third (34%) thinks the rate increase is unreasonable.

- The highest rates of acceptance come from Central Toronto (67%), East York (65%), and York (63%) with less support in the rest of Outer Toronto (North York: 53%; Etobicoke: 52%; Scarborough 52%).
- Consumption rates have little effect on acceptance numbers.
- Residential customers who feel their electricity bills are a significant toll on their finances are much less likely to accept a rate increase (51% "toll on their finances" support the increase; 70% "not a toll").
- Single person households (53%) are least likely to support the rate increases.

General Service customers are less willing to accept of rate increases than residential customers; just under half (48%) of organizational customers support the proposed Toronto Hydro plan. Much of that acceptance appears to be reluctant: they "don't like the rate increase, but feel it is necessary" (30%). Four in ten (41%) think the bill impact is too high and Toronto Hydro needs to scale back.

- Regionally, there is little difference in opinion among GS customers.
- However, businesses that consume high levels of electricity (60%) are much more likely to accept a rate increase than low consumption businesses (34%).

Reasons why Customers Accept or Opposed Toronto Hydro's proposed DSP:

- In the residential breakdown, those who are most strongly accepting of the rate increase cite "concerns over future infrastructure needs" (29%) and "better service" (22%) as their key reasons.
- Those who are satisfied with the balance give "reasonable cost" (31%) as the main reason.
- Residents who are reluctantly accepting they don't like it, but it's necessary cite "reasonable cost" (22%), "necessary sacrifice" (18%), "better service" (14%) and the "future infrastructure crisis" (11%) as the main reasons.
- Six in ten (60%) of those against the rate increase cite "cost too much" as the reason for their disapproval, followed by "concerns about non-capital expenses" (15%).

Preamble for Assessment of Plan Section 1

Prior to the questions given in the Assessment of Plan Section, residential customers were presented with a preamble concerning the breakdown of pricing for Toronto Hydro's 5 year plan:

To maintain the reliability of the local electricity system, Toronto Hydro's proposed 5 year plan will cost an estimated $500 million per year. This includes…

- 54% to replace aging infrastructure;
- 19% to maintain metering and connect new customers to the electricity system;
- 13% to invest in tools, computers and software systems, vehicles and facilities needed to manage the electricity system;
- 8% to expand system capacity to accommodate future growth; and
- 6% for new technologies to make the system more efficient, reliable and safe.

To fund this plan, Toronto Hydro is proposing the average residential customers' rate increase by $2.90 on the distribution portion of their bill for the next five years. So, by 2019, the average residential household will be paying an estimated $14.50 more per month on the distribution portion of its electricity bill.

(Note: in the GS Survey, the two bolded phrases in the last paragraph were replaced with "average small and medium sized business customers' rate increase by $5.75" and "estimated $28.75 more per month", respectively. The rest of the preamble remained the same for organizational customers.)

Note: In the online workbook and the workbook led facilitated discussions, the monthly bill impact was presented differently from the telephone surveys. The telephone surveys were updated to reflect adjustments to Toronto Hydro's capital plan made over the course of the consultation process.

- For Residential: Toronto Hydro's proposal is expected to lead to a total increase of approximately $11.75 on the average residential customer's monthly bill by 2019.
- For GS < 50 kW: Toronto Hydro's proposal is expected to lead to a total increase of approximately $30.50 on the average small business customer's monthly bill by 2019.

1

Assessment of Plan

When asked the "acceptance question" on rate increases, nearly (58%) six in ten residential customers agree to the rate increase. Four percent (4%) of respondents think that Toronto Hydro should plan to achieve higher incomes even with increased rates and 15% state they were satisfied with the balance between outcomes and the proposed rate increase. Four in ten (39%) residents don't like the rate increase, but think it's necessary to maintain the infrastructure. Just one third (34%) of respondents feel the bill impact is too high and Toronto Hydro needs to scale back its plans.

- Looking regionally, Central Toronto (67%), East York (65%) and York (63%) are most likely to accept the rate increases. The rest of Outer Toronto (Etobicoke: 52%, Scarborough: 52%; North York: 53%) are the least supportive of the rate increase.
- A majority of support exists across all consumption levels (56 61%).
- Residential customers who feel their electricity bills are a significant toll on their finances are much less likely to support a rate increase (51% "toll on their finances" support the increase; 70% "not a toll").
- Single person households (53%) are the least likely to support the rate increase.

Figure 4.14 RS 1A, Acceptance of Rate Increase

General Service customers, on the other hand, are less likely to support rate increases just under half (48%) of GS respondents accept the increase.

Breaking down "acceptance": 3% of GS respondents thought Toronto Hydro should plan to achieve even higher outcomes despite rates; 15% were satisfied with the balance between outcomes and proposed rate increase and 30% do not like the rate increase, but think it's necessary to maintain the grid. Four in ten (41%) think the bill impact is too high and Toronto Hydro needs to scale back its plan.

- No significant differences emerge by region for General Service customers.
- Consumption appears to play a significant role in assessment of the plan: just a third (34%) of low consumption customers accept the plan compared to six in ten among high consumption organizations (60%).
- GS customers struggling with the cost of their electricity bill (46%) are less likely to accept the proposed increase than those who are unaffected financially by their electricity bill (67%).

Figure 41.14 GS 1A Acceptance of Rate Increase 1

1

Opinions on Proposed Rate Increase

For residential customers, due to the larger sample size, the responses can be broke down into four groups: "acceptance hydro should plan higher"; "acceptance satisfied with the balance"; "acceptance don't like, but necessary" and "no acceptance cost impact too high".

When broken down into these subgroups, some striking differences emerge:

- Residents who are most strongly accepting of the plan are most likely to answer "future infrastructure crisis" (29%) and "better service" (22%) as the reasoning, with "reasonable cost" (12%) as the third key driver.
- For those who accept and are "satisfied with the balance", the most important reason is again cost (31%) it is "reasonable" to them. Other key reasons include the "future infrastructure crisis" (13%), "better service" (13%) and "necessary sacrifice" (11%).
- For those who reluctantly accept they don't like it, but feel it is necessary the "reasonable cost" (22%), "necessary sacrifice" (18%) and "better service" (14%) and the "future infrastructure crisis" (11%) were given as the main reasons.
- Among those against the proposed increase, six in ten (60%) state "cost too much" as the reason and about one in seven (15%) citing "concerns about non capital expenses".

Figure 4.15 RRS 10 Opinion on Proposed Rate Increase

And why do you say that? (Rate increase for local distribution system)
Residential Customers

ACCEPTANCE HYDRO SHOULD PLAN HIGHER	% RS
Future infrastructure crisis	29%
Better service most important	22%
Cost increase reasonable	17%
Necessary sacrifice	7%
Cost too much	5%
Other	12%
Don't know/Refused	7%

N=41

ACCEPTANCE SATISFIED WITH BALANCE	% RS
Cost increase reasonable	31%
Future infrastructure crisis	13%
Better service most important	13%
Necessary sacrifice	11%
Satisfied with Toronto Hydro (general)	7%
Concerns about non capital expenses	4%
Cost too much	3%
Other	6%
Don't know/Refused	11%

N=151

ACCEPTANCE DON'T LIKE, BUT NECESSARY	% RS
Cost increase reasonable	22%
Necessary sacrifice	18%
Better service most important	14%
Future infrastructure crisis	11%
Concerns about non capital expenses	8%
Efficiency	4%
Cost too much	4%
Someone else should pay	3%
Other	6%
Don't know/Refused	10%

N=392

NO ACCEPTANCE IMPACT TOO HIGH	% RS
Cost too much	60%
Concerns about non capital expenses	15%
Efficiency	8%
Someone else should pay	5%
Future infrastructure crisis	1%
Other	7%
Don't know/Refused	4%

N=339

For general service customers, the responses are be broken down into the same four groups: "acceptance hydro should plan higher"; "acceptance satisfied with the balance"; "acceptance don't like, but necessary" and "no acceptance cost impact too high".

When broken down into these subgroups, some striking differences emerge:

- Residents who are most strongly accepting of the plan are most likely to answer "better service most important" (50%). It is important to note however, that this group consists of only 6 customers.
- For those who accept and are "satisfied with the balance", the most important reason is that they see the cost as reasonable (40%). Other key reasons include the "better service" (17%), "future infrastructure crisis" (13%) and "necessary sacrifice" (10%).
- Those who give reluctant acceptance they don't like it, but feel it is necessary are most likely to see it as a necessary sacrifice (17%), many are worried the cost is high (13%), while some others are motivated by "future infrastructure crisis" (10%) and "better service" (10%).
- Among those against the proposed increase, about half (48%) state "cost too much" and after that the main reasons are "concerns about efficiency" (12%) and "concerns about non-capital expenses" (12%).

Figure 4.15 GS – Opinion on Proposed Rate Increase

And why do you say that? (Rate increase for local distribution system)
General Service Customers

ACCEPTANCE – HYDRO SHOULD PLAN HIGHER	%GS
Better service most important	50%
Cost increase reasonable	17%
Necessary sacrifice	17%
Other	17%

N=6

ACCEPTANCE – SATISFIED WITH BALANCE	%GS
Cost increase reasonable	40%
Better service most important	17%
Future infrastructure crisis	13%
Necessary sacrifice	10%
Refused	10%
Good for business	3%
Other	3%
Don't Know	3%

N=30

ACCEPTANCE – DON'T LIKE, BUT NECESSARY	%GS
Necessary sacrifice	17%
Cost too much	13%
Future infrastructure crisis	10%
Better service most important	10%
Efficiency	7%
Cost increase reasonable	7%
Someone else should pay the costs	5%
Concerns about non-capital expenses	5%
Refused	5%
Good for business	3%
Other	10%
Don't Know	8%

N=60

NO ACCEPTANCE – IMPACT TOO HIGH	%GS
Cost too much	48%
Efficiency	12%
Concerns about non-capital expenses	12%
Someone else should pay the costs	10%
Better service most important	2%
Refused	2%
Necessary sacrifice	1%
Other	6%
Don't Know	6%

N=82

Survey Instruments

Residential Survey Instrument 1

Section A: Introduction

Hello, my name is _____ and I'm calling from Innovative Research Group on behalf of Toronto Hydro, your local utility for electricity. Innovative Research Group is a national public opinion research firm. We have been commissioned by Toronto Hydro to help them better understand the needs and preferences of customers who are responsible for paying their household's electricity bill.

Toronto Hydro – which distributes electricity to customers in the Toronto area – is in the process of developing its 5 year grid investment plan and wants to hear from their customers to help inform this plan.

A1. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1 [continue]
No – NOT PRIMARY BILL PAYER	2 [go to TRANSFER]
No – BAD TIME	3 ARRANGE CALLBACK
No – HARD REFUSAL	4 [Terminate]

MONIT

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS 1 TO CONTINUE	1

A2. Have I reached you at your home phone number?

INTERVIEWER NOTE; IF "NO" ASK: May I speak to someone who does live there?

Yes [SPEAKING, CONTINUE]	1 [continue to A3]
YES [TRANSFERRED, GO BACK TO INTRODUCTION)	2 [back to INTRO]
No [NOT AVAILABLE – (ARRANGE CALLBACK)	3 [ARRANGE CALLBACK]
Refused – LOG (THANK AND TERMINATE)	9 [Terminate]

A3. Are you the person primarily responsible for paying the electricity bill in your household?

Yes	1 [continue to A4]
No	2 [go to TRANSFER]
Don't know (DNR)	98 [Terminate]

TRANSFER

Can I speak with the person in your household who usually pays the electricity bill?

Yes	1 [BACK TO INTRO]
No – NOT AVAILABLE/BAD TIME – (ARRANGE CALLBACK)	2 [ARRANGE CALLBACK]
No – HARD REFUSAL	3 [Terminate]
Don't know (DNR)	98 [Terminate]

A4. Can you confirm that your household receives an electricity bill from Toronto Hydro?

Yes	1 [continue]
No	2 [Terminate]
Don't know (DNR)	98 [Terminate]

GENDER Note gender by observation:

Male	1
Female	2

Section B: General Satisfaction

B5. PREAMBLE

To start, I'd like to ask you a few questions about the electricity system…

As you may know, Ontario's electricity system has three key components: generation, transmission and distribution.

- Generating stations convert various forms of energy into electric power;
- Transmission lines connect the power produced at generating stations to where it is needed across the province; and
- Distribution lines carry electricity to the homes and businesses in our communities.

Today we're going to talk about your local distribution system which is maintained and operated by Toronto Hydro.

How familiar are you with the local electricity distribution system? Would you say…[READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (DNR)	98
Refused (DNR)	99

B6. Generally speaking, how satisfied are you with the job Toronto Hydro is doing running your local distribution system? Would you say…[READ LIST]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (DNR)	98
Refused (DNR)	99

B7. Is there anything in particular Toronto Hydro can do to improve their service to you? [OPEN]

Don't know (DNR)	98
Refused (DNR)	99

Section C: Bill Knowledge

I'd now like to talk with you about your electricity bill …

C8. While some customers pay more and other pay less, the average residential customer pays about $132 a month for electricity of which $33 or approximately 25% goes to Toronto Hydro. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to Toronto Hydro? Would you say…[READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar	4
Don't know (DNR)	98
Refused (DNR)	99

Section D: System Reliability

D9. This past year Toronto Hydro customer experienced unusually extreme weather – flooding last July and an ice storm in December. These major weather events caused power outages across Toronto Hydro's service area.

Did either of these storms cause a power outage at your home?

INTERVIEWER NOTE: Make sure respondents specify which storm affected their power.

Yes – flooding	1
Yes – the ice storm	2
Yes – both storms	3
No – neither weather events affected my power service	4
Don't know (DNR)	98
Refused (DNR)	99

[Ask all respondents]

D10. Not including power outages caused by these extreme weather events, did you have any other power outages in the last 12 months?

Yes	1
No	2
Don't know (DNR)	98
Refused (DNR)	99

[Ask all respondents]

D11. Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. The more reliable the system, the more expensive the system is to build and maintain.

With that said – not including outages caused by extreme weather – the average Toronto Hydro customer experiences between one and two power outages per year.

In your view, how do you think Toronto Hydro should address the number of customer power outages? Would you say…[READ LIST]

[Rotate response code 1 and 3]

Spend what is needed to reduce the number of power outages	1
Spend what is needed to maintain the current level of outages	2
Accept more power outages in order to keep customer costs down	3
Don't Know (DNR)	98
Refused (DNR)	99

D12. Again, not including outages caused by extreme weather, the average Toronto Hydro customer is without power for one and a half hours per year.

In your view, how do you think Toronto Hydro should address the length of time customers are without power? Would you say…[READ LIST]

[Rotate response code 1 and 3]

Spend what is needed to reduce the length of power outages	1
Spend what is needed to maintain the current length of power outages	2
Accept longer power outages in order to keep customer costs down	3
Don't Know (DNR)	98
Refused (DNR)	99

Section E: System Challenges & Priorities

E13. As you may be aware, much of your local electricity system is aging and needs to be replaced in the near future. The time lost to power service interruptions caused by aging equipment has been growing steadily over the past decade.

According to Toronto Hydro's engineers, almost 60% of Toronto's electricity distribution infrastructure needs to be rebuilt over the next two decades. The price of these upgrades is approximately $5.6 billion overall.
As part of its 5 year plan, Toronto Hydro is proposing to continue its significant annual infrastructure renewal investment program. Although this plan will allow Toronto Hydro to make necessary investments, it will have an impact on customer bills.

Throughout Toronto Hydro's consultation process, customers have made a number of statements about this proposed increased investment. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]
Some customers have said…

> Toronto Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years. 1

Others have said…

> Toronto Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages. 2

Don't know (DNR) 98
Refused (DNR) 99

E14. Other Toronto Hydro customers have made a number of statements about aging infrastructure and future investments required to improve the reliability of the electricity system. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said…

> In these tough economic times, investments in new technologies are more of a luxury than a necessity and will cost customers more than they are willing to pay. 1

Others have said…

> Investments in new technology will increase system reliability, make our local distribution system more efficient, and save us money in the long run. 2

Don't know (DNR) 98
Refused (DNR) 99

E15. Toronto Hydro is not just the local electricity distribution system itself, but a company that operates the system. As a company, Toronto Hydro needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information.

Again, customers have made number of statements about this sort of investment. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said…

Toronto Hydro should find ways to make do with the buildings, equipment and IT systems it already has.	1

Others have said…

While Toronto Hydro should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.	2
Don't know (DNR)	98
Refused (DNR)	99

Section F: Reaction to Customer Consultation Input

The following statements have been made by customers throughout Toronto Hydro's consultation process.

For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

Strongly agree	1
Somewhat agree	2
Neither agree nor disagree (DNR)	3
Somewhat disagree	4
Strongly disagree	5
Don't Know (DNR)	98
Refused (DNR)	99

RANDOMIZE QUESTIONS

F16. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

F17. I'm willing to pay a bit more for my electricity if it means better service reliability.

F18. I can personally afford to pay more for electricity, but I am worried about the impact this will have on others.

F19. We need to modernize the local electricity system so consumers can have greater control over their electricity usage.

F20. We need to invest in new infrastructure and technology to minimize the number and duration of power service interruptions.

F21. We should invest in our electricity system infrastructure <u>now</u> or we will end up paying more the longer we delay our system renewal.

F22. The electricity sector is so complicated and confusing, we just have to trust that the experts will find the right balance in keeping cost down while making the right investments.

F23. A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly.

F24. When it comes to reducing power outages and improving reliability, the first priority should be business customers, then residential customers.

F25. Although waiting until electric equipment breaks down is a good way to get full value out of Toronto Hydro's assets, an important city like Toronto cannot afford the associated service interruptions and should have a higher standard of system reliability.

F26. I think Toronto Hydro should do more to help customers find ways to reduce their electricity consumption and costs.

F27. Toronto Hydro should have charged its customers more over the past decade to create a reserve fund that could have helped pay to replace the system's aging electrical infrastructure.

F28. Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local grid for future generations.

END BATTERY

Section G: Overall Assessment of Plan

G29. PREAMBLE

To maintain the reliability of the local electricity system, Toronto Hydro's proposed 5 year plan will cost an estimated $500 million. This includes…

- 54% to replace aging infrastructure;
- 19% to maintain metering and connect new customers to the electricity system;
- 13% to invest in tools, computers and software systems, vehicles and facilities needed to manage the electricity system;
- 8% to expand system capacity to accommodate future growth; and
- 6% for new technologies to make the system more efficient, reliable and safe.

To fund this plan, Toronto Hydro is proposing the average residential customers' rate increase by $2.90 on the distribution portion of their bill for the next five years. So, by 2019, the average residential household will be paying an estimated $14.50 more per month on the distribution portion of its electricity bill.

G30. Looking at the cost of the Toronto Hydro plan and outcomes it is expected to achieve, which point of view is closest to your own? Would you say [READ LIST]…?
Rotate response code order: "4 to 1" vs. "1 to 4"

Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more	1
I am satisfied with the balance between outcomes and the proposed rate increase	2
I don't like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard	3
I think the bill impact is too high and Toronto Hydro needs to scale back its plans	4
Not sure (DNR)	98
Refused (DNR)	99

Ask only if G30 = 1, 2, 3 or 4

G31. And why do you say that? [OPEN]

Don't know (DNR)	98
Refused (DNR)	99

Section H: Demographics

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

H32. In which year were you born? [Enter YEAR]

INTERVIEWER NOTE if REFUSED, ask "AGE".

AGE: Can you tell me what age category do you fall into? [READ LIST]

Less than 18	0
18 to 24	1
25 to 34	2
35 to 44	3
45 to 54	4
55 to 64	5
65 years or older	6
Refused (DNR)	99

H33. Do you own or rent your home?

Own	1
Rent	2
Refused (DNR)	99

H34. How would you describe your primary residence? Would you say you live in … [READ LIST]

A fully detached home;	1
A semi-detached home;	2
An apartment or condo building less than 5 stories; or	3
An apartment or condo building 5 stories or higher?	4
Refused (DNR)	99

H35. Counting yourself, how many people live in your household?

1 person	1 SKIP TO END
Enter number of people	2 to 7
8 or more	8
Refused (DNR)	99 SKIP TO END

Ask only if H35 = 2 thru 8

H36. And how many of them are under 18?

None	0
Enter number of children	1 to 7
8 or more	8
Refused (DNR)	99

These are all the questions we have for you today. Thank you very much for taking the time to complete this survey.

General Service Survey Instrument 1

Section A: Introduction

Hello, my name is _____ and I'm calling from Innovative Research Group on behalf of Toronto Hydro, your local utility for electricity.

A1 QUAL PREAMBLE:

Innovative Research Group is a national public opinion research firm. We have been commissioned by Toronto Hydro to help them better understand the needs and preferences of their customers.

Toronto Hydro – which distributes electricity to customers in the Toronto area – is in the process of developing its 5 year grid investment plan and wants to hear from their customers to help inform this plan.

A1. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1	[continue]
No – NOT PRIMARY BILL PAYER	2	[go to TRANSFER]
No – BAD TIME	3	ARRANGE CALLBACK
No – HARD REFUSAL	4	[Terminate]

MONIT

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS 1 TO CONTINUE	1

A2. Just to confirm, does your organization receive an electricity bill from Toronto Hydro?

YES	1	[continue]
NO	2	[Terminate]
DK (volunteered)	98	[Terminate]

A3. As part of your job, are you in charge of <u>managing</u> or <u>overseeing</u> your organization's electricity bill?

Yes	1	[Continue to A4]
No	2	CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S ELECTRICITY BILL? [Return to NEW]
DK	3	CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S ELECTRICITY BILL? [Return to NEW]

A4. Do you make OR oversee decisions about electricity management for your organization at a single facility, multiple facilities across Toronto OR multiple facilities in and outside Toronto? [If prompt required, read list]

Only at the facility I work at	1
All operations in Ontario	2
Operations in Ontario and outside Ontario	3
Don't know (DNR)	98
Refused (DNR)	99

A5. Thinking about the areas of your organization that you manage, how much would you estimate is spent <u>every month</u> on electricity provided by Toronto Hydro? Would you say…[READ LIST]

Less than $500	1
$500 to less than $1,000	2
$1,000 to less than $2,000	3
$2,000 to less than $5,000	4
$5,000 to less than $10,000	5
$10,000 to less than $25,000	6
$25,000 or more	7
Don't know (DNR)	98
Refused (DNR)	99

A6. Which of the following best describes the sector in which your organization operates?

MASH (Municipalities, Academic, Schools, Hospitals	1
Multi residential	2
Commercial	3
Manufacturing/Industrial	4
Data Centre	5
Hospitality	6
Restaurant/Tavern	7
Retail	8
Warehouse	9
Other	88
Don't know (DNR)	98
Refused (DNR)	99

Section B: General Satisfaction

B7. PREAMBLE

To start, I'd like to ask you a few questions about the electricity system…

As you may know, Ontario's electricity system has three key components: generation, transmission and distribution.

- Generating stations convert various forms of energy into electric power;
- Transmission lines connect the power produced at generating stations to where it is needed across the province; and
- Distribution lines carry electricity to the homes and businesses in local communities.
-

Today we're going to talk about your local distribution system which is maintained and operated by Toronto Hydro.

How familiar are you with the local electricity distribution system? Would you say…[READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (DNR)	98
Refused (DNR)	99

B8. Generally speaking, how satisfied are you with the job Toronto Hydro is doing running your local distribution system? Would you say…[READ LIST]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (DNR)	98
Refused (DNR)	99

B9. Is there anything in particular Toronto Hydro can do to improve their service to your organization? [OPEN]

Don't know (DNR)	98
Refused (DNR)	99

Section C: Bill Knowledge and Impact

I'd now like to talk with you about your electricity bill …

C10. While some customers pay more and other pay less, the average small and medium sized business pays about $330 for electricity of which $80 or approximately 25% goes to Toronto Hydro.. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to Toronto Hydro? Would you say…[READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar	4
Don't know (DNR)	98
Refused (DNR)	99

Section D: System Reliability

D11. This past year Toronto Hydro customer experienced unusually extreme weather – flooding last July and an ice storm in December. These major weather events caused power outages across Toronto Hydro's service area.

Did either of these storms cause a power outage at your organization?

INTERVIEWER NOTE: Make sure respondents specify which storm affected their power.

Yes – flooding	1
Yes – the ice storm	2
Yes – both storms	3
No – neither weather events affected my power service	4
Don't know (DNR)	98
Refused (DNR)	99

[Ask all respondents]

D12. Not including power outages caused by these major weather events, did your organization experience any other power outages in the last 12 months?

Yes	1
No	2
Don't know (DNR)	98
Refused (DNR)	99

D13. Thinking back to the most recent power outage – which was caused by something other than last year's floods or ice storm – how did it affect your organization in terms of cost?

Would you say the most recent power outage…
[Rotate response codes 1 and 3]

Had a significant cost to my business	1
A minor cost to my business	2
No cost to my business just a bit of inconvenience	3
Don't know (DNR)	98
Refused (DNR)	99

[Ask all respondents]

D14. Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said – not including outages caused by extreme weather – the average Toronto Hydro customer experiences between one and two power outages per year.

In your view, how do you think Toronto Hydro should address the number of customer power outages? Would you say…[READ LIST]

[Rotate response code 1 and 3]

Spend what is needed to reduce the number of power outages	1
Spend what is needed to maintain the current level of outages	2
Accept more power outages in order to keep customer costs from rising	3
Don't Know (DNR)	98
Refused (DNR)	99

D15. Again, not including outages caused by extreme weather, the average Toronto Hydro customer is without power for one and a half hours per year.

In your view, how do you think Toronto Hydro should address the length of time customers are without power? Would you say…[READ LIST]

[Rotate response code 1 and 3]

Spend what is needed to reduce the length of power outages	1
Spend what is needed to maintain the current length of power outages	2
Accept longer power outages in order to help keep customer costs from rising	3
Don't Know (DNR)	98
Refused (DNR)	99

E16. As you may be aware, much of your local electricity system is aging and needs to be replaced in the near future. The time lost to power service interruptions caused by aging equipment has been growing steadily over the past decade.

According to Toronto Hydro's engineers, almost 60% of Toronto's electricity distribution infrastructure needs to be rebuilt over the next two decades. The price of these upgrades is approximately $5.6 billion overall.

As part of its 5 year plan, Toronto Hydro is proposing to continue its significant annual infrastructure renewal investment program. Although this plan will allow Toronto Hydro to make necessary investments, it will have an impact on customer bills.

Throughout Toronto Hydro's consultation process, customers have made a number of statements about this proposed increased investment. Which of the following statements best represents your point of view?

[Read and Rotate statements 1 and 2]
Some customers have said…

Toronto Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years. 1

Others have said…

Toronto Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase; even if that means more or longer power outages. 2

Don't know (DNR) 98
Refused (DNR) 99

E17. Other Toronto Hydro customers have made a number of statements about aging infrastructure and future investments required to improve the reliability of the electricity system. Which of the following statements best represents your point of view?

[Read and Rotate statements 1 and 2]

Some customers have said…

In these tough economic times, investments in new technologies are more of a luxury than a necessity and will cost customers more than they are willing to pay. 1

Others have said…

Investments in new technology will increase system reliability, make our local distribution system more efficient, and save us money in the long run. 2

Don't know (DNR) 98
Refused (DNR) 99

E18. Toronto Hydro is not just the local electricity distribution system itself, but a company that operates the system. As a company, Toronto Hydro needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information.

Again, customers have made number of statements about this sort of investment. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said…

Toronto Hydro should find ways to make do with the buildings, equipment and IT systems it already has.	1

Others have said…

While Toronto Hydro should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.	2
Don't know (DNR)	98
Refused (DNR)	99

Section F: Reaction to Customer Consultation Input

The following statements have been made by customers throughout Toronto Hydro's consultation process.

For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

Strongly agree	1
Somewhat agree	2
Neither agree nor disagree (DNR)	3
Somewhat disagree	4
Strongly disagree	5
Don't Know (DNR)	98
Refused (DNR)	99

RANDOMIZE QUESTIONS

F19. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important priorities and investments are put off.

F20. My organization would be willing to pay a bit more for electricity if it means better service reliability.

F21. My organization can afford to pay more for electricity, but I am worried about the impact this will have on some of my suppliers and customers.

F22. We need to modernize the local electricity system so consumers can have greater control over their electricity usage.

F23. We need to invest in new infrastructure and technology to minimize the number and duration of power service interruptions.

F24. We should invest in our electricity system infrastructure <u>now</u> or we will end up paying more the longer we delay our system renewal.

F25. The electricity sector is so complicated and confusing, we just have to trust that the experts will find the right balance in keeping cost down while making the right investments.

F26. Toronto is the country's economic engine and as such should strive to have much higher levels of system reliability than other Canadian cities.

F27. When it comes to reducing power outages and improving reliability, the first priority should be business customers, then residential customers.

F28. Although waiting until electric equipment breaks down is a good way to get full value out of Toronto Hydro's assets, an important city like Toronto cannot afford the associated service interruptions and should have a higher standard of system reliability.

F29. I think Toronto Hydro should do more to help business customers find ways to reduce their electricity consumption and costs.

F30. Toronto Hydro should have charged its customers more over the past decade to create a reserve fund that could have helped pay to replace the system's aging electrical infrastructure.

F31. Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local grid for future generations.

END BATTERY

Section G: Overall Assessment of Plan

G32. PREAMBLE

To maintain the reliability of the local electricity system, Toronto Hydro's proposed 5 year plan will cost an estimated $500 million. This includes…

- 54% to replace aging infrastructure;
- 19% to maintain metering and connect new customers to the electricity system;
- 13% to invest in tools, computers and software systems, vehicles and facilities needed to manage the electricity system;
- 8% to expand system capacity to accommodate future growth; and
- 6% for new technologies to make the system more efficient, reliable and safe.
-

To help pay for this plan, Toronto Hydro is proposing the average small and medium sized business customers' rate increase by $5.75 on the distribution portion of their bill for the next five years. So, by 2019, the average small and medium sized business will be paying an estimated $28.75 more per month on the distribution portion of its electricity bill.

G33. Looking at the cost of the Toronto Hydro plan and outcomes it is expected to achieve, which point of view is closest to your own? Would you say [READ LIST]…?
Rotate response code order: "4 to 1" vs. "1 to 4"

Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more	1
I am satisfied with the balance between outcomes and the proposed rate increase	2
I don't like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard	3
I think the bill impact is too high and Toronto Hydro needs to scale back its plans	4
Not sure (DNR)	98
Refused (DNR)	99

Ask only if G33 = 1, 2, 3 or 4

G34. And why do you say that? [OPEN]

Don't know (DNR)	98
Refused (DNR)	99

Section H: Firmographics

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

H35. Which of the following best describes the hours of operation of your business? Would you say…[READ LIST]

We are open 24/7	1
We operate several shifts each day, but are not open 24/7	2
We operate during regular business hours only	3
We operate outside of regular business hours, but do not have shifts	4
Other (please specify):_____	88

H36. And, which of the following best describes when your business operates through the week? Would you say…[READ LIST]

We operate on weekdays only	1
We operate on weekdays and weekends	2
Other (please specify):_____	88

These are all the questions we have for you today. Thank you very much for taking the time to complete this survey.

1

1

1

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Have your say about Toronto Hydro s proposed grid renewal plan and its impact on your rates

Toronto Hydro-Electric System (Toronto Hydro) is in the midst of modernizing a distribution system that was largely built in the 1950s and 1960s. The pace at which this is accomplished will inevitably impact your electricity rates and service reliability. The purpose of this consultation is to gather your feedback on Toronto Hydro s proposed ve-year grid renewal and modernization plan for 2015 to 2019.

About This Consultation

This consultation focuses speci cally on what Toronto Hydro does: taking electricity from the provincial grid and distributing it to people and businesses in Toronto.

The electricity industry in Ontario is regulated by the Ontario Energy Board, which recently developed a new framework requiring local distribution companies to gather customer preferences on electricity investments. Your feedback will be presented to the regulator when Toronto Hydro les its rate application for 2015 to 2019. During the rate hearing process, Toronto Hydro will be held accountable for the way you were consulted and the ways in which the utility s plans respond to what you said.

Will you be expected to answer technical questions about the grid?

Toronto Hydro does not expect you to make electrical engineering decisions. The utility is asking you about the electricity issues that matter most to you, and if you feel Toronto Hydro s priorities for investing your electricity dollars are reasonable.

Toronto s distribution system is aging, the city is facing unprecedented growth in the downtown core, and a variety of innovative grid technologies are providing new opportunities for electricity management. This workbook is designed to give you enough background about these issues to develop an informed opinion.

The most important parts of this workbook are the survey questions. By completing them, you can ensure that Toronto Hydro considers your views as they relate to future investments in the distribution grid.

Where are the survey questions located?

Questions are located on pages:

« « « « « « « « « « «
«« « « « « « « « « « «

How much will Toronto Hydro s proposed grid renewal plan cost me?

About one quarter of your electricity bill currently goes to Toronto Hydro. That s about $33 per month for the average residential customer. Toronto Hydro s proposed grid renewal plan will add:

- « ,,. 4%) 0(5« $2.35 each year to an average residential customer s monthly bill for the period of 2015 to 2019,
- «3$% $«)1*0/0 «0 (%* .! /
approximately $11.75 per month by 2019 compared to 2014.

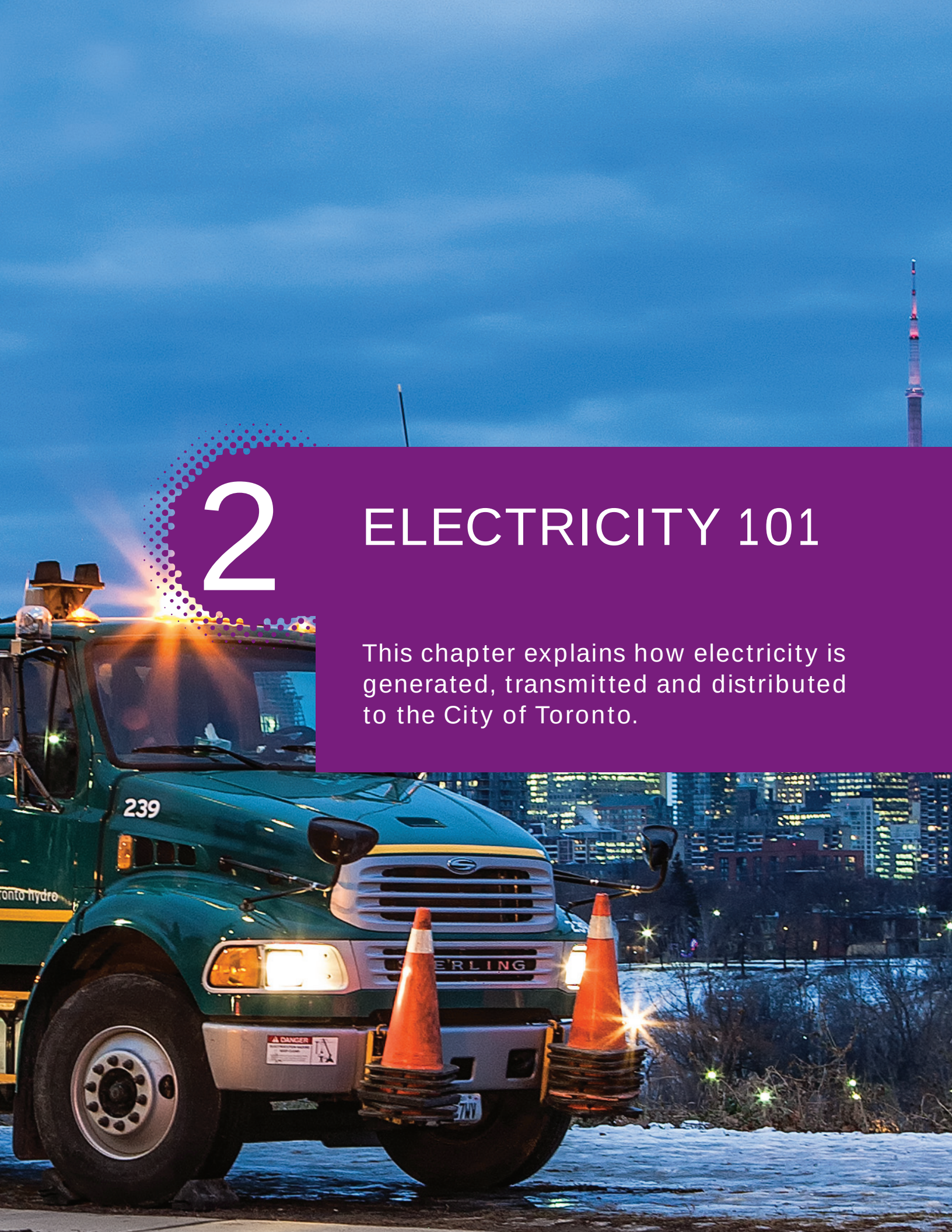
These bill impacts include capital investments and operating expenses. Toronto Hydro is planning to keep increases in operating expenses below in ation for the duration of the plan, which is why this consultation focusses solely on capital investments in the system.

How This Consultation is Being Managed

This public consultation process is being managed by a third-party research company. They will compile the results of all surveys and submit a report to Toronto Hydro. Your responses will be combined with others to protect your privacy.

You Can Participate in a Separate Conversation About Long-Term Energy Planning

Do we have enough electrical infrastructure to meet Toronto s needs? The Central Toronto Integrated Regional Resource Plan looks at where demand for electricity is growing and how this can be best managed over the next 25 years. Options considered include: conservation, local distributed generation, transmission and distribution infrastructure. You ll pay later for the choices being made today about your electricity system. Visit torontohydro.com/haveyoursay for more information.



2 ELECTRICITY 101

This chapter explains how electricity is generated, transmitted and distributed to the City of Toronto.

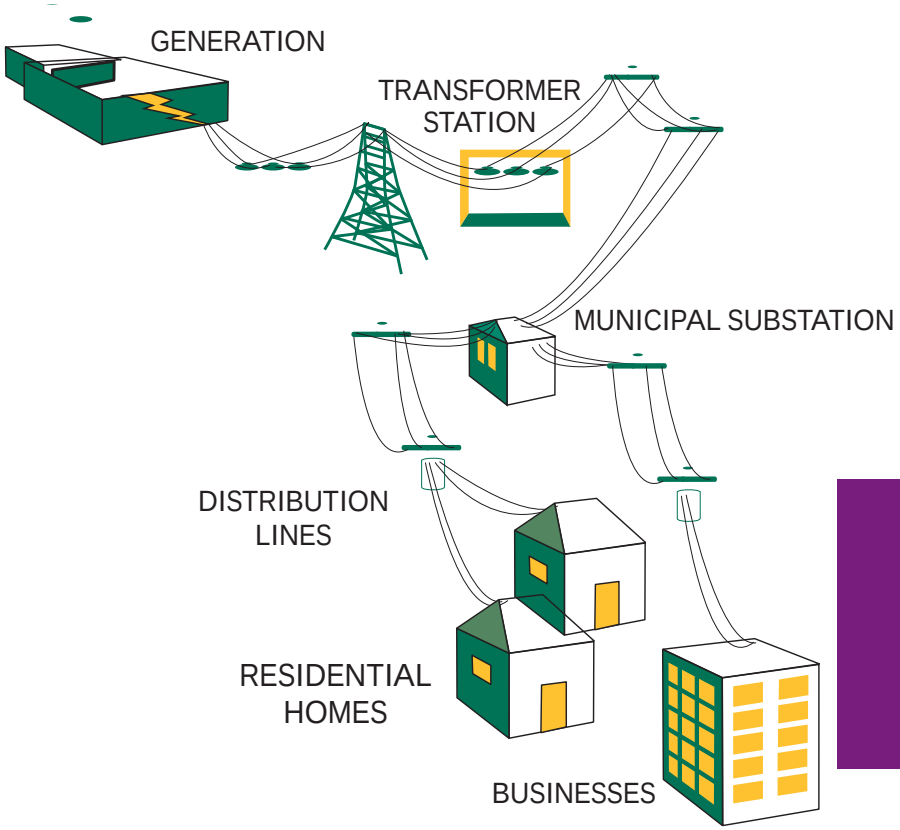
Understanding Toronto Hydro s Role in Ontario s Electricity System

There are three main components to all electricity systems: generation, transmission and distribution.

Where Electricity Comes From

In Ontario, 70 per cent of electricity is generated by Ontario Power Generation. This provincially-owned organization has generating stations across Ontario that produce electricity from hydroelectric, nuclear and fossil fuel sources.

Once electricity is generated, it must be delivered to urban and rural areas in need of power. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines*, owned mostly by Hydro One.



Toronto Hydro

Toronto Hydro is responsible for the last step of the journey: distributing electricity to customers in Toronto.

The City of Toronto

The City of Toronto is Toronto Hydro s sole owner and shareholder. The Ontario Energy Board allows Toronto Hydro to earn a speci ed annual return, part of which is used to pay an annual dividend to the shareholder. The City uses this dividend to fund city services like snow removal and garbage collection. Toronto Hydro reinvests the remaining portion of this amount back into the utility.

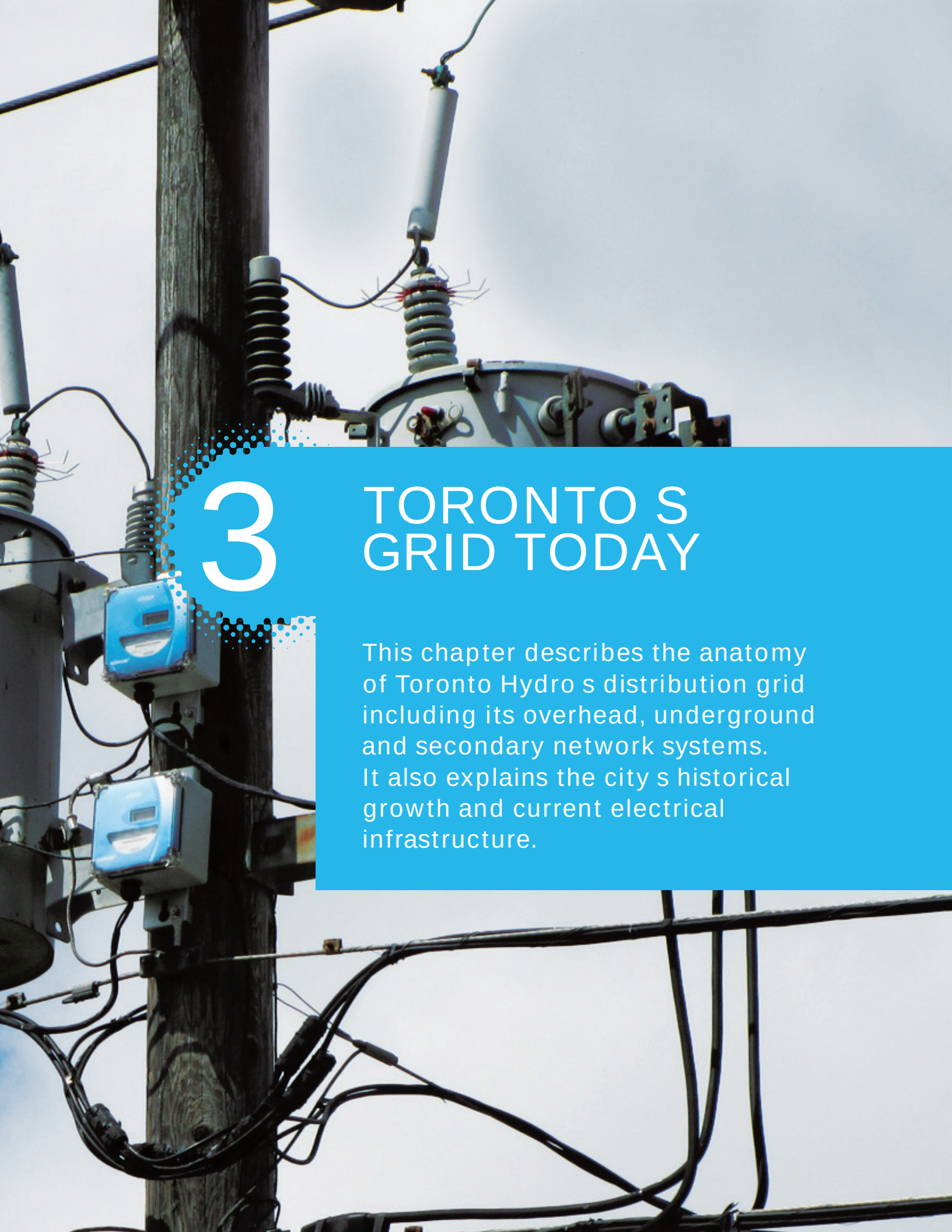
How are Electricity Rates Determined?

Toronto Hydro is funded by the distribution rates paid by its customers. Periodically, Toronto Hydro is required to le an application with the Ontario Energy Board to determine the funding available to operate and maintain the distribution system. Toronto Hydro must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity.

Who Protects Consumer Interests?

Toronto Hydro s evidence is assessed in an open and transparent public process known as a rate hearing. A number of public intervenors with electricity industry expertise submit their own evidence challenging Toronto Hydro s plans and assumptions. At the end of the process, the Ontario Energy Board weighs the evidence and decides on the rates Toronto Hydro can charge for distribution.

*Source: IESO. The Power System, www.ieso.ca



3 TORONTO S GRID TODAY

This chapter describes the anatomy of Toronto Hydro s distribution grid including its overhead, underground and secondary network systems. It also explains the city s historical growth and current electrical infrastructure.

The Nuts and Bolts of Toronto Hydro s Distribution Grid

Toronto s electricity grid is comprised of overhead, underground and secondary network systems. The mix is largely due to the utility s amalgamation. In 1998, Toronto Hydro merged with North York Hydro, Scarborough Hydro, East York Hydro, York Hydro, and Etobicoke Hydro. Each utility operated independent distribution systems, and as a result, the infrastructure varies from region to region. Toronto Hydro has been working to gradually standardize this equipment, which will help improve reliability and safety across the city, and make system operation more e cient.





A Look at Toronto Hydro s Growth



Toronto Hydro has been serving the city since 1911 and has experienced many changes over the years.

The rst electrically-powered trolley bus and electric tra c lights were introduced in the 1920s. Street lighting was introduced in the 1930s and was upgraded following World War II.

Between 1945 and 1955, the City s power consumption increased by 75 per cent thanks to the post-war baby boom and immigration. The dramatic growth created a need to expand the system. Toronto Hydro built 12 new municipal substations. Much of the equipment installed during this decade is still in operation today.

The 1970s saw dramatic skyline changes with the addition of the CN Tower, First Canadian Place, and the Royal Bank Plaza. As society started to become more environmentally conscious, Toronto Hydro introduced energy conservation programs and incentives to many of its customers.

In the early 1980s, Toronto Hydro introduced a computerized control system to remotely monitor the distribution system and respond more quickly to emergencies.

In 2006, facing the challenges described in the following chapters, Toronto Hydro embarked on the largest infrastructure renewal program in its history.

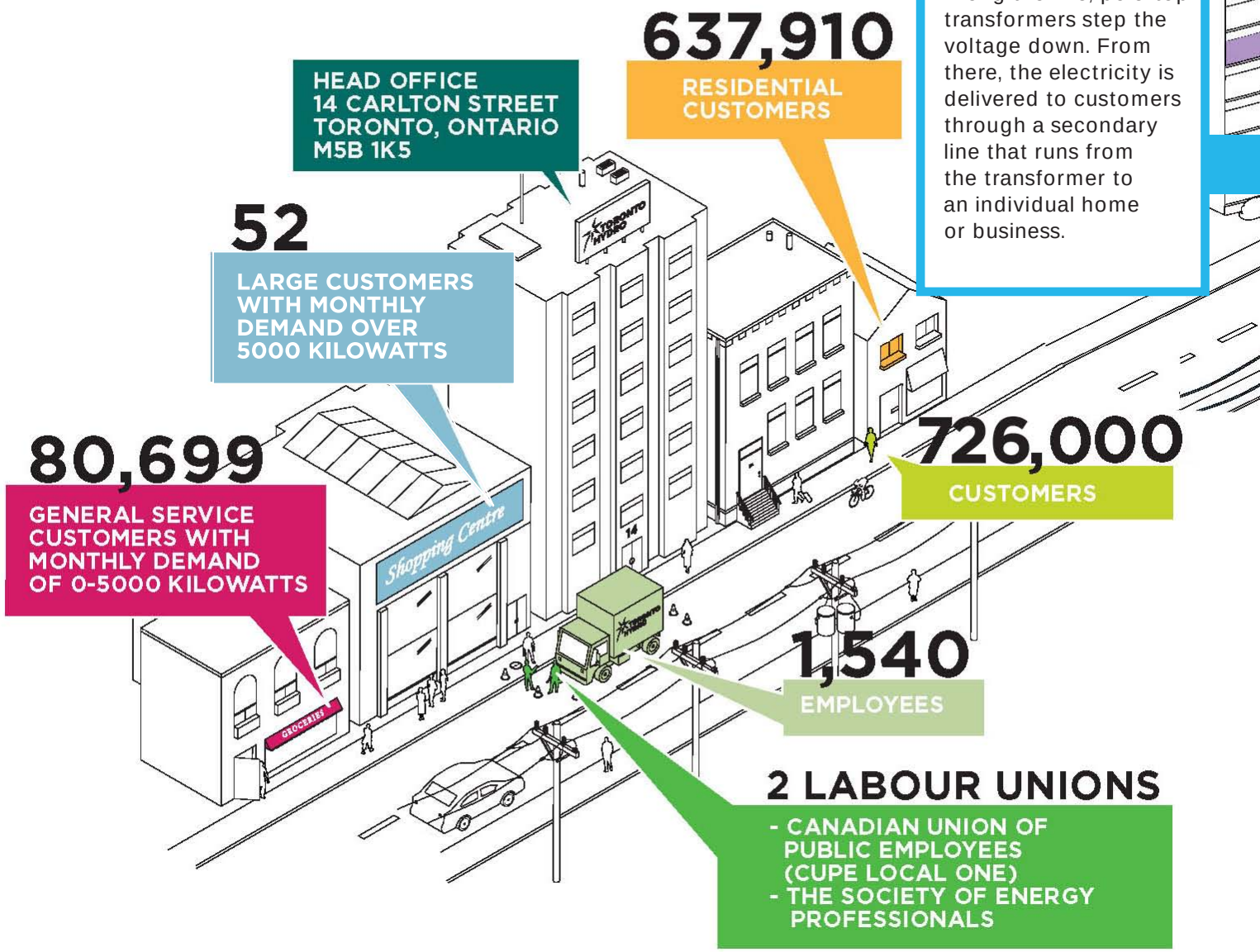
About Toronto Hydro

Toronto Hydro owns and operates $2.6 billion in capital assets and is the largest municipal electrical utility in Canada. It distributes about 19 per cent of Ontario s electricity demand.



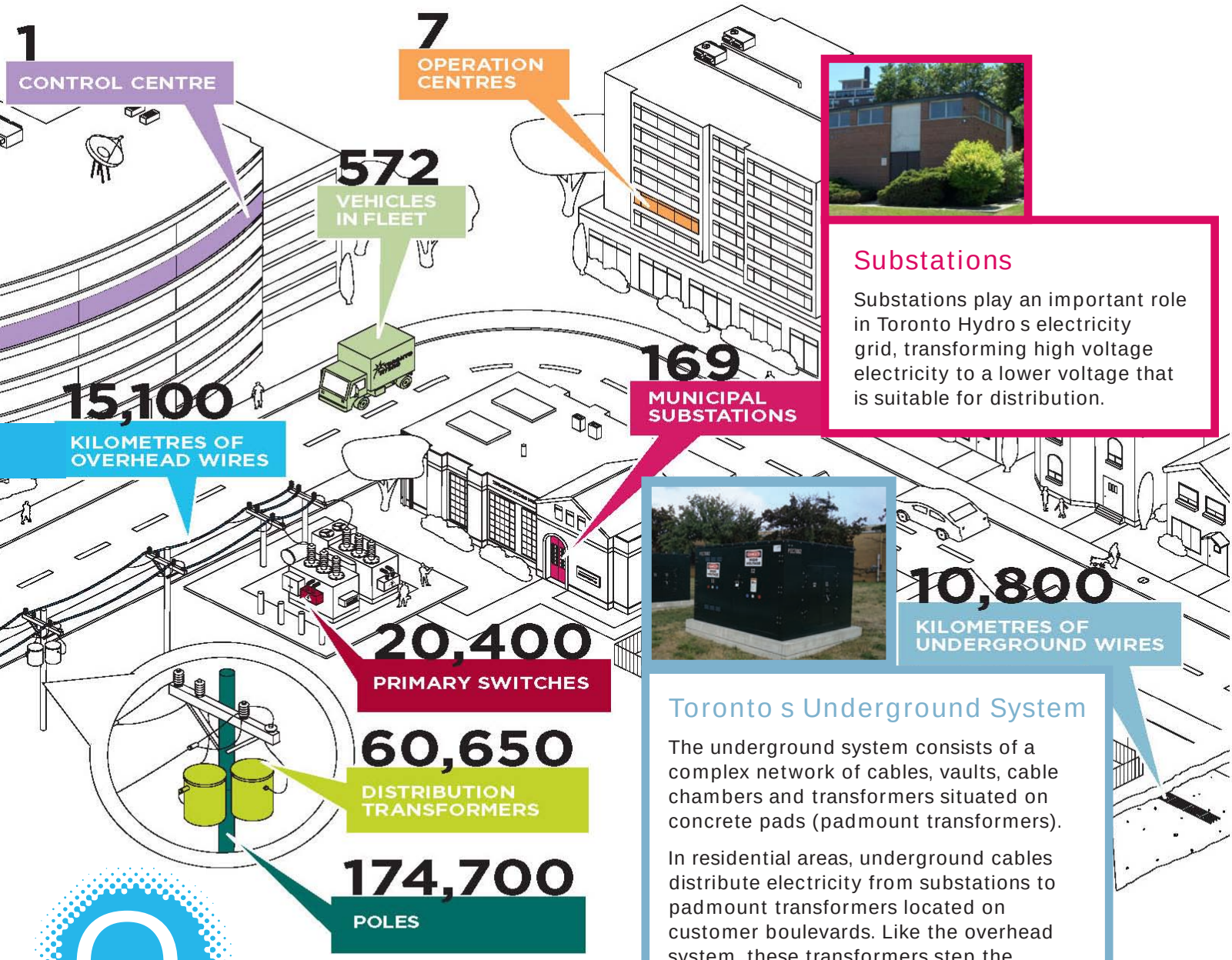
Toronto s Overhead System

The overhead system is made up of distribution lines that operate at either 4.16 kilovolts, 13.8 kilovolts or 27.6 kilovolts. These primary lines are strung across hydro poles. Along the line, pole-top transformers step the voltage down. From there, the electricity is delivered to customers through a secondary line that runs from the transformer to an individual home or business.



1. Given what you know and what you have read so far, how well do you feel you understand the important parts of the electricity system, how they work together and which services Toronto Hydro is responsible for?

   _____ Very well
   _____ Somewhat well
   _____ Not very well
   _____ I don t understand at all



Substations

Substations play an important role in Toronto Hydro s electricity grid, transforming high voltage electricity to a lower voltage that is suitable for distribution.

Toronto s Underground System

The underground system consists of a complex network of cables, vaults, cable chambers and transformers situated on concrete pads (padmount transformers).

In residential areas, underground cables distribute electricity from substations to padmount transformers located on customer boulevards. Like the overhead system, these transformers step the electricity down to a lower voltage, and current is delivered to customers through a secondary line. When distributing electricity to urban areas or larger customers, bigger vault transformers are used. Cable chambers are located throughout the underground system to provide crews with access to feeder cables.

2. How satis ed are you with the job Toronto Hydro is doing running your local distribution system?

____ Very satis ed
____ Somewhat satis ed
____ Somewhat dissatis ed
____ Very dissatis ed
____ Don t Know

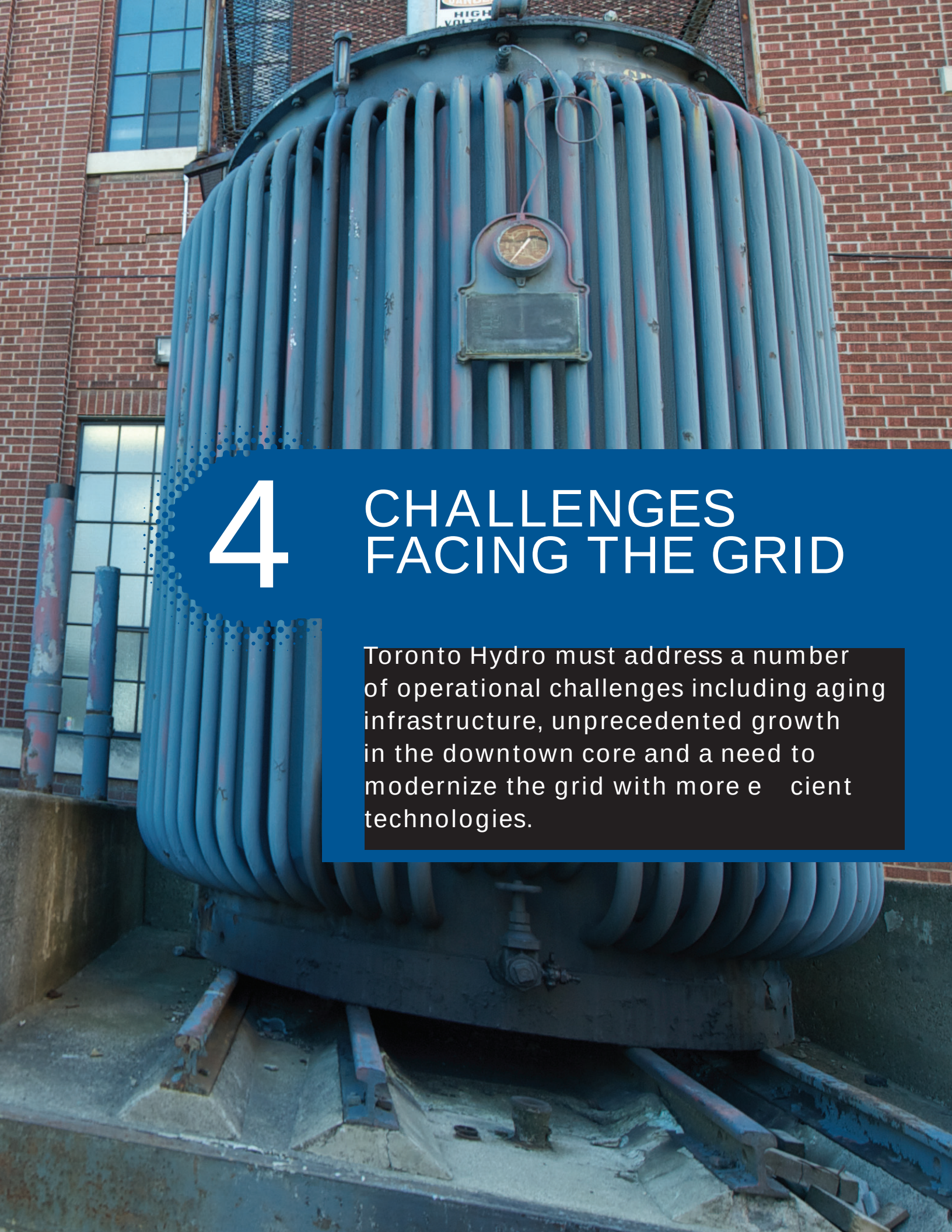
3. Is there anything in particular that Toronto Hydro can do to improve its service to you?

_____

_____

_____

_____



4 CHALLENGES FACING THE GRID

Toronto Hydro must address a number of operational challenges including aging infrastructure, unprecedented growth in the downtown core and a need to modernize the grid with more e cient technologies.

Toronto s Renaissance: Accommodating a City Under Construction

Recently crowned the fourth largest city by population in North America and a continued leader in high rise development, Toronto is a city under construction. Toronto Hydro plays an important role in this growth.

Toronto Hydro is required by law to:

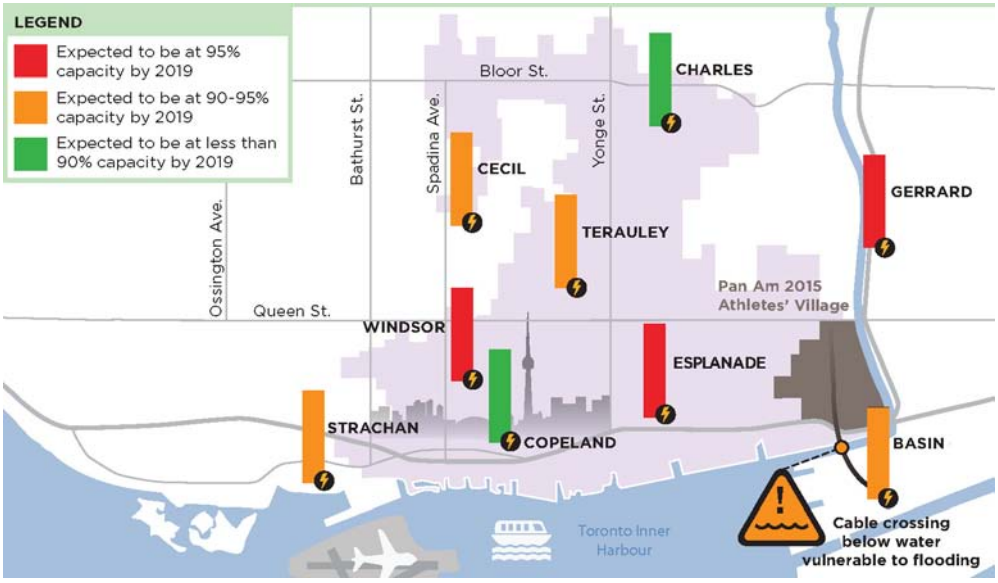
« *+! 0*B«1/0)!/00$#%
« 1. 0(5)0!«1/0)!(! 0.% %05«*/1),0%*
«4, *)+ 2!%/0.% 10%*!1%,)!0(«)+ 0!!0 %*&! 0/%*%0% 0!«50$!%05«
of Toronto, TTC, Metrolinx and GO Transit

The rate of Toronto s growth is making it increasingly di cult to ful ll these responsibilities while maintaining system performance:

« $!!.)!5/ . ,!/1* !«*/0.1 0%*0$ *B«%05$% #* 4% %05
« $!!.)!0$ *&!*0% ((+ 0%*&! 0/!(0!!*/0.1 0%*«50$!*

Growth from high-rise construction is putting immediate and longer-term pressures on the existing grid.

Downtown Stations are Overloaded



To help ensure the city s continued economic success and its ability to serve the growing population, Toronto Hydro is investing in expanding the capacity of its stations and feeders.

Under provincial legislation, there are several types of investments Toronto Hydro must make when the need presents itself. How reasonable do you feel it is to give each of these investments a priority over other investments (for example, replacing aging equipment)?

4. Connecting new customers such as new housing, condominiums or businesses. (Provincial regulations set connection fees which cover unusual costs).
   _____ Very reasonable _____ Somewhat reasonable
   _____ Not very reasonable _____ Not reasonable at all _____ Don t Know

5. Maintaining and upgrading customer meters to meet provincial standards.
   _____ Very reasonable _____ Somewhat reasonable
   _____ Not very reasonable _____ Not reasonable at all _____ Don t Know

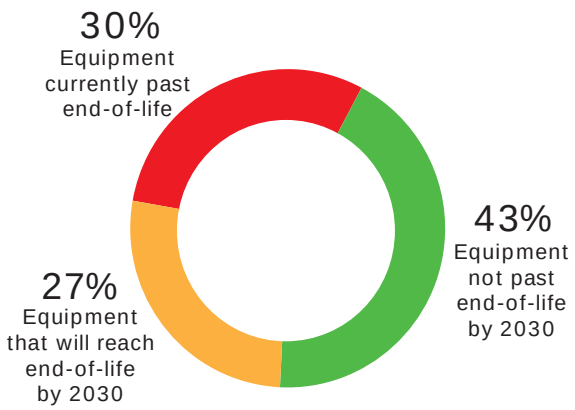
6. Moving existing electricity infrastructure such as poles and transformers to enable other projects such as street widening or new developments. (Provincial regulations set fees which cover unusual costs).
   _____ Very reasonable _____ Somewhat reasonable
   _____ Not very reasonable _____ Not reasonable at all _____ Don t Know

Aging Equipment: All Good Things Must Come to an End

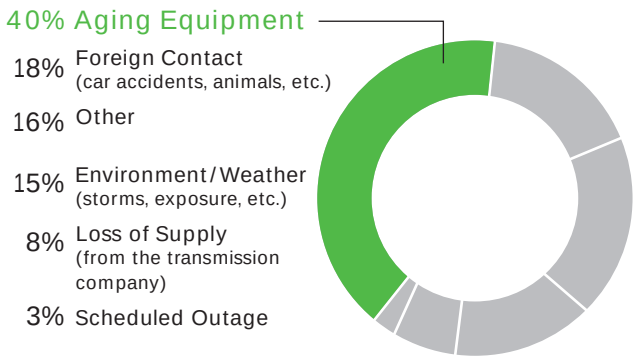
A large part of Toronto Hydro s distribution system was installed in the 1950s and 1960s. This infrastructure has served the city well beyond its expected lifespan. But now the grid is at a point where renewal investments can no longer be deferred without a ecting service reliability.

Almost 60% of the city s distribution infrastructure needs to be rebuilt over the next two decades. The price of these upgrades is approximately $5.6 billion overall.

How Fast is the System Aging?



Aging Equipment is Responsible for Approximately 40% of Outages



About 30 per cent of our distribution equipment is past its end of life and an additional 30 per cent will reach this state over the next 20 years.

7. Thinking about the aging equipment in the grid, do you feel it s best to wait until the equipment breaks down to get full value from each piece of equipment, even if it means power outages, or do you feel the best approach is to replace the equipment before it breaks down to avoid power outages, even if it means not getting all the use possible from each piece of equipment?

____ Wait until break down ____ Replace before break down

A Look at Toronto Hydro s Service Reliability

Aging infrastructure is a major challenge to service reliability. Toronto Hydro is managing this through grid renewal and modernization.

Toronto Hydro uses two main measures to evaluate service reliability: frequency and duration.

Over the past decade, the average customer has experienced:

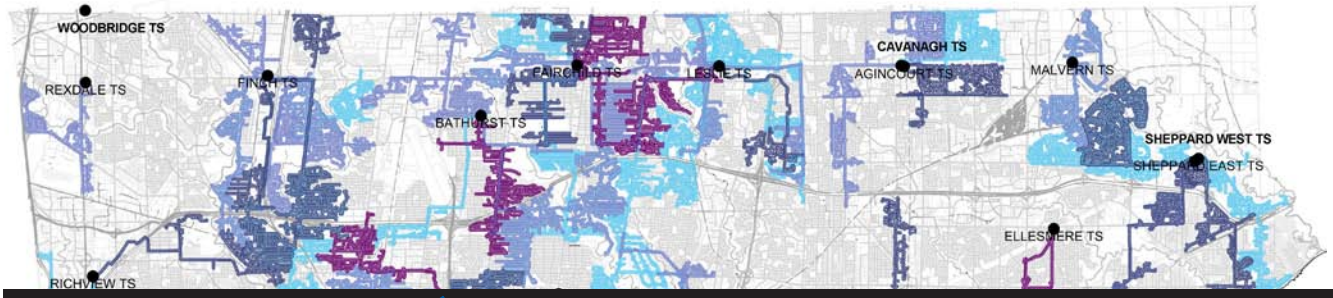
- 03 !« 1.4 and 2 outages per year.
- 03 !« 60 and 90 minutes without power per year.

While outage frequency and duration averages are trending downwards, actual customer experiences vary. Some customers on newer parts of the system may not experience any outages while others are experiencing as many as 20 outages per year.

The Least Reliable Equipment on the Block

Toronto Hydro pays special attention to circuits with exceptionally poor performance. Engineers maintain a list of circuits experiencing seven or more outages in a year, and addressing this list is a continuous e ort. The system is aging at such a rate that new poor performing circuits are added to the list almost as fast as Toronto Hydro can deal with existing problem circuits.

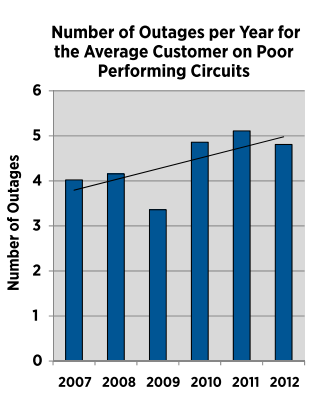
Where are Poor Performing Circuits Located?

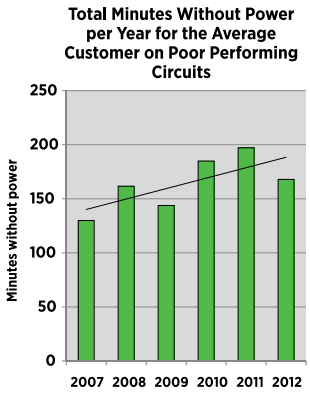


Customers Located in These Areas are Receiving Poor Service Reliability

Over the past decade, the average customer on a poor performing circuit has experienced:

- « ve outages per year (compared to the system average of two)
- «150 to 200 minutes without power per year (compared to the system average of 60 to 90 minutes for the year)





Without su cient investment in renewing and modernizing the distribution grid, Toronto Hydro expects service reliability of poor performing circuits to continue deteriorating.

8. Do you feel the current average number of electricity outages is acceptable or not acceptable?
   ____ Very acceptable ____ Somewhat acceptable
   ____ Not very acceptable ____ Not acceptable at all ____ Don t Know

9. Do you feel the current average amount of outage time is acceptable or not acceptable?
   ____ Very acceptable ____ Somewhat acceptable
   ____ Not very acceptable ____ Not acceptable at all ____ Don t Know

10. How many outages have you experienced over the past two years?
    ____ INSERT ACTUAL NUMBER

11. (IF 1 OR MORE OUTAGE) How long was the power out during your most recent power outage?
    ____ INSERT ACTUAL NUMBER

12. (IF 1 OR MORE OUTAGE) How did the power outage a ect you personally?

    _____
    _____
    _____
    _____
    _____
    _____

13. Is there a certain length of time at which the costs and consequences of an outage become more serious for you?

    _____
    _____
    _____
    _____
    _____
    _____

No system delivers perfectly reliable electricity. Generally, the more reliable the system, the more expensive the system is to build and maintain. Please answer the following two questions.

14. How many power service interruptions are reasonable in a year?
    ____ No outage is acceptable
    ____ One ____ Two ____ Three ____ Four ____ More than four

15. What is a reasonable duration for a service interruption?
    ____ No outage is acceptable
    ____ 30 minutes ____ 1 hour ____ 2 hours ____ 3 hours
    ____ 4 hours or more

Changing Weather Patterns





Climate change is raising the risk of severe weather events impacting the system more frequently in the future. Toronto has experienced several major storms over the last year-and-a-half alone:

- 0@$# Hurricane Sandy (October 2012), 65,000 customers were without power.
- $ torrential downpour on July 8, 2013, caused severe ooding in stations and the underground system. Approximately 300,000 customers were a ected about half of all customers and thousands experienced extended outages.
-) 0 ice storm in its history. Freezing rain caused massive destruction to trees and power lines, leading to widespread and extended outages. About 300,000 customers were impacted and some people were without power for as long as 12 days. Many customers spent their holidays in City of Toronto warming stations.

Planning for the weather

Toronto Hydro is studying the results of these unusual weather events to determine whether changes are needed to any of the utility s best practices. In the meantime, Toronto Hydro anticipates that a number of the planned capital investments for 2015 to 2019 will help improve system performance during major weather events. For example, replacing box construction circuits (explained on page 20) with taller, higher-voltage circuits will help reduce the impact of falling trees and branches in certain areas.

Why not move everything underground?

There are pros and cons to both overhead and underground circuits. Underground circuits were hit harder than overhead circuits in the summer ooding, while overhead circuits were hit harder in the ice storm. Underground circuits can cost many times more than simply replacing the existing overhead lines; the cost for moving all circuits underground would be in the range of $15 billion. Toronto Hydro must consider these options in light of the other capital needs discussed in this workbook and the need to keep increases in customer bills as low as possible.

16. Over the past year, Toronto has experienced two unusual weather events the ooding in July and the ice storm in December. Thinking back to the two major storm events of 2013, were you a ected by either or both of these events?

____ Yes the ooding in July
____ Yes the ice storm in December
____ Yes Both
____ No neither weather event a ected my electricity

17. Whether you were personally a ected or not, how satis ed are you with Toronto Hydro s management of these events?

____ Very satis ed
____ Somewhat satis ed
____ Somewhat dissatis ed
____ Very dissatis ed
____ Don t Know

18. Is there anything in particular that Toronto Hydro could have done to improve its service to you during these events?

Grid Modernization

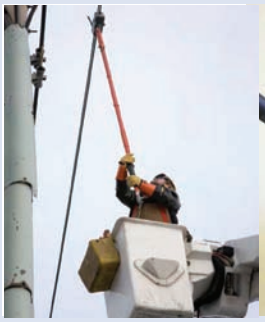
The pressures of economic growth and system aging are at the heart of Toronto Hydro s investment plan for 2015 and beyond. For the most part, responding to these pressures will involve rebuilding and expanding the system using tried and true distribution technology. At the same time, technological innovation in the industry has begun to change the way that utilities can manage the system and the way that customers can use the grid. The following section highlights some of the pressures and opportunities associated with the evolving technological landscape.

Here are some of the modern grid management technologies that Toronto Hydro is exploring:



Feeder Automation

« « (/ 0 +)0!3%0 $%0+«0! 0« « «
isolate power interruptions.
«(,/« !1 0$1) !1/0)!/«
a ected by an outage.
«%%ü *0(5%),. 2/0+ 0%*0%)* «
service reliability in a cost-e ective manner.





Power Line Monitors

« « +3!(%%/01. * /«%/ «
the causes.
«(,%*!/« . /0$0« 1/«
of interruptions to help prevent them
«. , (0%*0 +0%*/«
in real time.



Transformer Monitors

0! 0«2!(+ !0./1.)!/«0$0«
of power.
«(,« !% 0« %.. */)!/«
to assist with proactive maintenance and planning.



Energy Storage

« « 5 0+.%(%0%/« /!0+0+.« «
excess supply during o -peak hours.
« $0:5« *«, % (5(5!«5« «
system operators to address local capacity issues throughout the distribution system and to moderate peak power costs.

19. Modernizing the grid can allow Toronto Hydro to improve reliability. Investments such as automated switches may allow Toronto Hydro to minimize the number of people impacted by outages and to restore electricity to most customers in a matter of seconds. Given there are many other areas of needed investment, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for Toronto Hydro to invest now in modernizing the grid?

_____ Very important
_____ Somewhat important
_____ Not very important
_____ Not important at all
_____ Don t Know

Here are some of the new technologies that are changing the way that customers use the grid:



Electric Vehicles

allows Toronto Hydro to develop charging pro les for all vehicle models.

vehicles on the lifespan and performance of equipment and make proactive upgrades when necessary.



Making Room for Renewable Generation Projects

Solar power and energy-from-waste facilities are renewable forms of distributed generation that are growing in popularity and a ordability. Toronto Hydro is mandated to connect distributed generation as part of the province s Feed-in Tari program. Since 2012, Toronto Hydro has connected more than 375 distributed generation projects to the grid.



5 HOW WE RE MANAGING GRID PRESSURES

This chapter covers the work Toronto Hydro is doing to address grid challenges. It includes information about historical grid investments, ongoing capital projects and productivity improvements.

Working Hard to Improve Reliability

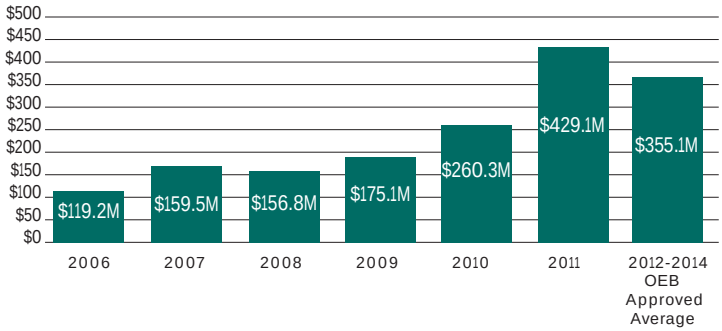
Since 2006, Toronto Hydro has invested approximately $2.5 billion in infrastructure renewal. This investment represents some of the largest construction programs in the utility s history, replacing approximately:

« «%(-0./ «+ « %*# «(%*/
« «(«(/
« «0. */!)!/

From 2006 to 2009, Toronto Hydro gradually increased its capital spending on poor performing feeders and underground cables that were negatively impacting reliability.

In 2010 and 2011, the utility increased spending to a level needed to execute a broader grid renewal and modernization program.

Toronto Hydro has increased capital spending



The following case studies provide a snapshot of major projects being executed across Toronto Hydro s distribution system. Feel free to read about whichever projects interest you.

What s Happening with the Overhead System?

Box Construction

« !/0+05,*2!$!« installed in the former City of Toronto.

CHALLENGES:

« (+/*0«%. 1%0/%0«%þ1(0« for crews to safely access equipment.

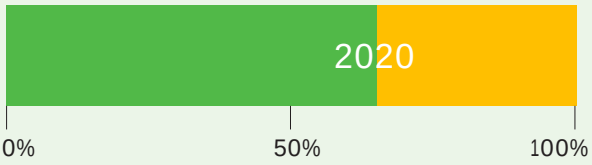
« 3*0 #(/0«3% /(*#/*« overhead feeders.

«(! 0.% (« , %05%/*0$%. *« « feeders making it di cult to accommodate the increasing number of large customers in the downtown core.

SOLUTION:

« +.+0+5 .+%/#1((5«+2!0%# +4« « construction to modern standards, which will help improve safety, reliability and exibility.

PROGRESS BY 2020:



PLAN FOR 2015-2019:

« $*0%(%05%/4% 0%#.+4%)0(5« 3 per cent of its budget to box construction conversion.

What s Happening with the Overhead System?



Rear Lot Feeders

« !/0+05,k*2!$!«+/0.1 0%+* «
installed in residential backyards during the 1950s and 1960s.

CHALLENGES:

« + 0%+*/%0«%1(0*+./+/0(5« «
to access and repair, especially during major storms.

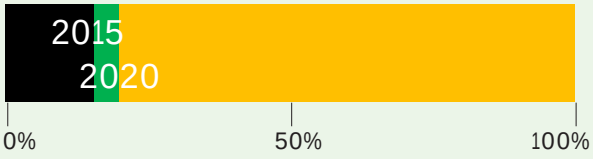
«10 %0/«#* «+%0%*%0 /4,! 0!« «
to fail at an increasing rate.

« :* !/% %(%05%/«,0!0% (/ 05%/«
for crews and the public.

SOLUTION:

« $10%(%05%/«+2!0%0$/!/«
to safer and more reliable underground streetside construction.

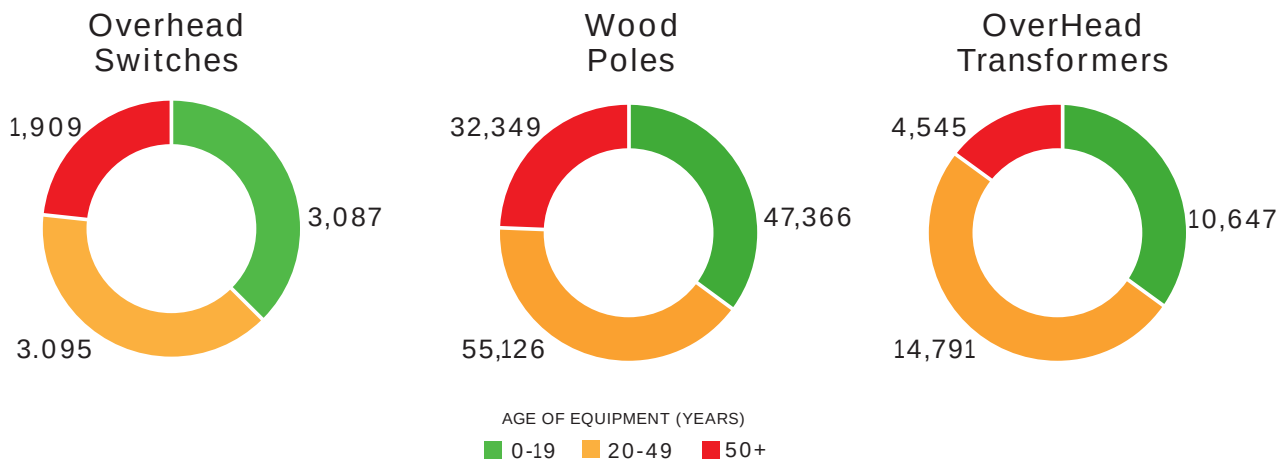
PROGRESS BY 2020:



PLAN FOR 2015-2019:

« +.+0+5 .+%/4,! 0%0+«% 0«
approximately 2 per cent of its budget to convert this legacy construction to standard.

How Old is the Overhead System?



What s Going on with the Underground System?



Direct Buried Cable

« !/0+#5055,*!#1*«
construction where cables are laid directly in underground trenches without a protective barrier.

CHALLENGES:

« (/« 1/ !0% (0+10#« ! 1/
they are exposed to environmental stress, including excessive moisture.

« &%05$/ (/«. *!
immediate repair or replacement.

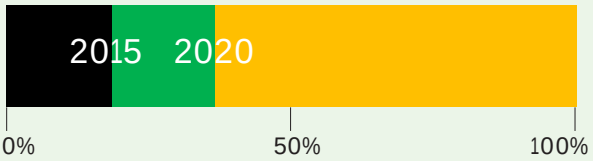
«*« «%.! 0«1.%!« (/« 1/!
than half of all outages associated with underground equipment.

SOLUTION:

« +.+0+ .+%/(%#%.! 0« 1.%!« (
with water resistant cables in plastic ducts, encased in protective concrete.

« $%/«+/0.1 0%+%/«+0 0%2! 1/%0«
extends the life of the system and allows for easier repairs.

PROGRESS BY 2020:



PLAN FOR 2015-2019:

« *!#1*«%. 1%0«(%/,! 0!0+«
account for approximately 18 per cent of the proposed budget.

«0%/0$. #0« ,%0 (#)%*0$(*«
addressing underground equipment including direct buried cable, switches and transformers.

What s Going on with the Underground System?



Chambers, Vaults and Ducts

« !/0+1*1#1*«%2%(%*/0.1 01.
that houses and protects Toronto Hydro s electrical equipment.

CHALLENGES:
« $/1/D/0!%+.0%1/%
outages.
« $5«(/0!0% (1 D5$ 6 .
crews working in vaults and chambers.

SOLUTION:
« +.+0+5 .+%/1((5 1%(%$/1
structures.

PLAN FOR 2015-2019:
Underground civil renewal work is expected to account for approximately 2 per cent of the renewal budget for 2015-2019.



Leaking Paper Insulated Lead Covered Cable

Paper insulated lead covered (PILC) cable was the rst type of underground cable installed in Toronto.

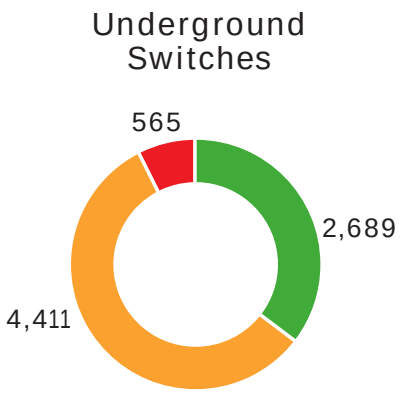
CHALLENGES:
« /0$5$«/%. %
leaking oil.
« ! %* (/« *«%(«* /$!«
sometimes violently.
« 0.% 0! D5(0%+/$ 2 %./«
costly and time consuming.

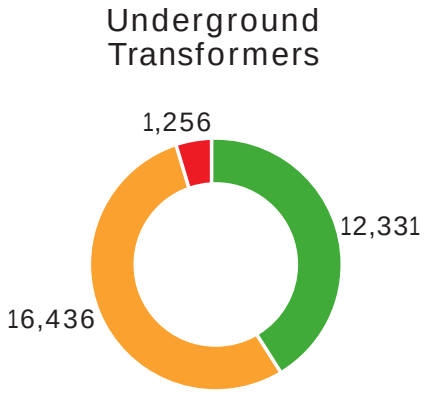
SOLUTION:
« $0%(%05$/« %/3%0$0$
oldest stock of PILC cables and repairing all of the leaks at once.

PLAN FOR 2015-2019:
« %.3+.%/,! 0!0+« +1«.«
approximately 0.4 per cent of the budget for 2015-2019.

How Old is the Underground System?

AGE OF EQUIPMENT (YEARS)
0-19 20-49 50+





What s Happening to the Underground Network in the Downtown Core?



Network Vaults

Refers to civil infrastructure that houses underground transformers and other underground electrical equipment unique to the downtown system.

CHALLENGES:

« (
are causing rebar and the roofs of network vaults to deteriorate and corrode.

« *
«
electrical equipment.

SOLUTION:

« +.+
higher quality materials like galvanized rebar and corrosion-resistant beams.

« $%/
because it lengthens the life of new structures.

PLAN FOR 2015-2019:

« +.+ «
2 per cent of its budget to rebuilding network vaults.



Obsolete Network Equipment

Refers to electrical assets in the downtown network system that are failing and are no longer used.

CHALLENGES:

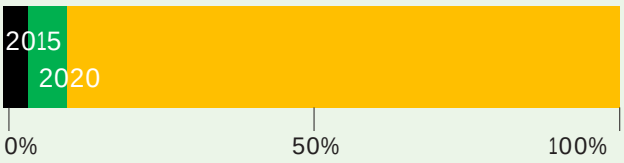
« +) « «
their age and wear; particularly bertop network units installed in the original system.

« $
require extensive repairs and cause outages impacting a large number of customers.

SOLUTION:

« +.+
proactive replacement of this equipment.

PROGRESS BY 2020:



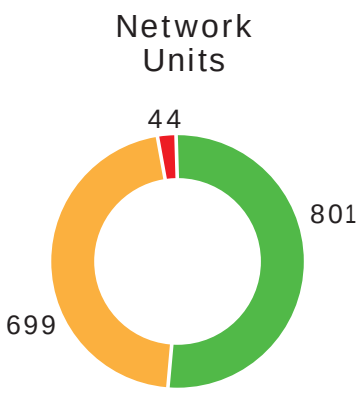
PLAN FOR 2015-2019:

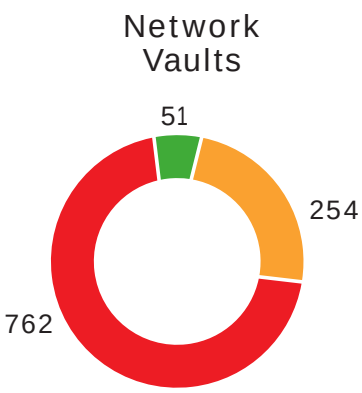
« +.+
2 per cent of its capital budget to these network projects.

How Old is the Underground Network?

AGE OF EQUIPMENT (YEARS)

0-19 20-49 50+





What s Going on with Toronto Hydro s Distribution Stations?



Obsolete Stations Switchgear

Refers to electrical equipment used to switch load between feeders inside the substation.

CHALLENGES:

« +)k3%0 $#%/ 0%0/ /%#k
lifespan and is now obsolete.
« .05 .%/«1/0)k« .% 0%*#!0 %*« «
parts that are no longer available, but this is increasingly expensive, unreliable and unsustainable.
« /(0k1%,)!0 H 0!0% (k 05«
risks to sta within the substation building and could potentially cause signi cant damage to surrounding equipment.

SOLUTION:

« +.+0+5 .+4,! 0/0+(k
number of these units over the course of its capital plan through its Stations Switchgear Renewal program. This is expected to help minimize maintenance and operating costs and improve system reliability.

PLAN FOR 2015-2019:

« $k0%+3%0 $#(«
program accounts for approximately 4 per cent of the proposed budget and three quarters of the total proposed stations renewal budget.

Stations Expansion

Toronto Hydro is expanding the capacity of its distribution grid through stations upgrades and expansions.

CHALLENGES:

« $k%05/#3%#,1(0%+%/k0./ /%# «
the grid.

SOLUTION:

« +.+0+5 .+%/«./ /%#$%/30$«
mix of cost-e ective solutions including new stations, stations upgrades and the purchase of mobile switchgear units that can be deployed during widespread outages.

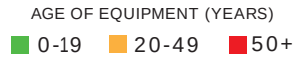
PROGRESS:

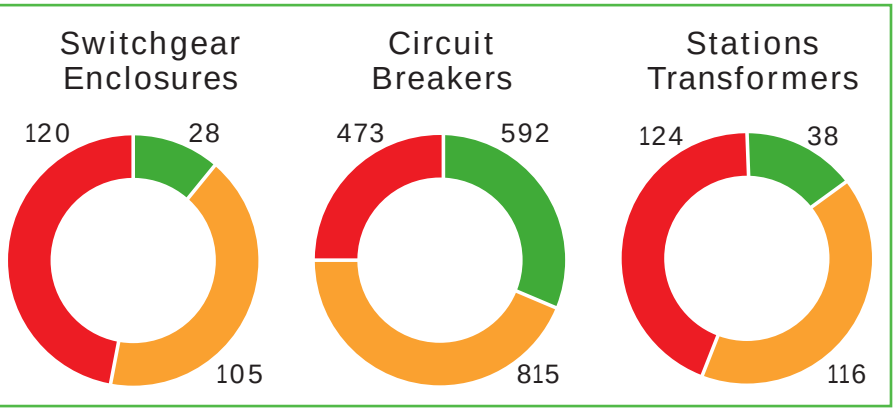
« +,(*0 0%+3k!#1*«
transformer station, is being constructed at the Roundhouse Park next to the CN Tower to help alleviate capacity constraints in the downtown core.
« $k0 0%*3%((« « %0%* («
capacity equivalent to 70 skyscrapers, allowing Toronto Hydro to take other aging stations o ine for needed repairs and upgrades.
« $k&! 0%/4,! 0!0«k},(D!« «
by the end of 2014.

PLAN FOR 2015-2019:

« +.+0+5 .+,(/0+«% 0k
approximately 14 per cent of its renewal budget to stations expansion.

How old is the Distribution Stations Equipment?





What s Happening with Grid Modernization?



Feeder Automation

Refers to overhead intelligent switches installed on feeders to detect and isolate outages.

- « $¥k3%0 $¥/« .¡k#))!0d« #%6k «
  feeder outages and will open and close accordingly.
- « .#05 .$ /‰*/0 ((!«10} 0!«
  switches on 10 of its worst performing feeders to test its e ectiveness.

PLAN FOR 2015-2019:

- «0 ((%¥k3%0 $¥/$2k+2!0+« k
  cost e ective technology that signi cantly reduces outage impacts on problem feeders.
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  approximately 3 per cent of its capital budget to feeder automation projects.

How is Toronto Hydro Keeping the Business Running?



In addition to investing in grid renewal, Toronto Hydro must invest in the tools required to keep the utility going. This includes vehicles, facilities and information technology (IT).

CHALLENGES:

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  can carry out work safely and e ciently.
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  management. Engineers, project managers and construction crews have shifted from manual paper drawings to digital records made possible by computer software that helps sta design and track projects.
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  maintenance and updates.

SOLUTION:

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  IT hardware and upgrade software as necessary.
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  system that crews use to communicate with system operators when working in vaults and chambers to help reduce safety risks. The existing system will no longer be supported by the vendor after 2016.
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  management IT system which supports a number of critical engineering, project planning, human resource and nance functions.
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  adequately supported by the vendor.

Stretching your Electricity Dollars

Reducing Strain on the Grid

Toronto Hydro is reducing strain on the grid by supporting provincial conservation and demand management programs for residential, business and industrial customers. These programs are not generally an alternative to renewing the aging distribution system in the near-term, but they may help defer the need for capacity expansion and renewal investments over the longer-term.

Conservation Program Results from 2012

Here is a look at conservation programs provided to customers and the electricity savings they yielded.

saveONenergy℠ Conservation Programs	Results	MW Saved	MWH Saved
FRIDGE & FREEZER PICK-UP	2,802 refrigerators and freezers collected	0.2	1,092
COUPONS	Bi-annual customer events and coupons for energy e cient products held at participating retailers	0.2	3,606
DEMAND RESPONSE CONTRACTUAL DR3	48 commercial and industrial customers contracted to reduce energy use at speci ed times	14.7	312
SMALL BUSINESS LIGHTING	3,498 lighting retro ts installed	2.5	9,383
HEATING & COOLING INCENTIVE	13,047 participants received an incentive for installing an ENERGY STARfi quali ed central heating or cooling system	2.8	4,782
peaksaver PLUSfi	43,149 installation	22.9	169
RETROFIT PROGRAM	1,168 project applications	15.9	80,294

Total 2012 Results: 112,200 MWh and a total demand reduction of 61,088 MW



20. For conservation and demand management programs to slow the pace of renewal and expansion, they must provide an acceptable level of certainty. How likely is it that you would participate in Demand Response programs that would allow electricity system managers to turn o equipment you are using? For residential customers, this would involve automated devices to turn o your water heater and air conditioner for short periods during times of peak demand.
    _____Very likely
    _____Somewhat likely
    _____Not very likely
    _____Not at all likely

Smart Grid, Smart People, Smart Business

Toronto Hydro is trying to temper the cost of investment by improving the productivity and e ciency of its overall business. Here s how the utility is nding ways to do more with less:

- «Reducing employee headcount Toronto Hydro has reduced sta levels by 35% and senior executives by 65% since 1998.
- «Keeping absenteeism low According to Statistics Canada, Toronto Hydro s absentee rate is 15% below the average for public and private sector companies.
- «Working safely Toronto Hydro is avoiding injuries and staying productive on the job site. The utility has achieved 3.5 million hours without a lost-time injury.
- «Reducing operating costs Toronto Hydro is downsizing work centres and relocating sta from leased buildings to utility-owned facilities that are better suited to the business.
- «Improving coordination of capital projects Toronto Hydro is executing more cost-e cient projects by grouping high-priority projects with lower priority projects in the same neighbourhoods. This allows the utility to use its crews and equipment more e ciently, and reduces the set up time and number of permits required to complete work.

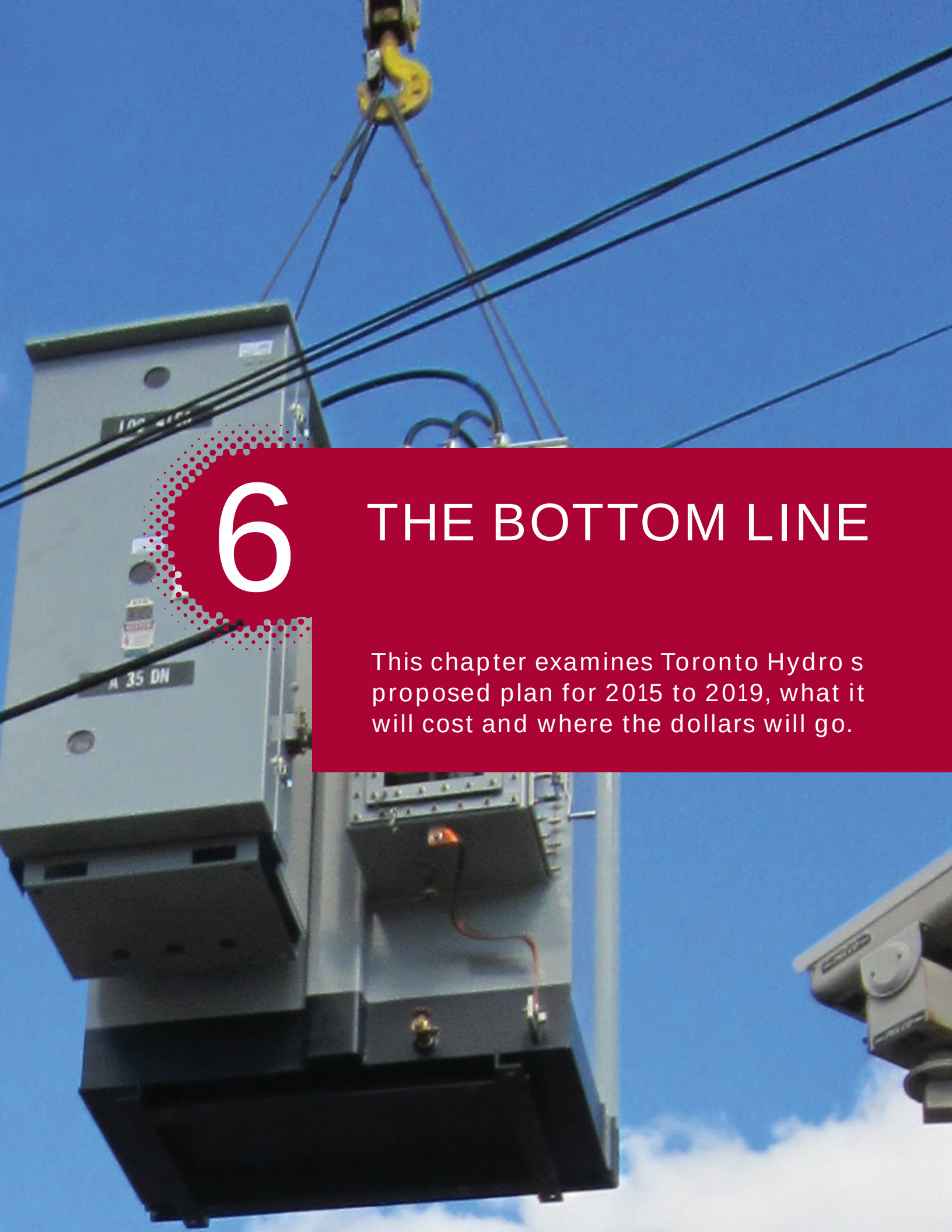


21. Given what you know and what you have read so far, how well do you feel you understand the challenges facing the Toronto Hydro grid and what they are planning to meet those challenges?
    _____ Very well
    _____ Somewhat well
    _____ Not very well
    _____ I don t understand at all

22. From what you have read and what you may have heard elsewhere, does Toronto Hydro s investment plan seem like it is going in the right direction or the wrong direction?
    _____ Right direction
    _____ Wrong direction
    _____ Not sure

23. And why do you feel that way?

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6 THE BOTTOM LINE

This chapter examines Toronto Hydro s proposed plan for 2015 to 2019, what it will cost and where the dollars will go.

Here s What We ve Covered so Far:

The Ontario Energy Board (OEB) requires that Toronto Hydro gather customer feedback on the utility s proposed investment plans. Toronto Hydro will present your feedback to the OEB as part of the rate setting process. The OEB and a number of public intervenors will hold Toronto Hydro accountable for both the way that you were consulted and the way that the utility s nal plan re ects what you said.

About a quarter of your electricity bill goes to Toronto Hydro. The money that Toronto Hydro receives is invested in the local distribution system and the people, buildings and vehicles that support it.



Much of Toronto s existing distribution system was built in the 1950s and 60s. Toronto Hydro s customers have bene ted from the longer than expected lifespan of this equipment.

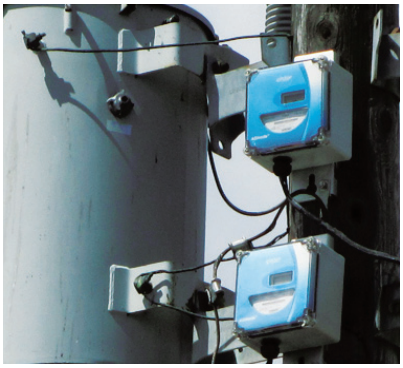
Today, much of the system is at an age where it must be replaced to maintain the reliability that Torontonians expect. Renewing the system will help ensure that the next generation of electricity users enjoys the same long-term value-for-money as previous generations.

Toronto Hydro is also dealing with other pressures, like the need to build more system capacity to accommodate the city s growth and the need to upgrade outdated and unsupported IT systems.



At the same time, the industry is changing, and Toronto Hydro has the opportunity to explore innovative grid modernization technologies that will help the utility cost-e ectively improve system performance and reduce the risks and costs associated with aging equipment over the long-run.

Renewing the system for the next generation will take more than a decade, but delaying these investments is expected to gradually worsen reliability across the system and lead to even higher bill increases down the road.



In recognition of growing capital needs, Toronto Hydro has been working to reduce operating costs by reducing employee headcount, avoiding injuries, and downsizing work centres.

The Dollars and Cents

Toronto Hydro is preparing a 2015-2019 investment plan that will require an annual bill increase of approximately $2.35 on the monthly bill. This amounts to a total increase of approximately $11.75 per month by 2019 compared to 2014 electricity rates.



Here s how Toronto Hydro believes your electricity dollars should be invested during these years:

Replacing Aging and Obsolete Equipment
These investments are paced and prioritized to maintain reliability standards and to address the worst performing feeders rst. Introduction of modern equipment standards is expected to reduce the impact of storms.

47.1%

Expanding Capacity for Long-term Growth
Expanding the capacity and exibility of the local distribution network to accommodate forecasted growth in electricity demand.

14.3%

Connecting Customers
Bringing new customers onto the system; these investments are mandatory, but the cost is generally recovered through the additional revenue that new customers contribute.

11.2%

Improving Reliability by Recon guring Circuits
Targetted investments to cost-e ectively reduce the impact and frequency of outages. For example, converting main feeder sections from overhead to underground will help reduce the impact of future storms.

8.0%

Updating IT Infrastructure
Replacing outdated and unsupported software and communications systems that are critical to Toronto Hydro s planning, operations and outage response.

7.8%

Accommodating Construction Projects in the City
Relocating or recon guring distribution equipment that is on or near the path where other agencies are working.

3.3%

Modernizing the Grid
Introducing innovative technologies like intelligent switches and sensors that are expected to cost-e ectively improve the reliability of the system and reduce the risks and costs associated with aging equipment.

3.2%

Maintaining and Upgrading Customer Meters
Routine meter replacements and improvements to data quality.

1.9%

Building Maintenance
Routine capital investments to maintain Toronto Hydro s facilities.

1.3%

Connecting Renewable Generation
Installing protection and control equipment and energy storage facilities that allow for the e cient use of new renewable generation connections.

0.9%

Vehicles and Equipment for Crews
Routine capital investments in Toronto Hydro s eet of trucks, cars and equipment

0.7%

Accommodating Electric Vehicles
Accommodating electric vehicle connections to the grid and investing in ways to manage and optimize electric vehicle storage capacity on the system

0.1%



Have Your Say: Is Toronto Hydro Investing Wisely?

Let s Talk Priorities:



24. When you look at how much Toronto Hydro is spending on each of its investment priorities, do you think they have the balance right or would you change the relative priorities?

_____ The balance looks right
_____ They should change some of the priorities

25. What areas do you feel need more spending than planned?

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26. What areas do you feel should have less spending than planned?

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Let s Talk Pacing

Toronto Hydro s proposal is expected to lead to a total increase of approximately $11.75 on the average residential customer s monthly bill by 2019. A lower bill impact is possible in the short-term, but there are trade-o s: system performance will be worse and future bill impacts will be higher. The following table compares Toronto Hydro s plan to another likely utility management practice called run-to-failure. This approach is typical for smaller utilities with newer systems.

	"RUN-TO-FAILURE" APPROACH	TORONTO HYDRO'S PROPOSED PLAN
Description	With this approach, Toronto Hydro would only replace equipment as it fails (with the exception of critical assets such as stations equipment). This is a purely reactive approach using close to the minimum amount of funding that Toronto Hydro could receive from the Ontario Energy Board.	feeders rst. modern grid technologies and recon guring circuits.
Estimated increase in monthly bill	$6.18/month	$11.75/month
Reliability outcomes by 2019	customer: 1.6/year customer: 1.38 hours/year experiencing seven or more interruptions a year: 13 per cent	customer: 1.15/year customer: 0.65 hours/year experiencing seven or more interruptions a year: 6 per cent
Percentage of equipment past end-of-life in 2020	31 - 34 per cent	25 - 28 per cent

Why Does Toronto Hydro Think This Pace is Best?

As seen in the table above, Toronto Hydro estimates that a run-to-failure approach, when compared to the proposed plan, would result in double the average duration of outages across the system and more than double the percentage of customers on poor performing feeders. Because of the aging system, Toronto Hydro would expect reliability to continue worsening well beyond 2019 if the utility stuck with a run-to-failure approach.

Of course, the two plans presented here are <u>not</u> the only options for pacing system investment. Toronto Hydro can invest more or less capital to achieve a wide variety of outcomes.

So how did Toronto Hydro arrive at the proposed plan?
Since the utility is so large, Toronto Hydro s engineers rely on a software model to help calculate the year in which it is most cost-e ective to rebuild any given part of the system. The model suggests that Toronto Hydro should, in fact, be spending more than it is proposing in the years 2015 to 2019.

So why is Toronto Hydro proposing to invest less than the model recommends?
In reality, there are constraints that prevent the utility from spending above a certain amount. One such restriction is the limited number of skilled resources available to carry-out the work. Resource limitations are also and important reason why Toronto Hydro believes it is wise to invest now and not later: increasing the number of quali ed trades people takes time, and the industry will not train new workers unless there is a consistent and predictable amount of work. This means that the longer Toronto Hydro allows the system to age, the less likely it is that the utility will be able to keep up with investment needs.

Ultimately, Toronto Hydro believes that the proposed plan will deliver improved system performance at a pace that is sustainable for both the utility and the customer.

27. When you consider the options outlined in the table on the previous page, do you think Toronto Hydro s goals are too high, too low or about right?

_____ Too high _____ About right
_____ Too low _____ Not sure

28. What are the goals you feel are too high?

_____
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29. What are the goals you feel are too low?

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30. Looking at the cost of the Toronto Hydro plan and the outcomes it is expected to achieve, which point of view is closest to your own?

_____ Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more.

_____ I am satis ed with the balance between outcomes and the proposed rate increase.

_____ I don t like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard.

_____ I think the bill impact is too high and Toronto Hydro needs to scale back its plans.

_____ Not sure

What Do You Think About This Review?

Toronto Hydro values your feedback. This is the first time the utility has conducted a review about its upcoming investment plan in this type of format. What did you think about the workbook?

1. Volume of Information Did Toronto Hydro provide too much information, not enough, or just the right amount?

2. Content Covered Was there any content missing that you would have liked to have seen included?

3. Outstanding Questions Is there anything that you would still like answered?

4. Suggestions for Future Consultations How would you prefer to participate in these consultations?

Technical Glossary

Cable Chamber An opening to the underground duct system that facilitates the installation, removal, inspection and repair of cables.

Cable Fault A hole in a cable caused by a short circuit (due to corrosion, overloading over time, water, age) which can result in an explosion.

Circuit A continuous system of conductors providing a path for electricity.

Circuit Breaker A protective switch in a substation that automatically disconnects power to the circuit in the event of a fault. Performs the same function as a circuit breaker in a home.

Conductor An object that permits the ow of electricity, like a wire or cable that allows electricity to ow along its length.

Distribution Transformer A piece of equipment required to reduce voltage to a level that can be used by customers in their homes and businesses.

Feeder A distribution circuit carrying power from a substation to customers. Feeders consist of circuits and other electrical equipment supported by civil infrastructure like poles and ducts.

Kilovolt = 1,000 volts

Megawatt Equals 1,000 kilowatts or enough to power 10,000 100-watt light bulbs.

Primary Cables Cables that distribute electricity throughout the system at a higher (primary) voltage (i.e. greater than 750 volts).

Secondary Cables (or Mains) Low voltage cables that are connected to the secondary (low voltage) side of the distribution transformer and deliver current to customers.

Substations Large power transformers and miscellaneous protection and control equipment (e.g. circuit breakers) that transform electricity from a higher primary voltage to a lower primary voltage. Substations are part of generation, transmission and distribution systems.

Switch A device for isolating a piece of equipment or a section of feeder to allow repairs or replacements to be made on them while in a safe, de-energized state.

Transformer A device used to transform voltage levels to facilitate the transfer of power from the generating plant to the customer.

Transformer Vault A large room (above - or below-ground) that houses transformers, switches and protective equipment.

Volt A measure of electricity. The Standard International unit of electro-motive force, the di erence of potential that would carry one ampere of current against a resistance of one ohm.*

Watt A measure of the work electricity can do.

1,000 watts = 1 kilowatt (the amount of power used by 10 100-watt light bulbs)

1,000,000 watts = 1,000 kilowatts = 1 megawatt

*Source: Oxford Dictionary of Current English

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Have your say about Toronto Hydro s proposed grid renewal plan and its impact on your rates

Toronto Hydro-Electric System (Toronto Hydro) is in the midst of modernizing a distribution system that was largely built in the 1950s and 1960s. The pace at which this is accomplished will inevitably impact your electricity rates and service reliability. The purpose of this consultation is to gather your feedback on Toronto Hydro s proposed ve-year grid renewal and modernization plan for 2015 to 2019.

About This Consultation

This consultation focuses speci cally on what Toronto Hydro does: taking electricity from the provincial grid and distributing it to people and businesses in Toronto.

The electricity industry in Ontario is regulated by the Ontario Energy Board, which recently developed a new framework requiring local distribution companies to gather customer preferences on electricity investments. Your feedback will be presented to the regulator when Toronto Hydro les its rate application for 2015 to 2019. During the rate hearing process, Toronto Hydro will be held accountable for the way you were consulted and the ways in which the utility s plans respond to what you said.

Will you be expected to answer technical questions about the grid?

Toronto Hydro does not expect you to make electrical engineering decisions. The utility is asking you about the electricity issues that matter most to you, and if you feel Toronto Hydro s priorities for investing your electricity dollars are reasonable.

Toronto s distribution system is aging, the city is facing unprecedented growth in the downtown core, and a variety of innovative grid technologies are providing new opportunities for electricity management. This workbook is designed to give you enough background about these issues to develop an informed opinion.

The most important parts of this workbook are the survey questions. By completing them, you can ensure that Toronto Hydro considers your views as they relate to future investments in the distribution grid.

Where are the survey questions located?

Questions are located on pages:

« « « « « « « « « « «
«« « « « « « « « « « «

How much will Toronto Hydro s proposed grid renewal plan cost me?

About one quarter of your electricity bill currently goes to Toronto Hydro. That s about $73 per month for the average small business owner. Toronto Hydro s proposed grid renewal plan will add:

- « ,,. 4%) 0(5« $6.10 each year to an average small business owner s monthly bill for the period of 2015 to 2019,
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  approximately $30.50 per month by 2019compared to 2014.

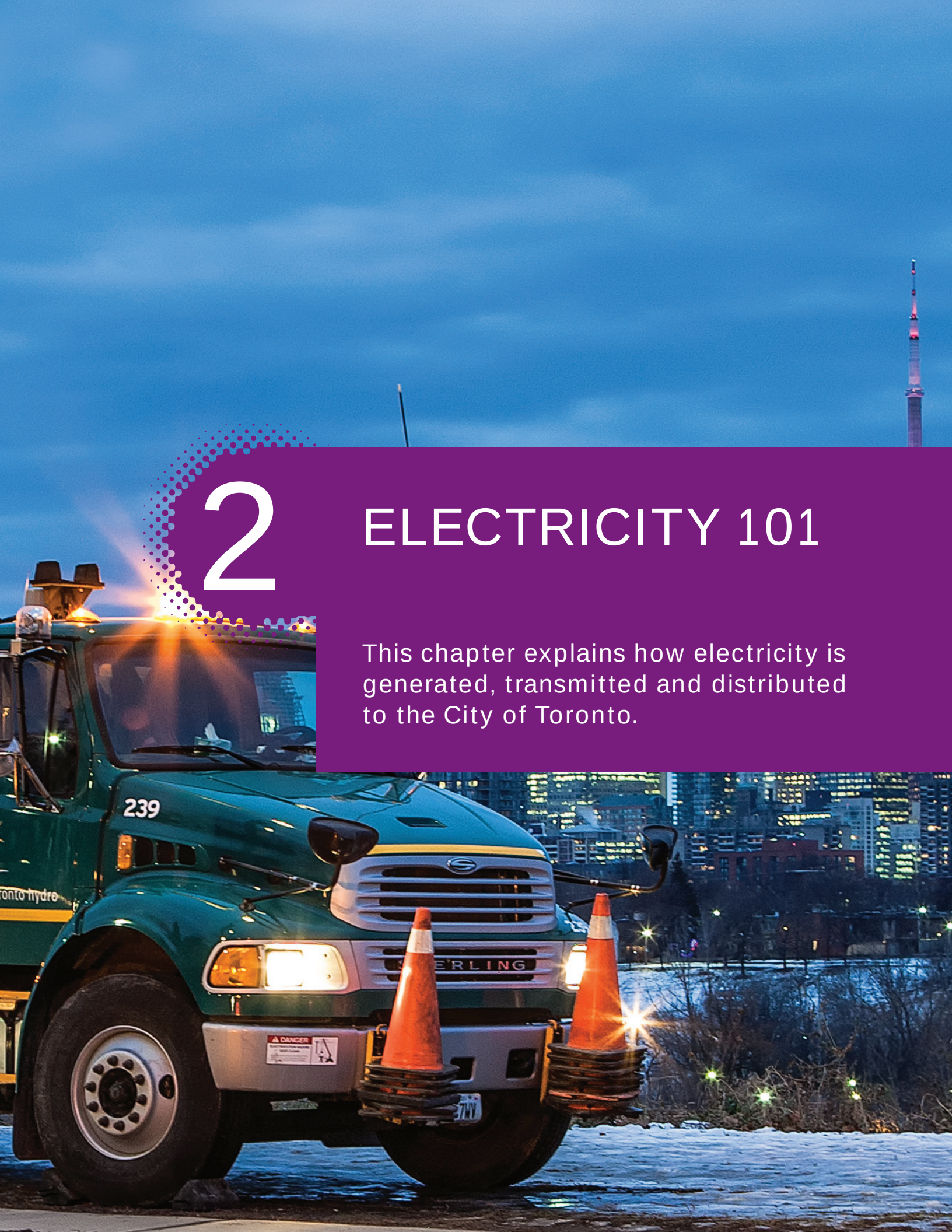
These bill impacts include capital investments and operating expenses. Toronto Hydro is planning to keep increases in operating expenses below in ation for the duration of the plan, which is why this consultation focusses solely on capital investments in the system.

How This Consultation is Being Managed

This public consultation process is being managed by a third-party research company. They will compile the results of all surveys and submit a report to Toronto Hydro. Your responses will be combined with others to protect your privacy.

You Can Participate in a Separate Conversation About Long-Term Energy Planning

Do we have enough electrical infrastructure to meet Toronto s needs? The Central Toronto Integrated Regional Resource Plan looks at where demand for electricity is growing and how this can be best managed over the next 25 years. Options considered include: conservation, local distributed generation, transmission and distribution infrastructure. You ll pay later for the choices being made today about your electricity system. Visit torontohydro.com/haveyoursay for more information.



2 ELECTRICITY 101

This chapter explains how electricity is generated, transmitted and distributed to the City of Toronto.

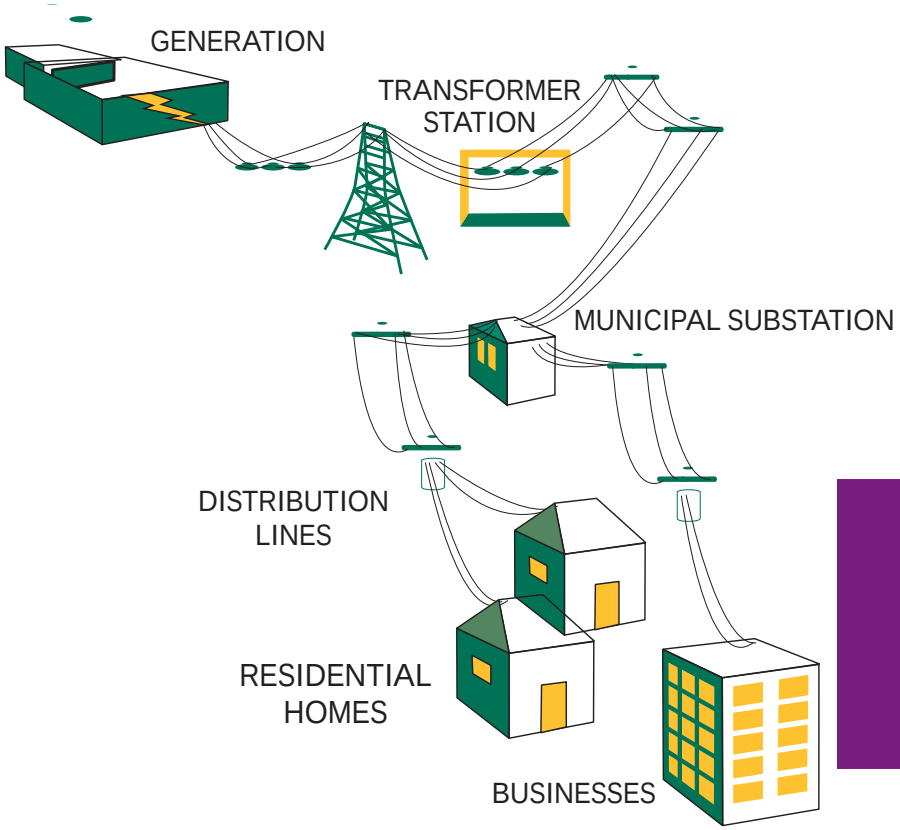
Understanding Toronto Hydro s Role in Ontario s Electricity System

There are three main components to all electricity systems: generation, transmission and distribution.

Where Electricity Comes From

In Ontario, 70 per cent of electricity is generated by Ontario Power Generation. This provincially-owned organization has generating stations across Ontario that produce electricity from hydroelectric, nuclear and fossil fuel sources.

Once electricity is generated, it must be delivered to urban and rural areas in need of power. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines*, owned mostly by Hydro One.



Toronto Hydro

Toronto Hydro is responsible for the last step of the journey: distributing electricity to customers in Toronto.

The City of Toronto

The City of Toronto is Toronto Hydro s sole owner and shareholder. The Ontario Energy Board allows Toronto Hydro to earn a speci ed annual return, part of which is used to pay an annual dividend to the shareholder. The City uses this dividend to fund city services like snow removal and garbage collection. Toronto Hydro reinvests the remaining portion of this amount back into the utility.

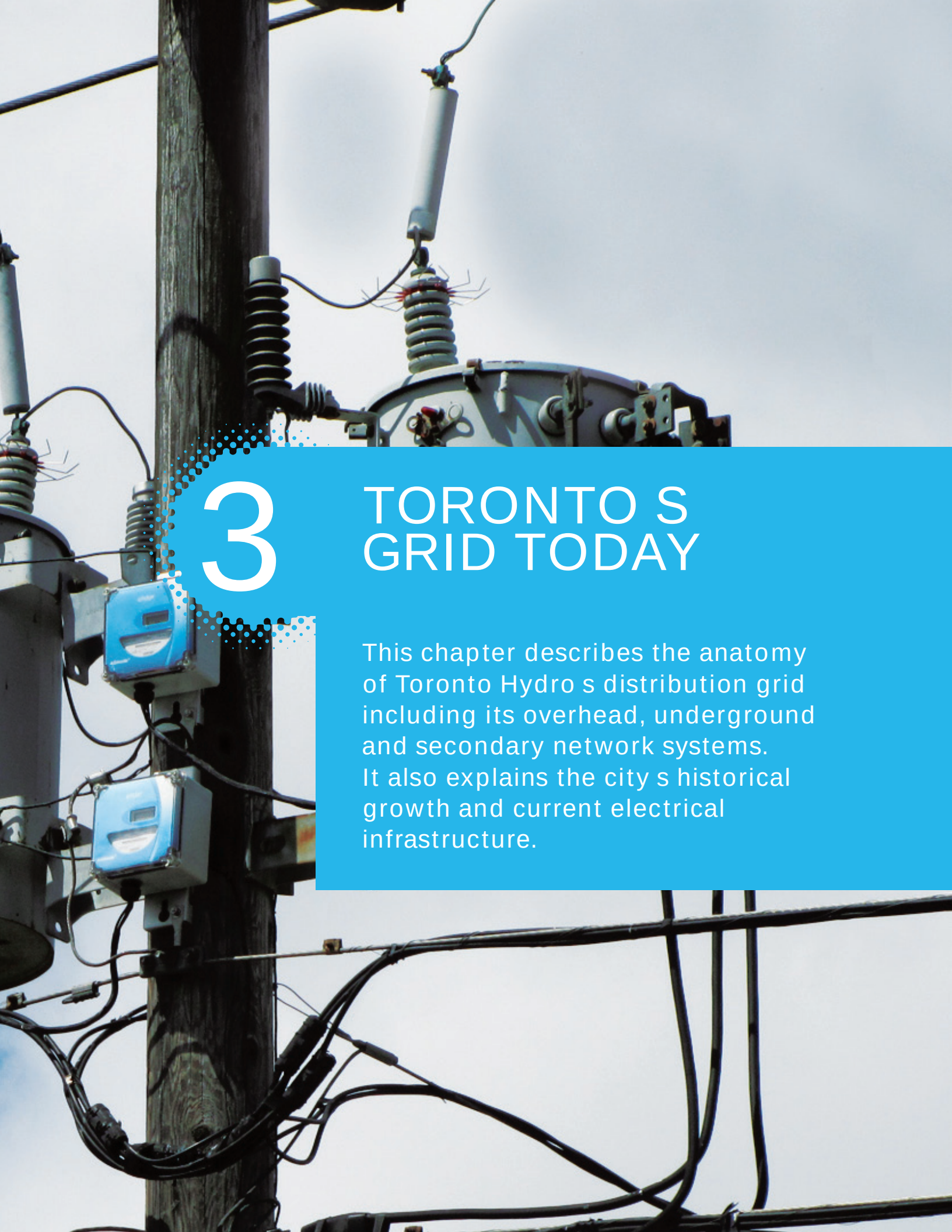
How are Electricity Rates Determined?

Toronto Hydro is funded by the distribution rates paid by its customers. Periodically, Toronto Hydro is required to le an application with the Ontario Energy Board to determine the funding available to operate and maintain the distribution system. Toronto Hydro must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity.

Who Protects Consumer Interests?

Toronto Hydro s evidence is assessed in an open and transparent public process known as a rate hearing. A number of public intervenors with electricity industry expertise submit their own evidence challenging Toronto Hydro s plans and assumptions. At the end of the process, the Ontario Energy Board weighs the evidence and decides on the rates Toronto Hydro can charge for distribution.

*Source: IESO. The Power System, www.ieso.ca



3 TORONTO S GRID TODAY

This chapter describes the anatomy of Toronto Hydro s distribution grid including its overhead, underground and secondary network systems. It also explains the city s historical growth and current electrical infrastructure.

The Nuts and Bolts of Toronto Hydro s Distribution Grid

Toronto s electricity grid is comprised of overhead, underground and secondary network systems. The mix is largely due to the utility s amalgamation. In 1998, Toronto Hydro merged with North York Hydro, Scarborough Hydro, East York Hydro, York Hydro, and Etobicoke Hydro. Each utility operated independent distribution systems, and as a result, the infrastructure varies from region to region. Toronto Hydro has been working to gradually standardize this equipment, which will help improve reliability and safety across the city, and make system operation more e cient.





A Look at Toronto Hydro s Growth



Toronto Hydro has been serving the city since 1911 and has experienced many changes over the years.

The rst electrically-powered trolley bus and electric tra c lights were introduced in the 1920s. Street lighting was introduced in the 1930s and was upgraded following World War II.

Between 1945 and 1955, the City s power consumption increased by 75 per cent thanks to the post-war baby boom and immigration. The dramatic growth created a need to expand the system. Toronto Hydro built 12 new municipal substations. Much of the equipment installed during this decade is still in operation today.

The 1970s saw dramatic skyline changes with the addition of the CN Tower, First Canadian Place, and the Royal Bank Plaza. As society started to become more environmentally conscious, Toronto Hydro introduced energy conservation programs and incentives to many of its customers.

In the early 1980s, Toronto Hydro introduced a computerized control system to remotely monitor the distribution system and respond more quickly to emergencies.

In 2006, facing the challenges described in the following chapters, Toronto Hydro embarked on the largest infrastructure renewal program in its history.

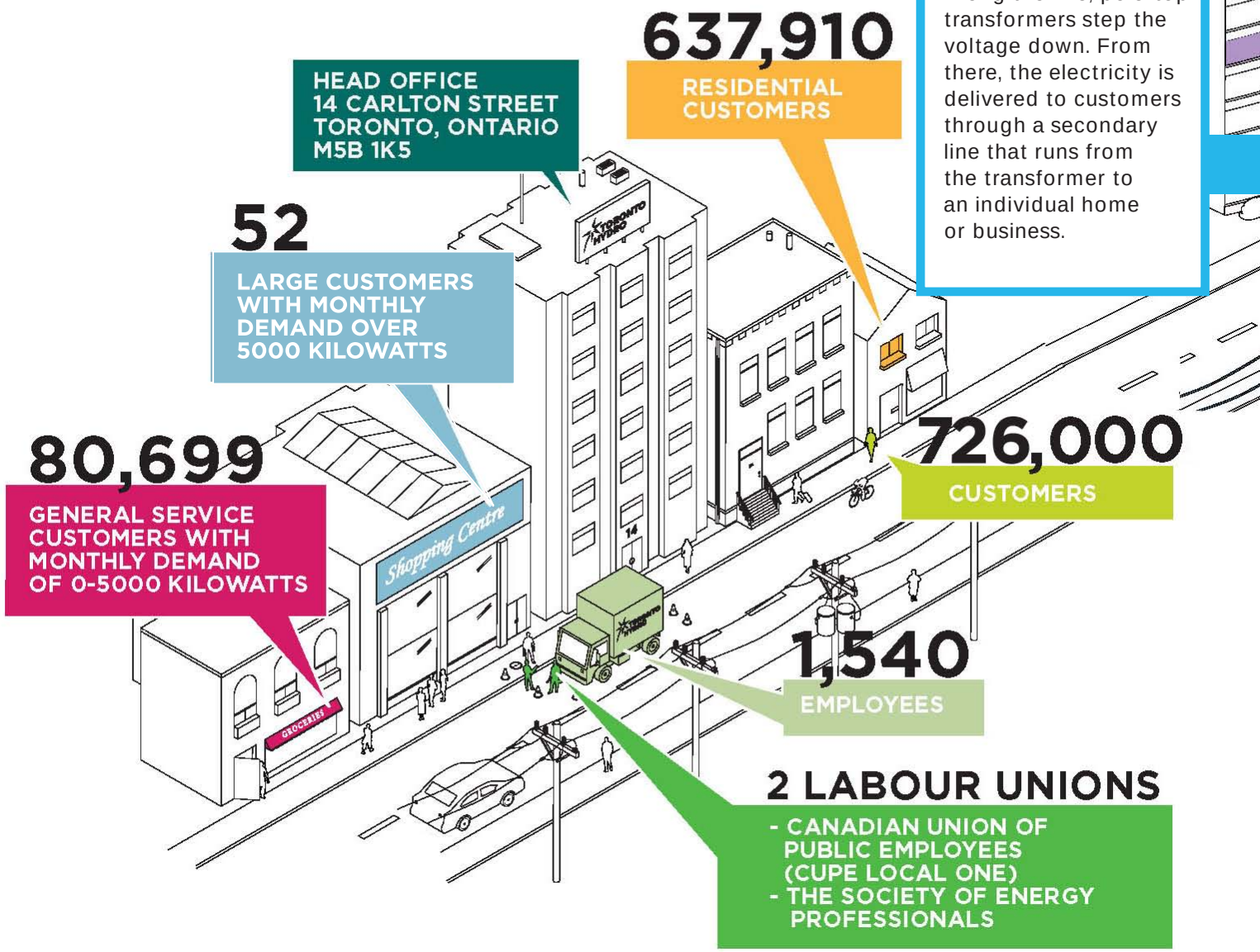
About Toronto Hydro

Toronto Hydro owns and operates $2.6 billion in capital assets and is the largest municipal electrical utility in Canada. It distributes about 19 per cent of Ontario s electricity demand.



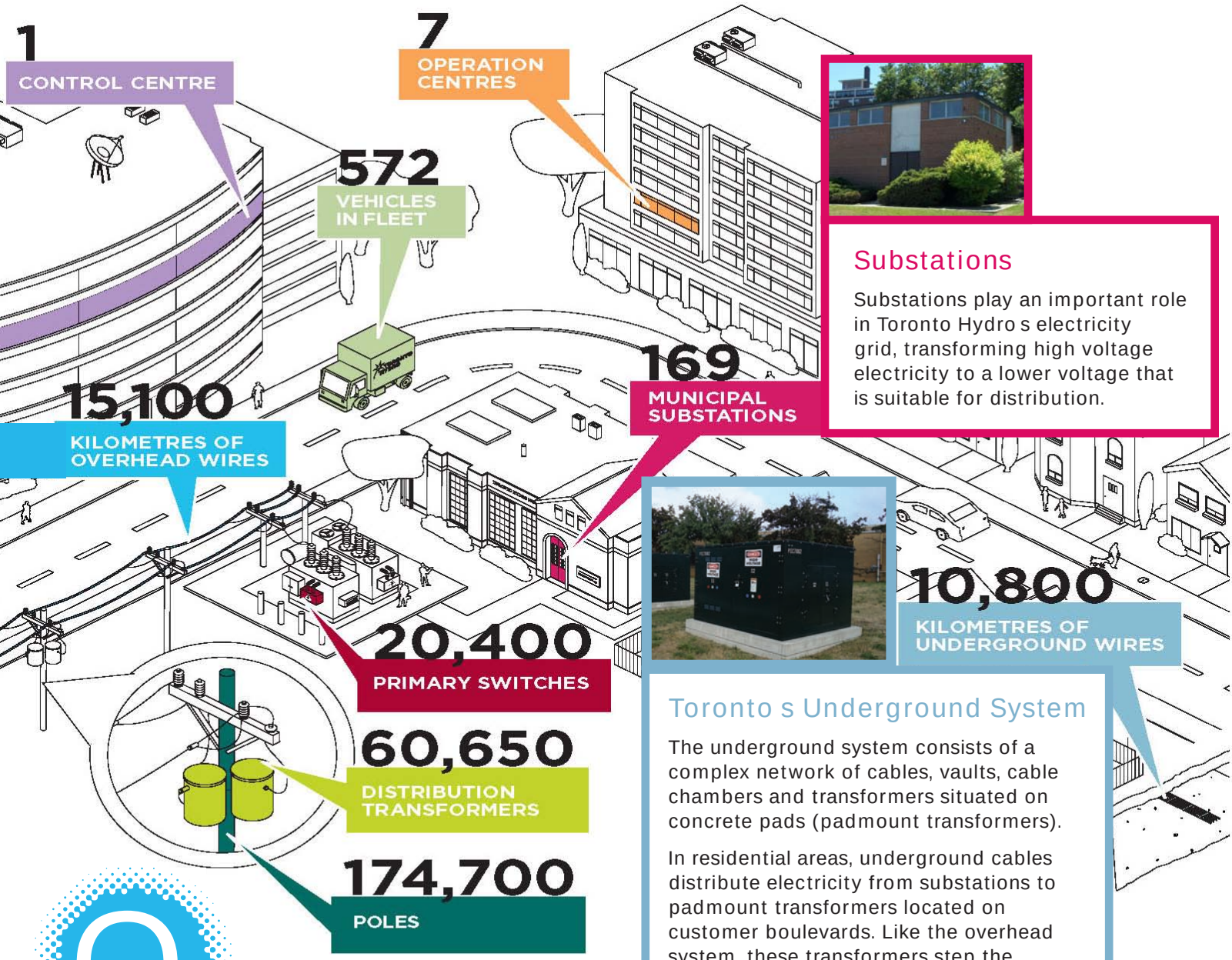
Toronto s Overhead System

The overhead system is made up of distribution lines that operate at either 4.16 kilovolts, 13.8 kilovolts or 27.6 kilovolts. These primary lines are strung across hydro poles. Along the line, pole-top transformers step the voltage down. From there, the electricity is delivered to customers through a secondary line that runs from the transformer to an individual home or business.



1. Given what you know and what you have read so far, how well do you feel you understand the important parts of the electricity system, how they work together and which services Toronto Hydro is responsible for?

   _____ Very well
   _____ Somewhat well
   _____ Not very well
   _____ I don t understand at all



Substations

Substations play an important role in Toronto Hydro s electricity grid, transforming high voltage electricity to a lower voltage that is suitable for distribution.

Toronto s Underground System

The underground system consists of a complex network of cables, vaults, cable chambers and transformers situated on concrete pads (padmount transformers).

In residential areas, underground cables distribute electricity from substations to padmount transformers located on customer boulevards. Like the overhead system, these transformers step the electricity down to a lower voltage, and current is delivered to customers through a secondary line. When distributing electricity to urban areas or larger customers, bigger vault transformers are used. Cable chambers are located throughout the underground system to provide crews with access to feeder cables.

2. How satis ed are you with the job Toronto Hydro is doing running your local distribution system?

____ Very satis ed
____ Somewhat satis ed
____ Somewhat dissatis ed
____ Very dissatis ed
____ Don t Know

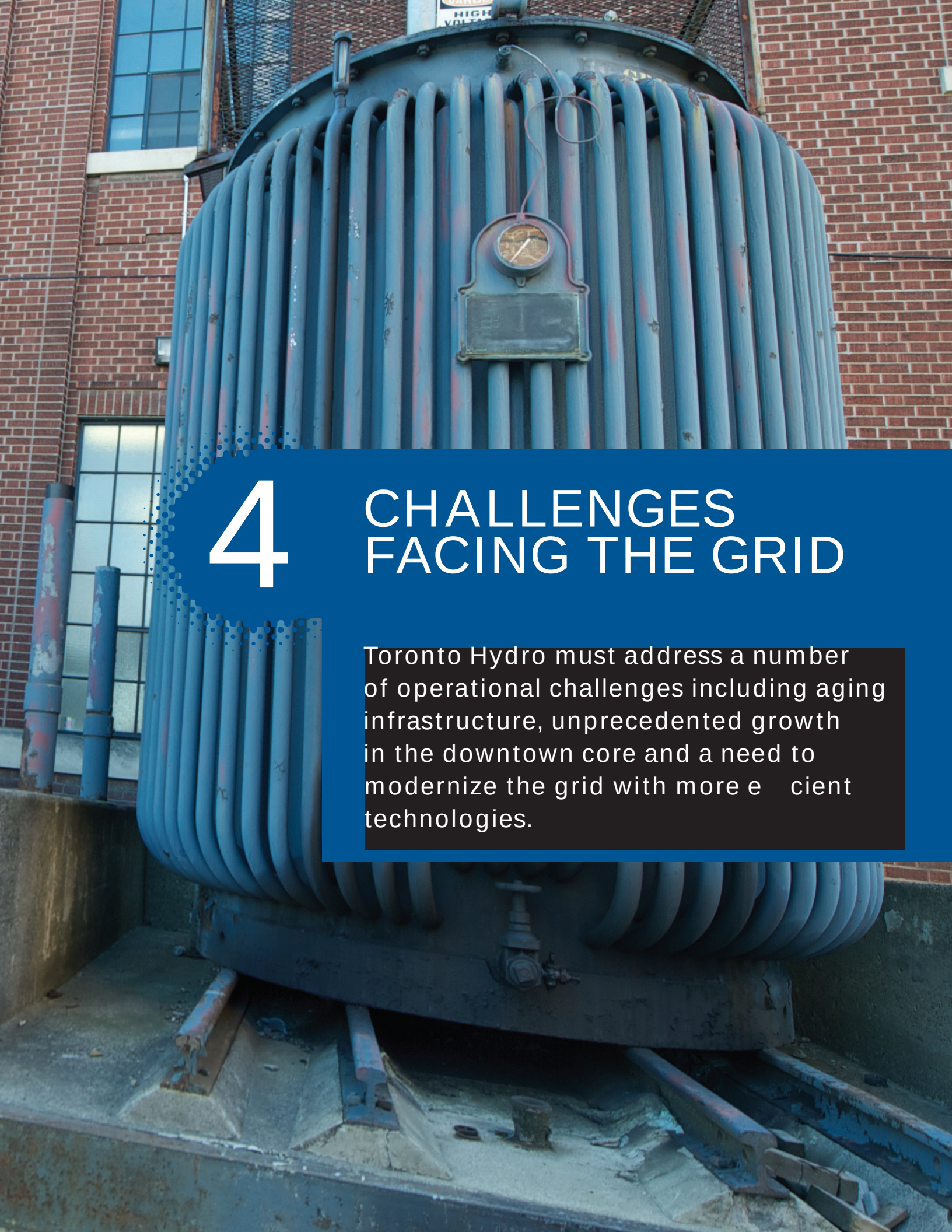
3. Is there anything in particular that Toronto Hydro can do to improve its service to you?

_____

_____

_____

_____



4 CHALLENGES FACING THE GRID

Toronto Hydro must address a number of operational challenges including aging infrastructure, unprecedented growth in the downtown core and a need to modernize the grid with more e cient technologies.

Toronto s Renaissance: Accommodating a City Under Construction

Recently crowned the fourth largest city by population in North America and a continued leader in high rise development, Toronto is a city under construction. Toronto Hydro plays an important role in this growth.

Toronto Hydro is required by law to:

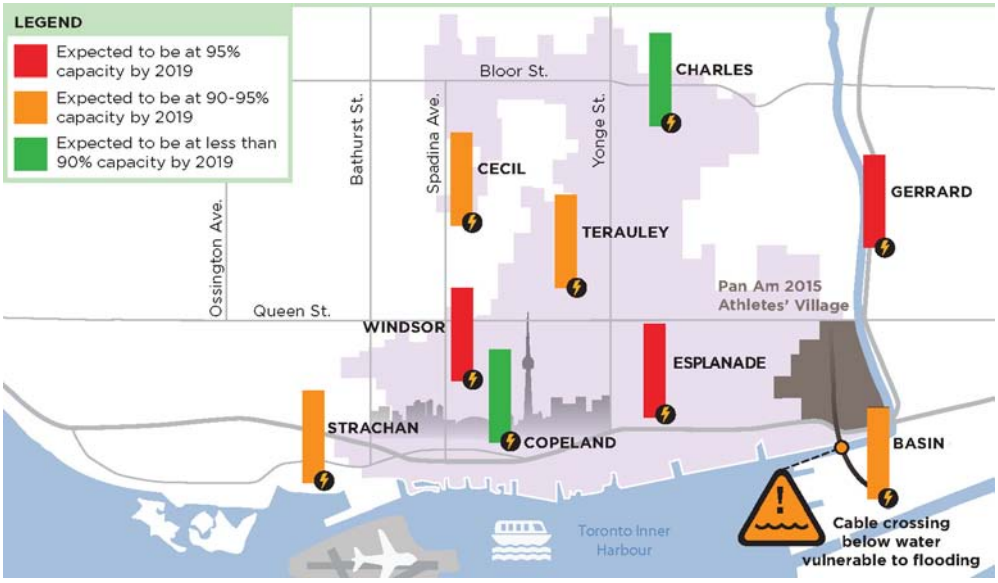
« *+! 0*B«1/0)!/00$#%
« 1. 0(5)0!«1/0)!(! 0.% %05«*/1),0%*
«4, *)+ 2!%/0.% 10%*!1%,)!0(«)+ 0!!0 %*&! 0/%*%0% 0!«50$!%05«
of Toronto, TTC, Metrolinx and GO Transit

The rate of Toronto s growth is making it increasingly di cult to ful ll these responsibilities while maintaining system performance:

« $!!.)!5/ . ,!/1* !«*/0.1 0%*0$ *B«%05$% #* 4% %05
« $!!.)!0$ *&!*0% ((+ 0%*&! 0/!(0!!*/0.1 0%*«50$!*

Growth from high-rise construction is putting immediate and longer-term pressures on the existing grid.

Downtown Stations are Overloaded



To help ensure the city s continued economic success and its ability to serve the growing population, Toronto Hydro is investing in expanding the capacity of its stations and feeders.

Under provincial legislation, there are several types of investments Toronto Hydro must make when the need presents itself. How reasonable do you feel it is to give each of these investments a priority over other investments (for example, replacing aging equipment)?

4. Connecting new customers such as new housing, condominiums or businesses. (Provincial regulations set connection fees which cover unusual costs).
   _____ Very reasonable _____ Somewhat reasonable
   _____ Not very reasonable _____ Not reasonable at all _____ Don t Know

5. Maintaining and upgrading customer meters to meet provincial standards.
   _____ Very reasonable _____ Somewhat reasonable
   _____ Not very reasonable _____ Not reasonable at all _____ Don t Know

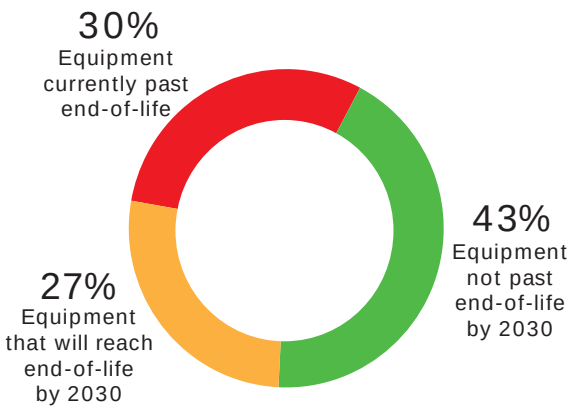
6. Moving existing electricity infrastructure such as poles and transformers to enable other projects such as street widening or new developments. (Provincial regulations set fees which cover unusual costs).
   _____ Very reasonable _____ Somewhat reasonable
   _____ Not very reasonable _____ Not reasonable at all _____ Don t Know

Aging Equipment: All Good Things Must Come to an End

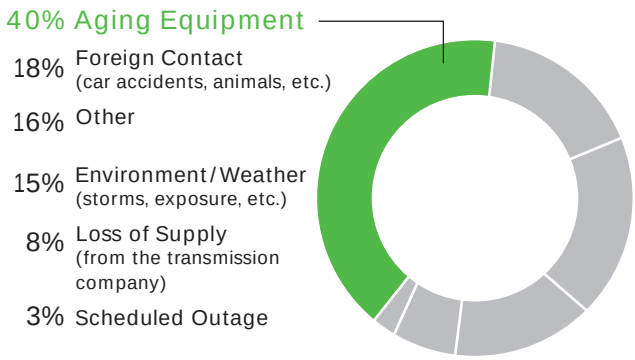
A large part of Toronto Hydro s distribution system was installed in the 1950s and 1960s. This infrastructure has served the city well beyond its expected lifespan. But now the grid is at a point where renewal investments can no longer be deferred without a ecting service reliability.

Almost 60% of the city s distribution infrastructure needs to be rebuilt over the next two decades. The price of these upgrades is approximately $5.6 billion overall.

How Fast is the System Aging?



Aging Equipment is Responsible for Approximately 40% of Outages



About 30 per cent of our distribution equipment is past its end of life and an additional 30 per cent will reach this state over the next 20 years.

7. Thinking about the aging equipment in the grid, do you feel it s best to wait until the equipment breaks down to get full value from each piece of equipment, even if it means power outages, or do you feel the best approach is to replace the equipment before it breaks down to avoid power outages, even if it means not getting all the use possible from each piece of equipment?

____ Wait until break down ____ Replace before break down

A Look at Toronto Hydro s Service Reliability

Aging infrastructure is a major challenge to service reliability. Toronto Hydro is managing this through grid renewal and modernization.

Toronto Hydro uses two main measures to evaluate service reliability: frequency and duration.

Over the past decade, the average customer has experienced:

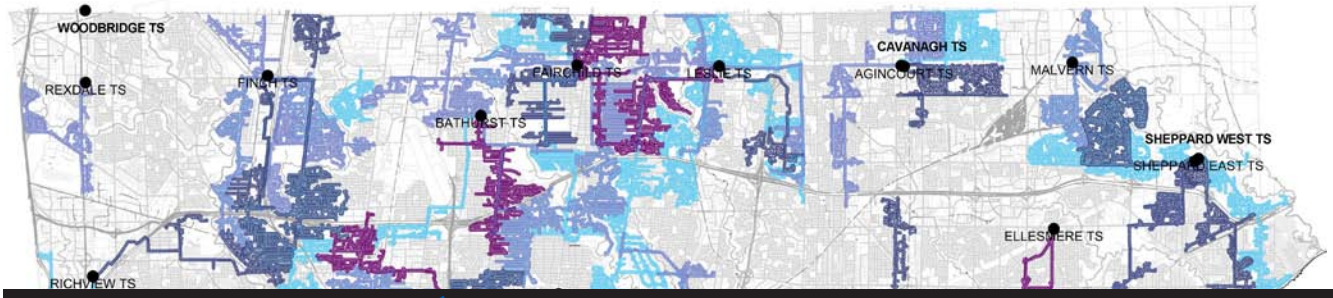
- 03 !« 1.4 and 2 outages per year.
- 03 !« 60 and 90 minutes without power per year.

While outage frequency and duration averages are trending downwards, actual customer experiences vary. Some customers on newer parts of the system may not experience any outages while others are experiencing as many as 20 outages per year.

The Least Reliable Equipment on the Block

Toronto Hydro pays special attention to circuits with exceptionally poor performance. Engineers maintain a list of circuits experiencing seven or more outages in a year, and addressing this list is a continuous e ort. The system is aging at such a rate that new poor performing circuits are added to the list almost as fast as Toronto Hydro can deal with existing problem circuits.

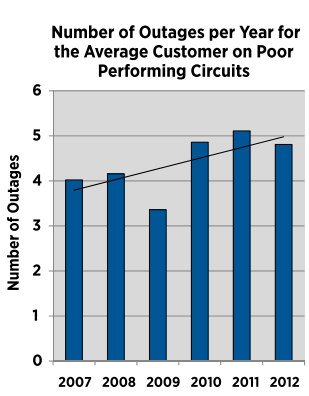
Where are Poor Performing Circuits Located?

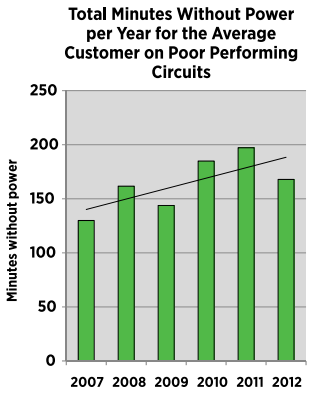


Customers Located in These Areas are Receiving Poor Service Reliability

Over the past decade, the average customer on a poor performing circuit has experienced:

- « ve outages per year (compared to the system average of two)
- «150 to 200 minutes without power per year (compared to the system average of 60 to 90 minutes for the year)





Without su cient investment in renewing and modernizing the distribution grid, Toronto Hydro expects service reliability of poor performing circuits to continue deteriorating.

8. Do you feel the current average number of electricity outages is acceptable or not acceptable?
   ____ Very acceptable ____ Somewhat acceptable
   ____ Not very acceptable ____ Not acceptable at all ____ Don t Know

9. Do you feel the current average amount of outage time is acceptable or not acceptable?
   ____ Very acceptable ____ Somewhat acceptable
   ____ Not very acceptable ____ Not acceptable at all ____ Don t Know

10. How many outages have you experienced over the past two years?
    ____ INSERT ACTUAL NUMBER

11. (IF 1 OR MORE OUTAGE) How long was the power out during your most recent power outage?
    ____ INSERT ACTUAL NUMBER

12. (IF 1 OR MORE OUTAGE) How did the power outage a ect your business?

    _____
    _____
    _____
    _____
    _____
    _____

13. Is there a certain length of time at which the costs and consequences of an outage become more serious for you?

    _____
    _____
    _____
    _____
    _____
    _____

No system delivers perfectly reliable electricity. Generally, the more reliable the system, the more expensive the system is to build and maintain. Please answer the following two questions.

14. How many power service interruptions are reasonable in a year?
    ____ No outage is acceptable
    ____ One ____ Two ____ Three ____ Four ____ More than four

15. What is a reasonable duration for a service interruption?
    ____ No outage is acceptable
    ____ 30 minutes ____ 1 hour ____ 2 hours ____ 3 hours
    ____ 4 hours or more

Changing Weather Patterns





Climate change is raising the risk of severe weather events impacting the system more frequently in the future. Toronto has experienced several major storms over the last year-and-a-half alone:

- 0@$# Hurricane Sandy (October 2012), 65,000 customers were without power.
- $ torrential downpour on July 8, 2013, caused severe ooding in stations and the underground system. Approximately 300,000 customers were a ected about half of all customers and thousands experienced extended outages.
-) 0 ice storm in its history. Freezing rain caused massive destruction to trees and power lines, leading to widespread and extended outages. About 300,000 customers were impacted and some people were without power for as long as 12 days. Many customers spent their holidays in City of Toronto warming stations.

Planning for the weather

Toronto Hydro is studying the results of these unusual weather events to determine whether changes are needed to any of the utility s best practices. In the meantime, Toronto Hydro anticipates that a number of the planned capital investments for 2015 to 2019 will help improve system performance during major weather events. For example, replacing box construction circuits (explained on page 20) with taller, higher-voltage circuits will help reduce the impact of falling trees and branches in certain areas.

Why not move everything underground?

There are pros and cons to both overhead and underground circuits. Underground circuits were hit harder than overhead circuits in the summer ooding, while overhead circuits were hit harder in the ice storm. Underground circuits can cost many times more than simply replacing the existing overhead lines; the cost for moving all circuits underground would be in the range of $15 billion. Toronto Hydro must consider these options in light of the other capital needs discussed in this workbook and the need to keep increases in customer bills as low as possible.

16. Over the past year, Toronto has experienced two unusual weather events the ooding in July and the ice storm in December. Thinking back to the two major storm events of 2013, were you a ected by either or both of these events?

____ Yes the ooding in July
____ Yes the ice storm in December
____ Yes Both
____ No neither weather event a ected my electricity

17. Whether you were personally a ected or not, how satis ed are you with Toronto Hydro s management of these events?

____ Very satis ed
____ Somewhat satis ed
____ Somewhat dissatis ed
____ Very dissatis ed
____ Don t Know

18. Is there anything in particular that Toronto Hydro could have done to improve its service to you during these events?

Grid Modernization

The pressures of economic growth and system aging are at the heart of Toronto Hydro s investment plan for 2015 and beyond. For the most part, responding to these pressures will involve rebuilding and expanding the system using tried and true distribution technology. At the same time, technological innovation in the industry has begun to change the way that utilities can manage the system and the way that customers can use the grid. The following section highlights some of the pressures and opportunities associated with the evolving technological landscape.

Here are some of the modern grid management technologies that Toronto Hydro is exploring:



Feeder Automation

« « (/ 0 +)0!3%0 $%0+0! 0« « «
isolate power interruptions.
«(,/« !1 $1) !1/0!/«
a ected by an outage.
«%%ü *0(5%),. 2/0+ 0%0%* «
service reliability in a cost-e ective manner.



Power Line Monitors

« « +3!(%%/01. * /«%/ «
the causes.
«(,%*!/« . /$0« 1/«
of interruptions to help prevent them
«. , (0%* 0%*/«
in real time.



Transformer Monitors

0! 0«2!(+ !0./!)!/«
of power.
«(,« !% 0 %0. */!)!/«
to assist with proactive maintenance and planning.



Energy Storage

« « 0+.%(%0%/« /!0+0+.« «
excess supply during o -peak hours.
« $0 5« *« ,% (5(5!«5« «
system operators to address local capacity issues throughout the distribution system and to moderate peak power costs.

19. Modernizing the grid can allow Toronto Hydro to improve reliability. Investments such as automated switches may allow Toronto Hydro to minimize the number of people impacted by outages and to restore electricity to most customers in a matter of seconds. Given there are many other areas of needed investment, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for Toronto Hydro to invest now in modernizing the grid?

_____ Very important
_____ Somewhat important
_____ Not very important
_____ Not important at all
_____ Don t Know

Here are some of the new technologies that are changing the way that customers use the grid:



Electric Vehicles

allows Toronto Hydro to develop charging pro les for all vehicle models.

vehicles on the lifespan and performance of equipment and make proactive upgrades when necessary.



Making Room for Renewable Generation Projects

Solar power and energy-from-waste facilities are renewable forms of distributed generation that are growing in popularity and a ordability. Toronto Hydro is mandated to connect distributed generation as part of the province s Feed-in Tari program. Since 2012, Toronto Hydro has connected more than 375 distributed generation projects to the grid.



5 HOW WE RE MANAGING GRID PRESSURES

This chapter covers the work Toronto Hydro is doing to address grid challenges. It includes information about historical grid investments, ongoing capital projects and productivity improvements.

Working Hard to Improve Reliability

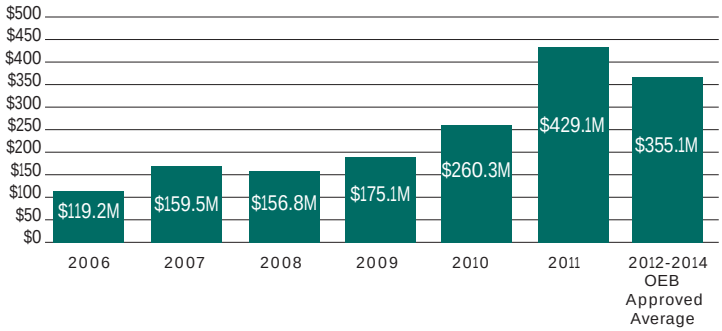
Since 2006, Toronto Hydro has invested approximately $2.5 billion in infrastructure renewal. This investment represents some of the largest construction programs in the utility s history, replacing approximately:

« «%(-0./ «+ « %*# «(%*/
« «(«(/
« «0. */!)!/

From 2006 to 2009, Toronto Hydro gradually increased its capital spending on poor performing feeders and underground cables that were negatively impacting reliability.

In 2010 and 2011, the utility increased spending to a level needed to execute a broader grid renewal and modernization program.

Toronto Hydro has increased capital spending



The following case studies provide a snapshot of major projects being executed across Toronto Hydro s distribution system. Feel free to read about whichever projects interest you.

What s Happening with the Overhead System?

Box Construction

« !/0+05,*2!$!« installed in the former City of Toronto.

CHALLENGES:

« (+/*0«%. 1%0/%0«%þ1(0« for crews to safely access equipment.

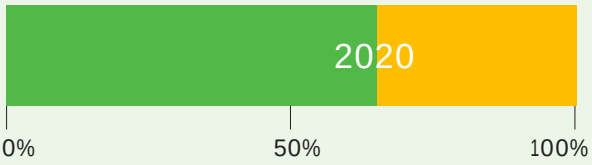
« 3!0 #(/03% /(*#/*!« overhead feeders.

«(! 0.% (« , %05%/*0$%. *!« « feeders making it di cult to accommodate the increasing number of large customers in the downtown core.

SOLUTION:

« +.+0+5 .+%/#1((5«+2!0%# +4« « construction to modern standards, which will help improve safety, reliability and exibility.

PROGRESS BY 2020:



PLAN FOR 2015-2019:

« $0%(%05%/4% 0%.+4%)0(5« 3 per cent of its budget to box construction conversion.

What s Happening with the Overhead System?



Rear Lot Feeders

« !/0+05,k*2!$!«+/0.1 0%+* «
installed in residential backyards during the 1950s and 1960s.

CHALLENGES:

« + 0%+*/%0«%1(0*+./+/0(5« «
to access and repair, especially during major storms.

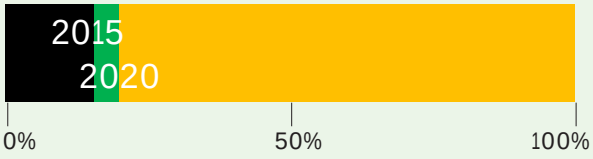
«10 %0/«#* «+%0%*%0 /4,! 0!« «
to fail at an increasing rate.

« :* !/% %(%05%/«,0!0% (/ 05%/«
for crews and the public.

SOLUTION:

« $10%(%05%/«+2!0%0$/!/«
to safer and more reliable underground streetside construction.

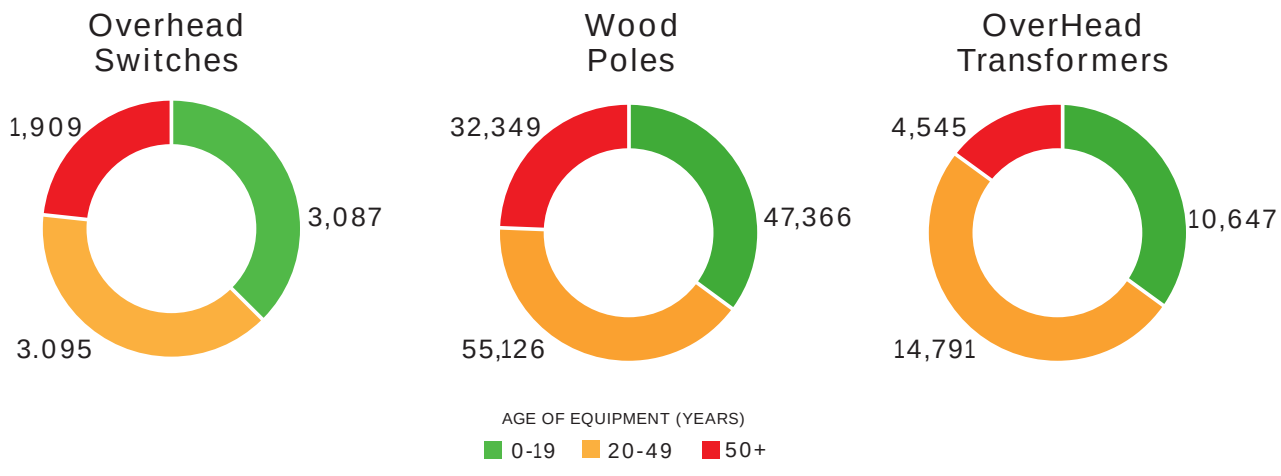
PROGRESS BY 2020:



PLAN FOR 2015-2019:

« +.+0+5 .+%/4,! 0%0+«% 0«
approximately 2 per cent of its budget to convert this legacy construction to standard.

How Old is the Overhead System?



What s Going on with the Underground System?



Direct Buried Cable

« !/0+#5055,*!#1*«
construction where cables are laid directly in underground trenches without a protective barrier.

CHALLENGES:

« (/« 1/ !0% (0+10#« ! 1/
they are exposed to environmental stress, including excessive moisture.

« &%05$/ (/«. *!
immediate repair or replacement.

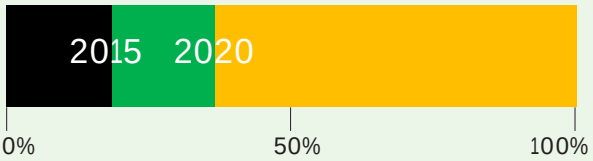
«*« «%.! 0«1.%!« (/« 1/!
than half of all outages associated with underground equipment.

SOLUTION:

« +.+0+ .+%/(%#%.! 0« 1.%!« (
with water resistant cables in plastic ducts, encased in protective concrete.

« $%/«+/0.1 0%+%/«+0 0%2! 1/%0«
extends the life of the system and allows for easier repairs.

PROGRESS BY 2020:



PLAN FOR 2015-2019:

« *!#1*«%. 1%0«(%/,! 0!0+«
account for approximately 18 per cent of the proposed budget.

«0%/0$. #0« ,%0 (#)%*0$(*«
addressing underground equipment including direct buried cable, switches and transformers.

What s Going on with the Underground System?



Chambers, Vaults and Ducts

« !/0+1*1#1*«%2%(%*/0.1 01.k
that houses and protects Toronto Hydro s electrical equipment.

CHALLENGES:
« $/k/D/D!%+.0%1/%#
outages.
« $5«(/0+5 .+%/#1((5 1%(%$/k
crews working in vaults and chambers.

SOLUTION:
« +.+5 .+%/#1((5 1%(%$/k
structures.

PLAN FOR 2015-2019:
Underground civil renewal work is expected to account for approximately 2 per cent of the renewal budget for 2015-2019.



Leaking Paper Insulated Lead Covered Cable

Paper insulated lead covered (PILC) cable was the rst type of underground cable installed in Toronto.

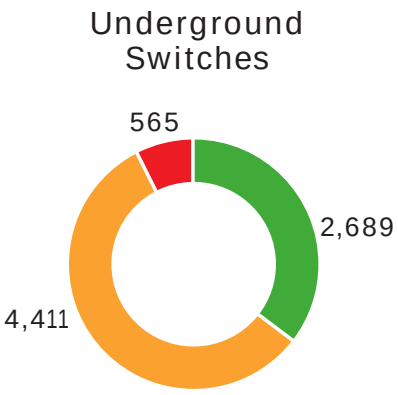
CHALLENGES:
« /0$5$(«/%k. %
leaking oil.
« ! %* (/« *«%(«*/$!«
sometimes violently.
« 0.% 0!k 5(0%*/$ 2k %./«
costly and time consuming.

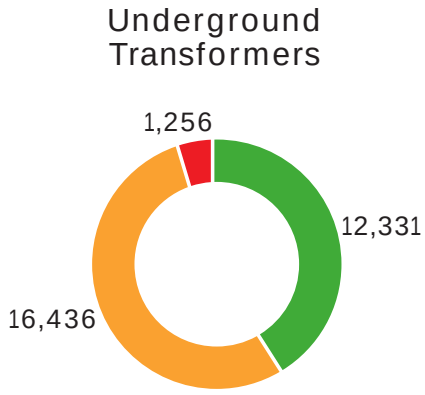
SOLUTION:
« $k0%(%05$/« %/3%0$0$k
oldest stock of PILC cables and repairing all of the leaks at once.

PLAN FOR 2015-2019:
« %.3+.%/!.! 0!0+« +10.«
approximately 0.4 per cent of the budget for 2015-2019.

How Old is the Underground System?

AGE OF EQUIPMENT (YEARS)
0-19 20-49 50+





What s Happening to the Underground Network in the Downtown Core?



Network Vaults

Refers to civil infrastructure that houses underground transformers and other underground electrical equipment unique to the downtown system.

CHALLENGES:

« (0 % +)
are causing rebar and the roofs of network vaults to deteriorate and corrode.

« * + / $ « . ((, / % * #

« ' « . (% * # * 3 0 % / «) % * #
electrical equipment.

SOLUTION:

« + . + 0 + 5 . + $ / « 1 % (% 1 (0 / / % #
higher quality materials like galvanized rebar and corrosion-resistant beams.

« $ % / 1 (0 / % * « + 0 2 % * # « 1 / 0 ! / «
because it lengthens the life of new structures.

PLAN FOR 2015-2019:

« + . + 0 + 5 . + (7 0 + % 0 . + 4 %) 0 (5 «
2 per cent of its budget to rebuilding network vaults.



Obsolete Network Equipment

Refers to electrical assets in the downtown network system that are failing and are no longer used.

CHALLENGES:

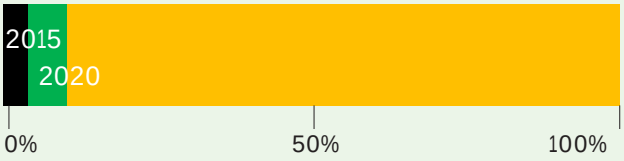
« +) 0 . % (/ D / % (% 1 (0 « « «
their age and wear; particularly bertop network units installed in the original system.

« $ % (1 $ 2 1 (0 ! % * 2 1 (0 3 $ % $
require extensive repairs and cause outages impacting a large number of customers.

SOLUTION:

« + . + 0 + 5 . + , ! 0 / 0 + « + 0 % 0 $ 1 («
proactive replacement of this equipment.

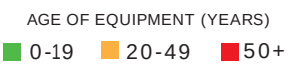
PROGRESS BY 2020:

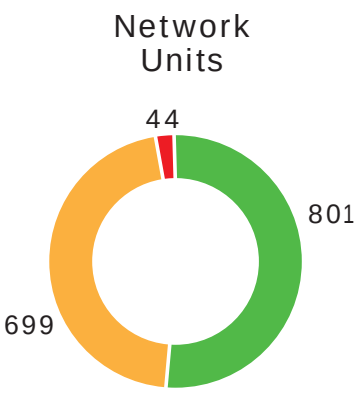


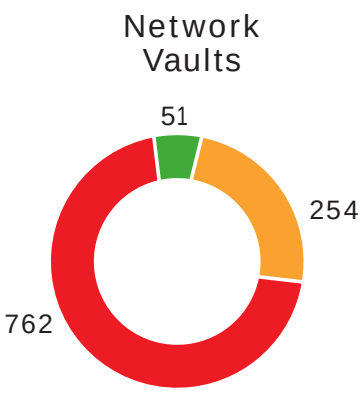
PLAN FOR 2015-2019:

« + . + 0 + 5 . + (7 0 + % 0 . + 4 %) 0 (5 «
2 per cent of its capital budget to these network projects.

How Old is the Underground Network?







What s Going on with Toronto Hydro s Distribution Stations?



Obsolete Stations Switchgear

Refers to electrical equipment used to switch load between feeders inside the substation.

CHALLENGES:

« +)k3%0 $#%/ 0%0/ %#k
lifespan and is now obsolete.
« .05 .%/«1/0)k« .% 0%*#!0 %*« «
parts that are no longer available, but this is increasingly expensive, unreliable and unsustainable.
« /(0k%,)!0 H 0!0% (k 05«
risks to sta within the substation building and could potentially cause signi cant damage to surrounding equipment.

SOLUTION:

« +.+0+5 .+4,! 0/0+(k
number of these units over the course of its capital plan through its Stations Switchgear Renewal program. This is expected to help minimize maintenance and operating costs and improve system reliability.

PLAN FOR 2015-2019:

« $k0%+3%0 $#(«
program accounts for approximately 4 per cent of the proposed budget and three quarters of the total proposed stations renewal budget.

Stations Expansion

Toronto Hydro is expanding the capacity of its distribution grid through stations upgrades and expansions.

CHALLENGES:

« $k%05/#3%#,1(0%+%/k0.!/%# «
the grid.

SOLUTION:

« +.+0+5 .+%/«.!/%#$%/3%0$«
mix of cost-e ective solutions including new stations, stations upgrades and the purchase of mobile switchgear units that can be deployed during widespread outages.

PROGRESS:

« +,(*0 0%+3k*!#1*«
transformer station, is being constructed at the Roundhouse Park next to the CN Tower to help alleviate capacity constraints in the downtown core.
« $k0 0%*3%((« « %0%* («
capacity equivalent to 70 skyscrapers, allowing Toronto Hydro to take other aging stations o ine for needed repairs and upgrades.
« $k&! 0%/4,! 0!0«k},(D!« «
by the end of 2014.

PLAN FOR 2015-2019:

« +.+0+5 .+,(*0+(0k
approximately 14 per cent of its renewal budget to stations expansion.

How old is the Distribution Stations Equipment?



What s Happening with Grid Modernization?



Feeder Automation

Refers to overhead intelligent switches installed on feeders to detect and isolate outages.

- « $¥k3%0 $¥/« .¡k#))!0d« #%6k «
  feeder outages and will open and close accordingly.
- « .#05 .$ /‰*/0 ((!«10} 0!«
  switches on 10 of its worst performing feeders to test its e ectiveness.

PLAN FOR 2015-2019:

- «0 ((%¥k3%0 $¥/$2k+2!0+« k
  cost e ective technology that signi cantly reduces outage impacts on problem feeders.
- « .#05 .‰/«*/% !%*#% 0%*#
  approximately 3 per cent of its capital budget to feeder automation projects.

How is Toronto Hydro Keeping the Business Running?



In addition to investing in grid renewal, Toronto Hydro must invest in the tools required to keep the utility going. This includes vehicles, facilities and information technology (IT).

CHALLENGES:

- « $% (¥k1/0« 3(()k%0%k+20$0«.3/« ««
  can carry out work safely and e ciently.
- « %/«*%* .! /%*(5%),-0 *0« /,! 0‰0%(%05«
  management. Engineers, project managers and construction crews have shifted from manual paper drawings to digital records made possible by computer software that helps sta design and track projects.
- « },10!/«* k03 .k1%‰(.«
  maintenance and updates.

SOLUTION:

- « +.+0+5 .+%/«+0%1%0+s(k /% « «
  IT hardware and upgrade software as necessary.
- « .#05 .(*/0d(‰0$k %«
  system that crews use to communicate with system operators when working in vaults and chambers to help reduce safety risks. The existing system will no longer be supported by the vendor after 2016.
- « $‰0%(%05«(/(*/0d(%0/k %*d1: k
  management IT system which supports a number of critical engineering, project planning, human resource and nance functions.
- « $¥k5/0}/«.k0 0!«* k(*#«
  adequately supported by the vendor.

Stretching your Electricity Dollars

Reducing Strain on the Grid

Toronto Hydro is reducing strain on the grid by supporting provincial conservation and demand management programs for residential, business and industrial customers. These programs are not generally an alternative to renewing the aging distribution system in the near-term, but they may help defer the need for capacity expansion and renewal investments over the longer-term.

Conservation Program Results from 2012

Here is a look at conservation programs provided to customers and the electricity savings they yielded.

saveONenergy℠ Conservation Programs	Results	MW Saved	MWH Saved
FRIDGE & FREEZER PICK-UP	2,802 refrigerators and freezers collected	0.2	1,092
COUPONS	Bi-annual customer events and coupons for energy e cient products held at participating retailers	0.2	3,606
DEMAND RESPONSE CONTRACTUAL DR3	48 commercial and industrial customers contracted to reduce energy use at speci ed times	14.7	312
SMALL BUSINESS LIGHTING	3,498 lighting retro ts installed	2.5	9,383
HEATING & COOLING INCENTIVE	13,047 participants received an incentive for installing an ENERGY STARfi quali ed central heating or cooling system	2.8	4,782
peaksaver PLUSfi	43,149 installation	22.9	169
RETROFIT PROGRAM	1,168 project applications	15.9	80,294

Total 2012 Results: 112,200 MWh and a total demand reduction of 61,088 MW



20. For conservation and demand management programs to slow the pace of renewal and expansion, they must provide an acceptable level of certainty. How likely is it that you would participate in Demand Response programs that would allow electricity system managers to turn o equipment you are using? For residential customers, this would involve automated devices to turn o your water heater and air conditioner for short periods during times of peak demand.
    _____Very likely
    _____Somewhat likely
    _____Not very likely
    _____Not at all likely

Smart Grid, Smart People, Smart Business

Toronto Hydro is trying to temper the cost of investment by improving the productivity and e ciency of its overall business. Here s how the utility is nding ways to do more with less:

- «Reducing employee headcount Toronto Hydro has reduced sta levels by 35% and senior executives by 65% since 1998.
- «Keeping absenteeism low According to Statistics Canada, Toronto Hydro s absentee rate is 15% below the average for public and private sector companies.
- «Working safely Toronto Hydro is avoiding injuries and staying productive on the job site. The utility has achieved 3.5 million hours without a lost-time injury.
- «Reducing operating costs Toronto Hydro is downsizing work centres and relocating sta from leased buildings to utility-owned facilities that are better suited to the business.
- «Improving coordination of capital projects Toronto Hydro is executing more cost-e cient projects by grouping high-priority projects with lower priority projects in the same neighbourhoods. This allows the utility to use its crews and equipment more e ciently, and reduces the set up time and number of permits required to complete work.

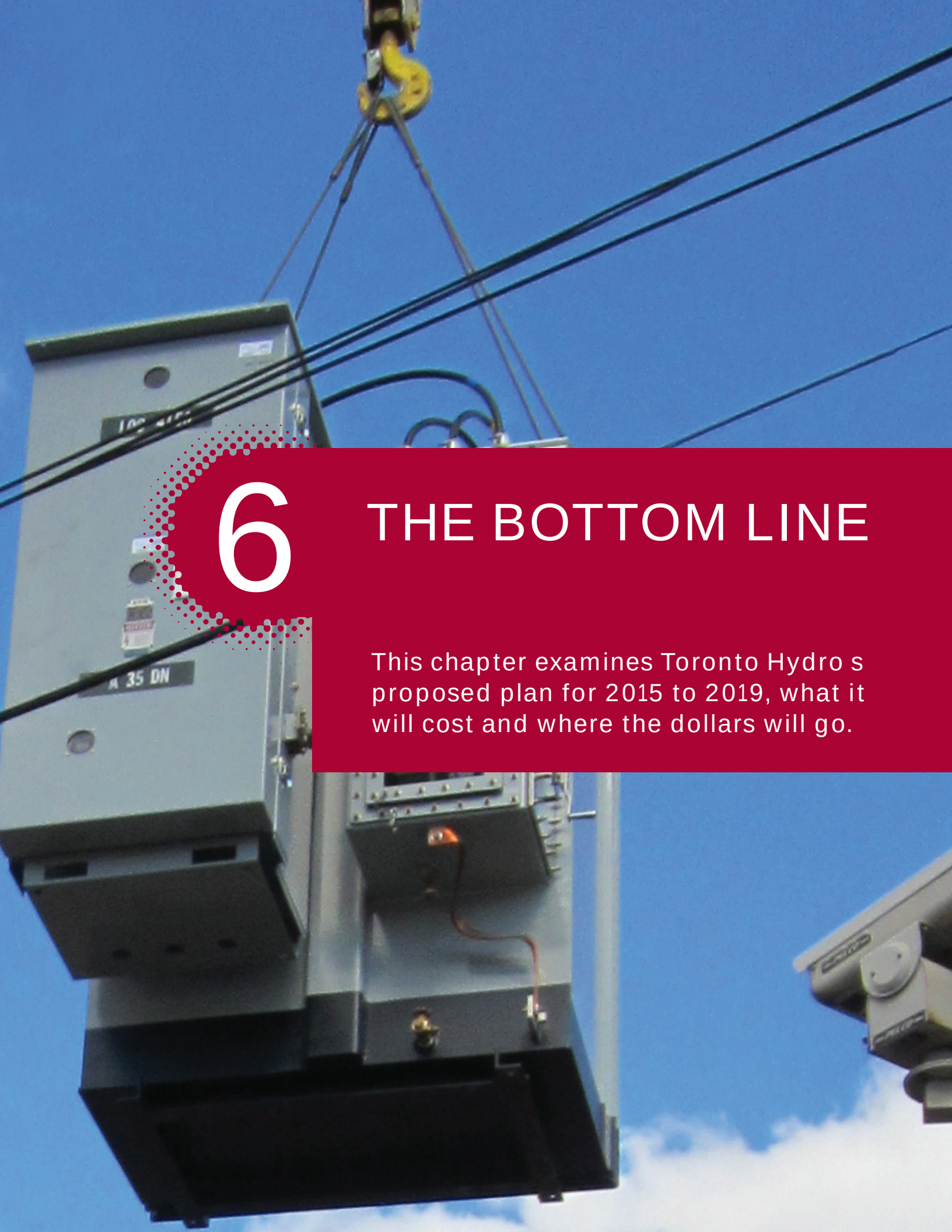


21. Given what you know and what you have read so far, how well do you feel you understand the challenges facing the Toronto Hydro grid and what they are planning to meet those challenges?
    _____ Very well
    _____ Somewhat well
    _____ Not very well
    _____ I don t understand at all

22. From what you have read and what you may have heard elsewhere, does Toronto Hydro s investment plan seem like it is going in the right direction or the wrong direction?
    _____ Right direction
    _____ Wrong direction
    _____ Not sure

23. And why do you feel that way?

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6 THE BOTTOM LINE

This chapter examines Toronto Hydro s proposed plan for 2015 to 2019, what it will cost and where the dollars will go.

Here s What We ve Covered so Far:

The Ontario Energy Board (OEB) requires that Toronto Hydro gather customer feedback on the utility s proposed investment plans. Toronto Hydro will present your feedback to the OEB as part of the rate setting process. The OEB and a number of public intervenors will hold Toronto Hydro accountable for both the way that you were consulted and the way that the utility s nal plan re ects what you said.

About a quarter of your electricity bill goes to Toronto Hydro. The money that Toronto Hydro receives is invested in the local distribution system and the people, buildings and vehicles that support it.



Much of Toronto s existing distribution system was built in the 1950s and 60s. Toronto Hydro s customers have bene ted from the longer than expected lifespan of this equipment.

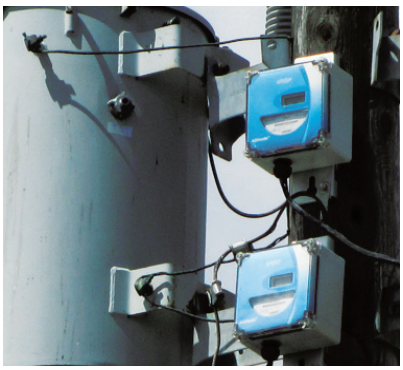
Today, much of the system is at an age where it must be replaced to maintain the reliability that Torontonians expect. Renewing the system will help ensure that the next generation of electricity users enjoys the same long-term value-for-money as previous generations.

Toronto Hydro is also dealing with other pressures, like the need to build more system capacity to accommodate the city s growth and the need to upgrade outdated and unsupported IT systems.



At the same time, the industry is changing, and Toronto Hydro has the opportunity to explore innovative grid modernization technologies that will help the utility cost-e ectively improve system performance and reduce the risks and costs associated with aging equipment over the long-run.

Renewing the system for the next generation will take more than a decade, but delaying these investments is expected to gradually worsen reliability across the system and lead to even higher bill increases down the road.



In recognition of growing capital needs, Toronto Hydro has been working to reduce operating costs by reducing employee headcount, avoiding injuries, and downsizing work centres.

The Dollars and Cents

Toronto Hydro is preparing a 2015-2019 investment plan that will require an annual bill increase of approximately $2.35 on the monthly bill. This amounts to a total increase of approximately $11.75 per month by 2019 compared to 2014 electricity rates.



Here s how Toronto Hydro believes your electricity dollars should be invested during these years:

Replacing Aging and Obsolete Equipment
These investments are paced and prioritized to maintain reliability standards and to address the worst performing feeders rst. Introduction of modern equipment standards is expected to reduce the impact of storms.

47.1%

Expanding Capacity for Long-term Growth
Expanding the capacity and exibility of the local distribution network to accommodate forecasted growth in electricity demand.

14.3%

Connecting Customers
Bringing new customers onto the system; these investments are mandatory, but the cost is generally recovered through the additional revenue that new customers contribute.

11.2%

Improving Reliability by Recon guring Circuits
Targetted investments to cost-e ectively reduce the impact and frequency of outages. For example, converting main feeder sections from overhead to underground will help reduce the impact of future storms.

8.0%

Updating IT Infrastructure
Replacing outdated and unsupported software and communications systems that are critical to Toronto Hydro s planning, operations and outage response.

7.8%

Accommodating Construction Projects in the City
Relocating or recon guring distribution equipment that is on or near the path where other agencies are working.

3.3%

Modernizing the Grid
Introducing innovative technologies like intelligent switches and sensors that are expected to cost-e ectively improve the reliability of the system and reduce the risks and costs associated with aging equipment.

3.2%

Maintaining and Upgrading Customer Meters
Routine meter replacements and improvements to data quality.

1.9%

Building Maintenance
Routine capital investments to maintain Toronto Hydro s facilities.

1.3%

Connecting Renewable Generation
Installing protection and control equipment and energy storage facilities that allow for the e cient use of new renewable generation connections.

0.9%

Vehicles and Equipment for Crews
Routine capital investments in Toronto Hydro s eet of trucks, cars and equipment

0.7%

Accommodating Electric Vehicles
Accommodating electric vehicle connections to the grid and investing in ways to manage and optimize electric vehicle storage capacity on the system

0.1%



Have Your Say: Is Toronto Hydro Investing Wisely?

Let s Talk Priorities:



24. When you look at how much Toronto Hydro is spending on each of its investment priorities, do you think they have the balance right or would you change the relative priorities?

_____ The balance looks right
_____ They should change some of the priorities

25. What areas do you feel need more spending than planned?

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26. What areas do you feel should have less spending than planned?

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Let s Talk Pacing

Toronto Hydro s proposal is expected to lead to a total increase of approximately $30.50 on the average small business owner s monthly bill by 2019. A lower bill impact is possible in the short-term, but there are trade-o s: system performance will be worse and future bill impacts will be higher. The following table compares Toronto Hydro s plan to another likely utility management practice called run-to-failure. This approach is typical for smaller utilities with newer systems.

	"RUN-TO-FAILURE" APPROACH	TORONTO HYDRO'S PROPOSED PLAN
Description	With this approach, Toronto Hydro would only replace equipment as it fails (with the exception of critical assets such as stations equipment). This is a purely reactive approach using close to the minimum amount of funding that Toronto Hydro could receive from the Ontario Energy Board.	feeders rst. modern grid technologies and recon guring circuits.
Estimated increase in monthly bill	$17.25/month	$30.50/month
Reliability outcomes by 2019	customer: 1.6/year customer: 1.38 hours/year experiencing seven or more interruptions a year: 13 per cent	customer: 1.15/year customer: 0.65 hours/year experiencing seven or more interruptions a year: 6 per cent
Percentage of equipment past end-of-life in 2020	31 - 34 per cent	25 - 28 per cent

Why Does Toronto Hydro Think This Pace is Best?

As seen in the table above, Toronto Hydro estimates that a run-to-failure approach, when compared to the proposed plan, would result in double the average duration of outages across the system and more than double the percentage of customers on poor performing feeders. Because of the aging system, Toronto Hydro would expect reliability to continue worsening well beyond 2019 if the utility stuck with a run-to-failure approach.

Of course, the two plans presented here are not the only options for pacing system investment. Toronto Hydro can invest more or less capital to achieve a wide variety of outcomes.

So how did Toronto Hydro arrive at the proposed plan?
Since the utility is so large, Toronto Hydro s engineers rely on a software model to help calculate the year in which it is most cost-e ective to rebuild any given part of the system. The model suggests that Toronto Hydro should, in fact, be spending more than it is proposing in the years 2015 to 2019.

So why is Toronto Hydro proposing to invest less than the model recommends?
In reality, there are constraints that prevent the utility from spending above a certain amount. One such restriction is the limited number of skilled resources available to carry-out the work. Resource limitations are also and important reason why Toronto Hydro believes it is wise to invest now and not later: increasing the number of quali ed trades people takes time, and the industry will not train new workers unless there is a consistent and predictable amount of work. This means that the longer Toronto Hydro allows the system to age, the less likely it is that the utility will be able to keep up with investment needs.

Ultimately, Toronto Hydro believes that the proposed plan will deliver improved system performance at a pace that is sustainable for both the utility and the customer.

27. When you consider the options outlined in the table on the previous page, do you think Toronto Hydro s goals are too high, too low or about right?

_____ Too high _____ About right
_____ Too low _____ Not sure

28. What are the goals you feel are too high?

_____
_____
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29. What are the goals you feel are too low?

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30. Looking at the cost of the Toronto Hydro plan and the outcomes it is expected to achieve, which point of view is closest to your own?

_____ Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more.

_____ I am satis ed with the balance between outcomes and the proposed rate increase.

_____ I don t like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard.

_____ I think the bill impact is too high and Toronto Hydro needs to scale back its plans.

_____ Not sure

What Do You Think About This Review?

Toronto Hydro values your feedback. This is the first time the utility has conducted a review about its upcoming investment plan in this type of format. What did you think about the workbook?

1. Volume of Information Did Toronto Hydro provide too much information, not enough, or just the right amount?

2. Content Covered Was there any content missing that you would have liked to have seen included?

3. Outstanding Questions Is there anything that you would still like answered?

4. Suggestions for Future Consultations How would you prefer to participate in these consultations?

Technical Glossary

Cable Chamber An opening to the underground duct system that facilitates the installation, removal, inspection and repair of cables.

Cable Fault A hole in a cable caused by a short circuit (due to corrosion, overloading over time, water, age) which can result in an explosion.

Circuit A continuous system of conductors providing a path for electricity.

Circuit Breaker A protective switch in a substation that automatically disconnects power to the circuit in the event of a fault. Performs the same function as a circuit breaker in a home.

Conductor An object that permits the ow of electricity, like a wire or cable that allows electricity to ow along its length.

Distribution Transformer A piece of equipment required to reduce voltage to a level that can be used by customers in their homes and businesses.

Feeder A distribution circuit carrying power from a substation to customers. Feeders consist of circuits and other electrical equipment supported by civil infrastructure like poles and ducts.

Kilovolt = 1,000 volts

Megawatt Equals 1,000 kilowatts or enough to power 10,000 100-watt light bulbs.

Primary Cables Cables that distribute electricity throughout the system at a higher (primary) voltage (i.e. greater than 750 volts).

Secondary Cables (or Mains) Low voltage cables that are connected to the secondary (low voltage) side of the distribution transformer and deliver current to customers.

Substations Large power transformers and miscellaneous protection and control equipment (e.g. circuit breakers) that transform electricity from a higher primary voltage to a lower primary voltage. Substations are part of generation, transmission and distribution systems.

Switch A device for isolating a piece of equipment or a section of feeder to allow repairs or replacements to be made on them while in a safe, de-energized state.

Transformer A device used to transform voltage levels to facilitate the transfer of power from the generating plant to the customer.

Transformer Vault A large room (above - or below-ground) that houses transformers, switches and protective equipment.

Volt A measure of electricity. The Standard International unit of electro-motive force, the di erence of potential that would carry one ampere of current against a resistance of one ohm.*

Watt A measure of the work electricity can do.

1,000 watts = 1 kilowatt (the amount of power used by 10 100-watt light bulbs)

1,000,000 watts = 1,000 kilowatts = 1 megawatt

*Source: Oxford Dictionary of Current English

Attendees

Date

Action Log

Note: If applicable, this slide contains information about customer-specific issues and outlines the action items undertaken by the parties to address those issues.

Agenda

1. Introduction
2. Improving Reliability and Services – Infrastructure Renewal Program
3. Key Account Management Services
4. Conservation and Demand Management (CDM)

Regulatory Infrastructure Renewal Up-date

- The Ontario Energy Board (OEB) has approved the Toronto Hydro 2013 Rate Application
  - Decision issued on April 2, 2013

- Toronto Hydro requested a rate increase to cover Incremental Capital for a variety of asset renewal projects
  - The capital program is intended to enhance safety and reliability of the distribution system for the benefit of customers and employees.
  - The decision provides for an increase in capital spending to address aging electricity distribution infrastructure, and allows for the construction of the new Copeland Transformer station in downtown Toronto to relieve existing stations and provide for future load growth in the area. Copeland Station will be the first transformer station built in downtown Toronto since the 1960s.

Regulatory Environment

Cost of Service

- To 2010
- Annual review of Operating and Capital Expenses to set rates
- LDC evidence tested through a public hearing process with Intervenors

Incentive Regulation + Incremental Capital

- 2012 – 2014
- Rates set by formula
- Operating expenses are fixed less a productivity factor
- Incremental capital is required to maintain asset renewal program; specific projects must be justified through the hearing process

Custom Incentive Regulation

- 2015 – 2019
- Rebase of OpEx and CapEx in 2015
- Regulatory goal of giving customers rate certainty for a 5 year period
- Risk to LDC of fixed budgets
- Opportunity for LDC to present evidence for unique needs for funding beyond the base formula

40% of Outages in Toronto are Due to Aging Equipment

- Some areas of the city are experiencing an unacceptable number of power outages. Thanks to our capital investment in infrastructure, equipment-related outages are down 10% since 2009. In 2013, we expect to invest approximately $327 million in infrastructure upgrades to help improve service reliability.

Investments to Improve Reliability

2013 Capital Investment by Ward (approximate)

	Capital Projects Category			
Ward	Overhead	Stations	Underground	Total Ward
1	5,740,767	507,036	3,449,452	$9,697,255
2	6,808,892			$6,808,892
3	2,545,439		268,122	$2,813,561
5	4,549,263	855,846	227,422	$5,632,531
6	2,469,781			$2,469,781
7	5,554,819		753,738	$6,308,557
8	876,595	1,558,702	3,912,393	$6,347,690
9	1,821,589		2,289,126	$4,110,714
10	660,842	826,110	317,566	$1,804,517
11	5,859,475	326,000	7,784	$6,193,259
12	2,920,027			$2,920,027
13	1,025,728		478,720	$1,504,448
14	63,788		206,859	$270,647
15	930,827			$930,827
16	37,947	83,300	1,727,030	$1,848,277
17	1,609,892		439,587	$2,049,479
18	120,902	87,935	2,312,805	$2,521,642
19	2,532,504	311,571	156,994	$3,001,070
20	12,000	761,971	6,799,544	$7,573,515
21	926,585		2,841,381	$3,767,966
22	79,534	422,007	3,175,399	$3,676,939
23	4,573,675	623,154	1,842,894	$7,039,723
24	559,957	332,500	2,199,797	$3,092,254
25	889,820		3,274,502	$4,164,322
26	497,859		2,031,802	$2,529,661
27	16,166	472,648	3,865,500	$4,354,314
28	700,000		7,532,868	$8,232,868
29			253,009	$253,009
30	1,991,317	151,503	436,254	$2,579,074
31			151,444	$151,444
32	10,323		1,031,598	$1,041,920
33	208,844		4,409,712	$4,618,556
34	1,661,766		717,608	$2,379,374
35	611,172			$611,172
36	816,927		309,593	$1,126,520
37	69,495	228,302	124,219	$422,016
38	205,755	126,888	261,134	$593,777
39		7,900	3,312,212	$3,320,112
40			3,798,678	$3,798,678
41	43,405	516,456	5,404,131	$5,963,992
42			7,726,828	$7,726,828
43	243,327	417,387	787,988	$1,448,702
44			2,705,952	$2,705,952
N/A	456,139	78,007	183,099	$717,246
N/A (Across City)	2,419,113	82,500	3,536,880	$6,038,493
Grand Total	$63,122,256	$8,777,723	$85,261,624	$157,161,604

Investments to Improve Reliability

Provincial Measures for Reliability

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)

Note: Momentary interruptions, those less than 1 minute, are not included

DO YOU LIVE/WORK/TRAVEL HERE?

Toronto Hydro's Grid: Areas of In Need of Attention

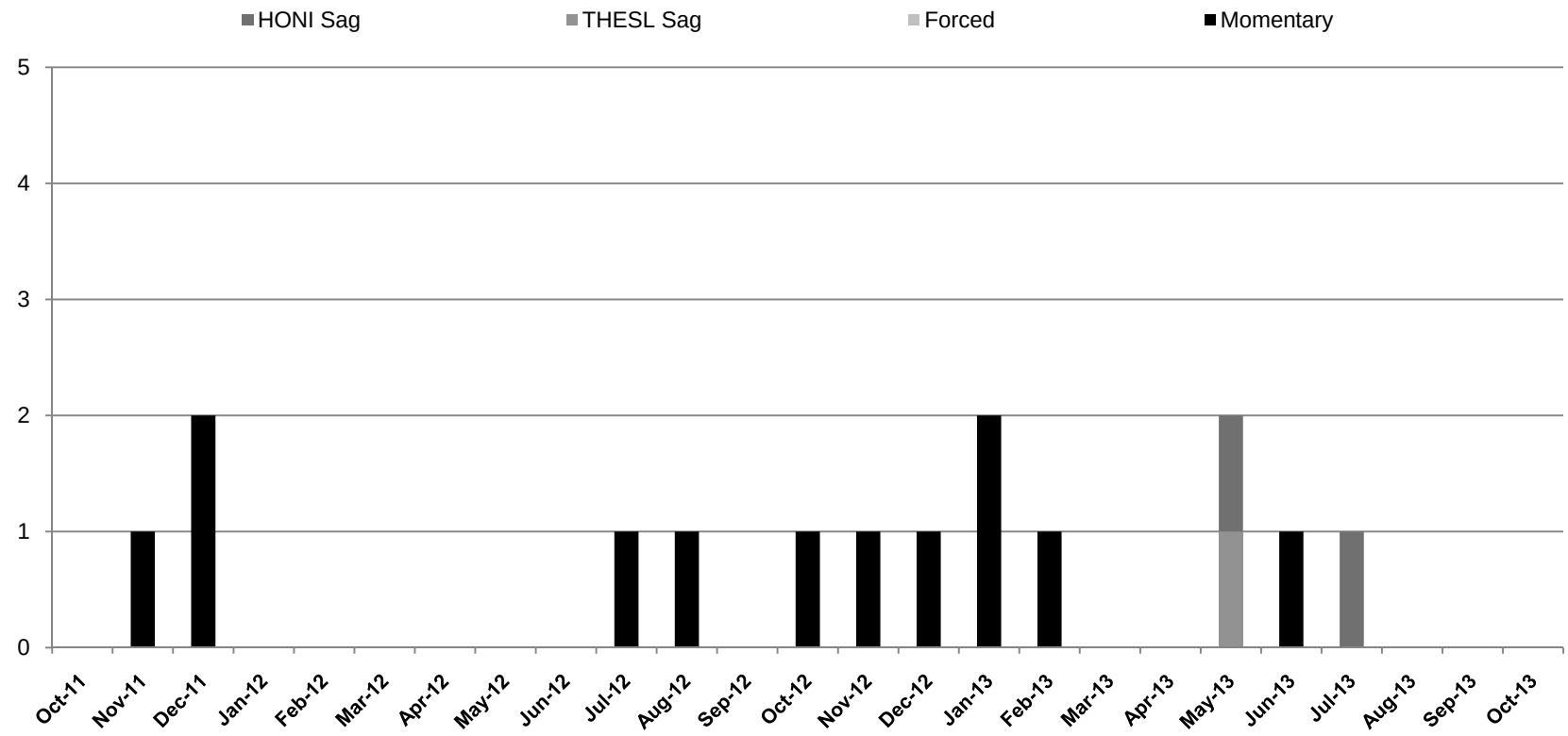


Your Outage Experience

Note: If applicable, this slide includes customer-specific outage information for each of the customer's facilities.

Your Power Reliability/Quality Summary

Note: If applicable, this slide includes customer-specific power reliability information, which may be presented as follows:



Root Cause Analysis

Note: If applicable, this slide includes a root cause analysis of a particular power reliability/quality issue (i.e. momentary outages) that the customer is experiencing, and provides an explanation of the mitigation measures that Toronto Hydro has taken or proposes to undertake to address the issue.

Inspection Programs and Status

Note: If applicable, this slide includes a description of the inspection programs that apply to the specific customer, and an update with respect to the status of those program for the given year. For example:

1. Infrared Audit Program

   Infrared inspection of both primary and secondary overhead line components is performed. This identifies potential “hot spots” and allows corrective measures to be taken before they have an impact on system reliability.

2. Cable Chamber Inspection Program

   Cable chambers for underground feeders are inspected for electrical and civil deficiencies.

3. Other Feeder Asset Inspections

   Inspections performed on assets which are attached to the same feeder that supplies the Molson plant. Insulators are pressure washed to reduce the possibility of flashovers.

2013 Rate Impact

General Service, 50 kW to 1MW

(150,000 kWh/month 349 kW, 90% PF)

Year	Distribution	Transmission	Regulatory	Commodity	Total
Change	3.4%	12.5%	-5.4%	10.2%	7.7%

General Service, 1 MW – 5 MW

(800,000 kWh/month, 1,600 kW, 90% PF)

Year	Distribution	Transmission	Regulatory	Commodity	Total
Change	3.0%	12.4%	-5.4%	10.2%	7.7%

Large User, > 5MW

(4,500,000 kWh/month, 8,491 kW, 90% PF)

Year	Distribution	Transmission	Regulatory	Commodity	Total
Change	3.2%	12.5%	-5.3%	10.2%	7.7%

- Rates reflect current best estimates and are subject to change
- Rate Order approved by the OEB on May 9, 2013, file EB-2012-0064; rate increases effective June 1.
- Commodity cost based on HOEP+GA rates

Toronto Hydro's Key Account Management Service

The Importance of Toronto Hydro's Business Customers

- Toronto Hydro has over 80,000 business customers
  - Representing all sectors – Municipal, Academic, Healthcare, Commercial, Industrial
  - 530 of these customers have a demand of over 1,000 kW – the Key Accounts
  - Customers with multiple sites, such as larger property management or institutional customers are also aggregated as a Key Account
- We recognize these customers as distinct from our residential customers:
  - Businesses support the economic development of the City and provide employment
  - You are important to THESL and the City - Substantial electricity revenue comes from THESL business sector – 12% of our customer base provides 80% of our revenue
  - We recognize that Business customers can be significantly affected by outages in lost productivity of goods and services produced and delivered, and human resource management to name a few
  - Business customers have sensitive technology. Power quality is essential to uninterrupted operations.
  - Communications is vital to outage management.

Key Account Customer Profile

Total Customers

530

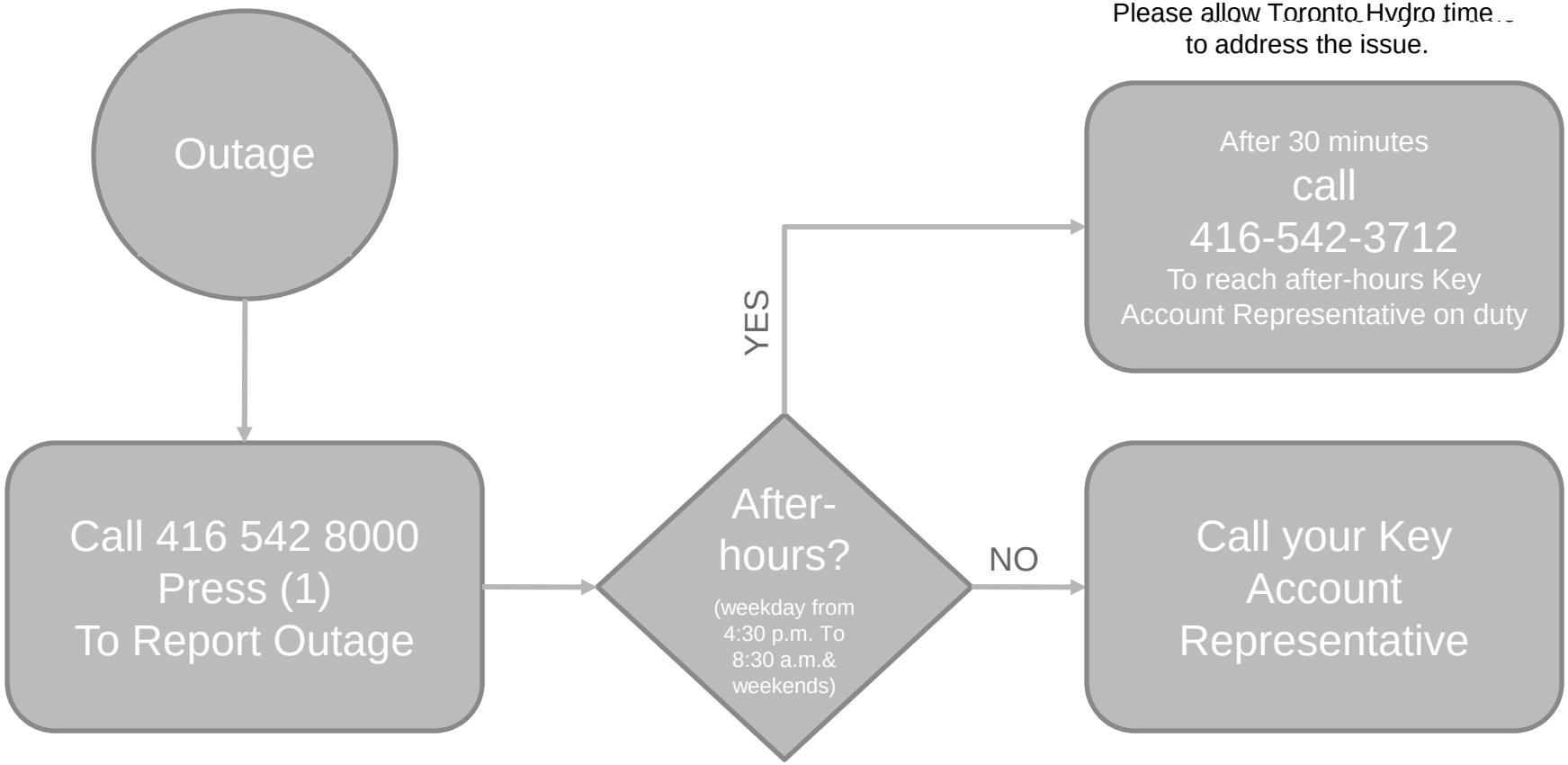
Revenue per Customer

Customer Segment	Total Revenue	Total Customers	Revenue Per Customer
Large Business	>1,000kW	$728 million	530	$1,373,280
Medium Business	50 to 1,000kW	$1,089 million	12,129	$89,762
Small Business	<50kW	$273 million	68,431	$3,989
Residential	<50kW	$709 million	637,910	$1,111
		$2,799 million	719,000	

Key Account Management Services

- Account Management
  - Single point of contact for all aspects of the relationship with Toronto Hydro
  - To manage issues and ensure customer needs are met
  - Work with internal Departments to improve levels of customer service
    - Distribution System, Customer Information System, Conditions of Service, Metering Systems, Billing, Collections, Rates, Power Quality & Reliability, CDM programs, Ministry of Energy, Ontario Energy Board and Independent Electricity System Operator, Regulatory Information
- Outage Management
  - 24/7 After hours outage response service
- Data Management
  - MV90 online energy consumption data
  - Special energy consumption data requests
- Billing Services
  - eBills
  - Pre-authorized payment

Power Outage -
Key Account Call-in Process



New Proactive Outage Management..

- Severe weather during the month of July impacted Toronto Hydro service and caused several prolonged outages throughout the city.
- The outages generated significant amounts of feedback from customers, including more frequent outage status updates are needed for businesses.
  - Key contacts have a need for ongoing updates related to outages at their facilities in order to shift business operations accordingly.
- We are developing a commercial customer outage communication program whereby commercial customers will receive customized outage alerts during severe weather emergencies via the communication channel of their choice (email, phone, text).

Continuously Improving Our Service …

Communications

- Power outage email notification – 2014 launch
- Quarterly Newsletters – “eConnect for Biz”

Metering

- Power quality, data access, analytics

Self Service

- Enhanced energy data management (MV Web Replacement)
- On line transactions

CDM

- Incentives, training and support
- Post 2015 program development

Other …

CDM Programs

- Government
- Industrial
- Small Business
- Agricultural
- Commercial
- Institutional

Conservation and Demand Management Business Incentive Programs

Commercial & Institutional Pro grams

SMALL BUSINESS LIGHTING

- Up to $1,500 of free lighting upgrades (increase from $1,000) New!

AUDIT FUNDING

- Funding of up to 50% of the cost to conduct an energy audit New!
- Building Systems audit to promote systems balancing (hydronic, air)

RETROFIT PROGRAM

- Funding to install high-efficiency equipment and new control systems
- Cover up to 50% of the cost; $400/kW (or $0.05/kWh) for lighting and $800/kW (or $0.10/kWh) for non-lighting
- Monitoring and Targeting measure now eligible New!
- Property Managers and Facility Managers now eligible participants

EXISTING BUILDING COMMISSIONING (EBCx)

- Paid for evaluating and implementing retro-commissioning strategies of systems with chilled water plants New!
- Up to $30,000 of incentives available for investigation

New Program Opportunities

APPLICANT REPRESENTATIVE INITIATIVE

- Applicant representative receive incentive payments for successful projects - we pay you or your contractor
  - $20/KW for the first 300kW
  - $40/kW beyond 300kW

PILOT PROGRAMS UNDERWAY

- Multi-unit Residential Building Demand Response (“Suitesaver")
- Commercial Energy Management and Load Control (“Gridsaver")

Training and Support

- Energy into Action conference held spring and fall
- Dollars to $ense Workshops with NRCan
- Industry specific events: Compressed Air Workshop, Refrigeration
- Staff support on projects and process - to help identify CDM opportunities, develop business cases and file CDM applications
- eConnect for Biz Newsletter for program updates

CDM Projects Summary

Note: If applicable, this slide contains information about customer-specific CDM projects.

CDM Beyond 2014

- OPA working with LDCs to extend current programs in to 2015 based on Minister's Directive in December 2012
- Provincial Long Term Energy Plan
  - ¾Released December 3
  - ¾Commits to 6 years of stable funding
  - ¾Framework is under development between distributors, Ministry and OPA
  - ¾Recognizes Conservation First as a way to mitigate new investments in supply, transmission and distribution
    - ¾ A necessary component of regional and distributor planning processes
  - ¾IESO will evolve existing Demand Response programs
    - ¾Development of a capacity market

Summary

- Investments to improve reliability
- Key Account Management Services
  - Outage communications
  - Issue resolution
- Support available from Toronto Hydro to help identify CDM opportunities, develop business cases and file CDM applications
- Information and Training opportunities
  - Energy into Action conference held spring and fall
  - Dollars to $ense Workshops with NRCan

Disclaimer

The information in these materials is based on information currently available to Toronto Hydro Corporation and its affiliates (together hereinafter referred to as “Toronto Hydro”), and is provided for information purposes only. Toronto Hydro does not warrant the accuracy, reliability, completeness or timeliness of the information and undertakes no obligation to revise or update these materials. Toronto Hydro (including its directors, officers, employees, agents and subcontractors) hereby waives any and all liability for damages of whatever kind and nature which may occur or be suffered as a result of the use of these materials or reliance on the information therein. These materials may also contain forward-looking information within the meaning of applicable securities laws in Canada ("Forward-Looking Information"). The purpose of the Forward-Looking Information is to provide Toronto Hydro’s expectations about future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All Forward-Looking Information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify Forward-Looking Information, although not all Forward-Looking Information contains these identifying words. The Forward-Looking Information reflects the current beliefs of, and is based on information currently available to, Toronto Hydro’s management. The Forward-Looking Information in these materials includes, but is not limited to, statements regarding Toronto Hydro’s future results of operations, performance, business prospects and opportunities. The statements that make up the Forward-Looking Information are based on assumptions that include, but are not limited to, the future course of the economy and financial markets, the receipt of applicable regulatory approvals and requested rate orders, the receipt of favourable judgments, the level of interest rates, Toronto Hydro’s ability to borrow, and the fair market value of Toronto Hydro’s investments. The Forward-Looking Information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the Forward-Looking Information. The factors which could cause results or events to differ from current expectations include, but are not limited to, the timing and amount of future cash flows generated by Toronto Hydro's investments, market liquidity and the quality of the underlying assets and financial instruments, the timing and extent of changes in prevailing interest rates, inflation levels, legislative, judicial and regulatory developments that could affect revenues, and the results of borrowing efforts. Toronto Hydro cautions that this list of factors is not exclusive. All Forward-Looking Information in these materials is qualified in its entirety by the above cautionary statements and, except as required by law, Toronto Hydro undertakes no obligation to revise or update any Forward-Looking Information as a result of new information, future events or otherwise after the date hereof.

Appendix

Customer Account Profile

Note: This slide contains customer-specific account information such as consumption profiles for the customer's facilities and a breakdown and explanation of the customer's invoice.

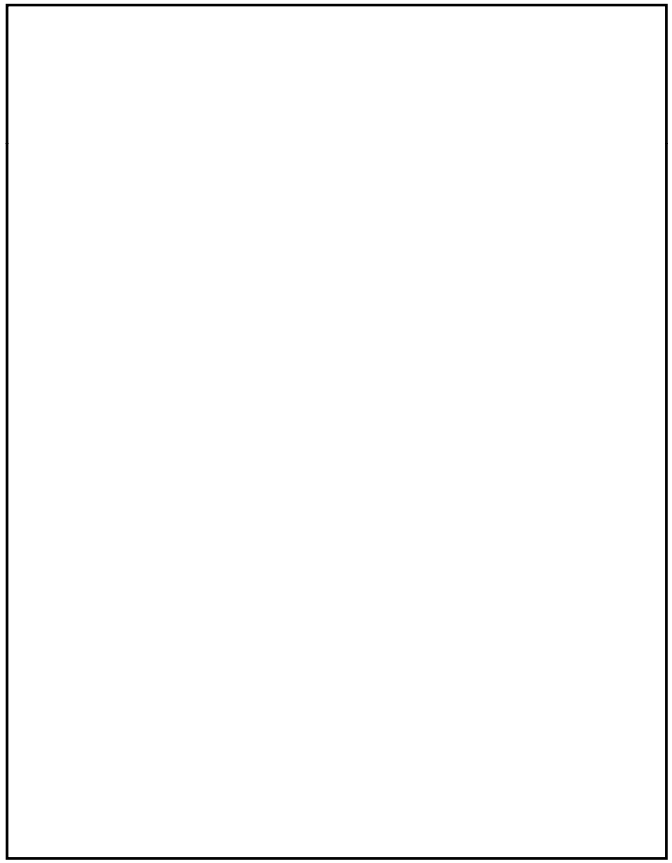
Investments to Improve Reliability

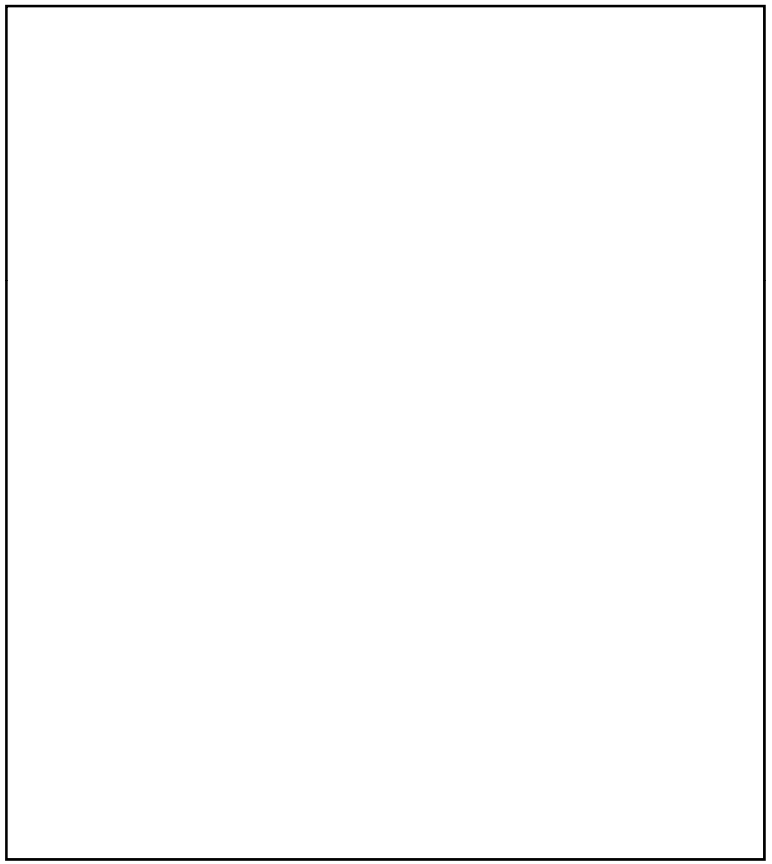
Investments to Improve Reliability

http://www.torontohydro.com/sites/corporate/LearnMore/Pages/CapitalProjectsMap.aspx

New Proactive Outage Management

- Letter sent to business customers
- Website registration





eConnect for Biz Newsletter

http://www.torontohydro.com/sites/electricsystem/electricityconservation/businessconservation/Pages/default.aspx

Web Links for Electricity Market Information

- Electricity system operation and regulation, IESO:
  http://www.ieso.ca/imoweb/siteShared/power_system.asp
- Electricity Planning:
  - Ministry of Energy: Long Term Energy Plan
    http://www.energy.gov.on.ca/en/ltep/
- Electricity Pricing:
  - Aegent Energy Advisors Inc.:
    www.aegent.ca/
  - AMPCO:
    www.ampco.org
  - E2Energy Inc.
    www.e2energyinc.com/index.php
  - IESO – Global Adjustment:
    www.ieso.ca/imoweb/siteShared/electricity_bill.asp?sid=bi
  - OPA – Global Adjustment:
    http://www.powerauthority.on.ca/about-us/electricity-pricing-ontario/understanding-electricity-system-costs/understanding-global-adjustment

STAKEHOLDER CONSULTATION

1. INTRODUCTION

This schedule details Toronto Hydro's approach to the stakeholder consultations held in preparing this application. This process is distinct from the customer engagement activities described in Exhibit 1B, Tab 2, Schedule 7.

2. PURPOSE

Toronto Hydro is committed to fostering and maintaining constructive relationships with its stakeholders and believes that active, two-way engagement is critical to achieving this objective.

As part of this commitment, Toronto Hydro undertook two stakeholder consultations with respect to this application prior to filing. This was the first time Toronto Hydro has formally consulted on a pre-filing rate application.

Toronto Hydro viewed the consultations as a forum through which a number of positive outcomes for all parties could be achieved, including the opportunity for it to:

- share broad insight into Toronto Hydro's needs and business drivers, setting the basic context in which this application is being brought forward while allowing stakeholders access to subject matter experts;
- provide more specific details of, and approaches to, the structure and content of the application;
- receive helpful input and feedback on a range of related issues; and,
- address questions or concerns prior to filing the application.

Both sessions were, in Toronto Hydro's view, positive experiences. The utility firmly believes that the participation by all those involved will ultimately contribute to a more effective and efficient hearing process.

3. APPROACH

The remainder of this schedule outlines Toronto Hydro's approach to the stakeholder consultations.

3.1. Participants

Given the separate stream of customer engagement activities occurring concurrent to this process, the intended audience for the stakeholder consultation was the regulatory community. Invitations to participate were sent to interveners of Toronto Hydro's previous rate filings and to Ontario Energy Board ("OEB") staff. City of Toronto officials were also invited to attend.

3.2. Format

Toronto Hydro held two stakeholder consultations prior to filing. Invitations and follow-up correspondence were sent out by email at least three weeks before both sessions. Efforts were made to ensure that dates and times for both sessions were chosen to maximize attendance. For those unable to attend in person, arrangements were made for remote participation.

The first consultation was held at the Toronto Hydro Hearing Room of the OEB's offices on February 11, 2014. Seventeen participants representing seven stakeholder organizations attended this consultation. A complete list of attendees is included in Facilitator's Report in Appendix A. This session was primarily an opportunity for Toronto Hydro to receive input from stakeholders. This was achieved by:

- providing an overview of Toronto Hydro's primary business needs and drivers; and,
- actively engaging in a roundtable-style facilitated discussion on a range of policy and application-related issues.

Following the first consultation, Toronto Hydro invited all stakeholders to approach Toronto Hydro with any concerns, questions or other matters relevant to the rate application at any time during the process.

The second consultation was held at the NEB Hearing Room of the OEB's offices on July 3, 2014. Eighteen participants representing eight stakeholder organizations attended this consultation. This session was primarily an opportunity for Toronto Hydro to reply to the many ideas and questions shared during the discussion at the first session and to update stakeholders on the status of the rate application. This was achieved by:

- providing specific responses to inquiries heard at the February 11 consultation; and,
- presenting on specific elements that stakeholders could expect would form part of the application.

3.3. Principles

Toronto Hydro's participation in both stakeholder consultations was intended to seek early and substantive input on its rate application. To this end, Toronto Hydro held the first consultation nearly six months prior to the ultimate filing date and involved Toronto Hydro staff representing many of the utility's core functions as presenters or participants.

Toronto Hydro expressly sought to create an environment that supported open, candid and constructive dialogue with its stakeholders. Many actions were taken to achieve this result, including:

- retaining the services of a professional facilitator to aid in fostering discussion;
- building significant time into the consultation schedule for questions and answers; and,
- carrying out the discussion on an without prejudice basis.

In accordance with this approach, Toronto Hydro did not record formal notes from either session for the purpose of inclusion in this exhibit nor can it attribute any specific element of this application, be it of substance, structure or otherwise, to a particular stakeholder. Nevertheless, the mutual benefits of those collaborations are very much embedded throughout this application. Toronto Hydro thanks those who participated in one or both of those consultations for their helpful insights and contributions.

3.4. Appendices

Appended to this exhibit are two documents related to the consultations:

1) Appendix A, Facilitator's Report; and
2) Appendix B, Terms of Reference.

Facilitator's Report on Toronto Hydro-Electric System Limited Stakeholder Consultation

February 11, 2014
And
July 3, 2014

Reported By:
Bob Betts, P. Eng.
President & CEO
Regulatory Support Services
(A Division of R.J. Betts Enterprises Ltd.)
Cambridge, Ontario

Regulatory Support Services

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I. Background:

ThisStakeholderConsultationis the first of two establishedby TorontoHydroElectricSystemLimited ("THESLor "TorontoHydro") to gaininput from interestedstakeholdersinto the designof their Custom IncentiveRegulationMechanism("CIR") applicationfor the years2015to 2019.

In preparationfor this consultationTorontoHydrocirculatedcorrespondenceto stakeholdersindicating their interestto engageintervenorsand OEBstaff in a consultationon its CIR. Theyproposedto hold two consultationsessions.Thefirst wasdesignedto shareinformation about THESL'scurrent business needsand drivers,and to facilitate a dialogueabout potential approachesto addressthem in the 2015–2019CIRapplication. Thesecondconsultationsession,which I wasnot able to attend for personal reasons,washeld to allow THESLto reply to many of thingsit heardduring the first sessionand to providedetailson its pendingCIRapplication.

TorontoHydroindicatedthat it wasexplicitlyseekingearly,candidand substantiveinput on its CIR applicationin the hopesof achievinga more effectivehearingprocess.In proposingthis plan,THESL emphasizedits commitmentto foster and maintainconstructiverelationshipswith its stakeholders, believingthat activetwo wayengagementis criticalto achievingthis objective.

Thetwo consultationstook placeon February11, 2014and July3, 2014. In an effort to supportopen and candiddiscussiontheywere establishedon a "without prejudice"basis,with no attribution of commentsto participatingparties.

II. Facilitator's Summary:

Consultation1 – February11, 2014

Thiswasa veryeffectivestakeholderconsultation.

Thediscussionwasalwayson topic, yet free and open. Commentsfrom all partieswere constructive and well received. Commentsfrom all partiesshowedа reasonablebalance,respectingthe interestsof the utility and all of its stakeholders.

Consultation2 – July3,2014

Unfortunately I was unable to attend this session as planned due to a grave family matter. Toronto Hydro proceeded with the session without a facilitator.

Attached as Appendices are:

A) February 11, 2014 Agenda
B) February 11, 2014 Participants
C) July 3, 2014 Agenda
D) July 3, 2014 Participants

III. Appendices:

A. February 11, 2014 Agenda

Toronto Hydro Electric System Limited
Stakeholder Consultation
February 11, 2014
9:00 AM to 4:30 PM
North Hearing Room – Ontario Energy Board

Agenda

Discussion Area	Presenter(s)
Opening and Introductory Presentation	Paul Sommerville, EVP Regulatory Affairs & General Counsel Amanda Klein, Director of Rates and Regulatory Affairs
Grid Response - The Ice Storm Experience	Lucas Millmore, Director of Distribution Grid Operations
Capital	Mike Walker, General Manager of Engineering & Investment Planning
Workforce	Jennifer Stulberg, Manager of Talent Acquisition
Productivity	Kaleb Ruch, Senior Regulatory Policy Advisor
Customer Engagement	Rob Barrass, Lead Regulatory Counsel
Problem Statements and Discussion	Bob Betts, Facilitator

B. February 11, 2014 Participants

AMPCO	Shelley Grice
BOMA	Tom Brett
City of Toronto	Jeff Climans
City of Toronto	Ralph Frebold
Energy Probe	Larry Schwartz David MacIntosh
SEC	Jay Shepherd
VECC	Mark Garner
OEB	Ted Antonopoulos Lisa Brickenden Martin Davies Donna Kwan Michael Millar David Richmond Stephen Vetsis
Toronto Hydro	Paul Sommerville Amanda Klein Lucas Millmore Mike Walker Jennifer Stulberg Kaleb Ruch Rob Barrass Darryl Seal Daliana Coban
Facilitator	Bob Betts

C. July 3, 2014 Agenda

Toronto Hydro-Electric System Limited
Stakeholder Consultation
July 3, 2014
9:00 AM to 3:00 PM
North Hearing Room – Ontario Energy Board

Agenda

Discussion Area	Presenter(s)
Opening and Introductory Presentation	Paul Sommerville, EVP Regulatory Affairs & General Counsel Amanda Klein, Director of Rates and Regulatory Affairs
Feeder Investment Model: Seminar	Rob Otal, Supervisor Projects, Long-term Strategy and Planning
Session 1 – Follow Up	Amanda Klein
2015-19 CIR Application	Amanda Klein Kaleb Ruch, Senior Regulatory Policy Advisor Darryl Seal, Manager, Rates
Q&A and Next Steps	Amanda Klein

D. July 3, 2014 Participants

AMPCO	Shelley Grice
BOMA	Tom Brett
City of Toronto	Ralph Frebold
CCC	Julie Girvan
Energy Probe	David MacIntosh Peter Faye
SEC	Jay Shepherd Mark Rubenstein
VECC	Bill Harper
OEB	Ted Antonopoulos Martin Davies Nabih Makhil Michael Millar David Richmond Duncan Skinner Georgette Vlahos
Toronto Hydro	Paul Sommerville Amanda Klein Kaleb Ruch Rob Barrass Darryl Seal Daliana Coban Matt Higgins Dmitry Balashov Brian Buchan Jack Lenartowicz
Torys'	Crawford Smith
Facilitator	

Yonge Street), and each session will be scheduled for a full day. THESL has engaged a third-party facilitator to run and record minutes of the sessions – the details of these minutes will be held on a without prejudice basis and not be disclosed in the Consultation Report. Brief outlines of each session are set out below, and agendas for each day will be provided to participants one week in advance of the scheduled session. THESL seeks and encourages live dialogue during the sessions, however will also provide participants an opportunity to submit written questions and comments - which will be available to view by all participants - following each session.

Session #1: Designing THESL's CIR Plan: February 11, 2014

THESL views Session #1 as an opportunity to discuss principles, facts, concepts and perspectives relevant to its CIR application. General topics include THESL's business needs/drivers, regulatory concepts and models (as relevant) with a view towards developing potential approaches to THESL's CIR application. THESL proposes to consider input and feedback received from Session #1 as part of the process of designing its CIR plan.

Session #2: Refining THESL's CIR Plan: July 3, 2014

THESL views Session #2 as an opportunity to report back to participants regarding the status and evolution of its application, and in particular, discuss certain structural and methodological aspects of its CIR application plan. THESL proposes to consider input and feedback received from Session #2 as part of refining its CIR plan.

Additional Consultation Opportunities

THESL seeks to maintain open channels of dialogue and engagement. In addition to the two sessions outlined above, THESL invites participants to approach THESL with any concerns, questions or other matters relevant to this application.

What Will THESL File with the OEB Regarding this Consultation?

The third-party facilitator will prepare a final Consultation Report that may be submitted to the OEB. This report will include these Terms of Reference, identify attendees at each meeting, and include copies of agendas and generic correspondence sent to participants (e.g. covering emails that accompany agendas). No notes or characterizations of the actual consultations will form part of the Consultation Report, and stakeholders will be provided an opportunity to review and comment on the Consultation Report prior to its finalization.

How Do Participants Receive Funding for the Consultation?

THESL will fund intervenor participation at the OEB's approved tariff rates, on the basis of one attendee per stakeholder. To the extent that stakeholders are of the view that funding for additional participants is required, THESL will address these requests on a case-by-case basis.

Who is the Contact at THESL for this Consultation?

Please direct any questions or concerns of a general nature to:

regulatoryaffairs@torontohydro.com

OPERATING ENVIRONMENT

Toronto Hydro-Electric System Limited ("Toronto Hydro") is the electricity distributor licensed (ED-2002-0497) by the Ontario Energy Board ("OEB") to serve the City of Toronto. Toronto Hydro is the successor to the six former hydro-electric commissions of the municipalities which amalgamated on January 1, 1998 to form the City of Toronto. For information about Toronto Hydro's Corporate Structure and Governance, please refer to Exhibit 1C, Tab 2.

Toronto Hydro is the second largest municipal electrical distribution utility in North America and serves the largest city in Canada. In 2013, Toronto Hydro distributed 24.4 terawatt-hours of electricity, representing approximately 18 percent of the electricity consumed in the province of Ontario. It served a peak demand of 4,914 megawatts.

Toronto Hydro services two distinct customer demographic areas: an urban center in downtown Toronto, and a suburban area around downtown Toronto, which is often referred to as the Horseshoe area. In total, Toronto Hydro has a total of approximately 730,000 customers in various classes, ranging from residential to general service and large use.[1]

The utility's service area includes some of Canada's largest banks, stock exchanges, major manufacturers, and other large customers that are sensitive to service interruptions. This includes data centres, manufacturing facilities, numerous hospitals, healthcare and long-term care facilities, schools, colleges and universities. Toronto Hydro also supplies electricity to Ontario's Provincial Legislature and Ministries, as well as Toronto's municipal government.

[1] Toronto has over 2,900 high-rise multi-residential condominium and apartment building accounts, many of which are "bulk-metered". Taking these bulk-metered multi-residential buildings into account, Toronto Hydro's effective customer count exceeds 1 million customers.

Toronto Hydro's distribution system consists of a mix of overhead, underground, secondary network and stations infrastructure. These systems operate at voltages of 27.6kV, 13.8kV, or 4.16kV, and distribute power through a complex network of approximately 175,000 poles, 60,600 distribution transformers, 16,000 primary switches, 15,000 km of overhead conductors and 11,200 km of underground cables. This network is composed of assets of varying vintages and types, reflective of the historical standards employed by the six pre-amalgamated utilities.

1. SERVICE TERRITORY

The City of Toronto is bounded by Lake Ontario to the South, Steeles Ave to the North, Mississauga (mainly Highway 427) to the West, and Scarborough/Pickering Townline to the East. A service territory map is filed at Exhibit 1C, Tab 1, Schedule 2.

2. NEIGHBOURING UTILITIES

Toronto Hydro's neighbouring electricity distribution utilities are:

- To the west, Enersource Hydro Mississauga;
- To the north-west, Hydro One Brampton;
- To the north, PowerStream Inc.; and
- To the east, Veridian Connections Inc.

Toronto Hydro is not a host utility and there are no embedded utilities in Toronto Hydro's distribution service area.

3. TRANSMISSION ASSETS DEEMED DISTRIBUTION ASSETS

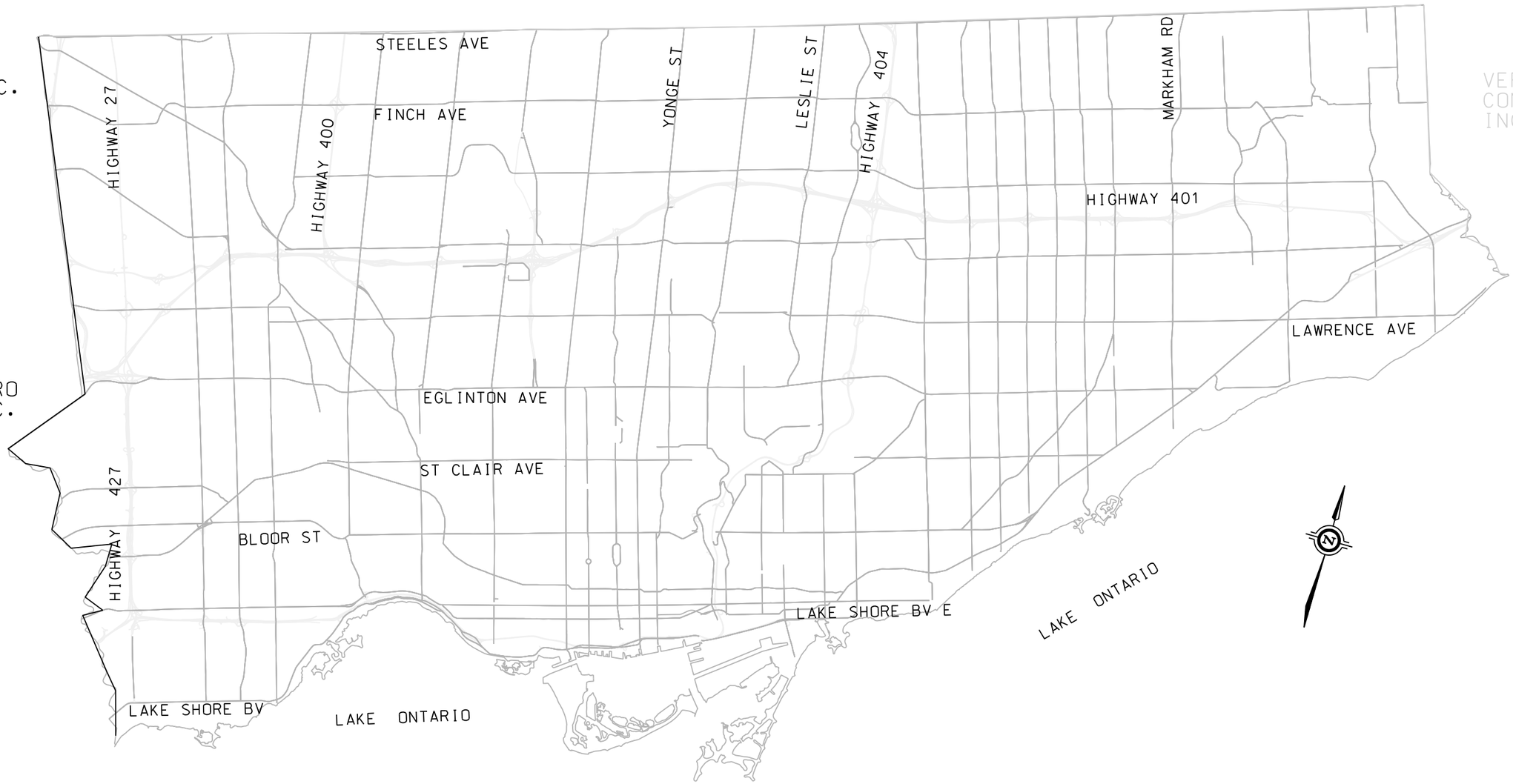
Toronto Hydro owns two transmission system terminal stations (one operational, one under construction) that have been deemed distribution assets, namely Cavanagh TS and Copeland TS, respectively. Toronto Hydro is not proposing any additional assets to be deemed as distribution assets as part of this application.

TORONTO HYDRO SERVICE TERRITORY

POWERSTREAM INC.

HYDRO ONE
BRAMPTON
NETWORKS INC.

VERIDIAN
CONNECTIONS
INC.



ENERSOURCE HYDRO
MISSISSAUGA INC.

Toronto Service Area.dgn 7/10/2014 4:53:20 PM

CORPORATE STRUCTURE AND GOVERNANCE

In accordance with s. 2.4.5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements"), this schedule provides information about Toronto Hydro's corporate structure organization and corporate governance framework. The schedule includes the following appendices:

- Appendix A: City of Toronto Shareholder Direction
- Appendix B: Mandate of the THC Board of Directors
- Appendix C: Mandate of the LDC Board of Directors
- Appendix D: Code of Business Conduct
- Appendix E: Audit Committee Charter
- Appendix F: Governance Committee Charter
- Appendix G: Human Resource Committee Charter

1. CORPORATE STRUCTURE

Toronto Hydro Corporation ("THC") is a holding company, the sole shareholder of which is the City of Toronto, and which wholly owns two subsidiaries (Figure 1): Toronto Hydro-Electric System Limited ("LDC"), a local distribution company which distributes electricity and engages in conservation and demand management ("CDM") activities; and Toronto Hydro Energy Services Inc. ("THE Energy"), a company which provides street lighting services in the City of Toronto.

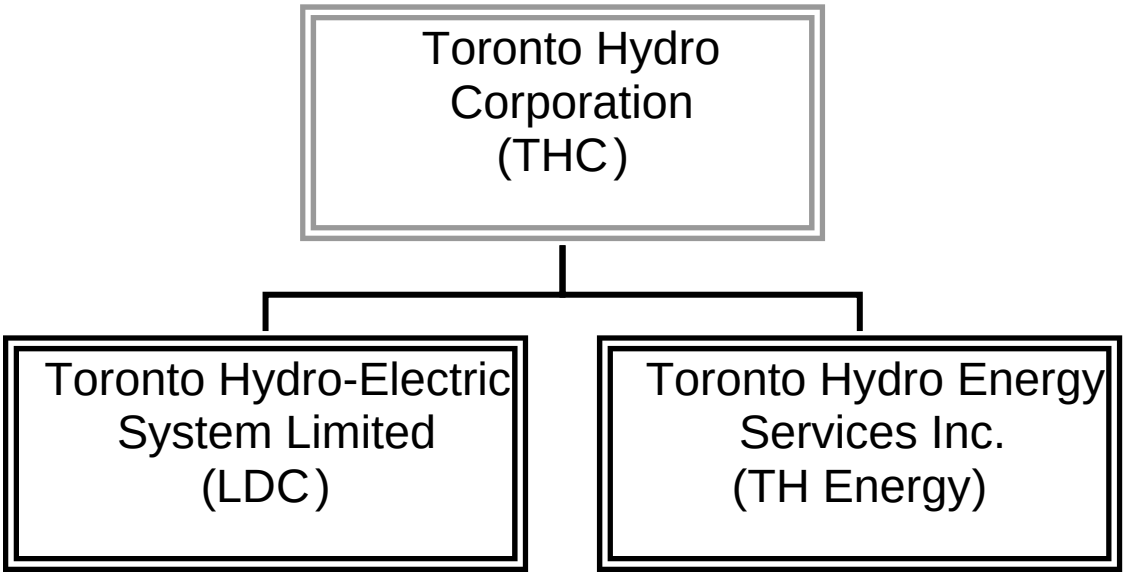


Figure 1: Toronto Hydro Corporate Organization Chart

The principal business of THC and its subsidiaries is the distribution of electricity by the LDC. THC was formed by amalgamation on January 1, 2011 as a wholly-owned subsidiary under the Business Corporations Act (Ontario) ("OBCA") on January 1, 2011. The predecessor corporation to THC was originally incorporated under the OBCA on June 23, 1999.

LDC owns and operates an electricity distribution system, which delivers electricity to approximately 730,000 customers located in the City of Toronto. LDC is the largest municipal electricity distribution utility in Canada and distributes approximately 18% of the electricity consumed in Ontario. LDC was formed by amalgamation with 1798594 Ontario Inc. under the OBCA on January 1, 2012. The predecessor corporation to LDC was originally incorporated under the OBCA on June 23, 1999.

TH Energy was incorporated under the OBCA on June 23, 1999, and currently holds electricity retailer and generator licences, and provides street lighting and expressway lighting services.

1.1. Executive Team

THC'S executive team is comprised of the Executive Vice-President and Chief Financial Officer ("CFO") and Executive Vice-President, Chief Regulatory Officer and General Counsel, both of whom are accountable to the President and Chief Executive Officer ("CEO") of THC. The CEO of THC is also the President and CEO of the LDC and of TH Energy.

The LDC's executive management team consists of the following positions that are overseen directly by the President and CEO:

- Executive Vice-President and Chief Financial Officer, who is also an executive member of THC and of TH Energy;
- Executive Vice-President and Chief Business Development Officer;
- Executive Vice-President and Chief Engineering and Construction Officer;
- Executive Vice-President and Chief Electric Operations and Procurement Officer;
- Executive Vice-President and Chief Information and Risk Officer;
- Executive Vice-President and Chief Customer Care and Conservation Officer;
- Executive Vice-President and Chief Human Resources and Safety Officer; and
- Executive Vice-President, Chief Regulatory Officer and General Counsel, who is also an executive member of THC and of TH Energy.

2. CORPORATE GOVERNANCE

2.1. Securities Law Requirements

As a venture issuer (i.e., a reporting issuer that does not have any of its securities listed or quoted on the TSX or other marketplace), THC must comply with certain corporate governance and public disclosure requirements under applicable securities legislation.

These requirements make THC's operations, practices and governance practices subject to scrutiny from both the Ontario Securities Commission ("OSC") and the public.

THC fulfills and routinely "over" complies with its securities law corporate governance and disclosure obligations. For example, as a venture issuer, THC is exempt from the requirements of Part 3 of National Instrument 52-110, which mandates the composition of an issuer's audit committee. Nonetheless, THC's audit committee meets all of the mandated requirements: it is composed of a minimum of three directors, and every audit committee member is a director of THC, is independent and is financially literate.

In addition, although THC is not required to file an Annual Information Form ("AIF") under National Instrument 51-102, THC has filed an AIF in respect of the financial years ended December 31, 2004 through December 31, 2013. THC's AIF discloses material information about THC and its business to the public, including information about operations, prospects, risks, governance and other factors that impact business. A copy of THC's 2013 AIF is filed at Exhibit 1C, Tab 4, Schedule 5.

In addition, to comply with National Instrument 58-101, THC provides extensive corporate governance disclosure in its AIF and annual Management Discussion and Analysis ("MD&A"). Such disclosure includes details about the following:

1) how the Board of Directors facilitates its exercise of independent supervision over management, including the identity and independence of its directors other reporting issuer directorships that its directors hold;
2) Board of Directors orientation and continuing education;
3) the promotion of ethical business conduct;
4) the process for nominating new directors;
5) the process of determining CEO and director compensation;
6) standing committees and their functions; and

7) how the Board of Directors assesses whether it is performing effectively.

The Board of Directors' decision to provide more extensive disclosure than required under securities legislation demonstrates the Board's commitment to providing effective, independent and rigorous oversight of the Company. The enhanced level of disclosure increases the transparency of the Company's operations and affairs, and facilitates effective monitoring of management by the Board and other stakeholders.

As a financial oversight measure, and to comply with certification requirements in National Instrument 52-109, all of THC's interim financial statements, interim MD&As, AIFs, annual financial statements and annual MD&As are certified by the CEO and CFO. The CEO and CFO certify that the filings do not contain any misrepresentations and fairly present the financial condition, results of operations and cash flows of THC as of the date of and for the periods presented in the filings. The certification process is one example of the Utility's system of internal checks and balances that fosters a culture of accountability amongst senior management.

2.2. Shareholder Direction

As the sole shareholder of THC, the City of Toronto (the "Shareholder" or the "City") has adopted a Shareholder Direction (see Appendix A to this schedule) which establishes, amongst other things, the following objectives and fundamental principles that govern the operations of the Company:

(a) to operate the Company on an efficient and commercially prudent basis;

(b) to optimize the Shareholder's return on equity and operate the Company with a view to meeting the financial performance objectives of the Shareholder as set out in the Shareholder Direction;

(c) to provide a reliable, effective and efficient electricity distribution system that supports the electricity demands of residents and businesses in the City;

(d) to operate the Company in an environmentally responsible manner consistent with the City's energy, climate change, urban forestry objectives and, as appropriate, utilizing emerging green technologies;

(e) to ensure that the business is managed in material compliance with all Law; and

(f) to engage in recruitment and procurement practices designed to attract employees and suppliers from the City's diverse community.

The Board of Directors is responsible for determining and implementing the appropriate balance among these principles. Ultimately, the City requires THC to operate on a commercially prudent and profitable basis, in compliance with law, and expects the Board of Directors to provide stewardship and independently oversee management and operations in accordance with best corporate governance practices.

2.3. Board of Directors

THC's Board of Directors consists of 11 directors, all of whom are appointed by THC's sole shareholder, the City. Of the 11 directors, one director is the Mayor of the City (or a member of City Council whom the Mayor recommends as his or her designate and who is appointed by City Council), two are members of City Council, and eight directors are independent residents of the City.

The LDC's Board of Directors currently consists of two directors. Of those two directors, one is a member of the Board of Directors of THC and one is an individual who is not a member of any affiliate of the LDC, in accordance with the independence requirements set out by the OEB in the Affiliate Relationships Code ("ARC").

2.3.1. Nomination of Directors

Pursuant to the Shareholder Direction, the City appoints directors who collectively represent a range of expertise including:

(a) experience on a public utility commission or board of a major corporation or other commercial enterprise;
(b) experience or knowledge with respect to:
    i. corporate finance;
    ii. corporate governance;
    iii. market development;
    iv. large system operation and management;
    v. urban energy industries;
    vi. public policy issues and the law relating to the Company and the electricity industry;
    vii. environmental matters;
    viii. labour relations;
    ix. occupational health and safety issues;
(c) commercial sensitivity and acumen;
(d) independence of judgment;
(e) personal integrity; and
(f) at least three directors with financial management expertise.

The City utilizes a board skills and competencies matrix, as reviewed and recommended to the City by the Board's Chair, in the evaluation of potential THESL Board of Directors members. The matrix's design reflects best practices for directors as recommended by the Institute of Corporate Directors.

THC appoints the LDC's Board of Directors from among the directors of THC and independent residents of the City. When appointing directors of the LDC, THC ensures that the directors have a mix of competencies and skills necessary to enable Toronto Hydro's Board of Directors to properly discharge their responsibilities.

2.3.2. Exercise of Independent Judgment

The Board of Directors for each of THC and LDC has a number of practices and policies in place to facilitate its ability to act independently of senior management and to ensure that its behaviour and decision-making processes are objective, responsible and effective.

- In Camera Board Meetings: Each of the Boards of Directors meets regularly in the absence of management to discuss the management of THC and LDC respectively.
- Outside Advisors: Under its mandate, each of the Board of Directors is authorized to retain independent legal counsel and other outside advisors if it considers this appropriate.
- Internal Audit Function: The internal audit department provides each of the Boards of Directors with an objective review of the Company's risk management, governance and internal control systems. The internal audit department's work is overseen by the Audit Committee of the Board of Directors of THC. To facilitate independence, the Director of Internal Audit has unrestricted access to any member of the Board of Directors of THC or LDC, as required. THC's external auditor reviews the competency and work of the internal audit department.
- Corporate Governance Committee: The Corporate Governance Committee of the Board of Directors of THC oversees and evaluates the exercise of independent judgment by the Board of Directors and its committees.

2.3.3. Board of Directors Mandate

The Board of Directors for each of THC and LDC has adopted a mandate on August 15, 2013 which is reviewed every two years and revised as required. The most recent Mandate of the Board of THC is filed at Appendix B to this schedule, and the Mandate of the Board of LDC is filed at Appendix C.

2.3.4. Schedule of Board of Directors Meetings

The schedule for THC's Board of Directors Meetings is as follows:

2013	2014
January 30, 2013	February 6, 2014
February 28, 2013	March 19, 2014
May 16, 2013	May 15, 2014
June 7, 2013	August 14, 2014
August 15, 2013	November 13, 2014
November 15, 2013	

The schedule for the LDC's Board of Directors Meetings is as follows:

2013	2014
February 28, 2013	March 19, 2014
August 15, 2013	March 24, 2014

2.3.5. Orientation and Continuing Education

Upon joining the Board of Directors of THC and/or LDC, each new director is given a set of materials designed to provide him/her with a summary of the key organizational, financial, regulatory, reporting and operational aspects of the Company. Directors have access to a variety of internal and external resources on topics related to THC's and LDC's businesses, as well as relating to the responsibilities of directors such as fiduciary obligations, issues of confidentiality and privilege, and public disclosure and whistle blowing requirements. Directors also have the opportunity to attend continuing education programs run by outside service providers such as the Institute of Corporate Directors designation program.

2.3.6. Ethical Business Conduct

All employees, officers and directors of THC and LDC are required to comply with the principles set out in the Code of Business Conduct (the "Code"), which is filed as Appendix D to this evidence. The Code was implemented in 2004, and is periodically

reviewed and re-approved by the Board of Directors of THC. The Code of Business Conduct is included in new directors' orientation materials and each director signs an acknowledgement that he or she will comply with the Code.

The Code provides for the appointment of an Ethics Officer and establishes a direct hotline to the Ethics Officer through which perceived violations of the principles set out in the Code may be raised, anonymously or otherwise. The Ethics Officer is accountable to the Audit Committee.

2.3.7. Board Committees

THC's Board of Directors has established three standing committees: the Audit Committee, the Corporate Governance Committee, and the Human Resources Committee.

- The Audit Committee oversees the adequacy and effectiveness of financial reporting, accounting systems, internal financial control structures and financial risk management systems. Among other things, the Audit Committee reviews THC's quarterly and annual financial statements (as well as financial statements prepared in connection with securities offerings or required by applicable regulatory authorities), reviews the audit plans of the external auditors, and oversees the internal audit of THC. All of the members of the Audit Committee are independent and financially literate in accordance with sections 1.4 and 3.1 of National Instrument 52-110 on Audit Committees. The Audit Committee Charter is attached as Appendix D to this schedule.
- The Corporate Governance Committee advises the Board of Directors with respect to matters relating to the corporate governance of the Company, including Board and committee composition and mandate, guidelines for assessing the effectiveness of the Board and its committees, and procedures to ensure that the Board functions independently from management. The Corporate Governance

Committee also reviews and approves all orientation and education materials and programs for new and current directors undertaken by management. The Governance Committee Charter is attached as Appendix E to this schedule.

X The Human Resources Committee assists the Board with the recruitment, assessment and compensation of the CEO, reviews and approves the compensation of the executive officer, oversees executive compensation disclosure under applicable securities laws, and advises the Board of Directors regarding the compensation structure, benefit plans and programs of Toronto Hydro, as well as collective bargaining and environmental and health and safety matters. The Human Resource Committee Charter is attached as Appendix F to this schedule.

GOVERNANCE – BOARD MANDATE

TORONTO HYDRO CORPORATION

Mandate – Board of Directors

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1. General

(1) The board of directors (Board) of Toronto Hydro Corporation (Corporation) is responsible for supervising the management of the business and affairs of the Corporation and its subsidiary entities (Group).

(2) The composition, responsibilities, and authority of the Board are set out in this Mandate.

(3) This Mandate, the Shareholder Direction issued by the City of Toronto (Shareholder) and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Board may adopt from time to time shall govern the meetings and procedures of the Board.

2. Composition

(1) The directors of the Corporation (Directors) should have a mix of competencies and skills necessary to enable the Board and any Board committees to properly discharge their responsibilities.

(2) All of the Directors shall be residents of Canada.

(3) The Shareholder shall appoint Directors every 2 years.

(4) In appointing Directors the Shareholder shall give due regard to the qualifications of the candidates including:

a) experience on a public utility commission or board of a major corporation or other commercial enterprise;

b) experience or knowledge with respect to:

i) corporate finance;

ii) corporate governance;

iii) market development;

iv) large system operation and management;

v) urban energy industries;

vi) public policy issues and laws relating to the Corporation and its subsidiary entities and the electricity industry;

vii) environmental matters;

viii) labour relations;

ix) occupational health and safety issues;

c) commercial sensitivity and acumen;

d) independence of judgement;

e) personal integrity; and

f) at least three directors with financial management expertise.

(5) For the purposes of determining whether a Director is independent, the Board shall use the definition of independence within the meaning of National Instrument 52-110 Audit Committees adopted by the Canadian Securities Administrators.

(6) The Shareholder shall appoint a Chair of the Board.

(7) The Secretary of the Corporation shall be secretary of the Board (the Secretary).

3. Responsibilities

(1) The Board is responsible for supervising the management of the business and affairs of the Group, including the following specific matters:

a) establishing sound financial principles and performance objectives;

b) approving any dividend payment or distribution of capital;

c) appointing the officers of the Corporation;

d) approving the overall business strategy and related business plan;

e) approving the financing strategy, including the selection of financial institutions and related banking authorities;

f) directing labour and employee relations matters; and

g) approving the financial statements in accordance with the requirements of the Business Corporations Act (Ontario).

(2) In discharging their responsibilities, the Directors owe the following fiduciary duties to the Corporation:

- a fiduciary duty – they must act honestly and in good faith with a view to the best interests of the Corporation; and
- a duty of care – they must exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

In discharging their responsibilities, the Directors are entitled to rely on the honesty and integrity of the senior officers of the Corporation and the auditors and other professional advisors of the Corporation.

In discharging their responsibilities, the Directors are also entitled to directors and officers liability insurance purchased by the Corporation and indemnification from the Corporation to the fullest extent permitted by law and the constating documents of the Corporation.

(3) The Board has specifically recognized its responsibilities for:

(a) to the extent feasible, satisfying itself as to the integrity of the Chief Executive Officer (CEO) and other senior officers of the Corporation and that the CEO and other senior officers of the Corporation create a culture of integrity throughout the Group;

(b) adopting a strategic planning process and approving annually (or more frequently if appropriate) a strategic plan which takes into account, among other things, the opportunities and risks of the business of the Group;

(c) overseeing the identification of the principal risks of the business of the Group and overseeing the implementation of appropriate systems to manage these risks;

(d) overseeing the integrity of the internal control and management information systems of the Group;

(e) succession planning (including appointing, training and monitoring the senior officers of the Corporation);

(f) recruiting and assessing the performance of the CEO, the compensation of the CEO and other officers of the Group, executive compensation disclosure and oversight of the compensation structure and benefit plans and programs of the Group;

(g) assessing the effectiveness of the Board;

(h) adopting a disclosure policy for the Group;

(i) developing and overseeing the orientation of new Directors, and the continuing education of existing Directors, of the Group; and

(j) developing the approach of the Corporation to corporate governance including a periodic review of the Code of Business Conduct of the Group.

(4) In addition to those matters which must by law be approved by the Board, the Board oversees the development of, and reviews and approves, significant corporate plans and initiatives, including the annual business plan and budget, major acquisitions and dispositions and other significant matters of corporate strategy or policy, including the Environmental Policy, Occupational Health and Safety Policy, Code of Business Conduct, Disclosure Policy, Signing Policy and Treasury Policy.

(5) The Board shall periodically review the Shareholder Direction and make recommendations to the Shareholder to facilitate and clarify interaction and communication between the Shareholder and the Board.

(6) The Board shall periodically review the performance of the Board against the Shareholder Direction.

(7) The Board shall periodically review the structure and mandate of each Board committee, the effectiveness of each committee, and the appointment and removal of committee members.

(8) The Board shall periodically review performance under the Environmental Stewardship Policy with management.

(9) To assist the Directors in discharging their responsibilities, the Board expects management of the Corporation to:

(a) review and update annually (or more frequently if appropriate) the strategic plan and report regularly to the Board on the implementation of the strategic plan in light of evolving conditions;

(b) prepare and present to the Board annually (or more frequently if appropriate) a business plan and budget and report regularly to the Board on the Corporation's performance against the business plan and budget; and

(c) report regularly to the Board on the Corporation's business and affairs and on any matters of material consequence to the Corporation and its Shareholder.

Additional expectations are developed and communicated during the annual strategic planning and budgeting process and during regular Board and Board committee meetings.

(10) The Board considers that generally management should speak for the Corporation in its communications with securityholders and the public. The Corporation's investor relations personnel are required to respond to inquiries from securities holders and the public after review and discussion, as appropriate, by senior management and the Board and Board committees. The Corporation's investor relations personnel are available to the securities holders by telephone, fax and e-mail. The Corporation maintains an investor relations section on its website. Presentations at investor conferences are posted promptly on the Corporation's website. They are also available on request. The Board

reviews the Corporation's major communications with securities holders and the public. All disclosures on behalf of the Corporation are to be made in compliance with the Corporation's disclosure policy.

(11) Directors are expected to attend Board meetings and meetings of Board committees of which they are members. Directors are also expected to spend the time needed, and to meet as frequently as necessary, to discharge their responsibilities.

(12) Directors are expected to undertake such activities as are required from them to remain current in their knowledge of issues relating to the business of the Group and matters relating to any Board committee of which they are members.

(13) Directors are expected to comply with the Code of Business Conduct of the Group.

4. Authority

(1) The Board is authorized to carry out its responsibilities as set out in this Mandate.

(2) The Board is authorized to retain, and set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(3) The Board is authorized to invite officers and employees of the Corporation and others to attend or participate in its meetings and proceedings if it considers this appropriate.

(4) The Directors have unrestricted access to the officers of the Corporation. The Directors will use their judgment to ensure that any such contact is not disruptive to the operations of the Corporation and, except for the chair of any committee established by the Board, will, to the extent not inappropriate, advise the Chair and the Chief Executive Officer of the Corporation of any direct communications between them and the officers of the Corporation.

(5) The Board and the Directors have unrestricted access to the advice and services of the Secretary.

(6) The Board may delegate certain of its functions to Board committees, each of which will have its own charter.

5. Meetings and Proceedings

(1) The Board shall meet as frequently as is determined to be necessary, but not less than four times each year.

(2) Any Director or the Secretary may call a meeting of the Board.

(3) The Chair is responsible for the agenda for each meeting of the Board, including input from other Directors and the officers and employees of the Corporation as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Directors, a notice of each meeting of the Board confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded to each Director at least ten days before the date of the meeting.

(5) The quorum for each meeting of the Board is a majority of the Directors. In the absence of the Chair, the other Directors shall appoint one of their number as chair of a meeting. The chair of a meeting shall not have a second or casting vote.

(6) The Secretary or his delegate shall keep minutes of all meetings of the Board, including all resolutions passed by the Board. Minutes of meetings shall be distributed to the Directors.

(7) An individual who is not a Director may be invited to attend a meeting of the Board for all or part of the meeting.

(8) The Directors shall meet regularly on one to facilitate full communication.

6. Review

(1) This Mandate shall be reviewed by the Corporate Governance Committee of the Corporation every 2 years and any recommended changes shall be brought to the Board of the Corporation for consideration and disposition.

August 2013

TORONTO HYDRO -ELECT RIC SYSTEM LIMITED.

Mandate – Board of Directors

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1. General

(1) The board of directors (Board) of Toronto Hydro-Electric System Limited (Corporation) is responsible for supervising the management of the business and affairs of the Corporation.

(2) The composition, responsibilities, and authority of the Board are set out in this Mandate.

(3) This Mandate and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Board may adopt from time to time shall govern the meetings and procedures of the Board.

2. Composition

(1) The directors of the Corporation (Directors) should have a mix of competencies and skills necessary to enable the Board and Board committees, if established, to properly discharge their responsibilities.

(2) A majority of the Directors shall be residents of Canada. At least one third of the Directors shall be independent Directors. For the purposes of determining whether a Director is independent, the Board shall use the definition of independence adopted by the Ontario Energy Board from time to time.

(3) The shareholder of the Corporation (Shareholder) shall appoint Directors every two years. Except for independent Directors, a Director shall cease to be a director of the Corporation if he or she ceases to be a director of the Shareholder.

(4) The Shareholder shall appoint a Chair of the Board.

(5) The Corporate Secretary of the Corporation shall be secretary of the Board (Secretary).

3. Responsibilities

(1) The Board is responsible for supervising the management of the business and affairs of the Corporation.

(2) In discharging their responsibilities, the Directors owe the following fiduciary duties to the Corporation:

- a fiduciary duty they must act honestly and in good faith with a view to the best interests of the Corporation; and

- a duty of care they must exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

In discharging their responsibilities, the Directors are entitled to rely on the honesty and integrity of the senior officers of the Corporation and the auditors and other professional advisors of the Corporation.

In discharging their responsibilities, the Directors are also entitled to directors and officers liability insurance purchased by the Corporation and indemnification from the Corporation to the fullest extent permitted by law and the constating documents of the Corporation.

(3) The Board has specifically recognized its responsibilities for:

(a) to the extent feasible, satisfying itself as to the integrity of the President and other senior officers of the Corporation and that the President and other senior officers of the Corporation create a culture of integrity throughout the Corporation;

(b) overseeing a strategic plan which (i) takes into account, among other things, the opportunities and risks of the business of the Corporation and (ii) is consistent with the overall strategic plan approved by the Toronto Hydro Corporation (THC) Board of Directors (THC Directors) for THC and its subsidiary entities (Group);

(c) overseeing the identification of the principal risks of the business of the Corporation and overseeing the implementation of appropriate systems to manage these risks;

(d) overseeing the integrity of the internal control and management information systems of the Corporation; and

(e) except to the extent any policy is not considered appropriate or relevant for the Corporation, adopting all policies, including the disclosure policy, adopted by the THC Directors for the Group and any amendments thereto and ensuring compliance with such policies.

(4) In addition to those matters which must by law be approved by the Board, the Board oversees the development of, and reviews and approves, in a manner consistent with the overall business plan and budget approved by the THC Directors for the Group, significant corporate plans and initiatives, major acquisitions and dispositions and other significant matters of corporate strategy or policy.

(5) To assist the Directors in discharging their responsibilities, the Board expects management of the Corporation to:

(a) review and update annually (or more frequently if appropriate) the strategic plan and report regularly to the Board on the implementation of the strategic plan in light of evolving conditions; and

(b) report regularly to the Board on the Corporation's business and affairs and on any matters of material consequence for the Corporation and its shareholder.

Additional expectations are developed and communicated during the annual planning and budgeting process and during regular Board and Board committee meetings.

(6) Directors are expected to attend Board meetings and meetings of Board committees of which they are members. Directors are also expected to spend the time needed, and to meet as frequently as necessary, to discharge their responsibilities.

(7) Directors are expected to undertake such activities as are required from them to remain current in their knowledge of issues relating to the business of the Group and matters relating to any Board committee of which they are members.

(8) Directors shall adopt the Code of Business Conduct of the Group and any amendments thereto and comply with the Code as amended.

4. Authority

(1) The Board is authorized to carry out its responsibilities as set out in this Mandate.

(2) The Board is authorized to retain, and set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(3) The Board is authorized to invite officers, employees of the Corporation and others to attend or participate in its meetings and proceedings if it considers this appropriate.

(4) The Directors have unrestricted access to the officers of the Corporation. The Directors will use their judgment to ensure that any such contact is not disruptive to the operations of the Corporation and, except for the chair of any committee established by the Board, will advise the Chair and the President of the Corporation of any direct material communications between them and officers of the Corporation.

5. Meetings and Proceedings

(1) The Board shall meet as frequently as is determined to be necessary.

(2) Any Director or the Secretary may call a meeting of the Board.

(3) The Chair is responsible for the agenda for each meeting of the Board, including input from other Directors and the officers and employees of the Corporation as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Directors, a notice of each meeting of the Board confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded to each Director at least ten days before the date of the meeting.

(5) The quorum for each meeting of the Board is a majority of the Directors. In the absence of the Chair, the other Directors shall appoint one of their number as chair of a meeting. The chair of a meeting shall not have a second or casting vote.

(6) The Secretary or his delegate shall keep minutes of all meetings of the Board, including all resolutions passed by the Board. Minutes of meetings shall be distributed to the Directors.

(7) An individual who is not a Director may be invited to attend a meeting of the Board for all or part of the meeting.

(8) The Directors shall meet regularly on-line to facilitate full communication.

6. Review

(1) This Mandate shall be reviewed by the Corporate Governance Committee of THC every 2 years and any recommended changes shall be brought to the Board of the Corporation for consideration and disposition.

POLICY

Code of Business Conduct	**Policy Owner:** **Vice President, Organizational Effectiveness, Environment, Health & Safety**
	Policy Approver: **Board of Directors, Toronto Hydro Corporation**
	Version Approval Date: **V3.0 2012-11-15**
	Last Review by PASC: **2012-10-31**
The most recent version of this policy can be obtained from http://pluggedin.torontohydro.com/policy/Pages/GovernancePolicies.aspx.	
The distribution of this policy is restricted not restricted.	

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1 DOCUMENT REVIEW & REVISION HISTORY

This policy is reviewed annually.

Version Number	Date of Review	Reviewed By	Brief Description of Change
V 3.0	2012-10-31	PASC	Added section 6.1.5 regarding image and reputation

2 DISTRIBUTION HISTORY

Version Number	Date of Issue	Recipients
V 3.0	2012-11-19	Toronto Hydro external website, and intranet site (http://pluggedin.torontohydro.com/policy/Pages/GovernancePolicies.aspx)

3 INTRODUCTION

As a reputable utility organization delivering electricity distribution and energy services to the City of Toronto, Toronto Hydro always strives to be a responsible business enterprise and corporate citizen, with strong and shared commitments to our stakeholders. We work to achieve the following strategic pillars:

People (fully-engaged, safe and healthy workforce that meets the changing business requirements)
Finance (meet financial objectives of the Shareholder)
Operations (improve reliability through optimal and sustainable system management)
Customer (provide value for money)

This requires us to execute our duties with highest standards of integrity and professionalism at all times. This Code of Business Conduct sets the basic principles on how Toronto Hydro and Toronto Hydro's employees should conduct the business activities to reach our business goals and fulfill commitments to our stakeholders.

4 POLICY OVERVIEW

This Code of Business Conduct sets forth the basic principles of business conduct Toronto Hydro expects its employees, officers and directors to follow.

It is expected that we will at all times exercise honesty and integrity in our duties, and live up to our commitments to society and our stakeholders. Our stakeholders include our customers and other business partners, our employees, the communities in which we operate, and our shareholder, the City of Toronto.

This Code outlines general principles of appropriate business conduct rather than attempting to cover every situation we may possibly encounter. It is not a substitute for the use of sound judgment and moral integrity in assessing such situations, and it does not supersede existing or subsequent Toronto Hydro policies issued in respect of specific matters. A failure by us to comply with the principles of appropriate business conduct set forth in this Code could result in damage to Toronto Hydro's economic well being or to its reputation and credibility with its stakeholders. The Code is designed to alert Toronto Hydro employees, officers, directors, consultants, suppliers and contractors to major legal and ethical issues that frequently arise. It also serves to establish appropriate channels for obtaining guidance and reporting Code violations.

The Vice President, Organizational Effectiveness and Environment, Health & Safety has been appointed to serve as Toronto Hydro's Ethics Officer.

All consultants, suppliers and contractors are to be made aware of the content of this Code. Each consultant, supplier and contractor shall either be provided with a copy of the Code or referred to the dedicated page on Toronto Hydro's website (www.torontohydro.com) each time an agreement to provide goods or services is executed with them or upon any change to the Code.

In this Code, "Toronto Hydro" means Toronto Hydro Corporation and all of its subsidiaries and related corporations.

Ethical Decision Making

One of the primary goals of this Code is to help all of us make ethical business decisions. The Code establishes principles to govern conduct in some general areas that pose ethical or legal concerns. No book of hard-and-fast rules, however long and detailed, could ever adequately cover all the dilemmas we face given the complexity and constantly changing nature of our work and our world.

Therefore, we may find it helpful to ask the following questions before taking action in specific situations:

- Am I adhering to the letter and spirit of the laws and regulations that may be involved?
- Is my action consistent with the overall values set forth in the Code?
- Would my action compromise my integrity or credibility, or that of Toronto Hydro?
- Does my action conform to Toronto Hydro's company policies?
- How would my actions appear to my supervisors, peers, subordinates, family, close personal friends, or to the public if reported in the news media?
- Does it make me feel uncomfortable?

Ultimately, employees are personally responsible for their decisions and should discuss ethical concerns, issues and questions with their supervisor or other contacts referred to under the "Compliance, Discipline and Reprisal" section below.

5 COMMITMENT TO SOCIETY

We believe that we have responsibilities to society because ultimately it is only with its implicit permission that the economy in which we participate is allowed to flourish. We therefore make the following commitments to society.

Obey the Law

5.1 We act in accordance with both the letter and the spirit of all laws and regulations applicable to the conduct of our business wherever we operate. To achieve this, Toronto Hydro provides us with the training required to obtain an understanding of the laws which apply to the carrying out of our responsibilities. With this training, we are expected to be sufficiently familiar, and act in accordance, with any laws that apply to our work, to recognize potential liabilities, and to know when to seek legal advice. If in doubt, we promptly seek clarification from Toronto Hydro's General Counsel.

5.2 We never commit or condone an illegal or improper act relating to Toronto Hydro's affairs, or instruct another employee, business partner or contractor to do so.

5.3 We acknowledge the importance to Toronto Hydro of complying with the Affiliate Relationships Code. We comply with, and ensure that all parties who provide services on behalf of Toronto Hydro comply with, the Affiliate Relationships Code.

5.4 We do not offer or make any payment (in money, property, services or any other form), directly or indirectly, through an agent or consultant, to any government official, political party, political party official, or candidate for political office for the purpose of persuading that person to exert influence in order to assist Toronto Hydro in obtaining or retaining business. We take measures reasonably within our power to ensure that any payment made to an agent is appropriate remuneration for legitimate services rendered and that no part is passed on by the agent as a bribe. We ensure that proper systems of control are in place to prevent and detect the payment of bribes.

5.5 We never request any payment (in money, property, services or any other form), directly or indirectly, to influence a decision or otherwise, nor do we accept any offered payment for any purpose other than as permitted in strict compliance with this Code.

5.6 We avoid all actions that are anti-competitive or otherwise contrary to laws that govern competitive practices in the marketplace.

5.7 We do not engage in, or give the appearance of being engaged in, any illegal or improper conduct that is in violation of this Code.

Confidentiality

5.8 We do not use for personal advantage any information that is obtained in the course of our employment and is not available to the public at large.

Examples of such information include:

(a) information concerning a proposed or existing business transaction with Toronto Hydro (e.g., a contract to purchase new transformers);
(b) the proposed acquisition or disposal of investments or other assets; and
(c) the pending award or change of contract for the supply of materials, goods or services to Toronto Hydro.

5.9 We do not inform anyone of any material fact or change relating to Toronto Hydro before it has been generally disclosed by Toronto Hydro in accordance with its Disclosure Policy except as may be required in the ordinary course of business. If it is necessary to inform any persons in the ordinary course of business, we ensure that the recipients of the information understand that it must be kept confidential. Where such recipients are from outside of Toronto Hydro we request, where appropriate, that they confirm their commitment to non-disclosure in the form of a written confidentiality agreement.

5.10 We will comply at all times with the privacy policies approved by Toronto Hydro (see Toronto Hydro website www.torontohydro.com).

6 COMMITMENT TO STAKEHOLDERS

Maintaining the trust and confidence of our stakeholders is crucial to Toronto Hydro's economic wellbeing and to its reputation and credibility with its stakeholders. If such trust and confidence is lost, we will lose their support and the valuable contribution which each makes to Toronto Hydro's success. It is in recognition of this that we make the following commitments to our stakeholders.

TO ALL OF OUR STAKEHOLDERS

We are committed to protecting their interest in Toronto Hydro's economic well-being

We acknowledge that all stakeholders have an interest in Toronto Hydro's economic well-being to provide employment opportunities, purchase goods and services, contribute to economic partnerships, contribute to the quality of life in communities where we operate, and to enhance the value of our shareholder's investment. To protect these interests, we will act in accordance with the following standards:

6.1 Protect Toronto Hydro's Assets

Each of us has a responsibility to safeguard Toronto Hydro's assets.

6.1.1 *With respect to corporate funds we will:*

(a) Exercise integrity, prudence and judgment in incurring and approving business expenses.
(b) Ensure that business expenses are reasonable and serve Toronto Hydro's business interests.
(c) Ensure that all transactions and expenses are properly authorized.
(d) Record all transactions and expenses accurately, completely and promptly.
(e) Ensure that the acquisition, use, disposal or movement of funds is made known, clearly identified, and not diverted for any other use than that for which they were approved.
(f) Not conceal any fund or transaction from finance, management or Toronto Hydro's auditors.
(g) Not enter into any transaction for the purpose of unlawfully evading any tax, duty or other levy imposed by a government, either for ourselves or for our counterparties.

6.1.2 *With respect to physical assets (including corporate property involved in carrying out duties) we will:*

(a) Use these assets prudently and with due care.

(b) Exercise reasonable safeguards to protect them against theft, damage, loss and waste.
(c) Ensure that the acquisition, use, disposal or movement of assets is made known, clearly identified, and not diverted for any other use than that for which they were approved.
(d) Not take, sell, loan, destroy or give away assets without proper authorization.

6.1.3 ***With respect to intellectual capital we will:***

(a) Treat any information that has not been publicly disclosed in accordance with Toronto Hydro's disclosure policy as confidential.
(b) Take precautions to avoid inadvertent disclosure, for instance, by not discussing such information in public and using extra care in transmitting such information by fax or electronic mail.
(c) Enter into confidentiality agreements to ensure those to whom we must disclose such information will not disclose it to others.
(d) Not release information to the media without proper authorization.
(e) Use only properly licensed computer software.
(f) Not reproduce, distribute or alter materials such as computer software or videotapes without the permission of the copyright owner or authorized agent but instead obtain additional copies of needed materials by purchasing them through the appropriate channels.
(g) Employ ethical means in conducting research by being honest in obtaining, interpreting, using and disclosing data.
(h) Use Toronto Hydro intellectual property --brand names, logos, trademarks – only in an authorized manner and in accordance with all laws.
(i) Comply with internal policies, procedures and guidelines relating to internal computer systems, including "Toronto Hydro Technology Use Guidelines". We acknowledge that Toronto Hydro reserves the broadest possible rights to ensure that Toronto Hydro's computer data base and all electronic communications systems, including electronic mail ("e-mail"), voice mail, the intranet and internet, and electronically created or stored data are used in compliance with internal policies, procedures and guidelines that guide the use, storage and transmission of information through this medium.

6.1.4 ***With respect to business records and reports we will****:*

(a) Ensure honest and accurate recording, reporting and retention of information (including all business records, including financial reports, research reports, marketing information, sales reports, tax refunds, time sheets, claims and other documents including those submitted to governmental agencies) since almost all business records may become subject to public disclosure in the course of litigation or governmental investigations and records are also often obtained by outside parties or the media.
(b) Ensure that all records and accounts accurately and truthfully reflect transactions and events, and conform both to generally accepted accounting principles and to the Toronto Hydro system of internal controls.
(c) Ensure that no entry is made in any record that intentionally hides or disguises the true nature of any transaction.
(d) Never withhold, or fail to communicate, information that should be brought to the attention of higher levels of management.
(e) Attempt to be as clear, concise, truthful and accurate as possible when recording any information and avoid exaggeration, inappropriate language, guesswork, legal conclusions, and derogatory characterizations of people and their motives.
(f) Not destroy or condone the destruction of records, except in accordance with internal document management, retention and disposition policies.

6.1.5 ***With respect to Toronto Hydro's image and reputation:***

(a) When presenting ourselves on behalf of Toronto Hydro, we must not conduct ourselves in any way that would negatively impact Toronto Hydro's image and reputation, and must comply with any relevant Toronto Hydro policies, procedures, and standards.
(b) Ensure that our communication via social networks and digital media is consistent with the directions laid out in the Toronto Hydro Social Media and Digital Communication Guidelines.

6.2 Avoid Conflicts of Interest

A "conflict of interest" occurs when our direct or indirect personal interests, activities or influences could compromise, or could reasonably appear to compromise, our ability to perform our responsibilities objectively and in the best interests of Toronto Hydro. Conflicts of interest, no matter how innocent the intention, threaten Toronto Hydro's economic interests (including its reputation) by potentially leading us to make decisions based on personal interests rather than in the best interests of Toronto Hydro. Even if we do not allow our personal interests to influence our decisions, the existence of the conflict will jeopardize the trust of our stakeholders if they perceive that we may not be acting solely with Toronto Hydro's best interests in mind. We must therefore exercise common sense, sound judgment and moral integrity to avoid any conflict of interest. We must also make any situation that might constitute a potential conflict of interest known to management and seek approval to proceed in accordance with this Code.

We are to seek guidance from our supervisors, or otherwise in accordance with this Code, whenever there is a question concerning a possible conflict of interest between our personal interest and the interests of Toronto Hydro. Conflicts include any activity (even when it is unpaid), interest or association that might compromise, or appear to compromise, the independent exercise of our judgment in the best interests of the Company.

To avoid the appearance of a conflict of interest, any request by a director or senior representative of the Shareholder related to the material use or handling of Toronto Hydro assets or resources or requesting actions to be taken by an officer or employee of Toronto Hydro other than those actions directed by the individual(s) to whom that officer or employee directly or indirectly reports shall be reviewed by the Corporate Governance Committee. If an officer or employee of Toronto Hydro receives such a request from a director such request shall be referred to the Chair, Corporate Governance Committee for a review by that Committee prior to such action being taken.

Our responsibility to avoid conflicts of interest means that we must always act in the best interests of Toronto Hydro.

6.2.1 ***With respect to outside business interests we will not, without approval:***

(a) Operate, serve as directors, officers, or partners of, or perform work or services as employees, consultants or advisors for, any competitor or any actual or potential "business partner" (including suppliers and customers) or any other entity that could lead to a conflict of interest or situation prejudicial to Toronto Hydro's interests (including any situation where our performance of duties for Toronto Hydro is adversely affected).
(b) Use Toronto Hydro time or resources (including equipment, tools, materials, supplies, facilities, personnel and information) to run our own business or engage in work for another organization, or to further the private interests of our family members, close personal friends or associates.

(c) Take part in a Toronto Hydro corporate decision which might confer any benefit, monetary or otherwise, on a business partner or competitor of Toronto Hydro in which we, our family members, close personal friends or associates hold a direct or indirect business or ownership interest. For example, we will not award a contract to, or obtain goods or services from, an entity in which we or such family members, friends or associates have a private interest, except where the interest is solely in the form of insignificant stock interests held in public companies.

(d) Take part in outside employment which creates the appearance of a, or an actual, conflict of interest.

(e) While performing duties as a Toronto Hydro representative, solicit customers for any outside employment. We will not recommend or refer customers to businesses, including those businesses operated by ourselves or other Toronto Hydro employees. For the purpose of interpretation, "solicit" includes any inquiry or request made by a customer for an employee's "off-duty" services.

6.2.2 ***With respect to property transactions we will not:***

(a) Use our position at Toronto Hydro to influence any corporate decision involving real estate or personal property in which we, our family members, close personal friends or associates have a direct or indirect business or ownership interest. For example, we will not participate in a decision concerning the location of a Toronto Hydro facility that would directly or indirectly benefit lands owned by any such individuals.

(b) Deal knowingly in real estate for the direct or indirect personal gain of ourselves, family members, close personal friends or associates, based on knowledge of any proposed or pending Toronto Hydro transaction such as the proposed location of a transmission line or other facility.

(c) Influence the settlement of a claim against Toronto Hydro to the advantage of a private interest held by us, our family members, close personal friends or associates.

6.2.3 ***With respect to political activity we acknowledge that:***

Each of us has the right to participate in the political process and to engage in political activities of our own choosing. However, while involved in such political activities we must at all times make clear that any views and actions are our own, and not those of Toronto Hydro. As in other activities, we must consider whether our political activity could adversely affect our performance of duties for Toronto Hydro or conflict with Toronto Hydro's responsibilities and, if so, avoid those activities. To determine if the political activity may create a potential conflict, we may contact the Ethics Officer, who will review the case and inform us of any action considered necessary to avoid the conflict.

6.2.4 ***With respect to gifts, gratuities, entertainment or benefits offered to us, our family members, close personal friends or associates (or to a third party receiving benefits for us or them) for less than full market value we will conduct ourselves as follows:***

We will only accept gifts, entertainment and benefits in the normal exchanges common to business relationships. The following criteria will guide our judgment:

(a) the gift, entertainment or benefit would be considered to be within the bounds of propriety taking into account all the circumstances of the occasion;

(b) it does not, nor is it expected to, create a sense of obligation;

(c) it would not appear to improperly influence a business decision or result in compromising objectivity;

(d) it occurs infrequently; and

(e) it would be valid for reimbursement on a Toronto Hydro expense statement if offered rather than received.

We will return inappropriate gifts or other benefits to the donor, accompanied by an explanation of Toronto Hydro's policy on this matter or, if considered appropriate, a copy of this Code. Perishable gifts can instead be donated to a charity and the donor notified. We will promptly advise our Ethics Officer of the circumstances of an inappropriate gift.

In some business settings, the return of a gift or refusal of a favour, benefit or entertainment would be offensive; in these cases, we should refer the circumstances to the Ethics Office for guidance.

Full and immediate disclosure in accordance with this Code of borderline cases will always be taken as good faith compliance with this Code.

6.3 TO OUR CUSTOMERS AND OTHER BUSINESS PARTNERS

We are committed to being fair and honest

6.3.1 To fulfill this commitment we:

(a) Treat our business partners courteously, respectfully and in a professional and helpful manner.
(b) Commit only to what we honestly believe we can deliver.
(c) Honour the commitments we make.
(d) Protect any information shared with us on a confidential basis by a business partner.
(e) Do not release customer information to any third party without proper authorization from the customer or Toronto Hydro management.
(f) Do not attempt to improperly influence the decisions of existing or potential business partners or attempt to secure preferential treatment for Toronto Hydro by offering gifts, entertainment or benefits which we ourselves would not be able to accept.
(g) Do not use our position at Toronto Hydro to obtain personal favors or special consideration for ourselves, our family members, close personal friends or associates.
(h) Select our suppliers objectively, based on fairness and the long-term best interests of Toronto Hydro.

6.4 TO OUR EMPLOYEES

We are committed to treating all employees with dignity and respect.

6.4.1 To fulfill this commitment we create a safe and healthy work environment where employees have opportunities for professional development, are treated with dignity and respect and are recognized for their contributions to Toronto Hydro and its customers.

6.5 TO THE COMMUNITIES WHERE WE OPERATE

We are committed to protecting the environment and enhancing the quality of life.

To fulfill this commitment we will act in accordance with the following standards:

6.5.1 Protect the Environment

We acknowledge that environmental protection is one of Toronto Hydro’s fundamental

values and to demonstrate such value we will:

(a) Ensure that we understand the environmental impact of our activities and treat it as an integral factor in all of our decisions.
(b) Report immediately any environment mishaps.
(c) Be open about and accountable for our environmental performance.
(d) Strive to find business partners which conduct their business in an environmentally responsible manner.

6.5.2 Enhance the Quality of Life

We believe that a fundamental responsibility is to conduct our business on a sound commercial basis in a socially responsible manner. This is, we believe, the greatest contribution we can make to the communities where we operate. We also believe we have a responsibility to contribute to the well-being of these communities in other ways. While this commitment will take different forms in different communities, we will:

(a) Support health, education and environmental initiatives.
(b) Support and work with voluntary and charitable organizations that respond to community needs.
(c) Get involved in and work with the community to assist in solving community problems.
(d) Encourage our employees to contribute to their communities through involvement with charitable, community service and professional organizations. However, employees must consider whether their activities could pose a conflict of interest or adversely affect their performance of duties for Toronto Hydro, and should only use Toronto Hydro time or resources for such activities with the prior approval of management.
(e) Encourage, support and seek partnerships with organizations which need our help, whether they be schools or social service organizations.
(f) Involve local communities in decision making for issues that affect them.

6.6 TO OUR SHAREHOLDER

We are committed to enhancing value for our shareholder, the City of Toronto.

All of our ethical commitments are directed at protecting Toronto Hydro's well-being. Through these commitments, we will seek to enhance the value of our shareholder's investment.

7 POLICY OWNERSHIP, ADMINISTRATION, APPROVAL AND RESPONSIBILITIES

7.1 This policy is owned by the Vice President, Organizational Effectiveness, Environment, Health and Safety.

7.2 The Vice President, Organizational Effectiveness, Environment, Health and Safety is responsible for:

(a) ensuring that this policy is comprehensive, clear and current;
(b) ensuring that this policy is implemented and communicated to the departments and staff that are impacted;
(c) ensuring ongoing compliance with this policy;
(d) approving any exceptions to this policy, as required;
(e) reviewing this policy as often as necessary, but at least annually;
(f) modifying, amending or rescinding this policy at any time.

7.3 This policy is approved by the President & CEO of Toronto Hydro.

8 COMPLIANCE, DISCIPLINE AND REPRISAL

8.1 All Toronto Hydro employees, officers and directors must adhere to and actively support the principles and standards described in this Code, and adhere to the standards set out in applicable policies, guidelines and legislation.

8.2 Regardless of the approach used, the person or office contacted will handle your request promptly, discreetly and professionally. Discussions and inquiries will be strictly confidential to the fullest extent possible or permitted by policy or law.

8.3 Violations of the Code will not be tolerated. Any employee who fails to comply with the Code, or who withholds information during the course of an investigation regarding a possible violation of the Code, is subject to disciplinary action up to and including dismissal. Depending on the nature of the non-compliance, Toronto Hydro may have legal obligation to report the non-compliance to the appropriate authorities, which may lead to criminal prosecution or civil action.

8.4 Any situation or transaction that may violate, or could appear to violate, the letter or intent of the Code must be reported immediately to your supervisor or if this is uncomfortable or seems inappropriate, must be reported immediately to the next level of your management; or if preferred, Toronto Hydro's Ethics Officer.

8.5 The Ethics Officer may be contacted by regular mail addressed to the Ethics Officer, 14 Carlton St., Toronto, Ontario M5B 1K5 and marked CONFIDENTIAL, in person, or by way of a dedicated phone line established solely for this purpose [416.542.2767]. All issues raised with, and reported to, the Ethics Officer will be handled promptly, discreetly and professionally.

8.6 The Ethics Officer shall have the discretion to determine how any reported matter will be handled. This discretion shall include deciding, in each instance, with whom she should or should not discuss the details of the reported matter. She shall not have any obligation to discuss the matter with the Chair of the Board of Directors or any of the other directors or officers of Toronto Hydro, except, if the reported matter involves the conduct of any of the directors, the CEO or any other officer of Toronto Hydro, then the Ethics Officer shall immediately report the matter to the Chair of the Audit Committee of Toronto Hydro and comply with any directives received from the Chair. It is important to note that it is hoped that all callers will identify themselves when contacting the Ethics Officer since that will facilitate resolving any issues. However, we will respond to anonymous contacts.

8.7 All disclosures to the Ethics Officer will be kept strictly confidential to the fullest extent possible or permitted by policy or law unless, in the sole opinion of the Ethics Officer, the matter disclosed constitutes an actual or potential threat of harm to Toronto Hydro, its employees or the general public. In that event, the Ethics Officer will act in accordance with any disclosure procedure issued by Toronto Hydro's General Counsel.

8.8 Management is responsible for ensuring that no retaliatory action will be taken against anyone for making in good faith a report of an ethical or legal concern or violation. However, anyone who takes part in a prohibited activity may be disciplined even if they report it. An employee's decision to report will, in all cases, be given due consideration in the event any disciplinary action is necessary.

8.9 Any employee found to be retaliating against an individual who, in good faith, reports a known or suspected violation or supplies information about a concern will be subject to disciplinary action up to and including dismissal. Employees who knowingly submit false reports will also be subject to disciplinary action.

9 POLICY COMMUNICATION

COMMUNICATION TRIGGER	TYPE OF COMMUNICATION	PARTY RESPONSIBLE FOR POLICY COMMUNICATION	AUDIENCE	ACKNOWLEDGEMENT?
New Hire Policy Revision Annual Review	Intranet Posting Email Hard Copy Provided	VP, Organizational Effectiveness, Environment, Health & Safety	All Employees	No

10 RELATED LAWS, REGULATIONS AND DOCUMENTATION

10.1 Refer to the Disclosure Policy located on the intranet at

http://pluggedin.torontohydro.com/policy/Pages/GovernancePolicies.aspx

10.2 Refer to the Fraud-Theft Prevention Policy located on the intranet at

http://pluggedin.torontohydro.com/policy/Pages/GovernancePolicies.aspx

10.3 Refer to the Social Media and Digital Communication Guidelines located on the intranet at

http://pluggedin.torontohydro.com/policy/Pages/GovernancePolicies.aspx

10.4 Refer to the Workplace Harassment Policy located on the intranet at

http://pluggedin.torontohydro.com/policy/Pages/OEEHSPOlicies.aspx

10.5 Refer to the Environmental Policy located on the intranet at

http://pluggedin.torontohydro.com/policy/Pages/OEEHSPOlicies.aspx

10.6 Refer to the Violence Prevention in the Workplace Policy located on the intranet at

http://pluggedin.torontohydro.com/policy/Pages/OEEHSPOlicies.aspx

TORONTO HYDRO CORPORATION

Charter – Audit Committee

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1. General

(1) The board of directors (Board) of Toronto Hydro Corporation (Corporation) has established the Audit Committee (Committee) to assist the Board in fulfilling its corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit and external audit functions.

(2) The composition, responsibilities and authority of the Committee are set out in this Charter.

(3) This Charter and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Committee may adopt from time to time shall govern the meetings and procedures of the Committee.

2. Composition

(1) The Committee shall be composed of at least three directors of the Corporation (Members).

(a) all Members shall be independent (as determined by the Board in accordance with the rules of the Canadian Securities Administrators with respect to the role and composition of audit committees); and

(b) at least one of whom, including the chair of the Committee (Chair), is financially literate (ie, have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the accounting issues that can reasonably be expected to be raised by the financial statements of the Corporation).

(2) Members shall be appointed by the Board on the recommendation of the Chair of the Board and shall serve until they resign, cease to be a Director or are removed or replaced by the Board.

(3) The Board shall designate one of the Members as Chair.

(4) The Secretary of the Corporation shall be secretary of the Committee (Secretary).

3. Responsibilities

The Committee shall assist the Board in fulfilling its corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit functions and external audit functions.

The Committee shall have the responsibilities set out below.

(1) Managing the Relationship between the Corporation and its External Auditors

The Committee shall be responsible for managing the relationship between the Corporation and its external auditors, including:

(a) appointing and replacing the external auditors, subject to shareholder approval;

(b) setting the compensation of the external auditors subject to the approval of the board of directors or shareholder, as applicable;

(c) overseeing the work of the external auditors, including resolving disagreements between management and the external auditors with respect to financial reporting;

(d) pre-approving all audit services and permitted non-audit services to be provided to the Corporation and its subsidiary entities by the external auditors in accordance with the "Policy on the Provision of Services by the External Auditors";

(e) having the external auditors report to the Committee in a timely manner with respect to all required matters, including those set out in paragraph 3(2);

(f) reviewing and approving the hiring policies of the Corporation with respect to present and former partners and employees of the external auditors;

(g) ensuring the rotation of the audit partner having primary responsibility for the external audit of the Corporation, the audit partner responsible for reviewing the external audit and the external auditors as such intervals as may be required; and

(h) reviewing and assessing the performance, independence and objectivity of the external auditors.

(2) Overseeing the External Audit

The Committee shall be responsible for overseeing the external audit of the Corporation, including:

(a) reviewing and approving the engagement letter and the audit plan, including financial risk areas identified by the external auditors and management;

(b) reviewing and assessing the accounting and reporting practices and principles used by the Corporation in preparing its financial statements, including:

(1) all significant accounting policies and practices used, including changes from preceding years and any proposed changes for future years;

(2) all significant financial reporting issues, estimates and judgments made;

(3) all alternative treatments of financial information discussed by the external auditors and management, the results of such discussions and the treatments preferred by the external auditors;

(4) any major issues identified by the external auditors with respect to the adequacy of internal control systems and procedures and any special audit steps adopted in light of material deficiencies and weaknesses;

(5) the effect of regulatory and accounting initiatives and off-balance sheet transactions or structures on the financial statements;

(6) any errors or omissions in, and any required restatement of, the financial statements for preceding years;

(7) all significant tax issues;

(8) the reporting of all material contingent liabilities; and

(9) any material written communications between the external auditors and management;

(c) reviewing and assessing the results of the external audit and the external auditors' opinion on the financial statements;

(d) reviewing and discussing with the external auditors and management any management or internal control letters issued or proposed to be issued by the external auditors;

(e) reviewing and discussing with the external auditors any problems or difficulties encountered by them in the course of the audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management); and

(f) reviewing and discussing with legal counsel any legal matters that may have a material impact on the financial statements, operations, assets or compliance policies of the Corporation and any material reports or enquiries received by the Corporation and its subsidiary entities from regulators or government agencies.

3. Overseeing the Internal Audit

The Committee shall be responsible for overseeing the internal audit of the Corporation, including:

(a) periodically reviewing the Internal Audit Charter and making recommendations to the Board;

(b) reviewing and approving the audit plan, including significant risk exposures identified by the internal auditor and management;

(c) reviewing and discussing with the internal auditor and management the results of any internal audits;

(d) reviewing and discussing with the internal auditors any problems or difficulties encountered by them in the course of the audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management);

(e) appointing and replacing the internal auditor;

(f) reviewing and assessing the performance of the internal auditor;

(g) ensure the Committee is kept informed of emerging trends and successful practices in internal auditing; and

(h) confirm there is effective and efficient coordination of activities between internal and external auditors.

(4) Reviewing and Approving and Recommending to the Board for Approval the Financial Statements, MD&A and Interim Reports of the Corporation

The Committee shall review and approve, and where required recommend to the Board for approval, the financial statements, management's discussion and analysis of financial condition and results of operations (MD&A) and interim financial reports of the Corporation, annual information form (AIF) and other public disclosure of financial information extracted from the financial statements of the Corporation with particular focus on:

(a) the quality and appropriateness of accounting and reporting practices and principles and any changes thereto;

(b) major estimates or judgments, including alternative treatments of financial information discussed by management and the external auditors, the results of such discussions and the treatment preferred by the external auditors;

(c) material financial risks;

(d) material transactions;

(e) material adjustments;

(f) compliance with loan agreements;

(g) material off-balance sheet transactions and structures;

(h) compliance with accounting standards;

(i) compliance with legal and regulatory requirements; and

(j) disagreements with management.

(5) Overseeing Internal Financial Control Structure and Financial Risk Management Systems

The Committee shall be responsible for overseeing the internal financial control structure and financial risk management systems of the Corporation, including:

(a) reviewing and discussing with management and the external auditors the quality and adequacy of internal control over financial reporting structures of the Corporation, including any major deficiencies or weakness and the steps taken by management to rectify these deficiencies or weaknesses;

(b) reviewing and discussing with management, the internal auditor and the external auditors the risk assessment and risk management policies of the Corporation, the major financial risk exposures of the Corporation and the steps taken by management to monitor and control these exposures;

(c) reviewing and discussing with the Chief Executive Officer and the Chief Financial Officer of the Corporation the procedures undertaken by them in connection with the certifications required to be given by them in connection with annual and other filings required to be made by the Corporation under applicable securities laws; and

(d) periodically reviewing the Treasury Policy and signing policies for the Corporation and its subsidiaries, making recommendations to the Board in respect of such policies and reviewing performance under these polices with Management.

(6) Establish and Review Certain Procedures

The Committee shall establish adequate policies and procedures, or require that adequate policies and procedures are established, with respect to the following and shall annually assess the adequacy of these procedures:

(a) the review of the public disclosure of financial information extracted from the financial statements of the Corporation;

(b) the receipt, retention and treatment of complaints received by the Corporation with respect to accounting, internal controls or auditing matters; and

(c) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

4. Authority

(1) The Committee is authorized to carry out its responsibilities as set out in this Charter and to make recommendations to the Board arising therefrom.

(2) The Committee may delegate by written policy to the Chair and the Chief Financial Officer of the Corporation (CFO) the authority, within specified limits, to authorize in advance all engagements of the external auditors to provide pre-approved services to the Corporation and its subsidiary entities. The Chair and the CFO shall report all engagements authorized by them to the Committee at its next meeting.

(3) The Committee shall have direct and unrestricted access to the external and internal auditors, officers and employees and information and records of the Corporation.

(4) The Committee is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(5) The Committee is authorized to invite officers and employees of the Corporation and outsiders with relevant experience and expertise to attend or participate in its meetings and proceedings if it considers this appropriate.

(6) The external auditors shall have direct and unrestricted access to the Committee and shall report directly to the Committee.

(7) The Corporation shall pay directly or reimburse the Committee for the expenses incurred by the Committee in carrying out its responsibilities.

5. Meetings and Proceedings

(1) The Committee shall meet as frequently as required but not less frequently than four times each year.

(2) Any Member or the Secretary may call a meeting of the Committee. The external auditors or the CFO may ask a Member to call a meeting of the Committee.

(3) The Chair shall approve the agenda of each meeting of the Committee, including input from the officers and employees of the Corporation, external auditors, other Members and other directors of the Corporation as appropriate. Meetings will include presentations by management or professional advisors and consultants when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Members, a notice of each meeting of the Committee confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded to each Member at least three days before the date of the meeting.

(5) The quorum for each meeting of the Committee is two Members. In the absence of the Chair, the other Members may appoint one of their number as chair of a meeting. The Chair of a meeting shall not have a second or casting vote.

(6) The Chair or a delegate of the Chair shall report to the Board following each meeting of the Committee.

(7) The Secretary or a delegate of the Secretary shall keep minutes of all meetings of the Committee, including all resolutions passed by the Committee. Minutes of all meetings shall be distributed to the Members. The minutes shall be available for review by the other directors of the Corporation after approval thereof by the Committee.

(8) An individual who is not a Member may be invited to attend a meeting of the Committee for all or part of the meeting. A standing invitation to all meetings shall be given to the Chairman of the Board, the President and Chief Executive Officer of the Corporation, the CFO except where the meeting, or part of the meeting, is for Members only or a private session with the internal auditor or the external auditors. A standing invitation should be given to the internal auditor and the engagement partners of the external auditors for all meetings where financial information is reviewed and approved..

(9) The Committee shall meet regularly alone and in private sessions with the internal audit leader, the external auditors and management of the Corporation to facilitate full communication.

6. Review

(1) This Charter shall be reviewed by the Corporate Governance Committee of the Corporation every 2 years and any recommended changes shall be referred first to the Audit Committee for review and comment and second, after consideration of the input from the Audit Committee, to the Board of the Corporation for consideration and disposition.

TORONTO HYDRO CORPORATION

Charter – Corporate Governance Committee

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1. General

(1) The board of directors (Board) of Toronto Hydro Corporation (Corporation) has established the Corporate Governance Committee (Committee) to assist the Board in fulfilling its responsibilities with respect to the operation of the Board, Board committees, boards of its subsidiaries and corporate governance standards and practices.

(2) The composition, responsibilities and authority of the Committee are set out in this Charter.

(3) This Charter and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Committee may adopt from time to time shall govern the meetings and procedures of the Committee.

2. Composition

(1) The Committee shall be composed of at least two directors of the Corporation (Members).

(2) Members shall be appointed by the Board upon the recommendation of the Chair of the Board and shall serve until they resign, cease to be a Director or are removed or replaced by the Board.

(3) The Board shall designate one of the Members as chair of the Committee (Chair).

(4) The Secretary of the Corporation shall be secretary of the Committee (Secretary).

3. Responsibilities

The Committee shall assist the Board in fulfilling its responsibilities with respect to the operation of the Board and Board committees and corporate governance standards and practices. The Committee shall have the responsibilities set out below.

3.1 Responsibilities with respect to the Operation of the Board and Board Committees

The Committee shall:

(a) facilitate the periodic review of the operation of the Board and Board committees, including the agenda for and reports and other information provided at, meetings and the conduct of meetings, and make recommendations to the Board;

(b) facilitate the periodic assessment of the performance of the Board and Board committees and report the results of that assessment to the Board;

(c) facilitate the periodic assessment of the effectiveness of the relationship between the Board and the Chief Executive Officer and other senior officers of the Corporation and report the results of that assessment to the Board; and

(d) facilitate the effective orientation and continuing education of the new and existing directors of the Corporation.

3.2 Responsibilities with respect to Corporate Governance

The Committee shall:

(a) review with Management corporate governance standards, practices and new laws applicable to the Corporation and make recommendations to the Board;

(b) annually review the Shareholder relationship with the City and make recommendations to the Board to facilitate and clarify interactions and communication between the Shareholder and the Board;

(c) periodically review the articles and by-laws of the Corporation, the Code Of Business Conduct, the mandates of the Board and the boards of its subsidiaries, charters of the Board committees, the shareholder directions for the subsidiaries, and the Disclosure Policy, and make recommendations to the Board;

(d) periodically review performance under the Disclosure Policy with Management;

(e) review and approve the disclosure with respect to corporate governance practices required to be included in the annual and other filings required to be made by the Corporation under applicable securities laws;

(f) review and approve any other disclosure of corporate governance practices before public disclosure by the Corporation; and

(g) periodically review the Shareholder Direction and make recommendations regarding Board compensation to the Board for delivery to the Shareholder to ensure compensation of the Board is comparable to that of similar Boards in order to attract and retain competent Board members.

4. Authority

(1) The Committee is authorized to carry out its responsibilities as set out in this Charter and to make recommendations to the Board arising therefrom.

(2) The Committee is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(3) The Committee is authorized to invite officers and employees of the Corporation and others with relevant experience and expertise to attend or participate in its meetings and proceedings if it considers this appropriate.

(4) The Corporation shall pay directly or reimburse the Committee for the expenses incurred by the Committee in carrying out its responsibilities.

5. Meetings and Proceedings

(1) The Committee shall meet as frequently as required but not less frequently than twice each year.

(2) Any Member or the Secretary may call a meeting of the Committee.

(3) The Chair is responsible for the agenda of each meeting of the Committee, including input from the officers and employees of the Corporation, other Members and other directors of the Corporation as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Members, a notice of each meeting of the Committee confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded to each Member at least three days before the date of the meeting.

(5) The quorum for each meeting of the Committee is two Members. In the absence of the Chair, the other Members may appoint one of their number as chair of a meeting. The chair of a meeting shall not have a second or casting vote.

(6) The Chair or his delegate shall report to the Board following each meeting of the Committee.

(7) The Secretary or his delegate shall keep minutes of all meetings of the Committee, including all resolutions passed by the Committee. Minutes of meetings shall be distributed to the Members. The minutes shall be available for review by the other directors of the Corporation after approval thereof by the Committee.

(8) An individual who is not a Member may be invited to attend a meeting of the Committee for all or part of the meeting. The Chair of the Board has a standing invitation to attend all meetings of the Committee except for those meetings or parts of meetings where the Committee meets alone.

(9) The Committee shall meet regularly alone to facilitate full communication.

6. Review

(1) This Charter shall be reviewed every two years by the Committee and any recommended changes shall be referred to the Board of the Corporation for consideration and disposition.

GOVERNANCE – BOARD COMMITTEES

TORONTO HYDRO CORPORATION

Charter – Human Resources Committee

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1. General

(1) established a Compensation Committee to assist the Board in fulfilling its responsibilities with respect to the recruitment and assessment of the performance of the Chief Executive Officer (CEO) of the Corporation, the compensation of the CEO and the other officers (Executive Officers) of the Corporation and its subsidiary entities (Group), the review and approval of executive compensation disclosure and the oversight of the compensation structure and benefit plans and programs of the Group.

(2) The Board also previously established a Health and Safety Committee to advise and assist the Board with respect to health and safety matters arising out of the activities of the Group.

(3) The Board has determined that it was in the best interests of the Corporation to combine the activities and responsibilities of the Compensation Committee and the Health and Safety Committee under a single Human Resources Committee (Committee) of the Board and to eliminate the separate Compensation Committee and Health and Safety Committees.

(4) The composition, responsibilities and authority of the Committee are set out in this Charter.

(5) This Charter and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Committee may adopt from time to time shall govern the meetings and procedures of the Committee.

2. Composition

(1) The Committee shall be composed of at least three (3) directors of the Corporation (Members)

(2) All Members shall be independent (as determined by the Board in accordance with the guidelines of the Canadian Securities Administrators), except as provided for in Subsection 2(3).

(3) In accordance with the City of Toronto Amended and Restated Shareholder Direction to the Corporation, the Committee shall include one director of the Corporation who is also a City of Toronto Councillor in its membership.

(4) Members shall be appointed by the Board upon the recommendation of the Chair of the Board and shall serve until they resign, cease to be a director or are removed or replaced by the Board. Where possible, the Board shall appoint Members who have skills and experience with respect to executive compensation matters and other human resources related matters, with a view to establishing a Committee that has the skills and experience to make decisions on the suitability of the Group's compensation policies and practices and other human resources-related policies and practices.

(5) The Board shall designate one of the Members as chair of the Committee (the Chair). Where possible, the Chair shall have direct skills and experience with respect to executive compensation matters.

(6) The Secretary of the Corporation shall be the secretary of the Committee (the Secretary).

3. Responsibilities

The Committee shall assist the Board in fulfilling its responsibilities with respect to the recruitment and assessment of the performance of the CEO, the compensation of the CEO and the Executive Officers, the review and approval of executive compensation disclosure, the oversight of the compensation structure and benefit plans and programs of the Group and in respect of the environmental and health and safety matters that arise from the activities of the Group. The Committee shall have the responsibilities set out in the following:

3.1 Responsibilities with respect to the CEO

The Committee shall:

(a) periodically review the position description of the CEO and make recommendations to the Board;

(b) when requested by the Board, oversee the process of identifying and recruiting new candidates for appointment as CEO, including assessing the competencies and skills of identified individuals, reporting the results of that assessment to the Board and making a recommendation for appointment of the CEO to the Board;

(c) annually, and more frequently if appropriate, make recommendations to the Board with respect to the compensation and benefits of the CEO, including:

(i) the review and approval of the base salary of the CEO;

(ii) the review and approval of the corporate and individual performance objectives relative to the performance-based incentive compensation of the CEO;

(iii) the assessment of the performance of the CEO in light of those corporate and individual performance objectives; and

(iv) the review and approval of the performance-based incentive compensation payable to the CEO for the attainment of those corporate and individual performance objectives; and

(d) review and approve the terms of the employment agreement and severance arrangements of the CEO for recommendation to the Board.

3.2 Responsibilities with respect to the Executive Officers

The Committee shall:

(a) annually, and more frequently if appropriate, review and approve the CEO's proposals with respect to the compensation and benefits of the Executive Officers, including:

(i) the base salaries of the Executive Officers; and

(ii) the performance-based incentive compensation payable to the Executive Officers; and

(b) review and approve the CEO's proposals with respect to the terms of the employment agreements and severance arrangements of the Executive Officers.

3.3 Responsibilities with respect to Executive Compensation Disclosure

The Committee shall:

(a) review and approve the statement of executive compensation required to be filed by the Corporation in connection with annual and other filings under applicable securities laws; and

(b) review and approve any other executive compensation disclosure before it is publicly disclosed by the Corporation.

3.4 Responsibilities with respect to the Group's Compensation Structure and Benefit Plans and Programs

The Committee shall be responsible to periodically review and assess the Group's compensation structure and benefit plans and programs and make recommendations to the Board with respect thereto.

Annually, and more frequently if appropriate, the Committee shall review and approve the corporate performance objectives of the Group and make recommendations to the Board with respect thereto.

3.5 Responsibilities with respect to Succession Planning

The Committee shall periodically, and at least annually, review with the Chair and the CEO succession planning for the CEO and the Executive Officers and report the results of that review to the Board.

3.6 Responsibility with respect to Collective Bargaining

The Committee shall review the recommendations of the Corporation's management in respect of collective bargaining negotiations and approve the parameters for such negotiations.

3.7 Responsibility with respect to Health and Safety Matters.

The Committee shall:

(a) periodically reviewing the Environmental Policy and the Occupational Health and Safety Policy and making recommendations to the Board;

(b) periodically reviewing performance under the Occupational Health and Safety Policy with Management;

(c) reviewing new health and safety legislation with Management and informing the Board of its responsibilities under such legislation; and

(d) reviewing significant health and safety issues.

4. Authority

(1) The Committee is authorized to carry out its responsibilities as set out in this Charter and to make recommendations to the Board arising therefrom.

(2) The Committee is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(3) The Committee is authorized to invite officers and employees of the Corporation and others with relevant experience and expertise to attend or participate in its meetings and proceedings if it considers this appropriate.

(4) The Corporation shall pay directly or reimburse the Committee for the expenses incurred by the Committee in carrying out its responsibilities.

5. Meetings and Proceedings

(1) The Committee shall meet as frequently as required but not less frequently than twice each year.

(2) Any Member, the CEO or the Secretary may call a meeting of the Committee.

(3) The Chair is responsible for the agenda of each meeting of the Committee, including input from the officers and employees of the Corporation, other Members and other directors of the Corporation as appropriate. Meetings will include presentations by

management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Members, a notice of each meeting of the Committee confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded to each Member at least three (3) days before the date of the meeting.

(5) The quorum for each meeting of the Committee is a majority of the Members. In the absence of the Chair, the other Members may appoint another Member as chair of a meeting. The chair of a meeting shall not have a second or casting vote.

(6) The Chair or his delegate shall deliver a report to the directors at the next meeting of the Board following each meeting of the Committee.

(7) The Secretary or his delegate shall keep minutes of all meetings of the Committee, including all resolutions passed by the Committee. Minutes of all meetings shall be distributed to the Members. The minutes shall be available for review by the other directors of the Corporation after approval thereof by the Committee.

(8) An individual who is not a Member may be invited to attend a meeting of the Committee for all or part of the meeting. The Chair of the Board, the President and Chief Executive Officer of the Corporation and the Vice President Organizational Effectives and Environment, Health & Safety of Toronto Hydro-Electric System Limited have a standing invitation to attend all meetings of the Committee except for those meetings or parts of meetings where the Committee meets alone. The Committee shall meet regularly alone to facilitate full communication.

6. Review

(1) This Charter shall be reviewed by the Corporate Governance Committee of the Board every two (2) years and any recommended changes shall be referred first to the Human Resources Committee for review and comment and second, after consideration of the input from the Human Resources Committee, to the Board of the Corporation for consideration and disposition.

(2) In addition to the bi-annual review, the Human Resources Committee may at any time review the Charter and make recommendations to the Corporate Governance Committee for their review and recommendations to the Board with respect thereto.

STRATEGIC PLANNING

This schedule provides an overview of Toronto Hydro's strategic planning framework.

The strategic planning framework is at the core of Toronto Hydro's governance practices, helping the utility run in such a way that it achieves its objectives in an effective and transparent manner. Strategic planning aids Toronto Hydro's management to govern the utility more efficiently, to allocate resources more strategically, and enables improved outcomes for the organization and, ultimately, for our ratepayers. Toronto Hydro's approach to strategic planning is governed through frameworks including:

1) Corporate Strategy;
2) Business Planning ;
3) Enterprise Risk Management ("ERM"); and
4) Corporate Disaster Preparedness ("CDP").

The strategic planning framework allows Toronto Hydro's leadership to:

- identify its strategic direction;
- better focus its resources on desired results;
- better understand and consider stakeholder needs and interests;
- control and mitigate risks through consistent and disciplined methods; and,
- better prepare for, respond to, and recover from, large-scale events facing the utility.

1. CORPORATE STRATEGY

Corporate Strategy is one of the key components of the Strategic Planning process. Toronto Hydro's Corporate Strategy guides the process of establishing strategic goals for

the utility. Strategic goals reflect the utility's efforts to optimize the financial, human, social, and technological resources of the organization.

Toronto Hydro's strategic vision is to continuously improve ratepayer satisfaction by operating in a safe, reliable and environmentally responsible manner at optimal costs. To realize this vision, Toronto Hydro employs a framework consisting of four strategic pillars as illustrated in Figure 1 below.

Figure 1: Toronto Hydro Strategic Pillars

The pillars are aligned with the Ontario Energy Board's ("OEB") performance outcomes described in the RRFE Report[1] and the other regulatory instruments adopted by the OEB from time to time. The pillars focus the organization on:

1) providing value to its ratepayers;
2) building a safe, reliable and efficient distribution system;
3) maintaining a fully- engaged, safe and healthy workforce; and

[1] Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (October 18, 2012) [the "RRFE Report"].

4) providing a financially stable and sustainable business model through efficient run of operations and a productive workforce.

Within in each of Toronto Hydro's pillars are a series of strategic objectives. Those objectives are shown in Figure 2.

Figure 2: Toronto Hydro's Strategic Objectives

Toronto Hydro reviews its corporate strategy annually using the four strategic pillars as guidance. The corporate strategy is developed by the utility's leadership for approval by the Board of Directors.

2. BUSINESS PLANNING

Upon approval, Toronto Hydro translates the updated corporate strategy and objectives into a Business Plan.

As with any enterprise business planning is an important element in the success of Toronto Hydro. Good business planning addresses major issues facing the organization and the industry. It engages and aligns Toronto Hydro business units on major initiatives

in support of achieving the strategy. It enables the respective business units to execute their programs with a view to meeting the broad corporate objectives outlined in the strategy and encourages them to keep on track of achievement. Business planning is also used as a means for deciding how to utilize limited resources and capabilities. Like all utilities regulated by the OEB, Toronto Hydro produces and publishes detailed financial reporting pursuant to the Electricity Reporting and Recordkeeping Requirements (the "RRR"). For more information about the budgeting process, please refer to Exhibit 4A, Tab 1, Schedule 1.

Leadership and managers are obligated to track divisional progress toward the goals adopted by the Board of Directors, and to provide remedial action plans where achievement is lagging.

This process is intended to create a sense of urgency within the organization with respect to the Strategic Objectives (Figure 2, above). Achievement is a priority of every level of the company and every effort is made to ensure that the organization as a whole has a firm grasp of expectations. This is a demanding process, requiring a level of commitment and focus that is significant. The utility takes the view that the development of the Corporate Strategy is integral to success and with a major, ongoing focus at every level.

As part of its performance-driven culture, Toronto Hydro uses a Balanced Scorecard framework to track the effects of the implementation of the business plan against its strategic goals.

The Balanced Scorecard approach is a commonly used framework to aid in the successful execution of a corporate strategy.[2] Applying a Balanced Scorecard approach at Toronto Hydro provides a number of benefits, including:

- aligning strategic objectives across all levels of the organization to improve outcomes;
- short interval control, which provides management with a comprehensive picture of business operations throughout the year and the ability to direct corrective actions to achieve desired results;
- facilitating communication and reinforce the utility's goals and strategies to all employees;
- encouraging dialogue within the organization about strategic goals and expectations; and
- strengthening good governance practices through the use of a consistent and systematic approach to measure and report results across the organization.

The Balanced Scorecard aligns the strategic pillars with operational outcomes by monitoring progress using a series of metrics. These metrics are referred to as Key Performance Indicators ("KPIs").

3. ENTERPRISE RISK MANAGMENT ("ERM")

ERM provides Toronto Hydro with a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting on risks. ERM is an integral part of the utility's strategic planning that embeds risk considerations in forecasting, planning and program execution.

3.1. Approach to ERM

To manage risk prudently and systematically, Toronto Hydro employs an ERM framework based on industry best practices and the International Organization for Standardization ("ISO") 31000 guidelines, illustrated in Figure 3 below.

Figure 3: ISO 31000 Relationships between the Risk Management Principles, Framework and Process.

The ISO 31000 establishes principles and provides generic guidelines on risk management. The guideline recommends that organizations develop, implement and continuously improve a risk framework that is integrated into their overall governance, strategy, planning, management, reporting processes, policies, values and culture.

Accordingly, Toronto Hydro's ERM framework:

- provides a consistent, disciplined methodology for identifying, assessing, treating, monitoring and reporting risks;
- facilitates training and awareness on risk management; and
- integrates reporting of all levels of risk through risk metrics and other indicators.

Toronto Hydro's ERM framework has been recognized for its level of sophistication and accomplishments and as an example of best practices.

3.2. ERM governance

Toronto Hydro's risk governance structure helps the utility fulfill the ERM framework objectives. Figure 4 illustrates the four levels of risk governance that Toronto Hydro uses to identify and ultimately mitigate key risks.



Figure 4: Toronto Hydro's risk governance structure

The Board of Directors reviews Toronto Hydro's risk profile to confirm that the greatest risks to the organization are being addressed and managed.

The responsibility of the Risk Oversight Committee ("ROC") is to assess the appropriateness and consistent application of the risk management systems that are in place to identify, manage, and monitor risks. The ROC is also responsible for bringing key risks to the attention of the Board of Directors and assisting management in addressing them.

Risk Management Forums and Working Groups oversee the execution of risk management in Toronto Hydro's operations and support the ROC and the Board of Directors by enabling effective, efficient, complete and transparent risk reporting.

3.3. Risk Assessment

Risk Assessment provides a framework through which risks are identified, evaluated and compared in support of determining appropriate risk tolerances. Toronto Hydro's Risk Assessment framework is based on the ISO 31000 risk management guideline illustrated in Figure 5 and has three phases.

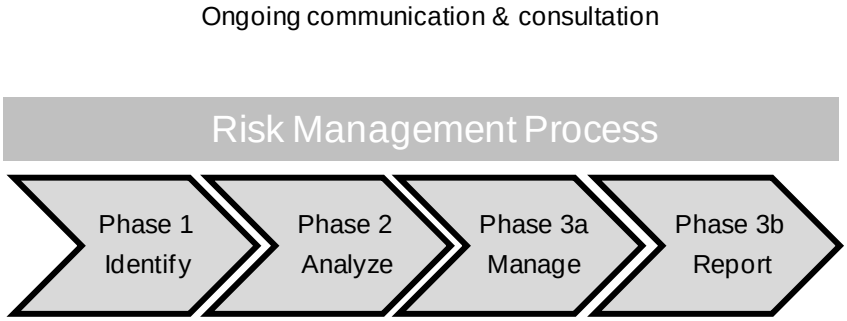


Figure 5: Toronto Hydro's Risk Management Process

Phase 1 (Risk Identification) is performed at an enterprise level and considers both internal and external factors. Key risks facing the organization are identified and then broken down into their constituent parts at the business unit level. Risks identified here are called component risks. Such risks are more closely aligned to a business unit's activities and are typically more specific.

In Phase 2, a risk analysis is performed on the component risks using a standard risk assessment and reporting schedule maintained through this framework. Upon

completion, component risk assessments are aggregated back to the enterprise level, but now with more granular information about how the risks can affect Toronto Hydro's operations.

Phase 3 includes the management of risk on an ongoing basis. Here risk mitigation plans are developed and reported on regularly. The framework provides a common risk reporting process. Consistency in reporting is essential to ensure that risks are easily comparable and can be aggregated.

Collectively, these three phases provide Toronto Hydro with the best information available at a given point in time to make informed, risk-based decisions. Accordingly, this approach has the following benefits to the utility:

- facilitating the engagement and support of staff at all levels in assessing risk and building a risk-aware culture;
- providing a consistent approach (i.e., processes, tools, methodologies and taxonomy) for the organization to talk about and compare risks;
- facilitating the allocation of accountability and responsibility for risk at the appropriate level of the organization; and
- allowing risks to be considered when making resource decisions.

3.4. Quantifying Risks

Toronto Hydro employs a risk quantification model in assessing risk. This model uses two main concepts: qualitative analysis and risk indicator scoring.

Qualitative analysis is composed of key concepts such as impact, likelihood and velocity. "Likelihood" is used to refer to the chance of a risk occurring something happening, whether defined, measured or determined objectively or subjectively, qualitatively or quantitatively, and described using general terms. "Impact" is defined as the degree to

which the outcomes of an event would affect the utility and its objectives. "Velocity" refers to defining how quickly the Risk impact will be realized in the utility. Risk impact is measured on a five-level scale (minor, moderate, major, severe and catastrophic). Risk likelihood is also measured on a five-level scale (remote, unlikely, likely, very likely, virtually certain). The higher the combined scores (i.e. impact multiplied by likelihood) the greater the risk exposure.

Supporting this is the use of risk indicators, a set of measures that demonstrates if risks are increasing, decreasing or remaining steady. These indicators are typically "leading" in nature. A leading indicator is a metric that can indicate a potential change in risk prior to that change occurring. This assists in forecasting potential future risk exposure. Collectively the risk indicators and the qualitative analysis are reviewed to quantify risks facing the utility.

3.5. Risk Tolerance

Toronto Hydro's Risk Appetite Statement ("RAS") supports the tools described above. The RAS establishes a common framework between Toronto Hydro and the Board of Directors regarding the utility's tolerance for risk in the execution of its corporate strategy.

Toronto Hydro's corporate RAS is broken down into two pieces. The first part is the Board of Director's risk philosophy statement that sets general guidance on risk tolerance. The risk philosophy statement is then broken down into more manageable risk limits. Toronto Hydro identifies the specific strategic drivers and establishes the risk tolerance along five levels (low to catastrophic) per strategic driver.

Toronto Hydro developed its RAS using a bottom-up approach, basing its risk acceptance on both internal and external factors. The utility uses the RAS to inform and guide decision making in its operations.

3.6. Risk Reporting

Risk reporting is an additional tool within the ERM framework used to ensure good governance and to inform decision makers about risk.

Regular risk reporting provides management and the Board of Directors with the assurance that established controls and risk treatment initiatives are functioning properly. At the ROC, risk information is received and reviewed following a risk assessment and risk reporting schedule. Key risk information is reviewed and decisions made regarding risk management activities. At the Board of Director level, enterprise risks are reviewed on a quarterly basis.

4. CORPORATE DISASTER PREPAREDNESS

The last piece of the Toronto Hydro strategic planning framework is the Corporate Disaster Preparedness ("CDP") framework. The CDP framework sets out an enterprise-wide standard to manage corporate disasters. A corporate disaster is an event which exceeds the organization's regular response capabilities and requires a fundamentally different set of operating procedures for effective corporate response. This framework is an overarching management system and corporate standard for the development, implementation and continuous improvement of all disaster preparedness functions, namely emergency management, business continuity and contingency planning.

As an example, Toronto Hydro has experienced more frequent, large scale, rapid on-set weather disasters that have impacted the reliable operation of Toronto Hydro's

distribution system and has exceeded its regulatory response capability. Events such as the recent Ice Storm (2013), July 8 Flash Floods (2013) and Hurricane Sandy (2012) are examples of the types of weather events that exceed Toronto Hydro's standard response practices and require additional planning and response resources for effective management. Other potential disasters such as, but not limited to, terrorist attack, pandemics also pose a potential disruption beyond the normal response capabilities of the corporation and also fall into the scope of this CDP framework.

The CDP framework is based on best practices and international standards (CSA Z1600, Emergency Management and Business Continuity and ISO 22301 Business Continuity Management). In addition, Toronto Hydro follows other international best practices such as the Incident Management System ("IMS") and Incident Command System ("ICS") to ensure effective emergency response during an emergency. The IMS and ICS frameworks are currently in the early stages of development and the utility plans to significantly expand their implementation across the company, as discussed in the Disaster Preparedness Management program.[3]

Training and scenario-based exercises are conducted throughout the year to help ensure that the disaster management system is understood and roles and responsibilities under emergencies are entrenched. As with the ICS and IMS framework, Toronto Hydro plans to substantially expand the scope and frequency of emergency-related training exercises to facilitate optimal preparedness to major contingency events by Toronto Hydro's workforce, as further discussed in Exhibit 4B, Tab 2, Schedule 4. Expanding training and other exercises over the 2015 to 2019 period would allow Toronto Hydro to rehearse the use of disaster preparedness plans and protocols to assist in providing a more efficient response.

[3] Exhibit 4B, Tab 2, Schedule 4.

In addition to building and implementing this framework, Toronto Hydro enables the utility to continuously improve its planning, response and coordination with municipal and provincial emergency agencies. During an emergency, engagement and cooperation between Toronto Hydro, the City and Province may be required for effective response actions to be taken. To allow the utility to respond effectively in an emergency, Toronto Hydro is available to liaise with these agencies twenty-four hours a day.

FINANCIAL PLANNING PROCESS

1. OVERVIEW

Currently, financial planning at Toronto Hydro is conducted annually and results in a three-year Plan – a detailed plan for the first year and a directional plan for the next two years. Given the requirements of the five-year Custom Incentive Rate ("CIR") application, the term of the planning activities for the period beginning 2015 was extended to five years (the "planning activity").

2. APPROACH

Toronto Hydro's corporate plans are informed by a number of operational needs such as asset investment requirements, maintenance requirements, staffing requirements and legislative and regulatory obligations. The plans are also informed by other important considerations such as customer needs and preferences (including service levels and consumption-management tools), rate impacts, value-for-money, productivity, and maintaining the financial health and viability of the utility.

In other words, the utility considers a number of input considerations and objectives in order to generate its plans. No one of these considerations is determinative of the utility's ultimate plan, but they all inform it. For example, while Toronto Hydro views that a capital investment approach well above $500 million per year over the 2015-2019 period is optimal from an assets-needs perspective, in light of rate impacts and execution constraints, it has constrained its actual plan (and corresponding funding request to the OEB) to approximately $500 million per year over the 2015-2019 period.

Toronto Hydro synthesizes these input considerations into a strategic planning philosophy called its four pillars, which are:

Toronto Hydro`s planning activity is guided by its Strategic Pillars and compliance requirements.

In executing its planning activities, the utility employs a combination of ‘top-down’ and ‘bottom-up’ planning models with an iterative planning process. That is, the overall business strategy outlining the general direction of the organization is communicated from the ‘top’ (senior management) ‘down’ to the operational teams. Subject matter experts then incorporate this direction into their different functional areas and operational realities, needs and strategies.

Finally, as operational plans incorporating the strategic direction are formed, they are proposed to the senior leadership at Toronto Hydro for review, impact assessments and approval.

In general, the planning process consists of four stages: 1. Corporate strategy establishment; 2. Operational plan proposals; 3. Proposal reviews and selection; and 4. Detailed development of projects and programs.

During the process, multiple planning activities are being concurrently conducted, and inputs and outcome considerations are being refined. An iterative planning approach is used in order to facilitate robust decision-making and prudent planning.

The results of the planning activity are reflected in this CIR application and include:

- A detailed OM&A plan for 2015; and
- Detailed annual capital investment plans for 2015 to 2019.

Further details of these results are in Exhibit 2B (DSP) and 4A (OM&A).

INTRODUCTION

In accordance with section 2.4.3 of the OEB's Filing Requirements (July 17, 2013), Exhibit 1C, Tab 4 provides the following financial information:

- Consolidated Audited Financial Statements for 2011-2013 (Schedule 2);
- Reconciliation of the financial results shown in the Audited Financial Statements with regulatory financial results (Schedule 3);
- Management's Discussion & Analysis for 2013 (Schedule 4);
- Annual Information From (Schedule 5);
- Public Offering Information (Schedule 6); and
- Rating Agency Reports (Schedule 7).

AUDITED FINANCIAL STATEMENTS

In accordance with section 2.4.3 of the OEB's Filing Requirements (July 17, 2013), this schedule includes the following materials:

- 2011 Audited Financial Statements (Appendix A);
- 2012 Audited Financial Statements (Appendix B); and
- 2013 Audited Financial Statements (Appendix C).

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2011

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2011

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

We have audited the accompanying financial statements of Toronto Hydro-Electric System Limited, which comprise the balanc sheet as at December 31, 2011, the statements of income, retained earnings and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statemen The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financ statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Toronto Hydro-Elec System Limited as at December 31, 2011, and its financial performance and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Other matter

The financial statements of Toronto Hydro-Electric System Limited as at and for the year ended December 31, 2010 were audited by another auditor who expressed an unmodified opinion on those statements on March 11, 2011.

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 2, 2012

Toronto Hydro-Electric System Limited

BALANCE SHEETS

[in thousands of dollars]

As at December 31	2011 $	2010 $
ASSETS		
Current		
Cash and cash equivalents	**66,744**	175,513
Accounts receivable, net of allowance for doubtful accounts *[note 15[b]]*	**191,456**	184,645
Unbilled revenue *[note 15[b]]*	**262,289**	283,141
Payments in lieu of corporate taxes receivable	**8,684**	2,530
Inventories *[note 4]*	**6,891**	7,501
Prepaid expenses	**4,404**	3,805
Total current assets	**540,468**	657,135
Property, plant and equipment, net *[note 5]*	**2,334,293**	2,064,942
Intangible assets, net *[note 6]*	**112,982**	85,987
Regulatory assets *[note 7]*	**77,322**	85,113
Other assets *[note 8]*	**7,331**	7,518
Future income tax assets *[note 17]*	**200,157**	224,570
Total assets	**3,272,553**	3,125,265
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[note 15[b]]*	**402,607**	363,970
Other liabilities *[note 9]*	**22,290**	19,734
Deferred revenue	**13,610**	1,669
Promissory note payable to related party *[notes 10 and 19]*	**-**	245,057
Total current liabilities	**438,507**	630,430
Long-term liabilities		
Notes payable to related party *[notes 10 and 19]*	**1,164,283**	865,539
Promissory note payable to related party *[notes 10 and 19]*	**245,058**	245,058
Post-employment benefits *[note 11]*	**176,370**	166,790
Regulatory liabilities *[note 7]*	**210,280**	273,706
Other liabilities *[note 12]*	**11,301**	679
Asset retirement obligations *[note 13]*	**4,831**	4,939
Customers' advance deposits	**35,930**	45,462
Total long-term liabilities	**1,848,053**	1,602,173
Total liabilities	**2,286,560**	2,232,603
Commitments, contingencies and subsequent events *[notes 20, 21 and 23]*		
Shareholder's equity		
Share capital *[note 18]*	**527,817**	527,817
Retained earnings	**445,419**	352,088
Contributed surplus	**12,757**	12,757
Total shareholder's equity	**985,993**	892,662
Total liabilities and shareholder's equity	**3,272,553**	3,125,265

The accompanying notes are an integral part of the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF INCOME

[in thousands of dollars]

Year ended December 31	2011 $	2010 $
Revenues		
Sale of electricity	**2,766,714**	2,561,418
Other income	**24,931**	29,644
	2,791,645	2,591,062
Costs		
Purchased power	**2,236,541**	2,057,747
Operating expenses	**235,643**	214,385
Depreciation and amortization	**146,505**	164,959
	2,618,689	2,437,091
Income before the following:	**172,956**	153,971
Net financing charges	**(74,478)**	(69,657)
Gain on disposals of property, plant and equipment *[note 5]*	**3,885**	3,650
Income before provision for payments in lieu of corporate taxes	**102,363**	87,964
Provision for payments in lieu of corporate taxes *[note 17]*	**9,032**	23,946
Net income	**93,331**	64,018

STATEMENTS OF RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31	2011 $	2010 $
Retained earnings, beginning of year	**352,088**	288,070
Net income	**93,331**	64,018
Retained earnings, end of year	**445,419**	352,088

The accompanying notes are an integral part of the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CASH FLOWS

[in thousands of dollars]

Year ended December 31	**2011** **$**	2010 $
OPERATING ACTIVITIES		
Net income	**93,331**	64,018
Adjustments for non-cash items		
Depreciation and amortization	**146,505**	164,959
Net change in other assets and liabilities	**(1,549)**	4,877
Payments in lieu of corporate taxes	**(6,154)**	8,962
Post-employment benefits	**9,580**	12,342
Future income taxes *[note 17]*	**279**	-
Gain on disposals of property, plant and equipment *[note 5]*	**(3,885)**	(3,650)
Changes in non-cash working capital balances		
Increase in accounts receivable	**(6,811)**	(26,624)
Decrease in unbilled revenue	**20,852**	9,604
Decrease (increase) in inventories	**610**	(1,277)
Increase in prepaid expenses	**(599)**	(595)
Increase in accounts payable and accrued liabilities	**38,861**	40,004
Increase (decrease) in deferred revenue	**13,316**	(324)
Net cash provided by operating activities	**304,336**	272,296
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 5]*	**(378,378)**	(356,525)
Purchase of intangible assets *[note 6]*	**(52,805)**	(28,387)
Net change in regulatory assets and liabilities	**(31,725)**	(16,011)
Proceeds on disposals of property, plant and equipment	**4,974**	3,486
Net cash used in investing activities	**(457,934)**	(397,437)
FINANCING ACTIVITIES		
Increase in note payable to related party *[note 10]*	**53,043**	198,680
Increase (decrease) in customers' advance deposits	**(8,214)**	12,554
Net cash provided by financing activities	**44,829**	211,234
Net increase (decrease) in cash and cash equivalents during the year	**(108,769)**	86,093
Cash and cash equivalents, beginning of year	**175,513**	89,420
Cash and cash equivalents, end of year	**66,744**	175,513
Supplementary cash flow information		
Total interest paid	**77,006**	70,992
Payments in lieu of corporate taxes	**11,615**	14,570

The accompanying notes are an integral part of the financial statements.

NOTES TO FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

1. INCORPORATION

On June 23, 1999, Toronto Hydro-Electric System Limited ["LDC"] was incorporated under the Business Corporations Act (Ontario) and is wholly-owned by Toronto Hydro Corporation [the "Corporation"]. The incorporation was required in accordance with the provincial government's Electricity Act, 1998 (Ontario) ["Electricity Act"].

LDC distributes electricity to customers located in the City of Toronto [the "City"] and is subjected to rate regulation. LDC is also engaged in the delivery of Conservation and Demand Management ["CDM"] activities.

2. REGULATION

In April 1999, the government of Ontario began restructuring the Province of Ontario ["Ontario"]'s electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator ["IESO"] and recovering the costs of electricity and certain other costs at retail rates in accordance with procedures mandated by the Ontario Energy Board [the "OEB"].

The OEB has regulatory oversight of electricity matters in Ontario. The Ontario Energy Board Act, 1998 (Ontario) [the "OEB Act"] sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

LDC is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

[i] Distribution Charges Distribution charges are designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and are comprised of a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

[ii] Electricity Price and Related Regulated Adjustments. The electricity price and related regulated adjustments represent a pass through of the commodity cost of electricity.

[iii] Retail Transmission Rate. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

a) Electricity Distribution Rates

LDC's electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, LDC's distribution revenue for the first four months of 2011 was based on the electricity distribution rates approved for the May 1, 2010 to April 30, 2011 rate year [the "2010 Rate Year"], and the distribution revenue for the remainder of 2011 and for the first four months of 2012 are and will be based on electricity distribution rates approved for the May 1, 2011 to April 30, 2012 rate year [the "2011 Rate Year"].

LDC's electricity distribution rates for the 2010 Rate Year and the 2011 Rate Year were determined through an application under the cost of service framework. The cost of service framework sets electricity distribution rates using a detailed examination of evidence and an assessment of the costs incurred by an electricity distributor to provide its service to its customers.

On April 9, 2010, the OEB issued its decision regarding LDC's electricity distribution rates for the 2010 Rate Year. The decision provided for a distribution revenue requirement and rate base of $518,700,000 and $2,140,700,000, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $350,000,000 and $204,100,000, respectively.

On July 7, 2011, the OEB issued its decision regarding LDC's electricity distribution rates for the 2011 Rate Year. The decision provided for a distribution revenue requirement and rate base of $522,044,000 and $2,298,227,000, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $378,800,000 and $238,000,000, respectively.

On August 26, 2011, LDC filed a rate application, following the cost of service framework, with the OEB seeking approval of separate and successive revenue requirements and corresponding electricity distribution rates for three rate years commencing on May 1, 2012, May 1, 2013 and May 1, 2014 [the "2012-2014 Rate Application"]. The requested distribution revenue requirements for these rate years were $571,369,000, $639,492,000, and $712,777,000, respectively, and the expected rate bases for these rate years were $2,636,291,000, $3,053,499,000, and $3,503,165,000, respectively.

Pursuant to the incentive regulation mechanism framework, the OEB established, as a preliminary issue in the 2012-2014 Rate Application, that it would consider the question of whether the application filed by LDC was acceptable or whether it should be dismissed. In particular, the OEB established that in order for it to find that LDC's 2012-2014 Rate Application was acceptable, LDC would be required to show why and how LDC cannot adequately manage its resources and financial needs under the incentive regulation mechanism framework. The incentive regulation mechanism framework provides for an annual adjustment to an electricity distributor's rates based on a formulaic calculation with no direct examination of evidence regarding the electricity distributor's actual costs and infrastructure needs.

LDC filed evidence supporting its position for electricity distribution rates to be set under the cost of service framework as part of its 2012-2014 Rate Application. In particular, LDC provided evidence that it cannot adequately manage its resources and financial needs under the incentive regulation mechanism framework. The OEB established a process by which a portion of LDC's evidence was tested during an oral hearing held in November 2011 [note 23[b]].

b) Street Lighting Activities

On June 15, 2009, LDC filed an application with the OEB seeking an electricity distribution licence for a new wholly-owned legal entity to which the Corporation intended to transfer the street lighting assets of Toronto Hydro Energy Services Inc. ["TH Energy"]. Concurrently, LDC filed another application with the OEB seeking approval for the merger of LDC and the new legal entity. The major objective of these applications was to transfer the street lighting assets to the regulated electricity distribution activities of LDC to increase the overall safety of the related infrastructure.

On February 11, 2010, the OEB issued its decision in regard to these applications. In its decision, the OEB agreed that, under certain conditions, the treatment of certain types of street lighting assets as regulated assets is justified. The OEB ordered the Corporation to provide a detailed valuation of the street lighting assets and to perform an operational review to determine which street lighting assets could become regulated assets. The Corporation performed a detailed asset operational review and final valuation of the street lighting assets, which was submitted to the OEB on January 31, 2011.

On August 3, 2011, the OEB issued its final decision allowing the transfer of a portion of the street lighting assets to the new wholly-owned legal entity, and for LDC to amalgamate with the new legal entity [note 23[a]].

c) Conservation and Demand Management Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 Gigawatt-Hours of energy savings and 286 Megawatts of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the Ontario Power Authority ["OPA"] to deliver CDM programs in the amount of approximately $50,000,000 extending from January 1, 2011 to December 31, 2014. As at December 31, 2011, LDC received approximately $19,875,000 from the OPA for the delivery of CDM

programs. All programs to be delivered are fully funded and paid in advance by the OPA. These programs are expected to support the achievement of the mandatory CDM targets described above.

On January 10, 2011, LDC filed an application with the OEB seeking an order granting approval of funding for CDM programs specific to its customer base. LDC requested funding for eight specific CDM programs amounting to $50,700,000. On July 12, 2011, the OEB issued its decision regarding the CDM programs of LDC. In its decision, the OEB approved with modifications two of the eight programs for a total funding of $5,320,000. The modifications directed by the OEB included changes to the term and nature of those two programs. The OEB did not approve the other six programs as it considered them to be duplicative of existing CDM programs already funded by the OPA.

On August 3, 2011, LDC filed a letter with the OEB informing them that, due to the modified terms and nature of the two approved programs, LDC's revised economic assessment showed these two programs to be uneconomic, and that they would not be implemented. Accordingly, LDC expects to continue to work with the OPA to expand the roster of current CDM programs in order to achieve its mandated CDM targets.

d) Contact Voltage

On December 10, 2009, the OEB issued an initial decision in regard to the costs incurred in 2009 for the remediation of safety issues related to contact voltage relating to LDC's electricity distribution infrastructure. The decision provided for the recovery of allowable actual expenditures incurred above the amount deemed as controllable expenses in LDC's 2009 approved electricity distribution rates. At the time of the decision, LDC estimated the allowable recovery of costs at $9,050,000.

On October 29, 2010, the OEB issued a second decision in the matter, following further review of costs incurred by LDC. In this decision, the OEB deemed the balance allowable for recovery at $5,296,000. The variance from LDC's original estimate is mainly due to the OEB's interpretation of the definition of controllable expenses used to determine the final allowable recovery. In connection with this decision from the OEB, LDC revised its recovery estimate for contact voltage costs, resulting in an increase in operating expenses of $3,754,000 in 2010. On November 18, 2010, LDC filed a motion to review the decision with the OEB seeking an amendment to allow for recovery in accordance with the initial decision rendered on December 10, 2009. On March 25, 2011, the OEB issued its decision on the LDC motion, denying the requested additional recovery.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements of LDC have been prepared in accordance with Canadian generally accepted accounting principles ["GAAP"], including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" ["AP Handbook"], are presented in Canadian dollars and reflect the significant accounting policies summarized below:

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

In accordance with Canadian GAAP, LDC currently follows specific accounting policies unique to a rate-regulated business. Under rate-regulated accounting ["RRA"], the timing and recognition of certain expenses and revenues may differ from those otherwise expected under Canadian GAAP in order to appropriately reflect the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These timing differences are recorded as regulatory assets and regulatory liabilities on LDC's balance sheets and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the disposition of these balances was assessed to no longer be probable, the balances would be recorded in LDC's statement of income in the period that the assessment is made. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation and the OEB's decisions.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property, plant and equipment of LDC. According to the AP Handbook, capital contributions received are treated as a "credit" to property, plant and equipment. The amount is subsequently depreciated by a charge to accumulated depreciation and a credit to depreciation expense at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

Allowance for funds used during construction

The AP Handbook provides for the inclusion of an Allowance for Funds Used During Construction ["AFUDC"] when capitalizing construction-in-progress assets, until such time as the asset is substantially complete. A concurrent credit of the same amount is made to net financing charges when the allowance is capitalized. The interest rate for capitalization is prescribed by the OEB and modified on a periodic basis, and is applied to the balance of the construction-in-progress asset on a simple interest basis. The interest rate for capitalization, for the period from January 1 to September 30, 2011, was 4.29% and from October 1, 2011 to December 31, 2011, was 3.92%. AFUDC is included in property, plant and equipment, intangible assets, and construction-in-progress assets for financial reporting purposes, charged to operations through depreciation and amortization expense over the service life of the related assets and recovered through future revenue.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition.

c) Inventories

Inventories consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution system infrastructure to property, plant and equipment. Once capitalized, these items are not depreciated until they are put into service. Inventories are carried at the lower of cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

d) Property, plant and equipment

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as an amount by which the carrying amount of the asset exceeds its fair value, which is determined by the estimated future discounted cash flows.

Effective January 1, 2011, LDC revised its estimates of useful lives of certain items of property, plant and equipment following a detailed review and analysis supported by external third-party evidence. These changes in estimates have been accounted for on a prospective basis in the financial statements effective January 1, 2011.

Effective January 1, 2011, LDC revised its estimates of burden rates of certain items of property, plant and equipment following a detailed review and analysis of all the components included in such burden rates. These changes in estimates of burden rates include changes in the allocation of engineering and administration costs, changes in the calculation of standard labour rates, and changes in the calculation of materials handling costs. These changes in estimates have been accounted for on a prospective basis in the financial statements effective January 1, 2011.

The changes discussed above were reflected in the 2011 electricity distribution rates approved by the OEB on July 7, 2011 [note 2[a]]. Accordingly, these changes decreased distribution revenues by approximately $24,600,000, increased operating expenses by approximately $22,000,000, decreased depreciation expenses by approximately $33,000,000 and decreased Payments in Lieu of Corporate Taxes ["PILs"] by approximately $13,600,000 for the year ended December 31, 2011 and are expected to impact depreciation expenses proportionately in future periods.

Depreciation is provided on a straight-line basis over the estimated service lives at the following annual rates:

	2011	2010
Distribution lines	2.0% to 5.0%	2.5% to 4.0%
Transformers	3.3% to 5.0%	3.3% to 4.0%
Stations	2.5% to 10.0%	2.5% to 6.7%
Meters	2.5% to 6.7%	2.9% to 6.7%
Buildings	1.3% to 5.0%	2.0%
Rolling stock	12.5% to 25.0%	12.5% to 33.3%
Other capital assets	4.0% to 20.0%	4.0% to 20.0%
Assets under capital lease	14.3% to 25.0%	25.0%
Equipment and tools	10.0% to 16.7%	10.0% to 16.7%
Computer hardware	16.7% to 25.0%	20.0% to 25.0%
Communications	10.0% to 20.0%	10.0% to 20.0%

Construction in progress relate to assets not currently in use and therefore are not depreciated.

e) Intangible assets

Intangible assets are stated at cost. Amortization is provided on a straight-line basis over their estimated service lives at the following annual rates:

	2011	2010
Computer software	20.0% to 25.0%	20.0%
Contributions	4.0%	4.0%

Software in development and contributions for work in progress relate to assets not currently in use and therefore are not amortized.

f) Workplace Safety and Insurance Act

LDC is a Schedule 1 employer for workers' compensation under the Workplace Safety and Insurance Act, 1997 (Ontario) [the "WSIA"]. As a Schedule 1 employer under the WSIA, LDC is required to pay annual premiums into an insurance fund established under the WSIA and recognizes expenses based on funding requirements.

g) Revenue recognition

Revenues from the sale of electricity are recorded on the basis of cyclical billings and also include unbilled revenues accrued in respect of electricity delivered but not yet billed.

Other income, which includes revenues from electricity distribution related services, is recognized as the services are rendered.

h) Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the statements of income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by LDC. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

The following summarizes the accounting classification LDC has elected to apply to each of its significant categories of financial instruments:

Cash equivalents and short-term investments	Investments Held to Maturity
Accounts receivable and unbilled revenue	Loans and Receivables
Accounts payable and accrued liabilities	Other Financial Liabilities
Obligations under capital lease	Other Financial Liabilities
Customers' advance deposits	Other Financial Liabilities
Short-term and long-term debt	Other Financial Liabilities

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheet:

- Cash equivalents, comprising short-term investments, are classified as "Investments Held to Maturity" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. The carrying amounts approximate fair value because of the short maturity of these instruments.
- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, are considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.
- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.
- Obligations under capital lease are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are based on discounted cash flow analysis and approximate their carrying values as management believes that the fixed interest rates are representative of current market rates.
- Customers' advance deposits are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of the current portion, and the discounted long-term portion approximates the carrying value, taking into account interest accrued on the outstanding balance.
- Short-term debt and long-term debt are classified as "Other Financial Liabilities" and are initially measured at their fair value. The carrying amounts are carried at amortized cost, based on the initial fair value as determined

at the time using quoted market price for similar debt instruments. The fair value of the long-term debt is calculated by discounting the related cash flows at the estimated yield to maturity of similar debt instruments [note 15].

i) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;
- Level 2 – Observable inputs other than level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities; and
- Level 3 – Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

j) Employee future benefits

Pension plan

LDC provides a pension plan for its full-time employees through the Ontario Municipal Employees Retirement System ["OMERS"]. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. LDC recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension

Employee future benefits other than pension provided by LDC include medical, dental and life insurance benefits, and accumulated sick leave credits. These plans provide benefits to employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render services on an accrual basis.

The accrued benefit obligations and the current service costs are calculated using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs arising from plan amendments are recognized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gains or losses over 10% of the accrued benefit obligation is amortized in excess over the average remaining service period of active

employees to full eligibility. The effects of a curtailment gain or loss are recognized in income in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in the period in which a settlement occurs.

k) Asset retirement obligations

LDC recognizes a liability for the future removal and handling costs for contamination in distribution equipment in service and in storage and for the future environmental remediation of certain properties. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is depreciated and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ["accretion expense"] and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ["ARO"] is incurred and when the fair value is determined.

l) Customers' advance deposits

Customers' advance deposits are cash collections from customers to guarantee the payment of energy bills. The customers' advance deposits liability includes interest credited to the customers' deposit accounts, with the debit charged to net financing charges. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

m) Payments in lieu of corporate taxes

LDC is exempt from tax under the Income Tax Act (Canada) ["ITA"] provided that all of its capital is owned by the Corporation, a Municipal Electricity Utility ["MEU"], and not more than 10% of its respective income is derived from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the Taxation Act, 2007 (Ontario) ["TA"] and the Corporations Tax Act (Ontario) ["CTA"].

LDC is a MEU for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA, the CTA and the TA is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TA (for years ending after 2008) or the CTA (for years ending prior to 2009) if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time LDC was deemed to have commenced a new taxation year for purposes of determining its respective liability for PILs payments.

LDC uses the liability method of accounting for income taxes. Under the liability method, future income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established. In accordance with the Canadian Institute of Chartered Accountants ["CICA"] Handbook Section 3465 – "Income Taxes", LDC recognizes future income taxes associated with its rate-regulated operations and records an offsetting regulatory asset or liability for the future income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

n) Use of estimates

The preparation of LDC's financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the year. The estimates are based on past experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as identifying and assessing the accounting treatment with respect to commitments and contingencies. Significant areas requiring the use of management estimates relate to unbilled revenue, regulatory assets and liabilities, environmental liabilities and AROs, employee future benefits, and revenue recognition. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy, or the Ministry of Finance of Ontario ["Ministry of Finance"].

o) Future Accounting Pronouncements

Adoption of New Accounting Standards

Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ["IFRS"] in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the Accounting Standards Board granted an optional one-year deferral for IFRS adoption for entities subject to rate regulation due to the uncertainty created by the International Accounting Standards Board ["IASB"] in regard to RRA. To date, the IASB has not approved any temporary exemption or finalized a RRA standard under IFRS. LDC elected to take the optional one-year deferral of its adoption of IFRS; therefore, it continues to prepare its financial statements in accordance with Canadian GAAP accounting standards in Part V of the CICA Handbook in 2011.

LDC's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date. In the absence of a definitive plan to consider the issuance of a RRA standard by the IASB, LDC decided to evaluate the option of adopting United States ["US"] GAAP effective January 1, 2012 as an alternative to IFRS. LDC's current application of Canadian GAAP for RRA is generally consistent with US GAAP. Under US GAAP, LDC's financial reporting is expected to be more comparable with its current Canadian GAAP results than it would be under IFRS and is expected to facilitate comparability with other large North American utilities.

On July 8, 2011, the Corporation filed an application with the applicable Canadian securities regulatory authorities pursuant to section 5.1 of National Instrument 52-107 "Acceptable Accounting Principles and Auditing Standards", to permit the Corporation to prepare its consolidated financial statements in accordance with US GAAP without qualifying as a US Securities and Exchange Commission issuer.

On July 21, 2011, the applicable Canadian securities regulatory authorities issued a decision which gave the Corporation the option to prepare its consolidated financial statements in accordance with US GAAP for its fiscal years beginning on or after January 1, 2012 but before January 1, 2015. The decision is similar to that obtained by other Canadian rate-regulated utilities.

On August 19, 2011, LDC filed a letter with the OEB stating its intention to adopt US GAAP as the basis for the calculation of electricity distribution rates starting in 2012 in accordance with the guidelines provided by the OEB. In the OEB guidelines, the OEB indicated to Ontario utilities that it would permit the use of US GAAP for the calculation of electricity distribution rates if such utilities receive approval from the Ontario Securities Commission and if it benefits electricity distribution consumers.

On August 26, 2011, the board of directors of the Corporation approved the adoption of US GAAP for financial reporting purposes for the year beginning on January 1, 2012. Accordingly, LDC plans to commence reporting under US GAAP in its first quarterly financial statements in 2012. As a result of this decision, LDC's IFRS conversion project efforts have been reduced. However, the work has been managed in such a way that it can effectively be restarted when a future transition to IFRS is required.

LDC's interim financial statements for the first quarter of 2012 are expected to be prepared in accordance with US GAAP and applied retrospectively to LDC's opening US GAAP balance sheet as at January 1, 2011. Based on the results of the detailed assessment of the differences between US GAAP and Canadian GAAP as it applies to its business, LDC does not believe that the adoption of US GAAP will have a material impact on its financial statements in the future.

4. INVENTORIES

Inventories consist of the following:

	2011 $	2010 $
Consumables, tools and other maintenance items	1,745	2,077
Fuses	1,625	1,731
Drums and reels	938	1,092
Other	2,583	2,601
	6,891	7,501

For the year ended December 31, 2011, LDC recognized operating expenses of $6,507,000, related to inventory used to service electrical distribution assets [2010 - $4,727,000].

NOTES TO FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

5. PROPERTY, PLANT AND EQUIPMENT, NET

Property, plant and equipment consist of the following:

	2011			2010		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	16,761	—	16,761	9,560	—	9,560
Distribution lines	2,755,344	1,404,998	1,350,346	2,517,584	1,353,037	1,164,547
Transformers	652,102	360,398	291,704	609,702	341,706	267,996
Stations	277,905	137,246	140,659	259,337	128,254	131,083
Meters	238,459	124,117	114,342	214,859	114,808	100,051
Buildings	154,932	62,403	92,529	151,543	55,609	95,934
Rolling stock	78,016	43,154	34,862	73,749	43,208	30,541
Other capital assets	68,282	43,805	24,477	58,700	35,177	23,523
Assets under capital leas	14,269	1,251	13,018	886	351	535
Equipment and tools	44,208	31,785	12,423	41,604	29,732	11,872
Computer hardware	44,625	35,602	9,023	40,634	31,228	9,406
Communications	31,537	23,912	7,625	26,818	21,013	5,805
Construction in progress	226,524	—	226,524	214,089	—	214,089
	4,602,964	2,268,671	2,334,293	4,219,065	2,154,123	2,064,942

For the year ended December 31, 2011, AFUDC in the amount of $3,786,000 [2010 - $1,158,000] was capitalized to property, plant and equipment and credited to net financing charges.

As at December 31, 2011, the net book value of stranded meters related to the deployment of smart meters amounting to $20,366,000 [December 31, 2010 - $23,120,000] was included in property, plant and equipment. In the absence of rate regulation, property, plant and equipment would have been $20,366,000 lower as at December 31, 2011 [December 31, 2010 - $23,120,000 lower].

For the year ended December 31, 2011, LDC recognized a gain of $3,885,000 [2010 - $3,650,000] on disposals of surplus properties, of which $1,375,000 [2010 - $2,750,000] relates to surplus properties for which the OEB reduced electricity distribution rates in 2010. LDC began recognizing the actual gain realized on the sale of these properties over a one-year period from May 1, 2010 to mirror the actual timing of the reduction in 2010 electricity distribution rates.

For the year ended December 31, 2011, LDC recorded depreciation expense of $120,690,000 [2010 - $148,744,000] of which $1,177,000 [2010 - $204,000] related to assets under capital lease.

6. INTANGIBLE ASSETS, NET

Intangible assets consist of the following:

	2011			2010		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Computer software	222,598	154,186	68,412	172,692	129,293	43,399
Contributions	14,059	1,440	12,619	2,043	524	1,519
Software in development	3,582	—	3,582	39,191	—	39,191
Contributions for work in progress	28,369	—	28,369	1,878	—	1,878
	268,608	155,626	112,982	215,804	129,817	85,987

For the year ended December 31, 2011, LDC acquired $52,805,000 of intangible assets [2010 - $28,387,000]. All intangible assets are subject to amortization when they become available for use. Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized.

For the year ended December 31, 2011, $49,907,000 of software in development were transferred to computer software [2010 - $29,266,000].

For the year ended December 31, 2011, AFUDC in the amount of $1,419,000 [2010 - $1,568,000] was capitalized to intangible assets and credited to net financing charges.

For the year ended December 31, 2011, LDC recorded amortization expense on intangible assets of $25,809,000 [2010 - $16,215,000].

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	2011 $	2010 $
Smart meters	61,422	67,719
Late payment penalties settlement	—	7,750
IFRS conversion project	—	6,089
Settlement variances	14,119	—
Special purpose charge variance	572	3,555
Other	1,209	—
	77,322	85,113

Regulatory liabilities consist of the following:

	2011 $	2010 $
Future income taxes	200,436	224,570
Regulatory assets recovery account	6,361	40,275
PILs variances	2,365	5,675
Settlement variances	—	2,277
Other	1,118	909
	210,280	273,706

For the year ended December 31, 2011, LDC disposed of approved net regulatory liabilities amounting to $34,528,000 through permitted distribution rate adjustments [2010 - $23,003,000].

The regulatory assets and liabilities of LDC are as follows:

a) Smart Meters

The smart meters regulatory asset account relates to Ontario's decision to install smart meters throughout Ontario. LDC substantially completed its smart meter project as at December 31, 2010. In connection with this initiative, the OEB ordered LDC to record all expenditures and related revenues from 2008 to 2010 to a regulatory asset account and allowed LDC to keep the net book value of the stranded meters in property, plant and equipment. Starting on January 1, 2011, LDC began recording smart meter costs in property, plant and equipment and intangible assets as a regular distribution activity as directed by the OEB. LDC expects to apply to the OEB to transfer the 2008 to 2010 smart meter costs from regulatory assets to property, plant and equipment and intangible assets, as well as to transfer the net book value of the stranded meters from property, plant and equipment to regulatory assets in 2012.

LDC incurred smart meter capital expenditures amounting to $19,799,000 for the year ended December 31, 2011 [2010 - $19,799,000]. As at December 31, 2011, smart meter capital expenditures, net of accumulated depreciation, totalling $59,227,000 were recorded to regulatory assets [December 31, 2010 - $65,588,000]. These expenditures would otherwise have been recorded as property, plant and equipment and intangible assets under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $54,825,000 and $4,402,000 higher, respectively, as at December 31, 2011 [December 31, 2010 - $59,416,000 and $6,172,000 higher, respectively].

For the year ended December 31, 2011, deferred smart meter operating expenses were reduced by $490,000 which would have reduced expenses under Canadian GAAP for unregulated businesses [2010 – were increased by $3,109,000]. For the year ended December 31, 2011, smart meter depreciation expense of $6,361,000 [2010 - $5,357,000] were deferred which would have been expensed under Canadian GAAP for unregulated businesses. In the absence of rate regulation, for the year ended December 31, 2011, operating expenses would have been $490,000 lower [2010 - $3,109,000 higher], and depreciation expense would have been $6,361,000 higher [2010 - $5,357,000 higher].

For the year ended December 31, 2011, smart meter customer revenues of $5,866,000 were deferred [2010 - $5,774,000]. In the absence of rate regulation, for the year ended December 31, 2011, revenue would have been $5,866,000 higher [2010 - $5,774,000 higher].

b) Late Payment Penalties Settlement

The late payment penalties settlement regulatory asset account was related to the settlement costs associated with the late payment charges class action. All of the MEUs involved in the settlement, including LDC, requested an order from the OEB allowing for the future recovery from customers of all costs related to the settlement. On February 22, 2011, the OEB approved the recovery of the costs of $7,526,000. The recovery is occurring over a 21-month period which commenced on August 1, 2011. Accordingly, the balance approved for recovery was transferred to the Regulatory Assets Recovery Account ["RARA"].

c) IFRS Conversion Project

This regulatory asset account included the incremental costs incurred by LDC for its initially planned conversion to IFRS. On July 7, 2011, the OEB reduced the allowable recoverable costs from $6,134,000 to $3,050,000 as it appeared that a portion of the costs claimed for recovery by LDC were included in prior period electricity distribution rates. In connection with this decision from the OEB, LDC revised its estimate for IFRS conversion costs recovery, resulting in an increase in operating expenses of $3,017,000 in the second quarter of 2011. The remaining regulatory asset balance of $3,050,000, which included carrying charges, was transferred to the RARA and is being recovered over a nine-month period which commenced on August 1, 2011. Under Canadian GAAP for unregulated businesses, these costs would have been recorded to operating expenses. In the absence of rate regulation, for the year ended December 31, 2011, operating expenses would have been $3,017,000 lower [2010 - $3,108,000 higher].

d) Settlement Variances

This account is comprised of the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by LDC. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB in the AP Handbook.

The balance for settlement variances continues to be tracked and attract carrying charges in accordance with the OEB's direction. For the year ended December 31, 2011, settlement variances of $34,938,000 were disposed through rate adjustments [2010 - $20,016,000].

e) Special Purpose Charge Variance

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge ["SPC"] assessment under Section 26.1 of the OEB Act, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed LDC the amount of $9,698,000 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10 [the "SPC Regulation"]. In accordance with Section 9 of the SPC Regulation, LDC was allowed to recover this balance. The recovery was completed as at April 30, 2011.

As at December 31, 2011, the balance in this account consists of LDC's assessment of $9,698,000 less the recoveries received from customers. In the absence of rate regulation, revenue for the year ended December 31, 2011, would have been $3,050,000 higher [2010 - $6,123,000 higher] and operating expenses for the year ended December 31, 2011 would have $nil impact [2010 - $9,698,000 higher].

f) Future Income Taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets [note 3[m]].

As at December 31, 2011, LDC recorded a future income tax asset and a corresponding regulatory liability of $200,436,000 [December 31, 2010 - $224,570,000] with respect to its rate-regulated activities. The future income tax asset and the corresponding regulatory liability as at December 31, 2010 have been recast to reflect an adjustment of $30,247,000 resulting from a change in methodology used to determine the timing differences between the tax value and book value of the assets for accounting purposes.

g) Regulatory Assets Recovery Account

The RARA consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and related rates.

On April 16, 2009, the OEB approved the disposition of regulatory liabilities of $7,582,000, for amounts arising from the extended effectiveness of certain rate riders into the 2008 rate year, over a one-year period commencing on May 1, 2009 and ending on April 30, 2010.

On April 9, 2010, the OEB approved the disposition of net regulatory liabilities of $68,140,000, consisting of credit balances for settlement variances and PILs variances of $58,225,000 and $11,900,000, respectively, and intangible assets debit balance of $1,985,000, over a two-year period commencing on May 1, 2010 and ending on April 30, 2012.

On October 29, 2010, the OEB approved the disposition of regulatory assets of $5,296,000, for amounts in connection with the contact voltage remediation activities, for the period commencing on November 1, 2010 and ending on April 30, 2012 [note 2[d]].

On February 22, 2011, the OEB approved the disposition of the Late Payment Penalties Settlement regulatory asset of $7,526,000, over a 21-month period commencing on August 1, 2011 and ending on April 30, 2013.

On July 7, 2011, the OEB approved the disposition of net regulatory liabilities of $8,572,000, consisting of credit balances for settlement variances, PILs variances and 2008 RARA residual of $7,460,000, $3,373,000, and $789,000, respectively, and an IFRS cost debit balance of $3,050,000, over a nine-month period commencing on August 1, 2011 and ending on April 30, 2012.

h) PILs Variances

The PILs variances regulatory liability account relates to the differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the rate adjustment model. As at December 31, 2011, the balance in this account consisted of an over-recovery from customers of $2,365,000 [December 31, 2010 - $5,675,000].

8. OTHER ASSETS

Other assets consist of the following:

	2011 $	2010 $
Prepaid leases	7,279	7,368
Other	52	150
	7,331	7,518

NOTES TO FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

9. CURRENT PORTION OF OTHER LIABILITIES

Current portion of other liabilities consist of the following:

	2011 $	2010 $
Customers' advance deposits	20,108	18,790
Obligations under capital lease [note 20]	1,871	182
Other	311	762
	22,290	19,734

10. LONG-TERM DEBT

Long-term debt consists of the following:

	2011 $	2010 $
Notes payable to the Corporation:		
6.16% Long-term note payable to the Corporation due May 6, 2013	179,456	179,100
5.20% Long-term note payable to the Corporation due November 14,	244,186	244,062
4.54% Long-term note payable to the Corporation due November 12,	243,814	243,686
5.59% Long-term note payable to the Corporation due May 21, 2040	198,708	198,691
3.59% Long-term note payable to the Corporation due November 18,	298,119	—
6.16% Promissory note payable to the Corporation due May 6, 2013	245,058	490,115
Total notes payable to the Corporation	1,409,341	1,355,654
Less: Current portion of promissory note payable	—	245,057
Long-term debt	1,409,341	1,110,597
Comprising:		
Long-term notes payable to the Corporation	1,164,283	865,539
Promissory note payable to the Corporation	245,058	245,058

All long-term debt of LDC ranks equally.

NOTES TO FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

a) Long-term notes payable to the Corporation

Long-term notes payable to the Corporation are comprised of the following:

[i] $180,000,000, which bears interest at a rate of 6.16% per annum, with a maturity date of May 6, 2013, extendable upon mutual consent.

[ii] $245,058,000, which bears interest at a rate of 5.20% per annum, with a maturity date of November 14, 2017, extendable upon mutual consent.

[iii] $245,058,000, which bears interest at a rate of 4.54% per annum, with a maturity date of November 12, 2019, extendable upon mutual consent.

[iv] $200,000,000, which bears interest at a rate of 5.59% per annum, with a maturity date of May 21, 2040, extendable upon mutual consent.

[v] $300,000,000, which bears interest at a rate of 3.59% per annum, with a maturity date of November 18, 2021, extendable upon mutual consent.

b) Promissory note payable to the Corporation

On July 1, 1999, LDC issued a promissory note to the City ["Initial Note"] in the principal amount of $947,000,000 in partial consideration for the assets in respect of the electricity distribution system transferred by the Toronto Hydro-Electric Commission and the City to LDC effective July 1, 1999. The Initial Note was non-interest bearing until December 31, 1999 and interest bearing thereafter at the rate of 6% per annum. Pursuant to the terms of By-law No. 374-1999 of the City made under section 145 of the Electricity Act, the principal amount of the Initial Note was adjusted effective January 1, 2000 to $980,231,000 to reflect the deemed debt to equity structure of LDC permitted by the OEB. At the same time, the Initial Note was replaced by a promissory note ["Replacement Note"] issued by LDC, which was interest bearing at the rate of 6.8% per annum. At December 31, 2002, the Replacement Note was payable on the earlier of demand and December 31, 2003.

Concurrent with the closing of the Corporation's debenture offering on May 7, 2003, the City transferred the Replacement Note to the Corporation in consideration for the issuance by the Corporation to the City of a new promissory note in the principal amount of $980,231,000. Following the issuance of the new promissory note to the City, on May 7, 2003, LDC issued a promissory note payable on demand to the Corporation in the principal amount of $980,231,000.

On September 5, 2006, LDC amended and restated the promissory note payable to the Corporation effective May 1, 2006 by fixing the interest rate at 6.16% and establishing an agreed repayment schedule. LDC is required to pay the principal amount of the note as follows: $245,057,000 on the last business day before each of December 31, 2007, December 31, 2009, December 31, 2011 and on May 6, 2013. On December 31, 2007, LDC made the first scheduled payment of $245,057,000 to the Corporation. On December 31, 2009, LDC made the second scheduled payment of $245,057,000 to the Corporation. On December 30, 2011, LDC made the third scheduled payment of

$245,057,000 to the Corporation. Interest is calculated and payable quarterly in arrears on the last business day of March, June, September and December of each year.

11. EMPLOYEE FUTURE BENEFITS

Pension

For the year ended December 31, 2011, LDC's OMERS current service pension costs were $13,813,000 [2010 - $11,519,000]. For the year ended December 31, 2011, OMERS contributions were 7.4% up to the year's maximum pensionable earnings ["YMPE"] and 10.7% over YMPE for normal retirement age ["NRA"] of 65 [December 31, 2010 - 6.4% up to YMPE and 9.7% over YMPE for NRA of 65].

Employee future benefits other than pension

LDC has a number of unfunded benefit plans providing retirement and post-employment benefits (excluding pension) to most of its employees. LDC pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. LDC pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

LDC measures its accrued benefits obligation for accounting purposes as at December 31 of each year. The latest actuarial valuation was performed as at January 1, 2010.

a) Accrued benefit obligation

	2011 $	2010 $
Balance, beginning of year	198,630	172,280
Experience loss at beginning of year	—	7,547
Adjustment due to reorganization	478	4,235
Current service cost	3,820	3,407
Interest cost	11,307	10,911
Benefits paid	(7,383)	(7,083)
Actuarial losses	35,809	7,333
Balance, end of year	242,661	198,630

b) Reconciliation of the accrued benefit obligation to the balance sheet accrued benefit liability

	2011 $	2010 $
Accrued benefit obligation	242,661	198,630
Unamortized net actuarial losses	(65,425)	(30,094)
Unamortized past service costs	(866)	(1,746)
Post-employment benefits liability	176,370	166,790

c) Components for net periodic defined benefit costs

	2011 $	2010 $
Current service cost	3,820	3,407
Interest cost	11,307	10,911
Actuarial losses	35,809	14,880
Cost incurred in the year	50,936	29,198
Differences between costs incurred and costs recognized in the year in respect of:		
Actuarial gains	(35,022)	(14,514)
Past service costs	873	745
	(34,149)	(13,769)
Defined benefit costs recognized	16,787	15,429
Capitalized as part of property, plant and equipment	6,758	7,388
Charged to operations	10,029	8,041

d) Significant assumptions

	2011 %	2010 %
Accrued benefit obligation as at December 31:		
Discount rate	4.8	5.8
Rate of compensation increase	4.0	4.0
Benefit costs for years ended December 31:		
Discount rate	5.8	6.0
Rate of compensation increase	4.0	4.0
Assumed health care cost trend rates as at December 31:		
Rate of increase in dental costs	4.0	4.0

For December 31, 2011, medical costs are assumed to increase at 7.0% [2010 - 7.5%] graded down by 0.5% [2010 - 0.5%] annual decrements to 5.0% [2010 - 5.0%] in 2016 and thereafter.

e) Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for health and dental care plans. A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2011:

	Increase $	Decrease $
Total of current service and interest cost (at 5.8%)	2,675	(1,835)
Accrued benefit obligation as at December 31, 2011 (at 4.8%)	36,693	(28,227)

Assumed interest rates have a significant effect on the amounts reported for the total accrued benefit obligation and expense. A one-percentage-point change in assumed interest rates would have the following effects for 2011:

	Increase $	Decrease $
Accrued benefit obligation as at December 31, 2011	(32,872)	42,630
Estimated expense for fiscal 2012	(2,972)	3,378

12. OTHER LIABILITIES

Other long-term liabilities consist of the following:

	2011 $	2010 $
Obligations under capital lease [note 20]	11,301	369
Other	—	310
	11,301	679

For the year ended December 31, 2011, LDC acquired property, plant and equipment through capital lease transactions totalling $13,717,000 [2010 - $176,000]. These non-cash transactions have been excluded from the statements of cash flows.

13. ASSET RETIREMENT OBLIGATIONS

Reconciliation between the opening and closing ARO liability balances is as follows:

	2011 $	2010 $
Balance, beginning of year	4,939	7,490
ARO liabilities settled in the year	(688)	(2,290)
Accretion expense	168	190
Revision in estimated cash flows	412	(451)
Balance, end of year	4,831	4,939

As at December 31, 2011, LDC estimates the undiscounted amount of cash flows required over the next one to 45 years to settle the ARO liabilities is $5,676,000 [December 31, 2010 - $6,425,000]. Discount rates ranging from 1.39% to 5.29% [December 31, 2010 – 1.39% to 5.89%] were used to calculate the carrying value of the ARO liabilities. No assets have been legally restricted for settlement of the liability.

14. CAPITAL DISCLOSURES

LDC's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and refurbish its electricity distribution system; and
- align its capital structure for regulated activities with the deemed debt to equity structure set by the OEB.

As at December 31, 2011, LDC's definition of capital includes long-term debt and obligations under capital lease, including the current portion thereof, and shareholder's equity, and has remained unchanged from December 31, 2010. As at December 31, 2011, shareholder's equity amounted to $985,993,000 [December 31, 2010 -

$892,662,000] and long-term debt, including the current portion thereof, amounted to $1,422,513,000 [December 31, 2010 - $1,355,654,000]. LDC's capital structure as at December 31, 2011 was 59% debt and 41% equity [December 31, 2010 - 60% debt and 40% equity]. There were no changes in LDC's approach to capital management during the year.

15. FINANCIAL INSTRUMENTS

a) Recognition and measurement

The carrying value and fair value of LDC's financial instruments consist of the following:

	2011 $		2010 $	
	Carrying value	Fair value	Carrying value	Fair value
Cash and cash equivalents	66,744	66,744	175,513	175,513
Accounts receivable, net of allowance for doubtful accounts	191,456	191,456	184,645	184,645
Unbilled revenue	262,289	262,289	283,141	283,141
Accounts payable and accrued liabilities	402,607	402,607	363,970	363,970
Obligations under capital lease	13,172	13,172	551	551
Customers' advance deposits	56,038	56,038	64,252	64,252
Long-term notes payable to the Corporati				
6.16% due May 6, 2013	179,456	190,682	179,100	196,236
5.20% due November 14, 2017	244,186	278,458	244,062	268,272
4.54% due November 12, 2019	243,814	270,077	243,686	254,620
5.59% due May 21, 2040	198,708	244,838	198,691	217,091
3.59% due November 18, 2021	298,119	306,680	—	—
Promissory note payable to the Corporation due May 6, 2013	245,058	259,650	490,115	521,312

b) Risk Factors

The following is a discussion of risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

LDC's activities provide for a variety of financial risks, particularly credit risk, interest rate risk and liquidity risk.

Credit risk

LDC is exposed to credit risk from financial instruments as a result of the risk of counterparties defaulting on their obligations. LDC monitors and limits its exposure to credit risk on a continuous basis.

NOTES TO FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

LDC's credit risk associated with accounts receivable is primarily related to electricity bill payments from customers. LDC has approximately 709,000 customers, the majority of which are residential. LDC collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2011, LDC held security deposits in the amount of $58,000 [December 31, 2010 - $64,252,000].

The carrying amount of accounts receivable is reduced through an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statements of income. Subsequent recoveries of receivables previously provisioned are credited to the statements of income.

Credit risk associated with accounts receivable is as follows:

	2011 $	2010 $
Total accounts receivable	204,266	196,381
Less: Allowance for doubtful accounts	(12,810)	(11,736)
Total accounts receivable, net	191,456	184,645
Of which:		
Outstanding for not more than 30 days	163,675	163,618
Outstanding for more than 30 days but not more than 120 days	24,671	21,495
Outstanding for more than 120 days	15,920	11,268
Less: Allowance for doubtful accounts	(12,810)	(11,736)
Total accounts receivable, net	191,456	184,645

Reconciliation between the opening and closing allowance for doubtful accounts balances is as follows:

	2011 $	2010 $
Balance, beginning of year	(11,736)	(12,387)
Provision for doubtful accounts	(10,158)	(6,966)
Write-offs	9,741	9,224
Recoveries	(657)	(1,607)
Balance, end of year	(12,810)	(11,736)

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings but are unbilled at period-end. As at December 31, 2011, total unbilled revenue was $262,289,000 [December 31, 2010 - $283,141,000]. Unbilled revenue is considered current.

As at December 31, 2011, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. LDC's maximum exposure to credit risk is equal to the carrying value of its financial assets.

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[all tabular amounts in thousands of dollars]

December 31, 2011

Interest rate risk

LDC is exposed to interest rate risk through holding certain financial instruments, and short-term borrowings which may be obtained under the Corporation's revolving credit facility may expose LDC to fluctuations in short-term interest rates (borrowings in the form of prime rate loans in Canadian dollars and Bankers' Acceptance ["BAs"] and letters of credit). LDC attempts to minimize interest rate risk by borrowing in long-term fixed rate debt, and by extending or shortening the term of its short-term money market investments by assessing the monetary policy stance of the Bank of Canada, while ensuring that all payment obligations are met on an ongoing basis. The fee payable for BAs and letters of credit is based on a margin determined by reference to the Corporation's credit rating.

Cash balances, which are not required to meet day-to-day obligations of LDC, are either held in bank accounts or invested in Canadian money market instruments, exposing LDC to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by LDC.

LDC is exposed to fluctuations in interest rates as its regulated rate of return is derived using a formulaic approach, which is based in part on a forecast of long-term Government of Canada bond yields and A-rated Canadian utility bond spreads. LDC estimates that a 1% (100 basis point) reduction in long-term Government of Canada bond yields, used in determining its regulated rate of return would reduce LDC's annual net income, as at December 31, 2011, by approximately $4,600,000.

LDC is also exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations [note 11[e]].

Liquidity risk

LDC is exposed to liquidity risk related to commitments associated with financial instruments. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. LDC's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing net financing charges. LDC has access to credit facilities through the Corporation and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risks associated with financial commitments are as follows:

NOTES TO FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

December 31, 2011			
	Due within 1 year $	Due between 1 year and 5 years $	Due after 5 years $
Financial liabilities			
Accounts payable and accrued liabilities	402,607	—	—
Obligations under capital lease	1,871	8,042	3,259
Promissory note payable to the Corporation	—	245,058	—
Long-term notes payable to the Corporation			
6.16% due May 6, 2013	—	180,000	—
5.20% due November 14, 2017	—	—	245,058
4.54% due November 12, 2019	—	—	245,058
5.59% due May 21, 2040	—	—	200,000
3.59% due November 18, 2021	—	—	300,000
Interest payments on promissory note payable and long-t	72,392	194,031	360,893
notes payable to the Corporation			
	476,870	627,131	1,354,268

Hedging and Derivative risk

As at December 31, 2011 and December 31, 2010, LDC has not entered into hedging and derivative financial instruments.

Foreign exchange risk

As at December 31, 2011, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related payables commitments when required, the impact of these transactions is not material to the financial statements.

16. FINANCIAL GUARANTEES

LDC is required to satisfy prescribed prudential requirements with the IESO for the purchase of electricity.

As at December 31, 2011, $40,000,000 [December 31, 2010 - $45,000,000] was utilized under the Corporation's bilateral credit facility in the form of letters of credit to support the prudential requirements of LDC.

17. PAYMENTS IN LIEU OF CORPORATE TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. Reconciliation between the statutory and effective tax rates is set out below:

NOTES TO FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

Statements of Income

	2011 $	2010 $
Rate reconciliation		
Income before PILs	102,363	87,964
Statutory Canadian federal and provincial income tax rate	28.25%	31.00%
Expected provision for PILs	28,918	27,269
Temporary differences not benefited	(16,032)	(1,303)
Other	(3,854)	(2,020)
Provision for PILs	9,032	23,946
Effective tax rate	8.82%	27.22%
Components of provision for PILs		
Current tax provision	8,753	23,946
Future income tax provision related to the origination and reversal of temporary differences	279	—
Provision for PILs	9,032	23,946

Balance Sheets

Significant components of LDC's future income tax assets are as follows:

	2011 $	2010 $
Property, plant and equipment and intangible assets	100,933	121,872
Regulatory adjustments	50,109	56,142
Post-employment benefits liability	44,093	41,698
Other taxable temporary differences	5,022	4,858
Future income tax assets	200,157	224,570

18. SHARE CAPITAL

Share capital consists of the following:

	2011 $	2010 $
Authorized The authorized share capital of LDC consists of an unlimited number of common shares		
Issued and outstanding 1,000 common shares	527,817	527,817

19. RELATED PARTIES

For LDC, transactions with related parties include transactions with the City, the Corporation and TH Energy. All transactions with related parties are in the ordinary course of business and measured at exchange amounts and normal trade terms.

2011	City $	Corporation $	TH Energy $
Revenues	131,691	—	1,850
Operating expenses and capital expenditures	28,946	2,837	—
Net financing charges	—	77,609	—
Accounts receivable, net of allowance for doubtful accounts	6,761	—	20,978
Other Assets	7,279	—	—
Accounts payable and accrued liabilities	24,235	7,926	—
Long-term notes and promissory note payable	—	1,409,341	—
Customers' advance deposits	8,714	—	—

NOTES TO FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

2010	City $	Corporation $	TH Energy $
Revenues	128,931	—	2,018
Operating expenses and capital expenditures	14,019	3,784	—
Net financing charges	—	72,006	—
Accounts receivable, net of allowance for doubtful accounts	4,065	—	25,166
Other Assets	7,368	—	—
Accounts payable and accrued liabilities	12,164	6,473	—
Long-term notes and promissory note payable	—	1,355,654	—
Customers' advance deposits	10,953	—	—

Revenues represent amounts charged to the City primarily for electricity, and TH Energy for the provision of goods and services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, and the Corporation for purchased corporate and management services. Net financing charges represent interest paid to the Corporation on the long-term notes and promissory note payable [note 10].

Accounts receivable, net of allowance for doubtful accounts represent receivables from the City primarily for relocation services and sale of electricity, and TH Energy for the provision of goods and services. Other assets represent amounts for prepaid land leases from the City. Accounts payable and accrued liabilities represent amounts payable to the City relating to road cut repairs and other services, as well as funds received from the City for the construction of electricity distribution assets, and the Corporation for purchased corporate and management services. Long-term notes and promissory note payable represent amounts borrowed from the Corporation [note 10]. Customers' advance deposits represent funds received from the City for future expansion projects.

20. COMMITMENTS

Operating lease obligations and future commitments

As at December 31, 2011, the future minimum annual lease payments under property operating leases and future commitments with remaining terms from one to five years and thereafter were as follows:

	$
2012	27,713
2013	23,441
2014	7,490
2015	6,486
2016	6,307
Thereafter	4,755
Total amount of future minimum payments	76,192

During the first quarter of 2011, LDC entered into an agreement with Hydro One Networks Inc. to reinforce the 115 kilovolt transmission system between Leaside Transformer Station ["TS"] and Bridgman TS under the Toronto Midtown Transmission Reinforcement Project, which terminates on the 25th anniversary of the in service date. LDC is expected to pay the estimated capital contributions and work chargeable by making progress payments based on various payment milestone dates, with $17,600,000 and $15,278,000 payable in 2012 and 2013, respectively, and any difference from the estimated costs to be settled at a later date. These commitments have been reflected in the table above.

Capital lease obligations

As at December 31, 2011, the future minimum annual lease payments under capital leases with remaining lease terms from one to five years and thereafter were as follows:

	$
2012	2,454
2013	2,445
2014	2,404
2015	2,327
2016	2,267
Thereafter	3,380
Total amount of future minimum payments	15,277
Less interest and executory costs	2,105
	13,172
Current portion [note 9]	1,871
Long-term portion [note 12]	11,301

Included in the capital lease obligations is an equipment lease entered into by LDC in the third quarter of 2011 which expires in June 2018 and bears interest at a rate of 4.7%.

21. CONTINGENCIES

a) Legal Proceedings

In the ordinary course of business, LDC is subject to various litigation and claims with customers, suppliers, former employees and other parties. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and loss. A determination of the provision required, if any, for these contingencies is made after analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. LDC is subject to various legal actions that arise in the normal course of business and if damages were awarded under these actions, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with these actions.

December 31, 2011

Christian Helm Class Action

On December 6, 2010, a statement of claim in a proposed class action was issued against LDC. The claim seeks general and special damages in the amount of $100,000,000 for disgorgement of unjust gains allegedly resulting from the receipt of interest on overdue accounts at a rate exceeding 5% per annum in contravention of the Interest Act (Canada) ["Interest Act"]. A statement of defence has been filed. Prior to any certification of the action as a class proceeding, cross summary judgment motions were heard in June 2011 to determine whether the Interest Act has been breached [note 23[c]].

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the Class Proceedings Act, 1992 (Ontario) ["Class Proceedings Act"] seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. This action is at a preliminary stage. The statement of claim has been served on LDC, a statement of defence and third party claim have been served by LDC and a third party defence and counterclaim against LDC seeking damages in the amount of $51,000,000 have been filed. A certification order has been issued. Affidavits of documents have been produced by LDC and the other parties and examinations for discovery have commenced and are continuing. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with the action.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2,000,000 as a result of the fire at 2 Secord Avenue. A statement of defence and third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with the action.

By order of the court, the above actions and a smaller non-class action commenced in April 2009 involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the Class Proceedings Act seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $10,000,000 from LDC. Both actions are at a preliminary stage and the certification hearing is scheduled for September 2012. Statements of defence to the main action and to the third party claim have not been filed. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with these actions.

Another third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of the fire at 2369 Lakeshore Boulevard West. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $400,000 from LDC. LDC has filed a statement of defence, crossclaim and counterclaim. Examinations for discovery have not taken place but are to be completed by February 29, 2012 pursuant to a court ordered timetable. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with these actions.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2,000,000 as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with the action.

Adamopoulos

An action was commenced against LDC in November 2004 in the Ontario Superior Court of Justice seeking damages in the amount of $7,750,000 as compensation for damages allegedly suffered as a result of a motor vehicle accident involving an LDC vehicle on January 9, 2001. The plaintiff's motion increasing its claim for damages to $23,790,000 was granted on July 7, 2010. This matter has been settled and a court order has been issued dismissing the action and all related claims by payment of all to an amount of approximately $450,000. LDC's liability insurance covered the settlement amount.

b) OEB PILs Proceeding

The OEB conducted a review of the PILs variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain MEUs. On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts.

LDC has reviewed the balances of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. As at December 31, 2011, LDC estimated its liability at approximately $2,779,000. This balance has been recorded in LDC's financial statements. LDC intends to apply for disposition of this balance in 2012. The amount to be approved by the OEB will be based on the OEB's interpretation and application of its guidelines and the final balance which is yet to be approved by the OEB could differ materially from LDC's estimation of its liability.

c) Payments in Lieu of Additional Municipal and School Taxes

The Ministry of Finance has issued assessments in respect of payments in lieu of additional municipal and school taxes under section 92 of the Electricity Act that are in excess of the amounts LDC believes are payable. The

dispute arose as a result of inaccurate information incorporated into Ontario Regulation 224/00. LDC has worked with the Ministry of Finance to resolve this issue, and as a result the Ministry of Finance issued Ontario Regulation 423/11 on August 31, 2011. The new regulation revoked Ontario Regulation 224/00 and corrected inaccurate information retroactively to 1999.

The balance assessed by the Ministry of Finance on its most recent statement of account amounts to approximately $10,043,000 above the balance accrued by LDC. While LDC expects that reassessments will be issued as a consequence of the change in regulation, there can be no assurance that LDC will not have to pay the full assessed balance in the future.

22. COMPARATIVE FINANCIAL STATEMENTS

Certain comparative amounts of the financial statements have been reclassified from statements previously presented to conform to the presentation of the 2011 financial statements.

23. SUBSEQUENT EVENTS

a) Street Lighting Activities

On January 1, 2012, the Corporation completed the transfer of street lighting assets to LDC for a purchase price of $28,460,000, subject to post closing adjustment and transaction costs [note 2[b]].

b) Electricity Distribution Rates

On January 5, 2012, the OEB rendered its decision on the preliminary issue and dismissed LDC's cost of service 2012-2014 Rate Application. In its decision, the OEB found that LDC was not permitted to deviate from the standard incentive regulation mechanism framework cycle, and LDC will therefore be required to file its request for electricity distribution rates commencing on May 1, 2012 pursuant to the formulaic adjustment and the incremental capital module provided for under the incentive regulation mechanism framework [note 2[a]].

On January 25, 2012, LDC filed with the OEB a motion to review the OEB's January 5, 2012 decision.

On February 6, 2012, LDC filed a notice of appeal with the Ontario Divisional Court regarding the OEB's January 5, 2012 decision.

Pursuant to the OEB's decision of January 5, 2012, LDC is currently preparing an application for electricity distribution rates using the incentive regulation mechanism framework, including the filing of an incremental capital module. The quantum of this application is consistent with the capital program spending levels previously approved by the OEB for the 2011 Rate Year.

Under the incentive regulation mechanism framework, LDC has to significantly reduce its costs structure, and in particular its operating expenses, in order to meet its financial obligations. Accordingly, in the first quarter of 2012, LDC began implementing a restructuring program aimed at reducing its operating costs in the future. The main component of this restructuring program is a workforce reduction plan targeting both union and management

employees. As at March 2, 2012, the costs incurred as a result of the restructuring program amounted to approximately $19,300,000, which were mainly related to employee severance and buy-out costs.

LDC continues to assess all of the impacts related to the imposition by the OEB of the incentive regulation mechanism framework, which impacts may include additional restructuring costs. The incremental restructuring costs could have a material impact on LDC's financial statements in the future.

c) Christian Helm Class Action

On February 1, 2012, prior to the release of the decisions on the summary judgment motions, the parties reached a settlement of the matter, which settlement now requires court approval. The Settlement Approval Hearing is scheduled for April 30, 2012. If the settlement receives court approval, damages and costs of approximately $6,000,000 shall be paid by LDC. In 2010, LDC accrued a liability to cover the expected settlement.

If the settlement does not receive court approval, the decision on the cross summary judgment motions will be released. In this event, if the court finds a breach of the Interest Act, subject to appeals, the proceeding will continue, and LDC will rely on other defences. While LDC believes it has a defence to this claim, there is no guarantee that it will be successful defending the action and therefore, the outcome of this proceeding could have a material impact on LDC's financial statements and results of operations [note 21[a]].

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2012

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2012

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

We have audited the accompanying financial statements of Toronto Hydro-Electric System Limited, which comprise the balance sheets as at December 31, 2012 and December 31, 2011, the statements of net income and comprehensive income, shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Toronto Hydro-Electric System Limited as at December 31, 2012 and December 31, 2011 and its statements of net income and comprehensive income, shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011 in accordance with United States Generally Accepted Accounting Principles

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

February 28, 2013

Toronto Hydro-Electric System Limited

BALANCE SHEETS

[in thousands of dollars]

As at December 31	2012 $	2011 $
		[note 23]
ASSETS		
Current		
Cash and cash equivalents	**67,258**	66,744
Accounts receivable, net of allowance for doubtful accounts *[note 15[b]]*	**185,941**	191,456
Unbilled revenue *[note 15[b]]*	**274,272**	262,289
Income tax receivable	**4,710**	8,684
Inventories *[note 5]*	**7,555**	6,891
Regulatory assets *[note 9]*	**1,658**	-
Other assets *[note 6]*	**4,680**	4,404
Total current assets	**546,074**	540,468
Property, plant and equipment, net *[note 7]*	**2,504,428**	2,334,293
Intangible assets, net *[note 8]*	**134,080**	112,982
Regulatory assets *[note 9]*	**119,556**	143,038
Other assets *[note 10]*	**8,098**	7,331
Deferred income tax assets *[note 17]*	**193,242**	200,157
Total assets	**3,505,478**	3,338,269
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[note 15[b]]*	**377,948**	399,435
Restructuring accrual *[note 11]*	**11,954**	-
Customers' advance deposits	**40,048**	40,238
Deferred conservation credit	**19,908**	13,610
Post-retirement benefits *[note 13]*	**9,925**	7,915
Other liabilities *[note 20]*	**1,850**	2,182
Regulatory liabilities *[note 9]*	**-**	7,293
Notes payable to related party *[notes 12 and 19]*	**179,835**	-
Promissory notes payable to related party *[notes 12 and 19]*	**319,071**	-
Total current liabilities	**960,539**	470,673
Notes payable to related party *[notes 12 and 19]*	**985,343**	1,164,283
Promissory note payable to related party *[notes 12 and 19]*	**-**	245,058
Customers' advance deposits	**6,790**	15,800
Post-retirement benefits *[note 13]*	**243,965**	236,411
Other liabilities *[note 20]*	**9,385**	11,301
Regulatory liabilities *[note 9]*	**196,809**	203,919
Asset retirement obligations *[note 14]*	**5,004**	4,831
Total liabilities	**2,407,835**	2,352,276
Commitments, contingencies and subsequent events *[notes 2, 20 and 21]*		
Shareholder's equity		
Share capital *[note 18]*	**556,278**	527,817
Retained earnings	**528,608**	445,419
Contributed surplus	**12,757**	12,757
Total shareholder's equity	**1,097,643**	985,993
Total liabilities and shareholder's equity	**3,505,478**	3,338,269

The accompanying notes are an integral part of the financial statements.

STATEMENTS OF NET INCOME AND COMPREHENSIVE INCOME

[in thousands of dollars]

Year ended December 31	**2012** **$**	2011 **$**
		[note 23]
Revenues		
Sale of electricity	**2,799,404**	2,766,714
Other income	**41,057**	39,143
	2,840,461	2,805,857
Costs		
Purchased power	**2,275,209**	2,236,541
Operating expenses	**236,386**	252,378
Depreciation and amortization	**140,352**	146,505
	2,651,947	2,635,424
Income before the following:	**188,514**	170,433
Net financing charges	**(76,209)**	(74,478)
Gain on disposals of property, plant and equipment	**1,805**	3,885
Restructuring costs *[note 11]*	**(27,796)**	-
Income before income taxes	**86,314**	99,840
Income tax expense *[note 17]*	**3,125**	6,509
Net income and comprehensive income	**83,189**	93,331

STATEMENTS OF SHAREHOLDER'S EQUITY

[in thousands of dollars]

Year ended December 31	**2012** **$**	2011 **$**
Share capital ***[note 18]***	**556,278**	527,817
Retained earnings, beginning of year	**445,419**	352,088
Net income	**83,189**	93,331
Retained earnings, end of year	**528,608**	445,419
Contributed surplus	**12,757**	12,757
Total shareholder's equity	**1,097,643**	985,993

The accompanying notes are an integral part of the financial statements.

STATEMENTS OF CASH FLOWS

[in thousands of dollars]

Year ended December 31	2012 $	2011 $
		[note 23]
OPERATING ACTIVITIES		
Net income	**83,189**	93,331
Adjustments for non-cash items		
Depreciation and amortization	**140,352**	146,505
Change in other non-current assets	**(767)**	187
Change in other non-current liabilities	**626**	(253)
Post-retirement benefits	**9,564**	44,299
Deferred income taxes *[note 17]*	**(245)**	279
Gain on disposals of property, plant and equipment	**(1,805)**	(3,885)
Changes in non-cash working capital balances *[note 22]*	**(7,001)**	59,521
Net cash provided by operating activities	**223,913**	339,984
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 7]*	**(290,067)**	(378,378)
Purchase of intangible assets *[note 8]*	**(42,057)**	(52,805)
Net change in regulatory assets and liabilities	**14,581**	(66,379)
Proceeds on disposals of property, plant and equipment	**2,665**	4,974
Net cash used in investing activities	**(314,878)**	(492,588)
FINANCING ACTIVITIES		
Common shares issued *[note 18]*	**28,461**	-
Increase in notes payable to related party *[note 12]*	**74,013**	53,043
Decrease in customers' advance deposits	**(9,200)**	(8,214)
Repayment of capital lease liability	**(1,795)**	(994)
Net cash provided by financing activities	**91,479**	43,835
Net increase (decrease) in cash and cash equivalents during the year	**514**	(108,769)
Cash and cash equivalents, beginning of year	**66,744**	175,513
Cash and cash equivalents, end of year	**67,258**	66,744
Supplementary cash flow information		
Total interest paid	**72,998**	77,006
Total income taxes paid (recovered)	**(1,200)**	11,615

The accompanying notes are an integral part of the financial statements.

1. INCORPORATION

On June 23, 1999, Toronto Hydro-Electric System Limited ["LDC"] was incorporated under the Business Corporations Act (Ontario), and is wholly-owned by Toronto Hydro Corporation [the "Corporation"]. The incorporation was required in accordance with the provincial government's Electricity Act, 1998 (Ontario) ["Electricity Act"].

LDC distributes electricity to customers located in the City of Toronto [the "City"] and is subject to rate regulation. LDC is also engaged in the delivery of Conservation and Demand Management ["CDM"] activities.

2. BASIS OF PRESENTATION

These audited financial statements of LDC have been prepared in accordance with United States ["US"] Generally Accepted Accounting Principles ["GAAP"] with respect to the preparation of annual financial information, and are presented in Canadian dollars. These are LDC's first US GAAP annual financial statements. LDC's financial statements were prepared in accordance with Part V of Canadian GAAP until December 31, 2011. The comparative financial statements have been adjusted retroactively from the financial statements previously presented to conform to the presentation of LDC's 2012 financial statements prepared in accordance with US GAAP.

A reconciliation of the balance sheets between Canadian GAAP and US GAAP as at January 1, 2011 and December 31, 2011 and a reconciliation of net income for the year ended December 31, 2011 accompany the financial statements [note 23].

LDC has evaluated the events and transactions occurring after the balance sheet date through February 28, 2013 when LDC's financial statements were available to be issued after the approval by the Corporation's Board of Directors, and did not identify any events or transactions which required recognition in the financial statements and/or disclosure in the notes to the financial statements.

3. REGULATION

In April 1999, the Government of Ontario began restructuring Ontario's electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator ["IESO"] and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board [the "OEB"].

The OEB has regulatory oversight of electricity matters in Ontario. The Ontario Energy Board Act, 1998 (Ontario) sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses, and filing processes and requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued protection for rural and remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

[i] Distribution Charges. Distribution charges are designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and are comprised of a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity, and sustained periods of moderate weather which decrease the consumption of electricity).

[ii] Electricity Price and Regulated Adjustments. The electricity price and regulated adjustments represent the pass through of the commodity and other costs of electricity.

[iii] Retail Transmission Rate. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

a) Electricity Distribution Rates

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

LDC's electricity distribution rates for 2011 were determined through an application under the Cost of Service ["COS"] framework. The COS framework sets electricity distribution rates using a detailed examination of evidence and an assessment of the costs incurred by an electricity distributor to provide services to its customers.

On July 7, 2011, the OEB issued its decision regarding LDC's electricity distribution rates for 2011. The decision provided for a distribution revenue requirement and rate base of $522,044,000 and $2,298,227,000, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $378,800,000 and $238,000,000, respectively.

On August 26, 2011, LDC filed a rate application, following the COS framework, with the OEB seeking approval of separate and successive revenue requirements and corresponding electricity distribution rates for 2012, 2013 and 2014. Pursuant to the Incentive Regulation Mechanism ["IRM"] framework, the OEB established, as a preliminary issue in this application, that it would consider the question of whether the application filed by LDC under the COS framework was acceptable or whether it should be dismissed. The IRM framework provides for a standard adjustment to an electricity distributor's rates based on a formulaic calculation with the possibility to request an Incremental Capital Module ["ICM"] to address specific capital expenditure needs that occur during the IRM term, and are not otherwise funded by the formulaic calculation. In order to determine whether a distributor is eligible for the ICM, the OEB conducts a review of the application by way of a detailed examination of a distributor's evidence and consideration of a number of criteria, such as materiality, need and prudence.

LDC filed evidence supporting its position for electricity distribution rates to be set under the COS framework for 2012, 2013 and 2014. The OEB established a process by which a portion of LDC's evidence was tested during an oral hearing held in November 2011.

On January 5, 2012, the OEB rendered its decision on the preliminary issue and dismissed LDC's COS framework application for 2012, 2013 and 2014. In its decision, the OEB found that LDC was not permitted to deviate from the standard IRM framework cycle. Accordingly, LDC was required to file its request for electricity distribution rates for 2012, 2013, and 2014 pursuant to the IRM framework and to use the ICM to request the capital needed for infrastructure renewal.

On January 25, 2012, LDC filed a motion with the OEB to review the OEB's January 5, 2012 decision [the "Motion"].

On February 6, 2012, LDC filed a notice of appeal with the Ontario Divisional Court regarding the OEB's January 5, 2012 decision [the "Appeal"].

On May 10, 2012, LDC filed an application for electricity distribution rates for 2012, 2013, and 2014 using the IRM framework, including the filing of an ICM application [the "IRM/ICM Application"]. The formulaic adjustment, requested by LDC, follows the guidelines provided by the OEB and seeks to increase the current revenue requirement by 0.68% to $525,500,000 for 2012, $529,100,000 for 2013 and $532,700,000 for 2014. The 2013 and 2014 formulaic adjustment may be subject to change depending on future inflation and market data.

The IRM/ICM Application proposed by LDC requests rates that is to enable the recovery of capital expenditures. Accordingly, the amount of capital expenditures included in LDC's proposed IRM/ICM Application amounts to $448,700,000 for 2012, $534,500,000 for 2013 and $439,500,000 for 2014.

On August 16, 2012, the OEB issued its decision on the issues list for the application filed May 10, 2012. In that decision, the OEB stated that further procedural steps would be determined pending LDC's response to the OEB as to whether LDC would continue to pursue the Motion and the Appeal. On August 20, 2012, LDC filed a notice of abandonment with the Ontario Divisional Court thereby terminating the Appeal. On the same date, LDC advised the OEB that it would withdraw its Motion for review.

While the IRM/ICM Application proposed by LDC has been under consideration by the OEB, capital spending in 2012 has been maintained at a reduced amount. As it was no longer practical to achieve the previously requested capital spending of $448,700,000 in 2012, an update to the IRM/ICM Application was submitted by LDC on October 31, 2012 modifying the requested capital expenditures for 2012 and 2013 to $283,000,000 and $579,100,000, respectively, and requesting that consideration for 2014 be deferred to a second phase of the proceeding, once LDC has received a decision from the OEB in respect of phase one. On November 3, 2012, the OEB accepted LDC's request for a two phase proceeding: phase one comprising LDC's 2012 and 2013 work program proposals and phase two comprising LDC's 2014 work program proposal.

The current application is expected to be subject to an in-depth review by the OEB. There can be no assurance that the OEB will allow for the total or partial recovery of the capital expenditure balances requested in the current application. The financial effect of the OEB decision will be recorded in the period it becomes known and could be material to LDC's financial performance.

b) Street Lighting Activities

On June 15, 2009, LDC filed an application with the OEB seeking an electricity distribution licence for a new wholly-owned legal entity to which the Corporation intended to transfer the street lighting assets of Toronto Hydro Energy Services Inc. ["TH Energy"]. Concurrently, LDC filed another application with the OEB seeking approval for the merger of LDC and the new legal entity. The main objective of these applications was to transfer the street lighting assets to the regulated electricity distribution activities of LDC to increase the overall safety of the related infrastructure.

On February 11, 2010, the OEB issued its decision in regard to these applications. In its decision, the OEB agreed that, under certain conditions, the treatment of certain types of street lighting assets as regulated assets is justified.

The OEB ordered the Corporation to provide a detailed valuation of the street lighting assets and to perform an operational review to determine which street lighting assets could become regulated assets. The Corporation performed a detailed asset operational review and filed a valuation of the street lighting assets, which was submitted to the OEB on January 31, 2011.

On August 3, 2011, the OEB issued its final decision allowing the transfer of a portion of the street lighting assets to the new wholly-owned legal entity (1798594 Ontario Inc.), and for LDC to amalgamate with the new legal entity. On January 1, 2012, the Corporation completed the asset transfer and amalgamation. The purchase price for such assets, including a post-closing adjustment, was $42,473,000, subject to transaction costs [note 19].

c) CDM Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the Ontario Energy Board Act, 1998 (Ontario), directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 Gigawatt-Hours of energy savings and 286 Megawatts of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the Ontario Power Authority ["OPA"] in the amount of approximately $50,000,000 to deliver CDM programs extending from January 1, 2011 to December 31, 2014. As at December 31, 2012, LDC received approximately $35,036 [December 31, 2011 - $19,875,000] from the OPA for the delivery of CDM programs. All programs to be delivered are fully funded and paid in advance by the OPA. Amounts received but not yet spent are presented under current liabilities as deferred conservation credit. Upon the expiration of the agreement, LDC is required to return to the OPA any excess funding received for program administration less any cost efficiency incentives. These programs are expected to support the achievement of the mandatory CDM targets described above.

On December 21, 2012, the Minister of Energy of Ontario issued a direction to the OPA under subsection 25.32(4.1) of the Electricity Act to extend the funding time period for OPA-contracted province-wide CDM initiatives under the Green Energy Act, 2009 (Ontario) framework to December 31, 2015.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from US GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

LDC has determined that its assets and liabilities arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 – "Regulated Operations" ["ASC 980"], which includes accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors". Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under US GAAP in order to appropriately reflect the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These timing differences are recorded as regulatory assets and regulatory liabilities on LDC's balance sheets and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the disposition of these balances was assessed to no longer be probable, the balances would be recorded in LDC's statements of net income and comprehensive

income in the period that the assessment is made. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation and the OEB's decisions.

Regulatory assets and liabilities are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months after each reporting period. All other regulatory asset and liability balances are classified as long-term on the balance sheets.

Allowance for funds used during construction

The OEB provides for the inclusion of an Allowance for Funds Used During Construction ["AFUDC"] when capitalizing construction-in-progress assets, until such time as the asset is substantially complete. A concurrent credit of the same amount is made to net financing charges when the allowance is capitalized. The interest rate for capitalization is prescribed by the OEB and modified on a periodic basis, and is applied to the balance of the construction-in-progress assets on a simple interest basis. The interest rate for capitalization for the period from January 1, 2012 to March 31, 2012 was 3.92%, from April 1, 2012 to September 30, 2012 was 3.51%, and from October 1, 2012 to December 31, 2012 was 3.23% [January 1, 2011 to September 30, 2011 - 4.29%; October 1, 2011 to December 31, 2011 - 3.92%]. AFUDC is included in property, plant and equipment and intangible assets for financial reporting purposes, charged to operations through depreciation and amortization expense over the useful lives of the related assets and recovered through future revenue.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition.

c) Accounts receivable

Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. The carrying amount of accounts receivable is reduced through an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statements of net income and comprehensive income. Subsequent recoveries of receivables previously provisioned and written off are credited to the statements of net income and comprehensive income. Management estimates uncollectible accounts receivable after considering historical loss experience and the characteristics of existing accounts.

d) Inventories

Inventories consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution system infrastructure to property, plant and equipment. Once capitalized, these items are not depreciated until they are put into service. Inventories are valued at the lower of cost and market, with cost determined on an average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average useful lives, except in those instances where specific identification allows their removal at retirement or disposition. The cost of property, plant and equipment represents the original cost, consisting of direct materials and labour, contracted services, AFUDC, and overheads directly attributable to the capital project.

Capital contributions received are used to finance additions to property, plant and equipment. According to the accounting principles prescribed by the OEB, capital contributions received are treated as a credit to property, plant

and equipment. The amount is subsequently depreciated by a charge to accumulated depreciation and a credit to depreciation expense at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value, which is determined by the estimated future discounted cash flows.

Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution lines	2.0% to 5.0%
Transformers	3.3% to 5.0%
Stations	2.5% to 10.0%
Meters	2.5% to 6.7%
Buildings	1.3% to 5.0%
Rolling stock	12.5% to 25.0%
Other capital assets	4.0% to 20.0%
Equipment and tools	10.0% to 16.7%
Assets under capital lease	14.3% to 25.0%
Computer hardware	16.7% to 25.0%
Communications	10.0% to 20.0%

Construction in progress relates to assets not currently in use and therefore is not depreciated.

f) Intangible assets

Effective January 1, 2012, LDC revised its estimate of useful life of its Customer Care and Billing Customer Information System from five years to ten years as a result of an analysis completed related to the useful life assessment. This change has been accounted for on a prospective basis in the financial statements effective January 1, 2012. The change in estimate reduced amortization expense by approximately $4,000,000 for the year ended December 31, 2012 with an offsetting increase in the carrying value of intangible assets. The change in estimate will decrease future amortization expense by $4,000,000 per year over the term of the original useful life with no impact to the final year of the original useful life, and thereafter increase future amortization expense by $4,000,000 per year.

Intangible assets are stated at cost. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to Hydro One Networks Inc. for dedicated infrastructure pursuant to an agreement in order to receive contributions to transmission facilities.

g) Restructuring

Restructuring charges are recorded based upon planned employee termination dates, site closure and consolidation plans, and contract terminations. Restructuring charges can include severance costs to eliminate a specified number of employee positions, infrastructure charges to vacate facilities and consolidate operations, and contract

cancellation costs. The timing of associated cash payments is dependent upon the type of restructuring charge and can extend over a multi-year period.

h) Workplace Safety and Insurance Act

LDC is a Schedule 1 employer for workers' compensation under the Workplace Safety and Insurance Act, 1997 (Ontario) [the "WSIA"]. As a Schedule 1 employer under the WSIA, LDC is required to pay annual premiums into an insurance fund established under the WSIA and recognizes expenses based on funding requirements.

i) Revenue recognition

Revenue from the sale of electricity is recorded on the basis of cyclical billings and includes an estimated amount for electricity delivered and not yet billed, the amount of which is impacted by energy demand, customer class usage patterns and composition, and weather conditions.

Other income, which includes revenues from electricity distribution related services and revenues from demand billable activities, is recognized as the services are rendered.

In the course of its operations, LDC collects Harmonized Sales Tax ["HST"] from its customers. When customers are billed, a current liability for HST is recognized which corresponds to the revenue derived from the services provided by LDC. When expenses are incurred by LDC, a current asset for HST is recorded which corresponds to the expenditures derived from the goods or services received by LDC. LDC's revenues and expenses exclude HST. This net asset or liability is settled with the appropriate government authority.

j) Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the statements of net income and comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by LDC. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

The following summarizes the accounting classification LDC has elected to apply to each of its significant categories of financial instruments:

Cash equivalents and short-term investments	Held for Trading
Accounts receivable and unbilled revenue	Loans and Receivables
Accounts payable and accrued liabilities	Other Financial Liabilities
Obligations under capital lease	Other Financial Liabilities
Customers' advance deposits	Other Financial Liabilities
Short-term and long-term debt	Other Financial Liabilities

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash equivalents, comprising short-term investments, are classified as "Held for Trading" and are measured at fair value. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, are considered equivalent to fair value. Subsequent

measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Obligations under capital lease are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying value as management believes that the fixed interest rates are representative of current market rates.

- Customers' advance deposits are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value because of the short maturity of the current portion, and the long-term portion approximates the carrying value, taking into account interest accrued on the outstanding balance.

- Short-term debt and long-term debt are classified as "Other Financial Liabilities" and are initially measured at fair value. The carrying amounts are carried at amortized cost, based on an initial fair value as determined at the time using quoted market price for similar debt instruments. The fair value of the debt is calculated by discounting the related cash flows at the estimated yield to maturity of similar debt instruments [note 15[a]].

k) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included within level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

l) Employee future benefits

Multi-employer pension plan

LDC provides a pension plan for its full-time employees through the Ontario Municipal Employees Retirement System ["OMERS"]. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The OMERS plan is accounted for as a defined contribution plan where LDC recognizes the expense related to this plan as contributions are made, since it is not practicable to determine LDC's portion of pension obligations or the fair value of plan assets. LDC is not responsible for any other contractual obligations other than the contributions.

Post-retirement benefits other than pension

LDC has a number of unfunded benefit plans providing post-retirement benefits (other than pension) to its employees. LDC pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. LDC pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

LDC periodically measures its accumulated benefit obligation for accounting purposes as at December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2012.

The cost of providing benefits under the defined benefit plans is determined using the projected unit credit method and based on assumptions that reflect management's best estimates. All actuarial gains and losses and prior service costs are recognized in other comprehensive income ["OCI"] as they arise and subsequently reclassified to a regulatory asset on the balance sheets. This results in full recognition of the benefit obligation as a liability on the balance sheets.

Actuarial gains or losses are amortized into net periodic benefit cost for the current period when the net cumulative unrecognized actuarial gains or losses in the regulatory asset at the end of the previous reporting period exceed 10% of the accumulated benefit obligation at that date. These gains or losses are recognized over the expected average remaining service period of active employees participating in the plans.

The prior service costs in the regulatory asset are recognized as an expense on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The effects of a curtailment loss are recognized in the statements of net income and comprehensive income when its occurrence is probable and reasonably estimable. The effects of a curtailment gain are recognized in the statements of net income and comprehensive income when the related employees terminate or the plan suspension or amendment is adopted. The effects of a settlement gain or loss are recognized in the statements of net income and comprehensive income in the period in which a settlement occurs.

m) Asset retirement obligations

LDC recognizes a liability for the future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the capitalized amount is depreciated over the useful life of the related asset and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ["accretion expense"] and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ["ARO"] is incurred and when the fair value can be reasonably estimated.

LDC has not recorded a liability related to certain AROs as a reasonable estimate of fair value could not be made. LDC does not recognize an ARO for those properties which support LDC's distribution operations since it cannot reasonably determine the amount of any remediation costs related to possible contamination, and a reliable estimate cannot be made until environmental site assessments have been completed. LDC expects to use the majority of its installed assets in perpetuity. If, at some future date, a particular asset is shown not to meet the perpetuity assumption, it will be reviewed to determine if an ARO exists.

n) Customers' advance deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. The electricity customer security deposits liability includes accrued interest amounts owed to the customers with the debit charged to net financing charges. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on Offers to Connect are cash collected from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with the debit charged to net financing charges. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

o) Income Taxes

Under the Electricity Act, LDC is required to make Payments In Lieu of Corporate Taxes ["PILs"] to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying taxes similar to what would be imposed under the Federal and Ontario Tax Acts.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis using the enacted tax rates by the balance sheet date in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is more likely than not that they will be realized, and are measured at the largest amount of the benefit that has a likelihood greater than 50 percent of being realized upon settlement. Deferred income tax assets are evaluated and unless realization is considered more likely than not, a valuation allowance is established.

ASC 980 requires the recognition of deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future electricity distribution rates. As at December 31, 2012, LDC recorded a deferred income tax asset and a corresponding regulatory liability of $193,276,000 with respect to its rate-regulated activities that will be included in the rate-setting process [note 9]. These amounts include a gross up to reflect the income tax benefits associated with reduced revenues resulting from the recognition of deferred tax assets. Deferred income taxes that are not included in the rate-setting process are charged or credited to the statements of net income and comprehensive income.

The benefits of the refundable apprenticeship and co-operative investment tax credits ["ITCs"] are credited against the related expense in the statements of net income and comprehensive income. All other types of ITCs are recorded as a reduction to income tax expense in the current period to the extent that realization of such benefit is more likely than not.

p) Use of estimates

The preparation of LDC's financial statements in accordance with US GAAP requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as identifying and assessing the accounting treatment with respect to commitments and contingencies. Significant areas requiring the use of management estimates relate to unbilled revenue, regulatory assets and liabilities, environmental liabilities and AROs, employee future benefits, income taxes (including deferred income taxes), and revenue recognition. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy of Ontario, or the Ministry of Finance of Ontario ["Ministry of Finance"].

q) Future Accounting Pronouncements

A number of new standards and interpretations are not yet effective for the year ended December 31, 2012, and have not been applied in preparing these financial statements. LDC continues to analyze these standards and had initially determined that the following could have a significant effect on the financial statements.

In December 2011, the Financial Accounting Standards Board issued Accounting Standards Update ["ASU"] No. 2011-11, "Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities" ["ASU 2011-11"]. The amendments require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the balance sheets. ASU 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. Retrospective application is required. The ASU No. 2013-01, "Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities", was issued in January 2013 to amend the scope of ASU 2011-11 to clarify that the disclosure requirements are limited to derivatives, repurchase and reverse repurchase agreements, and securities borrowing and lending transactions that are either offset in the balance sheets or subject to enforceable master netting arrangements or similar agreements. Based on LDC's analysis, the adoption of these amendments are not expected to have an impact on LDC's balance sheets or significantly impact disclosures.

5. INVENTORIES

Inventories consist of the following:

	2012 $	2011 $
Fuses	2,137	1,625
Consumables, tools and other maintenance items	1,968	1,745
Drums and reels	1,115	938
Other	2,335	2,583
	7,555	6,891

For the year ended December 31, 2012, LDC recognized operating expenses of $9,334,000 related to inventory used to service electrical distribution assets [2011 - $9,196,000].

6. CURRENT PORTION OF OTHER ASSETS

Current portion of other assets consists of the following:

	2012 $	2011 $
Prepaid expenses	4,369	4,006
Deferred financing costs	311	398
	4,680	4,404

7. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following:

	2012			2011		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	16,747	—	16,747	16,761	—	16,761
Distribution lines	2,930,296	1,460,979	1,469,317	2,755,344	1,404,998	1,350,346
Transformers	672,981	377,900	295,081	652,102	360,398	291,704
Stations	286,229	145,601	140,628	277,905	137,246	140,659
Meters	243,152	133,789	109,363	238,459	124,117	114,342
Buildings	160,368	69,248	91,120	154,932	62,403	92,529
Rolling stock	73,239	43,834	29,405	78,016	43,154	34,862
Other capital assets	70,291	47,561	22,730	68,282	43,805	24,477
Equipment and tools	45,611	33,936	11,675	44,208	31,785	12,423
Assets under capital lease	13,538	2,948	10,590	14,269	1,251	13,018
Computer hardware	50,511	40,003	10,508	44,625	35,602	9,023
Communications	32,082	26,597	5,485	31,537	23,912	7,625
Construction in progress	291,779	—	291,779	226,524	—	226,524
	4,886,824	2,382,396	2,504,428	4,602,964	2,268,671	2,334,293

For the year ended December 31, 2012, AFUDC in the amount of $994,000 [2011 - $376,000] was capitalized to property, plant and equipment and credited to net financing charges.

As at December 31, 2012, the net book value of smart meters related to the deployment of smart meters amounting to $17,647,000 [December 31, 2011 - $20,366,000] was included in property, plant and equipment. In the absence of rate regulation, property, plant and equipment would have been $17,647,000 lower as at December 31, 2012 [December 31, 2011 - $20,366,000 lower].

For the year ended December 31, 2012, capital contributions in the amount of $26,261,000 [2011 - $36,381,000] were credited to property, plant and equipment.

For the year ended December 31, 2012, LDC recorded depreciation expense of $119,393,000 [2011 - $120,696,000] of which $1,985,000 [2011 - $1,177,000] related to assets under capital lease.

8. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2012			2011		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Computer software	242,254	174,410	67,844	222,598	154,186	68,412
Contributions	19,649	2,175	17,474	14,059	1,440	12,619
Software in development	14,210	—	14,210	15,598	—	15,598
Contributions for work in progress	34,552	—	34,552	16,353	—	16,353
	310,665	176,585	134,080	268,608	155,626	112,982

For the year ended December 31, 2012, LDC acquired $42,057,000 of intangible assets [2011 - $52,805,000]. Contributions for work in progress relate to payments for connection projects to increase electricity distribution system capacity. All intangible assets are subject to amortization when they become available for use. Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized.

For the year ended December 31, 2012, $29,656,000 of software in development was transferred to computer software [2011 - $49,907,000].

For the year ended December 31, 2012, AFUDC in the amount of $1,331,000 [2011 - $1,149,000] was capitalized to intangible assets and credited to net financing charges.

For the year ended December 31, 2012, LDC recorded amortization expense on intangible assets of $20,959,000 [2011 - $25,809,000].

As at December 31, 2012, estimated future amortization expense related to intangible assets is as follows:

	$
2013	17,940
2014	17,741
2015	16,815
2016	13,850
2017	11,481

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	2012 $	2011 $ [note 23]
Accounting policy changes	61,499	64,785
Smart meters	55,599	61,422
Regulatory assets recovery account	2,466	931
Settlement variances	1,071	14,119
Other	579	1,781
Total regulatory assets	121,214	143,038
Less: Current portion of regulatory assets	1,658	—
Long-term portion of regulatory assets	119,556	143,038

Regulatory liabilities consist of the following:

	2012 $	2011 $ [note 23]
Deferred income taxes	193,276	200,436
Income and other taxes variance account	2,398	2,365
Regulatory assets recovery account	—	7,293
Other	1,135	1,118
Total regulatory liabilities	196,809	211,212
Less: Current portion of regulatory liabilities	—	7,293
Long-term portion of regulatory liabilities	196,809	203,919

For the year ended December 31, 2012, LDC disposed of approved net regulatory liabilities amounting to $8,838,000 through permitted distribution rate adjustments [2011 - $34,528,000].

The regulatory assets and liabilities of LDC are as follows:

a) Accounting Policy Changes

This regulatory asset account relates to the accounting policy changes upon adoption of US GAAP, primarily related to the expected future electricity distribution charges to customers arising from timing differences in the recognition of actuarial losses and prior service costs of other post-retirement benefits [note 23]. The amount is amortized over the same period as the corresponding actuarial losses and prior service costs. The period in which recovery is expected cannot be determined at this time.

b) Smart Meters

The smart meters regulatory asset account relates to Ontario's decision to install smart meters throughout Ontario. LDC substantially completed its smart meter project as at December 31, 2010. In connection with this initiative, the OEB ordered LDC to record all expenditures and related revenues from 2008 to 2010 to a regulatory asset account and allowed LDC to keep the net book value of the stranded meters in property, plant and equipment. Effective January 1, 2011, LDC has recorded smart meter costs in property, plant and equipment and intangible assets as a

regular distribution activity as directed by the OEB. LDC expects to apply to the OEB in the future for both the transfer of the 2008 to 2010 smart meter costs from regulatory assets to property, plant and equipment and intangible assets, and the transfer of the net book value of the stranded meters from property, plant and equipment to regulatory assets.

As at December 31, 2012, smart meter capital expenditures, net of accumulated depreciation, totalling $52,865,000 were recorded to regulatory assets [December 31, 2011 - $51,227,000]. These expenditures would otherwise have been recorded as property, plant and equipment and intangible assets under US GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $50,234,000 and $2,631,000 higher, respectively, as at December 31, 2012 [December 31, 2011 - $54,825,000 and $4,402,000 higher, respectively].

For the year ended December 31, 2012, smart meter depreciation expense of $6,360,000 [2011 - $6,361,000] were deferred which would have been expensed under US GAAP for unregulated businesses. In the absence of rate regulation, for the year ended December 31, 2012, depreciation expense would have been $6,361,000 higher [2011 - $6,361,000 higher].

For the year ended December 31, 2012, smart meter customer revenues of $5,889,000 were deferred [2011 - $5,866,000]. In the absence of rate regulation, for the year ended December 31, 2012, revenue would have been $5,889,000 higher [2011 - $5,866,000 higher].

c) Regulatory Assets Recovery Account

The Regulatory Assets Recovery Account ["RARA"] consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate orders. The RARA is subject to carrying charges following the OEB prescribed methodology and related rates.

On April 9, 2010, the OEB approved the disposition of net regulatory liabilities of $68,140,000, consisting of credit balances for settlement variances and income and other taxes variances of $58,225,000 and $11,900,000, respectively, and intangible assets debit balance of $1,985,000, over a two-year period commencing on May 1, 2010 and ending on April 30, 2012.

On October 29, 2010, the OEB approved the disposition of regulatory assets of $5,296,000, for amounts in connection with the contact voltage remediation activities, for the period commencing on November 1, 2010 and ending on April 30, 2012

On February 22, 2011, the OEB approved the disposition of the Late Payment Penalties Settlement regulatory asset of $7,526,000, over a 21-month period commencing on August 1, 2011 and ending on April 30, 2013.

On July 7, 2011, the OEB approved the disposition of net regulatory liabilities of $8,572,000, consisting of credit balances for settlement variances, income and other taxes variances and 2008 RARA residual of $7,460,000, $3,373,000, and $789,000, respectively, and an International Financial Reporting Standards ["IFRS"] cost debit balance of $3,050,000, over a nine-month period commencing on August 1, 2011 and ending on April 30, 2012.

d) Settlement Variances

This account is comprised of the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by LDC. The settlement variances relate primarily to service charges, non-competitive electricity charges and the global adjustment. Accordingly, LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB.

The balance for settlement variances continues to be calculated and attracts carrying charges in accordance with the OEB's direction. For the year ended December 31, 2012, settlement variances of $12,249,000 were disposed through rate adjustments [2011 - $34,938,000].

e) Deferred Income Taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred income tax assets [note 4[o]].

As at December 31, 2012, LDC recorded a deferred income tax asset and a corresponding regulatory liability of $193,276,000 [December 31, 2011 - $200,436,000] in respect to its rate-regulated activities that will be included in the rate-setting process.

f) Income and Other Taxes Variance Account

The income and other taxes variance regulatory liability account relates to the differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the rate adjustment model. As at December 31, 2012, the balance in this account consisted of an over-recovery from customers of $298,000 [December 31, 2011 - $2,365,000].

10. OTHER ASSETS

Other long-term assets consist of the following:

	2012 $	2011 $
Prepaid expenses	7,191	7,279
Deferred financing costs	907	52
	8,098	7,331

11. RESTRUCTURING

In the first quarter of 2012, the Corporation's Board of Directors approved a workforce restructuring program aimed at reducing operating expenditures for LDC. The program was approved following the decision by the OEB to deny the request of LDC to set its electricity distribution rates for 2012, 2013 and 2014 under the COS framework. In preparing its revised application using the IRM framework, LDC concluded that significant cost reductions were necessary to manage its business within the confines of the expected allowed electricity distribution rates provided by the IRM framework [note 3[a]]. The main component of these operating cost reduction initiatives was a workforce restructuring program, which included the severance of management employees and a voluntary exit incentive program for targeted unionized positions.

For the year ended December 31, 2012, costs incurred as a result of these operating cost reduction initiatives amounted to $27,796,000 and were comprised of ongoing termination charges of $23,668,000 and one-time termination incentive charges of $4,128,000, of which $11,954,000 remains unpaid as at December 31, 2012.

12. LONG-TERM DEBT

Long-term debt consists of the following:

	2012 $	2011 $
Notes payable to related party:		
6.16% Long-term note payable to the Corporation due May 6, 2013	179,835	179,456
5.20% Long-term note payable to the Corporation due November 14,	244,316	244,186
4.54% Long-term note payable to the Corporation due November 12,	243,948	243,814
5.59% Long-term note payable to the Corporation due May 21, 2040	198,727	198,708
3.59% Long-term note payable to the Corporation due November 18,	298,352	298,119
6.16% Promissory note payable to the Corporation due May 6, 2013	245,058	245,058
6.16% Promissory note payable to the Corporation due on demand	45,000	—
3.32% Promissory note payable to the Corporation due on the earlier demand and January 1, 2022	15,000	—
3.09% Promissory note payable to TH Energy due on the earlier of demand and July 1, 2022	14,013	—
Total notes payable to related party	1,484,249	1,409,341
Less: Current portion of long-term notes payable	179,835	—
Less: Current portion of promissory notes payable	319,071	—
Long-term debt	985,343	1,409,341
Comprising:		
Long-term notes payable to related party	985,343	1,164,283
Promissory note payable to related party	—	245,058

All long-term debt of LDC ranks equally.

a) Long-term notes payable to the Corporation

Long-term notes payable to the Corporation are comprised of the following:

[i] $180,000,000, which bears interest at a rate of 6.16% per annum, with a maturity date of May 6, 2013, extendable upon mutual consent.

[ii] $245,058,000, which bears interest at a rate of 5.20% per annum, with a maturity date of November 14, 2017, extendable upon mutual consent.

[iii] $245,058,000, which bears interest at a rate of 4.54% per annum, with a maturity date of November 12, 2019, extendable upon mutual consent.

[iv] $200,000,000, which bears interest at a rate of 5.59% per annum, with a maturity date of May 21, 2040, extendable upon mutual consent.

[v] $300,000,000, which bears interest at a rate of 3.59% per annum, with a maturity date of November 18, 2021, extendable upon mutual consent.

b) Promissory notes payable to the Corporation

On July 1, 1999, LDC issued a promissory note to the City ["Initial Note"] in the principal amount of $947,000,000 in partial consideration for the assets in respect of the electricity distribution system transferred by the Toronto Hydro-Electric Commission and the City to LDC effective July 1, 1999. The Initial Note was non-interest bearing until December 31, 1999 and interest bearing thereafter at the rate of 6% per annum. Pursuant to the terms of By-law No. 374-1999 of the City made under section 145 of the Electricity Act, the principal amount of the Initial Note was adjusted effective January 1, 2000 to $980,231,000 to reflect the deemed debt to equity structure of LDC permitted by the OEB. At the same time, the Initial Note was replaced by a promissory note ["Replacement Note"] issued by LDC, which was interest bearing at the rate of 6.8% per annum. At December 31, 2002, the Replacement Note was payable on the earlier of demand and December 31, 2003.

Concurrent with the closing of the Corporation's debenture offering on May 7, 2003, the City transferred the Replacement Note to the Corporation in consideration for the issuance by the Corporation to the City of a new promissory note in the principal amount of $980,231,000. Following the issuance of the new promissory note to the City, on May 7, 2003, LDC issued a promissory note payable on demand to the Corporation in the principal amount of $980,231,000.

On September 5, 2006, LDC amended and restated the promissory note payable to the Corporation effective May 1, 2006 by fixing the interest rate at 6.16% and establishing an agreed repayment schedule. LDC is required to pay the principal amount of the note as follows: $245,058,000 on the last business day before each of December 31, 2007, December 31, 2009, December 31, 2011 and May 6, 2013. LDC made the first three scheduled payments on the respective due dates. Interest is calculated and payable quarterly in arrears on the last business day of March, June, September and December of each year.

On January 1, 2012, LDC issued a promissory note to the Corporation for general purposes. The principal amount of the promissory note is $45,000,000, which bears interest at a rate of 6.16% per annum, payable on demand. Interest is calculated and payable semi-annually in arrears on July 1 and January 1 of each year.

On January 1, 2012, LDC issued a promissory note to the Corporation for general purposes. The principal amount of the promissory note is $15,000,000, which bears interest at a rate of 3.32% per annum, payable on the earlier of demand and January 1, 2022. Interest is calculated and payable semi-annually in arrears on July 1 and January 1 of each year.

c) Promissory note payable to TH Energy

On July 1, 2012, LDC issued a promissory note to TH Energy in the principal amount of $14,013,000 [note 19], which bears interest at a rate of 3.09% per annum, payable on the earlier of demand and July 1, 2022. Interest is calculated and payable semi-annually in arrears on January 1 and July 1 of each year.

13. EMPLOYEE FUTURE BENEFITS

Pension

LDC provides a pension plan for its full-time employees through OMERS. Details of the plan are as follows:

Pension Plan	Funded Status as at December 31, 2012	Contributions	
		2012 $	2011 $
OMERS	86%	16,374	13,813

The OMERS plan assets are pooled together to provide benefits to plan participants and the plan assets are not segregated in separate accounts for each member entity. As at December 31, 2012, the OMERS plan financial statements disclosed an actuarial deficit of approximately $9,900,000, which is being addressed through increases in contribution rates for participating employers and employees. For the year ended December 31, 2012, the total contributions of all participating employers and employees were approximately $2,030,000,000. LDC's contributions represent less than five percent of total contributions to the plan.

For 2012, OMERS contribution rates were 8.3% up to the year's maximum pensionable earnings ["YMPE"] and 12.8% over YMPE for normal retirement age of 65 [2011 - 7.4% up to YMPE and 10.7% over YMPE for normal retirement age of 65].

As at December 31, 2012, OMERS had approximately 266,000 active members, of which approximately 1,700 members had a current relationship with LDC.

Post-retirement benefits other than pension

a) Benefit Obligations

	2012 $	2011 $
Balance, beginning of year	244,326	198,630
Adjustment due to reorganization	781	2,143
Service cost	5,035	3,820
Interest cost	11,454	11,307
Benefits paid	(7,960)	(7,383)
Actuarial loss	254	35,809
Balance, end of year	253,890	244,326

b) Amounts recognized in regulatory assets

	2012 $	2011 $
Actuarial loss	61,477	63,698
Prior service cost	22	1,087
Total recognized in regulatory assets [note 9]	61,499	64,785

As at December 31, 2012, the estimated actuarial loss and prior service cost that are expected to be amortized from regulatory asset to net periodic benefit cost in 2013 are $2,064,000 and $2,000, respectively.

c) Components of net periodic benefit costs

	2012 $	2011 $
Service cost	5,035	3,820
Interest cost	11,454	11,307
Amortization of actuarial loss	3,146	787
Amortization of prior service cost	840	873
Net periodic benefit cost	20,475	16,787
Capitalized as part of property, plant and equipment	7,305	6,758
Charged to operations	13,170	10,029

d) Expected benefit payments

The following benefit payments (net of recoveries from related companies), which reflect expected future service, as appropriate, are expected to be paid over the next five years, and in the aggregate for the five fiscal years thereafter:

	Post-retirement Benefits $
2013	10,015
2014	8,061
2015	8,263
2016	8,940
2017	9,384
2018-2022	55,001

e) Significant assumptions

	2012 %	2011 %
Accrued benefit obligation as at December 31:		
Discount rate	4.25	4.75
Rate of compensation increase	4.00	4.00
Benefit costs for years ended December 31:		
Discount rate	4.75	5.75
Rate of compensation increase	4.00	4.00
Assumed health care cost trend rates as at December 31:		
Rate of increase in dental costs assumed for next year	4.00	4.00
Rate of increase in medical costs assumed for next year		
For pre July 2000 retirements	6.50	7.00
For other retirements	8.00	8.50
Rate that medical cost trend rate gradually declines to		
For pre July 2000 retirements	5.00	5.00
For other retirements	5.00	5.00
Year that the medical cost trend rate reaches the ultimate trend rate		
For pre July 2000 retirements	2016	2016
For other retirements	2019	2019

f) Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for health and dental care plans. A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2012:

	Increase $	Decrease $
Total of current service and interest cost (at 4.75%)	2,483	(2,181)
Accrued benefit obligation as at December 31, 2012 (at 4.25%)	32,347	(28,380)

Assumed interest rates have a significant effect on the amounts reported for the total accrued benefit obligation and expense. A one-percentage-point change in assumed interest rates would have the following effects:

	Increase $	Decrease $
Accrued benefit obligation as at December 31, 2012	(39,382)	48,344
Estimated net periodic benefit cost for fiscal 2013	(2,563)	4,629

14. ASSET RETIREMENT OBLIGATIONS

The reconciliation between the opening and closing ARO liability balances is as follows:

	2012 $	2011 $
Balance, beginning of year	4,831	4,939
ARO liabilities settled in the year	(313)	(688)
Accretion expense	170	168
Revision in estimated cash flows	316	412
Balance, end of year	5,004	4,831

15. FINANCIAL INSTRUMENTS

a) Recognition and measurement

The fair values of cash and cash equivalents, net accounts receivable, unbilled revenue, accounts payable and accrued liabilities, and customers' advance deposits approximate their carrying values as at December 31, 2012 and December 31, 2011 [note 4[j]] .

The carrying value and fair value of LDC's other financial instruments consist of the following:

	2012 $		2011 $	
	Carrying value	Fair value [(1)]	Carrying value	Fair value [(1)]
Obligations under capital lease	11,235	11,235	13,172	13,172
Long-term notes payable to the Corporation				
6.16% due May 6, 2013	179,835	182,999	179,456	190,682
5.20% due November 14, 2017	244,316	278,314	244,186	278,458
4.54% due November 12, 2019	243,948	274,786	243,814	270,077
5.59% due May 21, 2040	198,727	256,357	198,708	244,838
3.59% due November 18, 2021	298,352	316,935	298,119	306,680
Promissory note payable to the Corporation d				
May 6, 2013	245,058	249,174	245,058	259,650
Promissory note payable to the Corporation d				
on demand	45,000	45,754	—	—
Promissory note payable to the Corporation d				
on the earlier of demand and January 1, 202	15,000	15,489	—	—
Promissory note payable to TH Energy due o				
the earlier of demand and July 1, 2022	14,013	14,043	—	—

[(1)] The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy.

b) Financial Risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

LDC's financial activities provide for a variety of financial risks, particularly credit risk, interest rate risk and liquidity risk.

Credit risk

LDC is exposed to credit risk from financial instruments as a result of the risk of counterparties defaulting on their obligations. LDC monitors and limits its exposure to credit risk on a continuous basis.

LDC's credit risk associated with accounts receivable is primarily related to electricity bill payments from customers. LDC has approximately 719,000 customers, the majority of which are residential. LDC collects security deposits from certain customers in accordance with direction provided by the OEB. As at December 31, 2012, LDC held security deposits in the amount of $46,838,000 [December 31, 2011 - $56,038,000], of which $25,666,000 [December 31, 2011 - $22,700,000] were related to security deposits on Offers to Connect to guarantee the payment of additional costs relating to expansion projects.

LDC did not have any single customer that generated more than 10% of total revenues for the years ended December 31, 2012 and December 31, 2011.

Credit risk associated with accounts receivable is as follows:

	2012 $	2011 $
Total accounts receivable	196,509	204,266
Less: Allowance for doubtful accounts	(10,568)	(12,810)
Total accounts receivable, net	185,941	191,456
Of which:		
Outstanding for not more than 30 days	164,523	163,675
Outstanding for more than 30 days and not more than 120 days	18,214	24,671
Outstanding for more than 120 days	13,772	15,920
Less: Allowance for doubtful accounts	(10,568)	(12,810)
Total accounts receivable, net	185,941	191,456

Reconciliation between the opening and closing allowance for doubtful accounts balances is as follows:

	2012 $	2011 $
Balance, beginning of year	(12,810)	(11,736)
Provision for doubtful accounts	(6,590)	(10,158)
Write-offs	9,242	9,741
Recoveries	(410)	(657)
Balance, end of year	(10,568)	(12,810)

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. As at December 31, 2012, total unbilled revenue was $274,272,000 [December 31, 2011 - $262,289,000]. Unbilled revenue is considered current.

As at December 31, 2012, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. LDC's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk

LDC is exposed to interest rate risk through holding certain financial instruments, and short-term borrowings which may be obtained under the Corporation's revolving credit facility may expose LDC to fluctuations in short-term interest rates (borrowings in the form of prime rate loans in Canadian dollars and Bankers' Acceptance and letters of credit). LDC attempts to minimize interest rate risk by borrowing in long-term fixed rate debt, and by extending or shortening the term of its short-term money market investments by assessing the monetary policy stance of the Bank of Canada, while ensuring that all payment obligations are met on an ongoing basis. The fee payable for bankers' acceptances and letters of credit is based on a margin rate determined by reference to the Corporation's credit rating.

Cash balances, which are not required to meet day-to-day obligations of LDC, are either held in bank accounts or invested in Canadian money market instruments, exposing LDC to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by LDC.

As at December 31, 2012, LDC has limited exposure to interest rate risk since its significant obligations are either non-interest bearing or bear fixed interest rates, its financial assets are predominately short-term in nature and mostly non-interest bearing, and its revenue is governed by a specified rate of return pricing structure set by the OEB. LDC estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in a decrease (increase) of approximately $200,000 per annum to net financing charges.

LDC is also exposed to fluctuations in interest rates for the valuation of its post-retirement benefit obligations [note 13[f]] .

Liquidity risk

LDC is exposed to liquidity risk related to commitments associated with financial instruments. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. LDC's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing net financing charges. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

Liquidity risks associated with financial commitments are as follows:

December 31, 2012						
	2013 $	2014 $	2015 $	2016 $	2017 $	Due after 5 years $
Financial liabilities						
Accounts payable and accrued liabilities	377,948	—	—	—	—	—
Obligations under capital lease	2,338	2,329	2,322	2,310	2,310	1,157
Long-term notes payable to the Corporatio						
6.16% due May 6, 2013	180,000	—	—	—	—	—
5.20% due November 14, 2017	—	—	—	—	245,058	—
4.54% due November 12, 2019	—	—	—	—	—	245,058
5.59% due May 21, 2040	—	—	—	—	—	200,000
3.59% due November 18, 2021	—	—	—	—	—	300,000
Promissory note payable to the Corporat due May 6, 2013	245,058	—	—	—	—	—
Promissory note payable to the Corporat due on demand	45,000	—	—	—	—	—
Promissory note payable to the Corporat due on the earlier of demand and Janu 1, 2022	15,000	—	—	—	—	—
Promissory note payable to TH Energy c on the earlier of demand and July 1, 202	14,013	—	—	—	—	—
Interest payments on long-term not payable and promissory notes payable	56,612	45,819	45,819	45,819	45,819	316,881
	935,969	48,148	48,141	48,129	293,187	1,063,096

Hedging and Derivative risk

As at December 31, 2012 and December 31, 2011, LDC has not entered into hedging and derivative financial instruments.

Foreign exchange risk

As at December 31, 2012, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related payables commitments when required, the impact of these transactions is not material to the financial statements.

16. FINANCIAL GUARANTEES

As at December 31, 2012, $3,488,000 [December 31, 2011 - $45,000,000] was utilized under the Corporation's demand credit facility in the form of letters of credit to satisfy the prescribed prudential requirements of LDC with the IESO for the purchase of electricity. An additional amount of $761,000 was utilized for the Ministry of Finance.

17. INCOME TAXES

LDC's effective tax rate for the year ended December 31, 2012 was 26.62% [2011 - 26.52%]. Income tax expense for the year ended December 31, 2012 was $3,125,000 [2011 - $6,509,000]. The effective tax rate and income tax

expense for the year ended December 31, 2012 was lower than the year ended December 31, 2011 due to a reduction in the statutory tax rate from 28.25% to 26.50% and changes in permanent and temporary differences between accounting and tax treatments.

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and Ontario income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

Statements of Net Income and Comprehensive Income

	2012 $	2011 $
Rate reconciliation		
Income before income taxes	86,314	99,840
Statutory Canadian federal and provincial income tax rate	26.50%	28.25%
Expected income tax expense	22,873	28,205
Temporary differences not benefited	(16,133)	(16,032)
Impact of change in expected future tax rate on existing deferred incon balances	(923)	—
Other	(2,692)	(5,664)
Income tax expense	3,125	6,509
Effective tax rate	3.62%	6.52%
Components of income tax expense		
Current tax	6,011	8,753
Deferred income tax related to the origination and reversal of temporary differences	(245)	279
Non-refundable ITCs	(2,641)	(2,523)
Income tax expense	3,125	6,509

Balance Sheets

Significant components of LDC's deferred tax assets are as follows:

	2012 $	2011 $
Property, plant and equipment and intangible assets	82,604	100,933
Regulatory adjustments	51,218	50,109
Post-retirement benefits liability	50,667	44,093
Other taxable temporary differences	8,753	5,022
Deferred income tax assets	193,242	200,157

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2012 $	2011 $
Balance, beginning of year	7,045	(574)
Increases for tax positions taken in the current year	248	374
Increases for tax positions taken in prior years	—	6,633
Decreases for tax positions taken in prior years	(38)	—
Settlements with tax authorities	(1,981)	612
Reductions resulting from the expiry of limitation periods	—	—
Balance, end of year	5,274	7,045

As at December 31, 2012, $5,274,000 of unrecognized tax benefits [December 31, 2011 - $7,045,000] would have a favourable effect on the effective tax rate if recognized. No interests and penalties have been accrued, since LDC is of the view that none are expected to be payable. During the next 12 months, unrecognized tax benefits are not expected to significantly change.

As at December 31, 2012, LDC's tax years still open to examination by taxing authorities include 2007 and subsequent years. Other than in respect of the fair market revaluation of LDC's assets on October 1, 2001 pursuant to Section 7 of Ontario Regulation 162/01 of the Electricity Act, tax years prior to 2007 are closed to further examination.

18. SHARE CAPITAL

Share capital consists of the following:

	2012 $	2011 $
Authorized The authorized share capital of LDC consists of an unlimited number of common shares		
Issued and outstanding 1,000 common shares	556,278	527,817

On January 1, 2012, LDC amalgamated with 1798594 Ontario Inc., a wholly-owned entity of the Corporation, with an initial share capital of $1,000 and a further share capital of $28,460,000 associated with the transfer of certain electricity distribution assets [note 19], whose shares were cancelled upon completion of the amalgamation.

19. RELATED PARTIES

For LDC, transactions with related parties include transactions with the City, the Corporation and TH Energy. All transactions with related parties are in the ordinary course of business and measured at exchange amounts and normal trade terms.

2012	City $	Corporation $	TH Energy $
Revenues	210,835	—	—
Operating expenses (recoveries) and capital expenditures	26,232	3,035	(1,530)
Net financing charges	—	75,303	433
Accounts receivable	5,603	—	14,271
Unbilled revenue	17,016	—	—
Other Assets	7,279	—	—
Accounts payable and accrued liabilities	38,013	11,426	433
Short-term notes and promissory notes payable	—	484,893	14,013
Long-term notes payable	—	985,343	—
Advance deposits	8,926	—	—

2011	City $	Corporation $	TH Energy $
Revenues	194,671	—	—
Operating expenses (recoveries) and capital expenditures	28,946	2,837	(1,850)
Net financing charges	—	77,609	—
Accounts receivable	6,761	—	10,494
Unbilled revenue	12,439	—	—
Other Assets	7,279	—	—
Accounts payable and accrued liabilities	24,235	7,926	—
Long-term notes and promissory note payable	—	1,409,341	—
Advance deposits	8,714	—	—

Revenues represent amounts charged to the City primarily for electricity, street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, and the Corporation for purchased corporate and management services. Operating expense recoveries represent amounts charged to TH Energy for the provision of goods and services. Net financing charges represent interest charged by the Corporation and TH Energy on the notes and promissory notes payable [note 12].

Accounts receivable represent receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services, including consolidated billing services. Unbilled revenue represents receivables from the City related to the provision of electricity not yet billed. Other assets represent amounts for prepaid land leases from the City. Accounts payable and accrued liabilities represent amounts payable to the City relating to road cut repairs and other services, as well as funds received from the City for the construction of electricity distribution assets. Included in the Accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on notes and promissory notes payable to the Corporation and TH Energy. Notes and promissory notes payable represent amounts borrowed from the Corporation and TH Energy [note 12]. Advance deposits represent funds received from the City for future expansion projects.

On January 1, 2012, certain electricity distribution assets of TH Energy were transferred to LDC through a newly created wholly-owned legal entity (1798594 Ontario Inc.) of the Corporation. Immediately thereafter, the new legal entity was amalgamated with LDC. The transfer was completed for a purchase price of $28,460,000, with a post closing adjustment of $14,013,000. The transfer was initially funded with share capital issued by the new wholly-owned legal entity to the Corporation. Subsequently, LDC issued an intercompany promissory note payable to TH Energy for the increase in the purchase price.

20. COMMITMENTS

Future capital commitments and operating lease obligations

As at December 31, 2012, the future minimum annual lease payments under property operating leases and future commitments with remaining terms from one to five years and thereafter were as follows:

	Future capital commitments[2]	Operating lease obligations and other
	$	$
2013	15,278	9,091
2014	—	8,999
2015	—	8,052
2016	—	6,666
2017	—	1,992
Thereafter	—	—
Total amount of future minimum payments[1]	15,278	34,800

[1] Refer to note 15 for repayments of long-term debt excluded from the table above.
[2] Reflect estimated capital contributions payable to Hydro One Networks Inc. under the Toronto Midtown Transmission Reinforcement Project.

LDC has the option to renew its two major property operating leases at the end of the current lease term for an additional five years at the then fair rental value.

Operating lease expense for the year ended December 31, 2012 was $6,547,000 [2011 - $5,271,000].

Capital lease obligations

As at December 31, 2012, the future minimum annual lease payments under capital leases with remaining lease terms from one to five years and thereafter were as follows:

	$
2013	2,338
2014	2,329
2015	2,322
2016	2,310
2017	2,310
Thereafter	1,157
Total amount of future minimum lease payments	12,766
Less: interest and executory costs	1,531
	11,235
Current portion included in Other liabilities	1,850
Long-term portion included in Other liabilities	9,385

21. CONTINGENCIES

a) Legal Proceedings

In the ordinary course of business, LDC is subject to various litigation and claims with customers, suppliers, former employees and other parties. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach such as a change in settlement strategy. LDC is subject to various legal actions that arise in the normal course of business and if damages were awarded under these actions, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with these actions.

Christian Helm Class Action

On December 6, 2010, a statement of claim in a proposed class action was issued against LDC. The claim sought general and special damages in the amount of $100,000,000 for disgorgement of unjust gains allegedly resulting from the receipt of interest on overdue accounts in contravention of the Interest Act (Canada). On April 30, 2012, a settlement reached by the parties was approved by Order of the Ontario Superior Court of Justice. Pursuant to the terms of the Order, LDC was required to pay the amount of $5,836,000 plus costs in settlement of all claims, substantially all of which had been paid as at December 31, 2012. LDC accrued a liability to cover the expected settlement in 2010. The action has been dismissed, and the claims by all class members have been released.

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the Class Proceedings Act, 1992 (Ontario) seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. This action is at a preliminary stage. The statement of claim has been served on LDC, a statement of defence and third party claim have been served by LDC and a third party defence and counterclaim against LDC seeking damages in the amount of $51,000,000 have been filed. A certification order has been issued. Affidavits of

documents have been produced by LDC to the other parties and examinations for discovery have commenced and are continuing. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with the action.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2,000,000 as a result of the fire at 2 Secord Avenue. A statement of defence and a third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with the action.

By order of the court dated January 24, 2012, the above actions and a smaller non-class action commenced in April 2009 involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the Class Proceedings Act, 1992 (Ontario) seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $100,000 from LDC. Both actions are at a preliminary stage and no certification hearing has yet to occur. Statements of defence to the main action and to the third party claim have not been filed. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with these actions.

Another third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of the fire at 2369 Lakeshore Boulevard West. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action sought damages in the amount of $400,000 from LDC. LDC has filed a statement of defence, crossclaim and counterclaim. Examinations for discovery have not taken place, notwithstanding a court ordered timetable to have them completed by February 29, 2012. By order dated December 5, 2012, these actions were dismissed by the court for delay.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2,000,000 as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with the action.

b) OEB PILs Proceeding

The OEB conducted a review of the PILs variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain Municipal Electricity Utilities [“MEUs”]. On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts. Subsequent to this decision, the OEB issued interrogatories and decisions for other MEUs.

LDC has reviewed the balances of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. As at December 31, 2012, LDC estimated its liability at approximately $7,048,000. This balance has been recorded in LDC's financial statements. LDC has applied for disposition of the balance as part of its pending IRM/ICM Application filed on May 10, 2012. The amount to be approved by the OEB will be based on the OEB's interpretation and application of its guidelines and the final balance which is yet to be approved by the OEB could differ materially from LDC's estimation of its liability.

c) Payments in Lieu of Additional Municipal and School Taxes

The Ministry of Finance had issued assessments in respect of payments in lieu of additional municipal and school taxes under section 92 of the Electricity Act that were in excess of the amounts LDC believed were payable. The dispute arose as a result of inaccurate information included in Ontario Regulation 224/00. LDC worked with the Ministry of Finance to resolve this issue, and as a result the Ministry of Finance issued Ontario Regulation 423/11 on August 31, 2011. The new regulation revoked Ontario Regulation 224/00 and corrected inaccurate information retroactively to 1999.

In May 2012, the Ministry of Finance completed its reassessment as a consequence of the change in regulation. The impact of the reassessment issued was favourable to LDC.

22. NON-CASH WORKING CAPITAL BALANCES

Changes in non-cash working capital provided (used) cash as follows:

	2012 $	2011 $
Accounts receivable	5,515	(5,101)
Unbilled revenue	(11,983)	20,852
Income tax receivable	3,974	(6,154)
Inventories	(664)	610
Other current assets	(276)	(599)
Accounts payable and accrued liabilities	(21,487)	37,086
Restructuring accrual	11,954	—
Deferred conservation credit	6,298	13,316
Other current liabilities	(332)	(489)
	(7,001)	59,521

23. US GAAP TRANSITION

Publicly accountable enterprises in Canada were required to adopt IFRS for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the Accounting Standards Board granted an optional one-year deferral for IFRS adoption for entities subject to rate regulation. The Corporation elected to take the optional one-year deferral of its adoption of IFRS. In the absence of a definitive plan to consider the issuance of a rate-regulated accounting standard by the International Accounting Standards Board, the Corporation decided to evaluate the option of adopting US GAAP effective January 1, 2012 as an alternative to IFRS. On July 21, 2011, the Ontario Securities Commission granted the Corporation an exemption to allow the Corporation to file financial statements under US GAAP for the years commencing on or after January 1, 2012 but before January 1, 2015. On August 26, 2011, the Board of Directors of the Corporation approved the adoption of US GAAP for financial reporting purposes for the year beginning on January 1, 2012. As a wholly-owned subsidiary, LDC elected to follow the Corporation and adopted US GAAP for financial reporting purposes for the year beginning on January 1, 2012.

These are LDC's first annual financial statements prepared in accordance with US GAAP. The accounting policies set out in note 4 have been applied consistently in preparing the financial statements for the year ended December 31, 2012 and the comparative periods.

LDC has adjusted amounts reported previously in its financial statements prepared in accordance with Canadian GAAP. For reporting purposes, the transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to LDC's 2012 financial statements. An explanation of how the transition from Canadian GAAP to US GAAP has affected LDC's financial statements is set out in the following tables and accompanying notes.

Given the Corporation's exemption to file under US GAAP to December 31, 2014 by the Ontario Securities Commission, the Corporation is actively monitoring developments by the International Accounting Standards Board on rate-regulated accounting should a future IFRS conversion be required. Although the conversion of LDC's general purpose financial statements to IFRS was suspended in 2011, the IFRS conversion work is being managed in such a way that if a future transition to IFRS is required, it can be effectively accomplished.

The reconciliation of the January 1, 2011 balance sheet from Canadian GAAP to US GAAP is as follows:

BALANCE SHEET

[in thousands of Canadian dollars]

As at January 1, 2011	Notes	Canadian GAAP $	Transitional Adjustments $	US GAAP $
ASSETS				
Current				
Regulatory assets	A	—	3,55	3,555
Other	A	657,135	1,71(	658,845
Total current assets		657,135	5,265	662,400
Regulatory assets	A	85,113	29,2	114,337
Other		2,383,017	—	2,383,017
Total assets		3,125,265	34,489	3,159,754
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current				
Customers' advance deposits	B	—	50,6	50,630
Post-retirement benefits	A	—	7,41	7,415
Regulatory liabilities	A	—	36,654	36,654
Other	A, B	630,430	(20,18	610,243
Total current liabilities		630,430	74,512	704,942
Customers' advance deposits	B	45,462	(31,(	13,622
Post-retirement benefits	A	166,790	25,8	192,612
Regulatory liabilities	A	273,706	(34,00	239,701
Other		1,116,215	—	1,116,215
Total liabilities		2,232,603	34,489	2,267,092
Total shareholder's equity		892,662	—	892,662
Total liabilities and shareholder's equity		3,125,265	34,489	3,159,754

The reconciliation of the December 31, 2011 balance sheet from Canadian GAAP to US GAAP is as follows:

BALANCE SHEET

[in thousands of Canadian dollars]

As at December 31, 2011	Notes	Canadian GAAP $	Transitional Adjustments $	US GAAP $
ASSETS				
Current				
Other		540,468	—	540,468
Total current assets		540,468	—	540,468
Regulatory assets	A	77,322	65,716	143,038
Other		2,654,763	—	2,654,763
Total assets		3,272,553	65,716	3,338,269
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current				
Customers' advance deposits	B	—	40,238	40,238
Post-retirement benefits	A	—	7,915	7,915
Regulatory liabilities	A	—	7,293	7,293
Other	A, B	438,507	(23,280)	415,227
Total current liabilities		438,507	32,166	470,673
Customers' advance deposits	B	35,930	(20,130)	15,800
Post-retirement benefits	A	176,370	60,041	236,411
Regulatory liabilities	A	210,280	(6,361)	203,919
Other		1,425,473	—	1,425,473
Total liabilities		2,286,560	65,716	2,352,276
Total shareholder's equity		985,993	—	985,993
Total liabilities and shareholder's equity		3,272,553	65,716	3,338,269

The reconciliation of net income from Canadian GAAP to US GAAP for the year ended December 31, 2011 is as follows:

RECONCILIATION OF NET INCOME FROM CANADIAN GAAP TO US GAAP

[in thousands of Canadian dollars]

	Notes	2011 $
Net income, Canadian GAAP		93,331
Revenues	C	14,212
Operating expenses	C, D	(16,735)
Income tax recovery	D	2,523
Net income, US GAAP		93,331

Notes to the transitional adjustments

A. Post-retirement benefits

Under Canadian GAAP, unamortized actuarial gains and losses and unamortized prior service costs are not recorded on the balance sheets. Under US GAAP, all actuarial gains and losses and prior service costs are fully recognized in OCI in the period in which they arise and are presented within equity as Accumulated Other Comprehensive Income ["AOCI"]. Due to the rate-regulated nature of LDC's business, the impact to AOCI on transition and the impact to OCI on a go-forward basis will be reclassified to a regulatory asset account [note 9[a]]. This reclassification results in the full recognition of the benefit obligation as a liability on LDC's balance sheets and no balance reported in OCI and AOCI. A portion of the benefit obligation will also be presented as a current liability on the balance sheets. The current portion is the amount of the actuarial present value of benefits included in the benefit obligation which is expected to be paid in the next 12 months.

B. Customers' advance deposits

Under US GAAP, deposits that are due on demand or will be due on demand within one year from the end of the reporting period have been reclassified as current liabilities.

C. Demand billable income and expenses

Under US GAAP, associated costs related to demand billable income have been reclassified on the statements of net income and comprehensive income. There is no impact to the overall net income.

D. Income tax recovery

Under Canadian GAAP, all ITCs are recognized as a reduction of the related expenditure. Under US GAAP, the benefits of the refundable apprenticeship and co-operative ITCs are recognized as a reduction of the related expenditure. All other ITCs are recorded as a reduction of income tax expense in the current period to the extent that realization of such benefits is more likely than not.

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2013 and 2012

See attached Glossary for abbreviations used in the audited financial statements.

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

We have audited the accompanying financial statements of Toronto Hydro-Electric System Limited, which comprise the balance sheets as at December 31, 2013 and December 31, 2012, the statements of net income and comprehensive income, shareholder's equity and cash flows for the years ended December 31, 2013 and December 31, 2012, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Toronto Hydro-Electric System Limited as at December 31, 2013 and December 31, 2012 and its statements of net income and comprehensive income, shareholder's equity and cash flows for the years ended December 31, 2013 and December 31, 2012 in accordance with United States Generally Accepted Accounting Principles

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada

March 19, 2014

BALANCE SHEETS

[in thousands of dollars]

As at December 31	2013 $	2012 $
ASSETS		
Current		
Cash and cash equivalents	**15,677**	67,258
Accounts receivable, net of allowance for doubtful accounts *[note 15[b]]*	**199,023**	185,941
Unbilled revenue *[note 15[b]]*	**326,111**	274,272
Income tax receivable	**342**	4,710
Inventories *[note 5]*	**8,566**	7,555
Regulatory assets *[note 9]*	**7,060**	1,658
Other assets *[note 6]*	**8,854**	4,680
Total current assets	**565,633**	546,074
Property, plant and equipment, net *[note 7]*	**2,640,028**	2,504,428
Intangible assets, net *[note 8]*	**171,489**	134,080
Regulatory assets *[note 9]*	**234,424**	119,556
Other assets *[note 10]*	**8,008**	8,098
Deferred income tax assets *[note 17]*	**155,867**	193,242
Total assets	**3,775,449**	3,505,478
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Advance from related party *[note 19]*	**150,000**	-
Accounts payable and accrued liabilities *[note 15[b]]*	**455,752**	377,948
Restructuring accrual *[note 11]*	**-**	11,954
Customers' advance deposits	**37,293**	40,048
Deferred conservation credit	**20,020**	19,908
Post-retirement benefits *[note 13]*	**8,003**	9,925
Other liabilities *[note 20]*	**2,100**	1,850
Regulatory liabilities *[note 9]*	**2,516**	-
Notes payable to related parties *[notes 12 and 19]*	**60,000**	498,906
Total current liabilities	**735,684**	960,539
Notes payable to related parties *[notes 12 and 19]*	**1,433,199**	985,343
Customers' advance deposits	**7,356**	6,790
Post-retirement benefits *[note 13]*	**230,789**	243,965
Other liabilities *[note 20]*	**8,175**	9,385
Regulatory liabilities *[note 9]*	**180,617**	196,809
Asset retirement obligations *[note 14]*	**6,247**	5,004
Total liabilities	**2,602,067**	2,407,835
Commitments, contingencies and subsequent events *[notes 2, 20 and 21]*		
Shareholder's equity		
Share capital *[note 18]*	**556,278**	556,278
Retained earnings	**604,347**	528,608
Contributed surplus	**12,757**	12,757
Total shareholder's equity	**1,173,382**	1,097,643
Total liabilities and shareholder's equity	**3,775,449**	3,505,478

The accompanying notes are an integral part of the financial statements.

STATEMENTS OF NET INCOME AND COMPREHENSIVE INCOME

[in thousands of dollars]

Year ended December 31	2013 $	2012 $
Revenues		
Sale of electricity	**3,145,455**	2,799,404
Other income	**42,288**	41,057
	3,187,743	2,840,461
Costs		
Purchased power	**2,567,512**	2,275,209
Operating expenses	**262,304**	236,386
Depreciation and amortization *[notes 7, 8 and 9]*	**171,475**	140,352
	3,001,291	2,651,947
Income before the following:	**186,452**	188,514
Net financing charges *[note 22]*	**(68,870)**	(76,209)
Gain on disposals of property, plant and equipment	**1,280**	1,805
Restructuring costs *[note 11]*	**-**	(27,796)
Income before income taxes	**118,862**	86,314
Income tax expense *[note 17]*	**3,123**	3,125
Net income and comprehensive income	**115,739**	83,189

STATEMENTS OF SHAREHOLDER'S EQUITY

[in thousands of dollars]

Year ended December 31	2013 $	2012 $
Share capital *[note 18]*	**556,278**	556,278
Retained earnings, beginning of year	**528,608**	445,419
Net income	**115,739**	83,189
Dividends *[notes 18 and 19]*	**(40,000)**	-
Retained earnings, end of year	**604,347**	528,608
Contributed surplus	**12,757**	12,757
Total shareholder's equity	**1,173,382**	1,097,643

The accompanying notes are an integral part of the financial statements.

STATEMENTS OF CASH FLOWS

[in thousands of dollars]

Year ended December 31	2013 $	2012 $
OPERATING ACTIVITIES		
Net income	**115,739**	83,189
Adjustments for non-cash items		
Depreciation and amortization *[notes 7, 8 and 9]*	**171,475**	140,352
Post-retirement benefits	**7,620**	12,850
Deferred income taxes *[note 17]*	**(48)**	(245)
Gain on disposals of property, plant and equipment	**(1,280)**	(1,805)
Other	**715**	815
Net change in regulatory assets and liabilities *[note 9]*	**(19,518)**	11,295
Net change in other non-current assets and liabilities	**187**	(956)
Changes in non-cash working capital balances *[note 23]*	**(32,540)**	5,130
Net cash provided by operating activities	**242,350**	250,625
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 23]*	**(355,232)**	(302,198)
Purchase of intangible assets *[note 8]*	**(54,455)**	(42,057)
Proceeds on disposals of property, plant and equipment	**1,663**	2,665
Net cash used in investing activities	**(408,024)**	(341,590)
FINANCING ACTIVITIES		
Common shares issued *[note 19]*	**-**	28,461
Increase in advance from related party *[note 19]*	**150,000**	-
Increase in notes payable to related parties *[note 12]*	**447,306**	74,013
Decrease in notes payable to related parties *[note 12]*	**(439,071)**	-
Decrease in customers' advance deposits	**(2,189)**	(9,200)
Repayment of capital lease liability	**(1,953)**	(1,795)
Dividends paid *[notes 18 and 19]*	**(40,000)**	-
Net cash provided by financing activities	**114,093**	91,479
Net increase (decrease) in cash and cash equivalents during the year	**(51,581)**	514
Cash and cash equivalents, beginning of year	**67,258**	66,744
Cash and cash equivalents, end of year	**15,677**	67,258
Supplementary cash flow information		
Total interest paid	**72,062**	72,998
Total income taxes recovered	**(3,106)**	(1,200)

The accompanying notes are an integral part of the financial statements.

1. INCORPORATION

On June 23, 1999, LDC was incorporated under the Business Corporations Act (Ontario), and is wholly-owned by the Corporation. The incorporation was required in accordance with the provincial government's Electricity Act.

LDC distributes electricity to customers located in the City and is subject to rate regulation. LDC is also engaged in the delivery of CDM activities.

2. BASIS OF PRESENTATION

These audited financial statements of LDC have been prepared in accordance with US GAAP with respect to the preparation of annual financial information, and are presented in Canadian dollars.

LDC has evaluated the events and transactions occurring after the balance sheet date through March 19, 2014 when LDC's financial statements were available to be issued after the approval by LDC's Board of Directors, and identified the events and transactions which required recognition in the financial statements and/or disclosure in the notes to the financial statements [notes 3, 4, 9, 13, 20 and 21]

3. REGULATION

In April 1999, the Government of Ontario began restructuring Ontario's electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors purchase electricity from the wholesale market administered by the IESO and recover the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in Ontario. The OEB Act sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for distribution and other activities, and requirements for rate-setting and other legal filings.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- Commodity Charge – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- Retail Transmission Rate – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through to operators of transmission facilities.

- WMS Charge – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through to the IESO.

- Distribution Rate – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and are comprised of fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

a) Electricity Distribution Rates

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

On May 10, 2012, LDC filed an application for electricity distribution rates for 2012, 2013, and 2014 using the IRM framework, including the filing of an ICM application [the "IRM/ICM Application"].

On October 31, 2012, LDC submitted an update to its IRM/ICM Application modifying the requested capital expenditures for 2012 and 2013 to $283,000,000 and $579,100,000, respectively, and requesting that consideration for 2014 be deferred to a second phase of the proceeding, once LDC had received a decision from the OEB in respect of phase one. On November 8, 2012, the OEB accepted LDC's request for a two-phase proceeding: phase one comprising LDC's 2012 and 2013 work program proposals and phase two comprising LDC's 2014 work program proposal.

On April 2, 2013, the OEB issued a partial decision and order for phase one of the proceeding comprising LDC's 2012 and 2013 work program proposals. The OEB's decision determined that eligible capital funding under the ICM framework was to be calculated on an in-service basis. This correlates to the approval of capital expenditures amounting to $203,330,000 for 2012 and $484,220,000 for 2013. New rates became effective June 1, 2013. In 2015, LDC will be allowed to seek recovery for capital spent in 2012 and 2013 that has not yet been approved by the OEB in the current ICM decision due to the standard operation of the regulatory model.

On August 1, 2013, LDC filed an application with the OEB requesting approval for the disposition of balances in its smart meter deferral account related to smart meter costs incurred in 2008, 2009 and 2010. In the application, LDC requested two new rate riders effective May 1, 2014. The first rate rider relates to the recovery of $23,927,000, which represents the cumulative revenue requirement net of recoveries from an existing smart meter rate rider. This existing smart meter rate rider would be discontinued when the new rate riders become effective. The second rate rider relates to the recovery of $9,631,000, which represents the forecasted 2014 incremental revenue requirement until LDC may be permitted to transfer the smart meter assets into rate base.

On August 19, 2013, LDC submitted an update to its IRM/ICM Application regarding its 2014 work program proposal. The filed update incorporates the OEB's guidance on the ICM methodology provided in the April 2, 2013 partial decision and order with respect to phase one of this proceeding. In phase two, LDC sought approval for total capital expenditures amounting to $398,780,000 for 2014.

On December 18, 2013, LDC filed a settlement agreement with the OEB, which allowed for the entirety of LDC's requested 2014 capital program. On December 19, 2013, the OEB approved this settlement agreement. Consistent with the April 2, 2013 partial decision and order with respect to phase one, eligible capital funding under the ICM framework is to be calculated on an in-service basis. This correlates to the approval of capital expenditures amounting to $398,780,000 for 2014.

On January 16, 2014, the OEB approved LDC's requested disposition of the smart meter deferral account balances, permitting the recovery of $23,927,000 and $9,631,000 through two separate rate riders effective May 1, 2014[note 9[c]].

b) CDM Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 GWh of energy savings and 286 MW of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the OPA in the amount of approximately $50,000,000 to deliver CDM programs extending from January 1, 2011 to December 31, 2014. As at December 31, 2013, LDC received approximately $45,919,000 [December 31, 2012 - $35,366,000] from the OPA for the delivery of CDM programs. All programs to be delivered are fully funded and paid in advance by the OPA. Amounts received but not yet spent are presented under current liabilities as deferred conservation credit. Upon the expiration of the agreement, LDC is required to repay to the OPA any excess funding received for program administration less any cost efficiency incentives. These programs are expected to support the achievement of the mandatory CDM targets described above.

On December 21, 2012, the Minister of Energy of Ontario issued a direction to the OPA under subsection 25.32(4.1) of the Electricity Act to extend the funding time period for OPA-contracted province-wide CDM initiatives under the Green Energy Act framework to December 31, 2015.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from US GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

LDC has determined that its assets and liabilities arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with FASB ASC 980 – "Regulated Operations", which includes accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors". Under RRA, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under US GAAP in order to appropriately reflect the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These timing differences are recorded as regulatory assets and regulatory liabilities on LDC's balance sheets and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the disposition of these balances was assessed to no longer be probable, the balances would be recorded in LDC's statements of net income and comprehensive income in the period that the assessment is made. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

Regulatory assets and liabilities are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months after each reporting period. All other regulatory asset and liability balances are classified as long-term on the balance sheets.

Allowance for funds used during construction

The OEB provides for the inclusion of an AFUDC when capitalizing construction-in-progress assets, until such time as the asset is substantially complete. A concurrent credit of the same amount is made to net financing charges when the allowance is capitalized. The interest rate for capitalization is prescribed by the OEB and modified on a

periodic basis, and is applied to the balance of the construction-in-progress assets on a simple interest basis. The interest rate for capitalization for the period from January 1, 2013 to September 30, 2013 was 3.23%, and from October 1, 2013 to December 31, 2013 was 3.70% [January 1, 2012 to March 31, 2012 - 3.92%; April 1, 2012 to September 30, 2012 - 3.51%; October 1, 2012 to December 31, 2012 - 3.23%]. AFUDC is included in PP&E and intangible assets for financial reporting purposes, and is recovered through depreciation and amortization expense over the useful lives of the related assets and recovered through future revenue.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition.

c) Accounts receivable

Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. The carrying amount of accounts receivable is reduced through an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statements of net income and comprehensive income. Subsequent recoveries of receivables previously provisioned and written off are credited to the statements of net income and comprehensive income. Management estimates uncollectible accounts receivable after considering historical loss experience and the characteristics of existing accounts.

d) Inventories

Inventories consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution system infrastructure to PP&E. As prescribed by the OEB, these items are depreciated when they are acquired. Inventories are carried at the lower of cost and market, with cost determined on an average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

PP&E are stated at cost. In accordance with group depreciation practices, assets in a group are not removed from the accounts on disposition and instead depreciation continues to be recorded until the asset group is fully depreciated. Readily identifiable assets are removed from the accounts at retirement or disposition. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, AFUDC, and overhead directly attributable to the capital project.

PP&E relating to eligible capital expenditures approved under the ICM framework for the 2012 and 2013 work program proposals are reclassified from construction in progress to regulatory assets once an asset is determined to be in-service, as directed by the OEB. The assets are then depreciated in the regulatory asset account over the estimated useful lives previously specified for PP&E. Upon final approval by the OEB and inclusion in LDC's rate base, the assets will be transferred back to PP&E.

Capital contributions received are used to finance additions to PP&E. According to the accounting principles prescribed by the OEB, capital contributions received are recorded as a credit to PP&E. The amount is subsequently depreciated by a charge to accumulated depreciation and a credit to depreciation expense at an equivalent rate to that used for the depreciation of the related PP&E.

Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution lines	2.0% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%

Stations	2.5% to 10.0%
Buildings	1.3% to 5.0%
Rolling stock	12.5% to 25.0%
Other capital assets	4.0% to 20.0%
Equipment and tools	10.0% to 16.7%
Computer hardware	16.7% to 25.0%
Assets under capital lease	14.3% to 25.0%
Communications	10.0% to 20.0%

Construction in progress relates to assets not currently in use and therefore is not depreciated.

In the event that facts and circumstances indicate that PP&E may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value, which is determined by the estimated future discounted cash flows.

f) Intangible assets

Effective January 1, 2012, LDC revised its estimate of useful life of its Customer Care and Billing Customer Information System from five years to ten years as a result of an analysis completed related to the useful life assessment. This change has been accounted for on a prospective basis in the financial statements effective January 1, 2012. The change in estimate reduced amortization expense by approximately $4,000,000 for the year ended December 31, 2012 with an offsetting increase in the carrying value of intangible assets. The change in estimate will decrease future amortization expense by $4,000,000 per year over the term of the original useful life with no impact to the final year of the original useful life, and thereafter increase future amortization expense by $4,000,000 per year.

Intangible assets are stated at cost. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to Hydro One Networks Inc. for dedicated infrastructure in order to receive connections to transmission facilities.

In the event that facts and circumstances indicate that intangible assets may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value, which is determined by the estimated future discounted cash flows.

g) Restructuring

Restructuring charges are recorded based upon planned employee termination dates, site closure and consolidation plans, and contract terminations. Restructuring charges can include severance costs to eliminate a specified number of employee positions, infrastructure charges to vacate facilities and consolidate operations, and contract cancellation costs. The timing of associated cash payments is dependent upon the type of restructuring charge and can extend over a multi-year period.

h) Revenue recognition

Revenue from the sale of electricity is recorded on the basis of cyclical billings and includes an estimated amount for electricity delivered and not yet billed, the amount of which is impacted by energy demand, customer class usage patterns and composition, and weather conditions. Revenue related to eligible capital expenditures under the ICM framework is recognized on the basis of in-service assets.

Other income, which includes revenues from electricity distribution related services and revenues from demand billable activities, is recognized as the services are rendered.

In the course of its operations, LDC collects HST from customers. When customers are billed, a current liability for HST is recognized which corresponds to the revenue derived from the services provided by LDC. When expenses are incurred by LDC, a current asset for HST is recorded which corresponds to the expenditures derived from the goods or services received by LDC. LDC's revenue and expenses exclude HST. This net asset or liability is settled with the appropriate government authority.

i) Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the statements of net income and comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by LDC. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

The following summarizes the accounting classification LDC has elected to apply to each of its significant categories of financial instruments:

Cash equivalents and short-term investments	Held for Trading
Accounts receivable and unbilled revenue	Loans and Receivables
Advance from related party	Other Financial Liabilities
Accounts payable and accrued liabilities	Other Financial Liabilities
Obligations under capital lease	Other Financial Liabilities
Customers' advance deposits	Other Financial Liabilities
Notes payable to related parties	Other Financial Liabilities

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash equivalents, comprising short-term investments, are classified as "Held for Trading" and are measured at fair value. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Advance from related party is classified as "Other Financial Liabilities" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amount approximates fair value because of the short maturity of this instrument.

- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are carried at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Obligations under capital lease are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying value as management believes that the fixed interest rates are representative of current market rates.

- Customers' advance deposits are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value because of the short maturity of the current portion, and the long-term portion approximates the carrying value, taking into account interest accrued on the outstanding balance.

- Notes payable to related parties are classified as "Other Financial Liabilities" and are initially measured at fair value. The carrying amounts are carried at amortized cost, based on an initial fair value as determined at the time using quoted market price for similar debt instruments. The fair value of the notes payable is calculated by discounting the related cash flows at the estimated yield to maturity of similar instruments [note 15[a]].

j) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included within level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

k) Employee future benefits

Multi-employer pension plan

LDC's full-time employees participate in a pension plan through OMERS. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The OMERS plan is accounted for as a defined contribution plan where LDC recognizes the expense related to this plan as contributions are made, since it is not practicable to determine LDC's portion of pension obligations or the fair value of plan assets. LDC is not responsible for any other contractual obligations other than the contributions.

Post-retirement benefits other than pension

LDC has a number of unfunded benefit plans providing post-retirement benefits (other than pension) to its employees. LDC pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on

behalf of its retired employees. LDC pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

LDC periodically measures its accumulated benefit obligation for accounting purposes as at December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2012.

The cost of providing benefits under the defined benefit plan is determined using the projected unit credit method and based on assumptions that reflect management's best estimates. All actuarial gains and losses and prior service costs are recognized in OCI as they arise and subsequently reclassified to a regulatory asset on the balance sheets. This results in the full recognition of the benefit obligation as a liability on the balance sheets.

Actuarial gains and losses are amortized into net periodic benefit cost for the current period when the net cumulative unrecognized actuarial gains or losses in the regulatory asset at the end of the previous reporting period exceed 10% of the accumulated benefit obligation at that date. These gains or losses are recognized over the expected average remaining service period of active employees participating in the plans.

The prior service costs in the regulatory asset are recognized as an expense on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The effects of a curtailment loss are recognized in the statements of net income and comprehensive income when its occurrence is probable and reasonably estimable. The effects of a curtailment gain are recognized in the statements of net income and comprehensive income when the related employees terminate or the plan suspension or amendment is adopted. The effects of a settlement gain or loss are recognized in the statements of net income and comprehensive income in the period in which a settlement occurs.

l) Asset retirement obligations

LDC recognizes a liability for the future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the capitalized amount is depreciated over the useful life of the related asset and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ["accretion expense"] and for changes in the underlying assumptions. The liability is recognized when the ARO is incurred and when the fair value can be reasonably estimated.

LDC has not recorded a liability related to certain AROs as a reasonable estimate of fair value could not be made. LDC does not recognize an ARO for active properties that support LDC's distribution operations since it cannot reasonably determine the amount of any remediation costs due to possible contamination, and a reliable estimate cannot be made until environmental site assessments have been completed. LDC expects to use the majority of its installed assets in perpetuity. If, at some future date, a particular asset is shown not to meet the perpetuity assumption, it will be reviewed to determine if an ARO exists.

m) Customers' advance deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. The electricity customer security deposits liability includes related interest amounts owed to the customers with the debit charged to net financing charges. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on Offers to Connect are cash collected from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with the debit charged to net financing charges. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

n) Income taxes

Under the Electricity Act, LDC is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying taxes similar to what would be imposed under the Federal and Ontario Tax Acts.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis, using the tax rates enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in an income tax return are recorded only when it is more likely than not that they will be realized, and are measured at the largest amount of the benefit that has a likelihood greater than 50 percent of being realized upon settlement. Deferred income tax assets are evaluated and unless realization is considered more likely than not, a valuation allowance is established.

ASC 980 requires the recognition of deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future electricity distribution rates. These amounts include a gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets. Deferred income taxes that are not included in the rate-setting process are charged or credited to the statements of net income and comprehensive income.

The benefits of the refundable apprenticeship and co-op ITCs are credited against the related expense in the statements of net income and comprehensive income. All other types of ITCs are recorded as a reduction to income tax expense in the current period to the extent that realization of such benefit is more likely than not.

o) Use of estimates

The preparation of LDC's financial statements in accordance with US GAAP requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as identifying and assessing the accounting treatment with respect to commitments and contingencies. Significant areas requiring the use of management estimates relate to unbilled revenue, regulatory assets and liabilities, ARO, post-retirement benefits, income taxes (including deferred income taxes), and revenue recognition. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy of Ontario, or the Ministry of Finance of Ontario.

p) Adoption of New Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities". The amendments require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the balance sheets. ASU No. 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. Retrospective application is required. The ASU No. 2013-01, "Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities", was issued in January 2013 to amend the scope of ASU No. 2011-11 to clarify that the disclosure requirements are limited to derivatives, repurchase and reverse repurchase agreements, and securities borrowing and lending transactions that are either offset in the balance sheets or subject to enforceable master netting arrangements

or similar agreements. The adoption of these amendments did not have an impact on LDC's balance sheets and related disclosures.

q) Future Accounting Pronouncements

On July 21, 2011, the OSC granted an exemption to allow the Corporation to prepare its financial statements in accordance with US GAAP for its fiscal years beginning on or after January 1, 2012 but before January 1, 2015. In the absence of the exemption, the Corporation would have previously been required to adopt IFRS on January 1, 2012. Accordingly, LDC decided to adopt US GAAP at the time to mirror the decision of the Corporation. On March 19, 2014, the Board of Directors of the Corporation approved the adoption of IFRS for the year beginning on January 1, 2015 due to the pending expiration of the exemption. Since the Corporation is converting to IFRS, on March 19, 2014 the Board of Directors of LDC also approved the adoption of IFRS for the year beginning on January 1, 2015. Accordingly, LDC's financial statements for 2015 are expected to be prepared in accordance with IFRS and applied retrospectively to LDC's opening IFRS statement of financial position as at January 1, 2014.

LDC has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. LDC believes that the impact on its financial statements could be material.

5. INVENTORIES

Inventories consist of the following:

	2013 $	2012 $
Fuses	2,498	2,137
Consumables, tools and other maintenance items	2,024	1,968
Drums and reels	1,473	1,115
Other	2,571	2,335
	8,566	7,555

For the year ended December 31, 2013, LDC recognized operating expenses of $6,936,000 related to inventory used to service electrical distribution assets [2012 - $6,934,000].

6. CURRENT PORTION OF OTHER ASSETS

Current portion of other assets consists of the following:

	2013 $	2012 $
Prepaid expenses	8,546	4,369
Deferred financing costs	308	311
	8,854	4,680

7. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	2013			2012		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	16,740	—	16,740	16,747	—	16,747
Distribution lines	3,064,167	1,519,944	1,544,223	2,930,296	1,460,979	1,469,317
Transformers	702,027	396,012	306,015	672,981	377,900	295,081
Meters	199,634	60,506	139,128	243,152	133,789	109,363
Stations	291,699	154,017	137,682	286,229	145,601	140,628
Buildings	172,306	76,793	95,513	160,368	69,248	91,120
Rolling stock	72,865	50,282	22,583	73,239	43,834	29,405
Other capital assets	73,420	51,728	21,692	70,291	47,561	22,730
Equipment and tools	47,711	36,191	11,520	45,611	33,936	11,675
Computer hardware	56,337	45,138	11,199	50,511	40,003	10,508
Assets under capital lease	13,723	4,836	8,887	13,538	2,948	10,590
Communications	33,092	28,498	4,594	32,082	26,597	5,485
Construction in progress	320,252	—	320,252	291,779	—	291,779
	5,063,973	2,423,945	2,640,028	4,886,824	2,382,396	2,504,428

For the year ended December 31, 2013, AFUDC in the amount of $1,306,000 [2012 - $94,000] was capitalized to PP&E and credited to net financing charges.

For the year ended December 31, 2013, capital contributions in the amount of $27,701,000 [2012 - $21,309,000] were credited to PP&E.

For the year ended December 31, 2013, LDC recorded depreciation expense of $144,375,000 [2012 - $119,393,000], of which $1,977,000 [2012 - $1,985,000] related to assets under capital lease and $21,537,000 [2012 - $nil] related to smart meter depreciation that had been deferred [note 9[c]].

8. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2013			2012		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Computer software	268,389	198,816	69,573	242,254	174,410	67,844
Contributions	22,181	3,077	19,104	19,649	2,175	17,474
Software in development	11,700	—	11,700	14,210	—	14,210
Contributions for work in progress	71,112	—	71,112	34,552	—	34,552
	373,382	201,893	171,489	310,665	176,585	134,080

Contributions for work in progress relate to payments made by LDC for connection projects to increase electricity distribution system capacity.

For the year ended December 31, 2013, AFUDC in the amount of $2,016,000 [2012 - $1,331,000] was capitalized to intangible assets and credited to net financing charges.

For the year ended December 31, 2013, LDC recorded amortization expense on intangible assets of $25,308,000 [2012 - $20,959,000], of which $7,196,000 [2012 - $nil] related to smart meter software amortization that had been deferred [note 9[c]].

Estimated future amortization expense related to intangible assets recorded as at December 31, 2013 is as follows:

	$
2014	19,306
2015	18,524
2016	17,029
2017	14,698
2018	10,748

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	2013 $	2012 $
ICM	151,930	—
Post-retirement benefits	38,781	61,499
Smart meters	25,230	55,599
Stranded meters	16,877	—
Settlement variances	8,227	1,071
RARA	—	2,466
Other	439	579
Total regulatory assets	241,484	121,214
Less: Current portion of regulatory assets	7,060	1,658
Long-term portion of regulatory assets	234,424	119,556

Regulatory liabilities consist of the following:

	2013 $	2012 $
Deferred income taxes	155,853	193,276
Revision of prior year tax position	19,421	—
RARA	4,277	—
Income and other taxes variance account	2,432	2,398
Other	1,150	1,135
Total regulatory liabilities	183,133	196,809
Less: Current portion of regulatory liabilities	2,516	—
Long-term portion of regulatory liabilities	180,617	196,809

For the year ended December 31, 2013, LDC disposed of approved net regulatory assets amounting to $153,000 through permitted distribution rate adjustments [2012 – approved net regulatory liabilities of $8,838,000].

The regulatory assets and liabilities of LDC consist of the following:

a) Incremental Capital Module

The ICM regulatory asset account relates to the partial decision and order from the OEB for LDC's 2012 and 2013 work program proposals and the associated rate rider, which became effective June 1, 2013 [note 3[a]]. As directed by the OEB, this account is comprised of the cost of the eligible in-service capital expenditures under ICM, offset by the amount collected through the rate rider. This account is also adjusted by the amount recognized into revenues related to the eligible in-service capital expenditures and their associated depreciation.

For the year ended December 31, 2013, eligible in-service capital expenditures of $159,672,000 [2012 - $nil] were reclassified from PP&E to regulatory assets. As a non-cash transaction, this has been excluded from the statements of cash flows. As at December 31, 2013, eligible in-service capital expenditures, net of accumulated depreciation, totalling $157,880,000, were recorded in regulatory assets [December 31, 2012 - $nil]. In the absence of rate regulation, PP&E would have been $157,880,000 higher at December 31, 2013 [December 31, 2012 - $nil impact].

For the year ended December 31, 2013, LDC recorded depreciation expenses of $1,792,000 [2012 - $nil] related to the eligible in-service capital expenditures.

For the year ended December 31, 2013, revenues related to the eligible in-service capital expenditures were $6,707,000 [2012 - $nil]. In the absence of rate regulation, for the year ended December 31, 2013, revenues would have been $5,925,000 higher [2012 - $nil impact].

b) Post-Retirement Benefits

This regulatory asset account relates to the expected future electricity distribution charges to customers arising from timing differences in the recognition of actuarial losses and prior service costs of other post-retirement benefits. In the absence of rate regulation, these amounts would be recorded in OCI and accumulated other comprehensive income. The amount is amortized over the same period as the corresponding actuarial losses and prior service costs. The period in which recovery is expected cannot be determined at this time.

c) Smart Meters and Stranded Meters

The smart meters and stranded meters regulatory assets relate to Ontario's decision to install smart meters throughout Ontario. LDC substantially completed its smart meter project as at December 31, 2010. In connection with this initiative, the OEB ordered LDC to record expenditures and related revenues from 2008 to 2010 to a regulatory asset account and allowed LDC to keep the net book value of the stranded meters in PP&E. Effective January 1, 2011, LDC has recorded post-2010 smart meter costs in PP&E and intangible assets as a regular distribution activity as directed by the OEB. On August 1, 2013, LDC filed an application with the OEB requesting approval for the disposition of balances in its smart meter deferral account related to smart meter installations in 2008, 2009 and 2010, and incremental revenue related to these assets. On January 16, 2014, the OEB approved LDC's request for incremental revenue and disposition of the smart meter deferral account balances [note 3[a]].

The OEB ruling on smart meters also permitted the recovery in principle of LDC's allowed cost of capital on smart meters since 2008, with a rate order issued to this effect. Accordingly, a new regulatory asset of $25,230,000 has been created to reflect the future amount to be recovered through rates, with a related amount recorded in revenue. For the year ended December 31, 2013, LDC ceased to defer operating and depreciation expenses related to the deployment of the 2008 to 2010 smart meters and recognized revenues as approved by the OEB, resulting in a decrease in the smart meters regulatory asset of $25,025,000, an increase in PP&E of $45,720,000, an increase in intangible assets of $1,066,000, an increase in revenues of $57,482,000, an increase in operating expenses of

$7,105,000, an increase in depreciation and amortization expenses of $28,733,000 and a decrease in net financing charges of $117,000.

The net book value of stranded meters related to the deployment of smart meters has been reclassified from PP&E to regulatory assets, resulting in an increase in regulatory assets of $17,362,000 and a decrease in PP&E of $17,362,000 as at December 31, 2013. Salvage proceeds of $485,000 have been applied to reduce the stranded meters regulatory asset account. LDC expects to apply to the OEB for recovery of the remaining stranded meters costs as part of its 2015 electricity distribution rates application.

In the absence of rate regulation, for the year ended December 31, 2013, revenues relating to smart meters and stranded meters would be $51,474,000 lower [2012 - $5,889,000 higher], operating expenses would be $7,105,000 lower [2012 - $nil impact] and depreciation and amortization expenses would be $25,461,000 lower [2012 - $3,518,000 higher].

d) Settlement Variances

This account is comprised of the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by LDC. The settlement variances relate primarily to service charges, non-competitive electricity charges and the global adjustment. Accordingly, LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. The balance for settlement variances continues to be calculated and attracts carrying charges in accordance with the OEB's direction.

For the year ended December 31, 2013, settlement variances included in the RARA of $nil were disposed through rate adjustments [2012 - $12,249,000].

e) Regulatory Assets Recovery Account

The RARA consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The RARA is subject to carrying charges following the OEB-prescribed methodology and related rates.

On February 22, 2011, the OEB approved the disposition of the Late Payment Penalties Settlement regulatory asset of $7,526,000, over a 21-month period commencing on August 1, 2011 and ending on April 30, 2013.

On April 2, 2013, the OEB approved the disposition of regulatory liabilities of $6,509,000, primarily consisting of PILs regulatory variance accounts, over an 11-month period commencing on June 1, 2013 and ending on April 30, 2014.

f) Deferred Income Taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred income tax assets [note 4[n]].

As at December 31, 2013, LDC recorded a deferred income tax asset and a corresponding regulatory liability of $155,853,000 [December 31, 2012 - $193,276,000] in respect to its rate-regulated activities that will be included in the rate-setting process.

g) Revision of Prior Year Tax Position

The revision of prior year tax position regulatory liability account relates to a favourable change to certain prior year tax positions based on reassessments received and in process, not reflected in electricity distribution rates charged to customers. As at December 31, 2013, the balance in this account consisted of an over-recovery of PILs from customers of $19,421,000 [December 31, 2012 - $nil].

h) Income and Other Taxes Variance Account

The income and other taxes variance regulatory liability account relates to the differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in applications for electricity distribution rates. As at December 31, 2013, the balance in this account consisted of an over-recovery of PILs from customers of $2,432,000 [December 31, 2012 - $2,398,000].

10. OTHER ASSETS

Other long-term assets consist of the following:

	2013 $	2012 $
Prepaid expenses	7,103	7,191
Deferred financing costs	905	907
	8,008	8,098

11. RESTRUCTURING

In the first quarter of 2012, the Corporation's Board of Directors approved a workforce restructuring program aimed at reducing operating expenditures for LDC. The program was approved following the decision by the OEB to deny the request of LDC to set its electricity distribution rates for 2012, 2013 and 2014 under the cost of service framework. In preparing its revised application using the IRM framework, LDC concluded that significant cost reductions were necessary to manage its business within the guidelines of the expected allowed electricity distribution rates provided by the IRM framework [note 3[a]]. The main component of these operating cost reduction initiatives was a workforce restructuring program, which included the severance of management employees and a voluntary exit incentive program for targeted unionized positions.

For the year ended December 31, 2013, costs incurred as a result of these operating cost reduction initiatives amounted to $nil [2012 - $27,796,000] and were comprised of ongoing termination charges of $nil and one-time termination incentive charges of $nil [2012 - $23,668,000 and $4,128,000, respectively], of which $nil remains unpaid as at December 31, 2013 [December 31, 2012 - $11,954,000].

12. NOTES PAYABLE TO RELATED PARTIES

Notes payable to related parties consist of the following:

	2013 $	2012 $
Notes payable to related parties:		
6.16% Long-term note payable to the Corporation due May 6, 2013	—	180,000
5.20% Long-term note payable to the Corporation due November 14,	245,058	245,058
4.54% Long-term note payable to the Corporation due November 12,	245,058	245,058
5.59% Long-term note payable to the Corporation due May 21, 2040	200,000	200,000
3.59% Long-term note payable to the Corporation due November 18,	300,000	300,000
2.96% Long-term note payable to the Corporation due April 10, 2023	250,000	—
4.01% Long-term note payable to the Corporation due April 9, 2063	200,000	—
6.16% Long-term note payable to the Corporation due May 6, 2013	—	245,058
6.16% Demand note payable to the Corporation due on demand	45,000	45,000
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	15,000	15,000
3.09% Demand note payable to TH Energy due on the earlier of dem and July 1, 2022	—	14,013
Total notes payable to related parties	1,500,116	1,489,187
Less: Unamortized discount/premium	6,917	4,938
Less: Current portion of notes payable to related parties	60,000	498,906
Long-term portion of notes payable to related parties	1,433,199	985,343

All notes payable to related parties of LDC rank equally.

On April 9, 2013, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $250,000,000, which bears interest at a rate of 2.96% per annum payable on April 10, 2023. Interest is calculated and payable semi-annually in arrears on October 10 and April 10 of each year.

On April 9, 2013, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200,000,000, which bears interest at a rate of 4.01% per annum payable on April 9, 2063. Interest is calculated and payable semi-annually in arrears on October 9 and April 9 of each year.

The net proceeds of the promissory notes were mainly used to repay LDC's notes payable to the Corporation which matured on May 6, 2013.

13. EMPLOYEE FUTURE BENEFITS

Pension

LDC's full-time employees participate in a pension plan through OMERS. The plan assets are pooled together to provide benefits to plan participants and are not segregated in separate accounts for each member entity. As at December 31, 2013, the OMERS plan was 88% funded, with a funding deficit of approximately $3,600,000,000. For the year ended December 31, 2013, the total contributions of all participating employers and employees were approximately $3,500,000,000. For the year ended December 31, 2013, LDC's contributions were $18,102,000 [2012 - $16,374,000], representing less than one percent of total contributions to the plan.

For 2013, OMERS contribution rates were 9.0% up to the year's maximum pensionable earnings ["YMPE"] and 14.6% over YMPE for normal retirement age of 65 [2012 – 8.3% up to YMPE and 12.8% over YMPE for normal retirement age of 65].

As at December 31, 2012, OMERS had approximately 266,000 active members. As at December 31, 2013, approximately 1,500 members [December 31, 2012: 2,700] had a current relationship with LDC.

Post-retirement benefits other than pension

a) Benefit Obligations

	2013 $	2012 $
Balance, beginning of year	253,890	244,326
Service cost	4,816	5,035
Interest cost	10,570	11,454
Benefits paid	(10,432)	(8,069)
Actuarial (gain) loss	(20,230)	254
Transfer from related parties	178	890
Balance, end of year	238,792	253,890

On February 13, 2014, LDC's unionized workforce ratified a collective agreement to expire at the end of January 2018. The agreement does not contain terms that create a retirement benefits liability in respect of past service.

b) Amounts recognized in regulatory assets

	2013 $	2012 $
Actuarial loss	38,767	61,477
Prior service cost	14	22
Total recognized in regulatory assets [note 9]	38,781	61,499

As at December 31, 2013, the estimated actuarial loss and prior service cost that are expected to be amortized from regulatory asset to net periodic benefit cost in 2014 are $909,000 and $nil, respectively.

c) Components of net periodic benefit costs

	2013 $	2012 $
Service cost	4,816	5,035
Interest cost	10,570	11,454
Amortization of actuarial loss	2,064	3,146
Amortization of prior service cost	2	840
Net periodic benefit cost	17,452	20,475
Capitalized as part of PP&E	6,623	7,305
Charged to operations	10,829	13,170

d) Expected benefit payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid over the next five years, and in the aggregate for the five fiscal years thereafter:

	Post-retirement Benefits $
2014	8,191
2015	8,403
2016	9,090
2017	9,541
2018	10,112
2019-2023	59,394

e) Significant assumptions

	2013 %	2012 %
Accrued benefit obligation as at December 31:		
Discount rate	4.75	4.25
Benefit costs for years ended December 31:		
Discount rate	4.25	4.75
Assumed health care cost trend rates as at December 31:		
Rate of increase in dental costs assumed for next year	4.00	4.00
Rate of increase in medical costs assumed for next year		
For pre July 2000 retirements	6.00	6.50
For other retirements	7.50	8.00
Rate that medical cost trend rate gradually declines to		
For pre July 2000 retirements	5.00	5.00
For other retirements	5.00	5.00
Year that the medical cost trend rate reaches the ultimate trend rate		
For pre July 2000 retirements	2016	2016
For other retirements	2019	2019

f) Sensitivity analysis

Assumed medical and dental care cost trend rates have a significant effect on the amounts reported for medical and dental care plans. A one-percentage-point change in assumed medical and dental care cost trend rates would have the following effects for 2013:

	Increase $	Decrease $
Total of current service and interest cost (at 4.25%)	2,327	(2,046)
Accrued benefit obligation as at December 31, 2013 (at 4.75%)	30,388	(26,664)

Assumed interest rates have a significant effect on the amounts reported for the total accrued benefit obligation and expense. A one-percentage-point change in assumed interest rates would have the following effects:

	Increase $	Decrease $
Accrued benefit obligation as at December 31, 2013	(37,041)	45,469
Estimated net periodic benefit cost for 2014	(1,713)	2,937

14. ASSET RETIREMENT OBLIGATIONS

The reconciliation between the opening and closing ARO liability balances is as follows:

	2013 $	2012 $
Balance, beginning of year	5,004	4,831
ARO liabilities settled in the year	(573)	(313)
Accretion expense	177	170
Revision in estimated cash flows	1,639	316
Balance, end of year	6,247	5,004

15. FINANCIAL INSTRUMENTS

a) Recognition and measurement

As at December 31, 2013 and December 31, 2012, the fair values of cash and cash equivalents, net accounts receivable, unbilled revenue, advance from related party, and accounts payable and accrued liabilities approximate their carrying values due to the short maturity of these instruments [note 4[i]]. The fair values of customers' advance deposits approximate their carrying values taking into account interest accrued on the outstanding balance. Obligations under capital lease are measured based on a discounted cash flow analysis and approximate the carrying value as management believes that the fixed interest rates are representative of current market rates.

The carrying value and fair value of LDC's notes payable consist of the following:

	2013 $		2012 $	
	Carrying value	Fair value [1]	Carrying value	Fair value [1]
Long-term notes payable to the Corporation				
6.16% due May 6, 2013	—	—	179,835	182,999
5.20% due November 14, 2017	244,453	269,601	244,316	278,314
4.54% due November 12, 2019	244,089	265,186	243,948	274,786
5.59% due May 21, 2040	198,747	226,700	198,727	256,357
3.59% due November 18, 2021	298,511	302,837	298,352	316,935
2.96% due April 10, 2023	248,701	232,888	—	—
4.01% due April 9, 2063	198,698	172,863	—	—
6.16% due May 6, 2013	—	—	245,058	249,174
Demand note payable to the Corporation due on demand	45,000	45,000	45,000	45,754
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	15,000	15,000	15,000	15,489
Demand note payable to TH Energy due on the earlier of demand and July 1, 2022	—	—	14,013	14,043

[1] The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy.

b) Financial Risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

LDC is exposed to a variety of financial risks, particularly credit risk, interest rate risk and liquidity risk.

Credit risk

LDC is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. LDC's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. LDC monitors and limits its exposure to credit risk on a continuous basis.

LDC's credit risk associated with accounts receivable is primarily related to electricity bill payments from customers. LDC has approximately 730,000 customers. LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2013, LDC held security deposits in the amount of $44,649,000 [December 31, 2012 - $46,088,000], of which $22,211,000 [December 31, 2012 - $25,666,000] were related to security deposits on Offers to Connect to guarantee the payment of additional costs relating to expansion projects. As at December 31, 2013, there were no significant concentrations of credit risk with respect to any customer.

LDC did not have any single customer that generated more than 10% of total revenues for the years ended December 31, 2013 and December 31, 2012.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2013 $	2012 $
Unbilled revenue	326,111	274,272
Accounts receivable		
Outstanding for not more than 30 days	175,124	164,523
Outstanding for more than 30 days and not more than 120 days	22,791	18,214
Outstanding for more than 120 days	11,874	13,772
Less: Allowance for doubtful accounts	(10,766)	(10,568)
Total accounts receivable, net	199,023	185,941
Total accounts receivable and unbilled revenue	525,134	460,213

Reconciliation between the opening and closing allowance for doubtful accounts balances is as follows:

	2013 $	2012 $
Balance, beginning of year	(10,568)	(12,810)
Provision for doubtful accounts	(7,805)	(6,590)
Write-offs	8,130	9,242
Recoveries	(523)	(410)
Balance, end of year	(10,766)	(10,568)

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered current and no allowance for doubtful accounts had been provided as at December 31, 2013 and December 31, 2012.

The credit risk related to cash, cash equivalents and investments is mitigated by LDC's treasury policies on assessing and monitoring the credit exposures of counterparties. LDC's maximum exposure to credit risk is approximately equal to the carrying value of its financial assets.

Interest rate risk

LDC is exposed to fluctuations in interest rates for the valuation of its post-retirement benefit obligations [Note 13[f]]. LDC is also exposed to short-term interest rate risk on the net of cash and cash equivalents, advances from related party, and customers' advance deposits. LDC manages interest rate risk by monitoring the mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance. Advances from related party bear interest based on the prevailing market conditions at the time of issuance.

As at December 31, 2013, aside from the valuation of its post-retirement benefit obligations, LDC was exposed to interest rate risk predominately from advances from the Corporation, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. LDC estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $1,800,000 to annual net financing charges.

Liquidity risk

LDC is exposed to liquidity risk related to its ability to fund its obligations as they become due. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily. LDC's

objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing net financing charges.

Liquidity risks associated with financial commitments are as follows:

December 31, 2013						
	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Financial liabilities						
Advance from related party	150,000	—	—	—	—	—
Accounts payable and accrued liabilities	455,752	—	—	—	—	—
Obligations under capital lease	2,537	2,537	2,537	2,537	1,270	—
Long-term notes payable to the Corporatio						
5.20% due November 14, 2017	—	—	—	245,058	—	—
4.54% due November 12, 2019	—	—	—	—	—	245,058
5.59% due May 21, 2040	—	—	—	—	—	200,000
3.59% due November 18, 2021	—	—	—	—	—	300,000
2.96% due April 10, 2023	—	—	—	—	—	250,000
4.01% due April 9, 2063	—	—	—	—	—	200,000
Demand note payable to the Corporation o on demand	45,000	—	—	—	—	—
Demand note payable to the Corporation o on the earlier of demand and January 2022	15,000	—	—	—	—	—
Interest payments on long-term not payable and demand notes payable[(1)]	50,466	61,239	61,239	61,239	48,496	673,996
	718,755	63,776	63,776	308,834	49,766	1,869,054

(1) The "Due within 1 year" column excludes $10,773,000 of interest on long-term notes payable and demand notes payable that was accrued as at December 31, 2013.

Foreign exchange risk

As at December 31, 2013, LDC had limited exposure to changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions is not material to the financial statements.

16. FINANCIAL ASSISTANCE

As at December 31, 2013, $48,388,000 [December 31, 2012 - $48,388,000] was utilized under the Corporation's demand credit facility in the form of letters of credit to satisfy the prescribed prudential requirements of LDC with the IESO for the purchase of electricity. As at December 31, 2013, an additional amount of $761,000 [December 31, 2012 - $761,000] was utilized for the Ministry of Finance of Ontario, and $905,000 [December 31, 2012 - $nil] was utilized to satisfy requirements of the City in relation to Copeland Station.

17. INCOME TAXES

LDC's effective tax rate for the year ended December 31, 2013 was 2.63% [2012 – 3.62%]. Income tax expense for the year ended December 31, 2013 was $3,123,000 [2012 - $3,125,000]. The effective tax rate and income tax

expense for the year ended December 31, 2013 were lower than those for the year ended December 31, 2012 due to changes in permanent and temporary differences between accounting and tax treatments.

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and Ontario income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

Statements of Net Income and Comprehensive Income

	2013 $	2012 $
Rate reconciliation		
Income before income taxes	118,862	86,314
Statutory Canadian federal and provincial income tax rate	26.50%	26.50%
Expected income tax expense	31,498	22,873
Temporary differences not benefited	(20,186)	(16,133)
Change in unrecognized tax benefits	(5,051)	(1,771)
Impact of change in expected future tax rate on existing deferred incon balances	—	(923)
Other	(3,138)	(921)
Income tax expense	3,123	3,125
Effective tax rate	2.63%	3.62%
Components of income tax expense		
Current tax	5,265	6,011
Deferred income tax related to the origination and reversal of temporary differences	(48)	(245)
Non-refundable ITCs	(2,094)	(2,641)
Income tax expense	3,123	3,125

Balance Sheets

Significant components of LDC's deferred income tax assets are as follows:

	2013 $	2012 $
PP&E and intangible assets	64,518	82,604
Post-retirement benefits liability	53,003	50,667
Regulatory adjustments	41,301	51,218
Other taxable temporary differences	(2,955)	8,753
Deferred income tax assets	155,867	193,242

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2013 $	2012 $
Balance, beginning of year	5,274	7,045
Increases for tax positions taken in the current year	18	248
Decreases for tax positions taken in prior years	(1,603)	(38)
Settlements with tax authorities	(3,466)	(1,981)
Balance, end of year	223	5,274

As at December 31, 2013, $223,000 of unrecognized tax benefits [December 31, 2012 - $274,000] would have a favourable effect on the effective tax rate, if recognized. No interest and penalties have been accrued, since LDC is of the view that none are expected to be payable. During the next 12 months, unrecognized tax benefits are not expected to significantly change.

As at December 31, 2013, LDC's tax years currently open to examination by tax authorities include 2007 and subsequent years. Other than in respect of the fair market revaluation of LDC's assets on October 1, 2001 pursuant to Section 7 of Ontario Regulation 162/01 of the Electricity Act, tax years prior to 2007 are closed to further examination.

18. SHARE CAPITAL

Share capital consists of the following:

	2013 $	2012 $
Authorized		
The authorized share capital of LDC consists of an unlimited number of common shares without par value		
Issued and outstanding		
1,000 common shares	556,278	556,278

Dividends

For the year ended December 31, 2013, the Board of Directors of LDC declared and paid dividends totalling $40,000,000 [2012 - $nil] to the Corporation.

19. RELATED PARTY TRANSACTIONS

For LDC, transactions with related parties include transactions with the City, which wholly owns the Corporation, the Corporation and TH Energy, a wholly-owned subsidiary of the Corporation. All transactions with related parties are conducted on terms similar to those offered to unrelated parties.

2013	City $	Corporation $	TH Energy $
Revenues	235,846	—	340
Operating expenses (recoveries) and capital expenditures	31,859	3,137	(863)
Net financing charges	—	69,136	270
Dividends	—	40,000	—
Accounts receivable	2,131	—	—
Unbilled revenue	19,425	—	—
Advance from related party	—	150,000	—
Accounts payable and accrued liabilities	45,152	11,565	—
Current portion of notes payable to related parties	—	60,000	—
Long-term portion of notes payable to related parties	—	1,433,199	—
Advance deposits	8,816	—	—

2012	City $	Corporation $	TH Energy $
Revenues	210,835	—	324
Operating expenses (recoveries) and capital expenditures	26,232	3,035	(1,029)
Net financing charges	—	75,303	433
Accounts receivable	5,603	—	14,271
Unbilled revenue	4,350	—	9,268
Accounts payable and accrued liabilities	38,013	11,426	433
Current portion of notes payable to related parties	—	484,893	14,013
Long-term portion of notes payable to related parties	—	985,343	—
Advance deposits	8,926	—	—

Revenues represent amounts charged to the City primarily for electricity, street lighting and ancillary services, and TH Energy for demand billable services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, and the Corporation for purchased corporate and management services. Operating expense recoveries represent amounts charged to TH Energy for the provision of goods and services. Net financing charges represent interest charged by the Corporation and TH Energy on the advances and notes payable [note 12]. Dividends are paid to the Corporation [note 18].

Accounts receivable represent receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services, including electricity billing activities. Unbilled revenue represents receivables from the City and TH Energy related to electricity provided and not yet billed. Advance from related party represents amounts payable to the Corporation for short-term borrowings obtained under the Corporation's revolving credit facility and commercial paper program. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services, as well as amounts received from the City for the construction of electricity distribution assets. Included in the accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on the notes payable to the Corporation and TH Energy. Notes payable to related parties represent amounts borrowed from the Corporation and TH Energy [note 12]. Advance deposits represent amounts received from the City for future expansion projects.

On January 1, 2012, certain electricity distribution assets of TH Energy were transferred to LDC through a newly created wholly-owned legal entity (1798594 Ontario Inc.) of the Corporation. Immediately thereafter, the new legal entity was amalgamated with LDC. The transfer was completed for a purchase price of $28,460,000, with a post closing adjustment of $14,013,000. The transfer was initially financed with share capital issued by the new wholly-owned legal entity to the Corporation. Subsequently, LDC issued an intercompany note payable to TH Energy for the increase in the purchase price. On August 16, 2013, the principal amount of the note was repaid to TH Energy.

20. COMMITMENTS

Operating leases and capital projects

As at December 31, 2013, the future minimum annual payments under property operating leases, capital projects and other commitments with remaining terms from one to five years and thereafter were as follows:

	Operating leases $	Capital projects [2] and other $
2014	6,175	79,797
2015	6,186	2,772
2016	5,784	—
2017	2,123	—
2018	—	—
Thereafter	—	—
Total amount of future minimum payments [1]	20,268	82,569

[1] Refer to note 15 for repayments of notes payable and advance from related party excluded from the table above.
[2] Reflects capital project commitments for construction services and estimated capital contributions, with the majority related to Copeland Station.

LDC has the option to renew its two major property operating leases at the end of the current lease term for an additional five years at the then fair rental value.

Operating lease expense for the year ended December 31, 2013 was $6,132,000 [2012 - $6,547,000].

Subsequent to December 31, 2013, LDC entered into capital commitments of approximately $21,000,000 for capital contributions payable to Hydro One Networks Inc. over the next year in respect of Copeland Station.

Capital leases

As at December 31, 2013, the future minimum annual lease payments under capital leases with remaining lease terms from one to five years and thereafter were as follows:

	$
2014	2,537
2015	2,537
2016	2,537
2017	2,537
2018	1,270
Thereafter	—
Total amount of future minimum lease payments	11,418
Less: interest and executory costs	1,143
	10,275
Current portion included in Other liabilities	2,100
Long-term portion included in Other liabilities	8,175

21. CONTINGENCIES

a) Legal Proceedings

In the ordinary course of business, LDC is subject to various legal actions and claims with customers, suppliers, former employees and other parties. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and loss. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with these actions.

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the Class Proceedings Act, 1992 (Ontario) seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. This action is at a preliminary stage. The statement of claim has been served on LDC, a statement of defence and third party claim have been served by LDC and a third party defence and counterclaim against LDC seeking damages in the amount of $51,000,000 have been filed. A certification order has been issued. Affidavits of documents have been produced by LDC to the other parties and examinations for discovery have commenced and are continuing. A mediation took place on January 15, 2014 and the parties have agreed to settle the action of the class plaintiffs by the payment by LDC of the total amount of $6,527,000, including all taxes and legal fees, subject to approval by the Ontario Superior Court of Justice. LDC will make a claim under its liability insurance which LDC believes will cover the settlement payment. A settlement approval hearing will be scheduled. If the settlement is approved by the court, the main action commenced by the class plaintiffs will be dismissed without costs, however the claims, counterclaims and third party claims amongst the various defendants to the class action will continue. Given the preliminary status of the remaining unsettled actions, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with the action.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2,000,000 as a result of the fire at 2 Secord Avenue. A statement of defence and a third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with the action.

By order of the court dated January 24, 2012, the above actions and a smaller non-class action commenced in April 2009 involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the Class Proceedings Act, 1992 (Ontario) seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks general damages in the amount of $10,000,000 and special damages in the amount of $20,000,000 from LDC. The proposed class action is at a preliminary stage. The plaintiff cancelled its certification motion set for November 2013 and advised it intends to reschedule. Cross-examinations for a certification motion have commenced, but have not been completed. Statements of defence to the main action and to the third party claim have not been filed. Given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with these actions.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2,000,000 as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of LDC. If damages were awarded, LDC would make a claim under its liability insurance which LDC believes would cover any damages which may become payable by LDC in connection with the action.

b) OEB PILs Proceeding

The OEB conducted a review of the PILs variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain MEUs. On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts.

LDC reviewed the balance of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. LDC applied for disposition of the balance as part of its IRM/ICM Application filed on May 10, 2012. The OEB issued its decision and order on April 2, 2013 approving the disposition of the balance. The impact was recorded previously in LDC's financial statements.

22. NET FINANCING CHARGES

Net financing charges consist of the following:

	2013 $	2012 $
Interest income	2,196	895
Interest expense		
Long-term debt[1]	(70,359)	(76,596)
Other interest	(4,029)	(2,833)
AFUDC	3,322	2,325
	(68,870)	(76,209)

(1) Includes amortization of debt issuance costs, premiums and discounts.

23. STATEMENTS OF CASH FLOWS

Changes in non-cash working capital provided/(used) cash as follows:

	2013 $	2012 $
Accounts receivable	(13,082)	5,515
Unbilled revenue	(51,839)	(11,983)
Income tax receivable	4,368	3,974
Inventories	(1,011)	(664)
Other current assets	(4,174)	(276)
Accounts payable and accrued liabilities	44,845	(9,356)
Restructuring accrual	(11,954)	11,954
Deferred conservation credit	112	6,298
Other current liabilities	195	(332)
	(32,540)	5,130

The reconciliation between total additions to PP&E and the amount presented on the statements of cash flows after factoring in the non-cash additions is as follows:

	2013 $	2012 $
Purchase of PP&E, cash basis	355,232	302,198
Net change in accruals related to PP&E	32,959	(12,131)
Capital lease additions	305	—
ARO additions	1,669	377
Capitalized overhead costs	2,315	1,620
Total additions to PP&E	392,480	292,064

24. Comparative Figures

Certain comparative figures have been reclassified from financial statements previously presented to conform to the presentation of the 2013 financial statements. During the fourth quarter of 2013, LDC changed its presentation of the statements of cash flows for the net change in regulatory assets and liabilities from investing activities to operating activities. Prior year comparatives have been retrospectively reclassified with $14,581,000 previously presented as investing activities for the year ended December 31, 2012 reclassified to operating activities.

RECONCILIATIONS

In accordance with section 2.4.3 of the OEB's Filing Requirements (July 17, 2013), this schedule provides reconciliations of the financial results shown in the Audited Financial Statements with the regulatory financial results filed under Section 2.1.13 of the OEB's Reporting and Record Keeping Requirements for years 2011 through 2013:

- Appendix A: 2011 Reconciliation;
- Appendix B: 2012 Reconciliation; and
- Appendix C: 2013 Reconciliation.

Toronto Hydro-Electric System Limited
Statements of Income
Year ended December 31, 2011

	THESI Consolidated Audited 2011 ($,000s) (1)	Unregulated Business ($,000s) (2)	Consolidation Adjustment ($,000s) (3)	Calculated THESI Regulated Business ($,000s) (4)=(1)-(2)-(3)	RRR Filing ($) (5)	RRR Filing ($,000s) (6)	Difference ($,000s) (7)=(4)-(6)	Notes
Revenues								
Sale of electricity	2,766,714			2,766,714	2,365,031,768	2,365,032	401,682	1 & 2
Other income	24,931	665		24,266	27,316,805	27,317	(3,050)	4
	2,791,645	665	0	2,790,980	2,392,348,573	2,392,349	398,632	
Costs								
Purchased power	2,236,541			2,236,541	1,834,492,283	1,834,492	402,049	2
Operating expenses	235,643	1,881		233,762	239,201,377	239,201	(5,438)	3 & 4
Depreciation and amortization	146,505	67		146,438	146,438,503	146,439	(0)	
	2,618,689	1,947	0	2,616,742	2,220,132,162	2,220,132	396,610	
Income before the following:	172,956	(1,283)	0	174,239	172,216,411	172,217	2,022	
Net financing charges	74,478	25		74,503	72,098,869	72,099	2,404	1 & 3
Gain on disposals of property, plant and equipment	3,885			3,885	3,885,315	3,885	(0)	
Income before provision for payments in lieu of corporate taxes	102,363	(1,258)	0	103,621	104,002,857	104,003	(382)	
Provision for payments in lieu of corporate taxes	9,032			9,032	9,031,912	9,032		0
Net income	93,331	(1,258)	0	94,589	94,970,945	94,971	(382)	

Notes:

Note 1: HST Adjustment: In the Financial statement, THESI has booked the HST to the HST / OVAT Input Tax Credits (ITCs) variance account with offset entry to distribution revenue. For RRR Reporting, THESI has booked HST to the HST / OVAT Input Tax Credits (ITCs) variance account with offset entry to HST/OVAT Contra Account accounts as per the OEB guidelines. The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,118k, Distribution Revenue (Cr.) $367k, Misc. Interest (Cr.) $15k and Retained Earning (Cr.) 736k.

Note 2: Global Adjustment (GA): Per Corporate Accounting Policy "GA Charge for Regulated Price Plan (RPP) Customers" for regulatory reporting COP expense and COP revenues shall exclude the GA COP charge for RPP customers. The adjustment is a decrease to COP expense and a decrease to COP revenue in the amount of $402,049k.

Note 3: $2,388k towards Financing Cost ($1,967k) and interest on customer advance deposits ($421k) are reclass to OM&A for the RRR.

Note 4: Special Purpose Charge (SPC) In the Audited Financial Statements (AFS) THESI had ($3,050k) as SPC recovered balances For the purpose of OEB RRR filing, the SPC recovery is booked in OEB account 4324 " Special Purpose Charge Recovery" and the SPC expense is booked in OEB account 5681 "Special purpose charge expense".

Toronto Hydro-Electric System Limited
Balance Sheet
As at December 31, 2012

	THESI Consolidated Audited 2012 ($,000s) (1)	Unregulated Business ($,000s) (2)	Consolidation Adjustment ($,000s) (3)	Calculated THESI Regulated Business ($,000s) (4)=(1)-(2)-(3)	RRR Filing ($) (5)	RRR Filing ($,000s) (6)	Difference ($,000s) (7)=(4)-(6)	Notes
ASSETS								
Current								
Cash and cash equivalents	67,258	10,654		56,604	56,603,702	56,604	0	
Accounts receivable, net of allowance for doubtful accounts	185,941	4,834	(1,237)	182,344	182,343,659	182,344	0	
Unbilled revenue	274,272	390		273,882	273,882,054	273,882	0	
Income tax receivable	4,710			4,710	4,710,484	4,710	0	
Inventories	7,555			7,555	7,555,372	7,555	0	
Regulatory assets	1,658			1,658	1,658,482	1,658	0	
Other assets	4,680			4,680	4,679,517	4,680	0	
Total current assets	546,074	15,879	(1,237)	531,433	531,433,271	531,433	0	
Property, plant and equipment, net	2,504,428	49,663		2,454,765	2,454,764,876	2,454,765	0	
Intangible assets net	134,080			134,080	134,080,101	134,080	0	
Regulatory assets	119,556			119,556	120,690,375	120,690	(1,134)	1
Other assets	8,098			8,098	8,097,653	8,098	0	
Deferred income tax assets	193,242			193,242	193,241,713	193,242	0	
Total assets	3,505,478	65,542	(1,237)	3,441,174	3,442,307,988	3,442,308	(1,134)	
LIABILITIES AND SHAREHOLDER'S EQUITY								
Current								
Accounts payable and accrued liabilities	377,948	4,835	(1,238)	374,351	374,351,769	374,352	0	
Restructuring accrual	11,954	9		11,945	11,945,063	11,945	0	
Customers advance deposits	40,048			40,048	40,048,468	40,048	0	
Deferred conservation credit	19,908	19,111		797	797,028	797	0	
Post-retirement benefits	9,925	19		9,906	9,906,000	9,906	0	
Other liabilities	1,850			1,850	1,849,683	1,850	0	
Notes payable to related party	179,835			179,835	179,834,837	179,835	0	
Promissory notes payable to related party	319,071	14,013		305,058	305,057,739	305,058	0	
Total current liabilities	960,539	37,987	(1,238)	923,790	923,790,588	923,791	0	
Notes payable to related party	985,343			985,343	985,342,797	985,343	0	
Customers advance deposits	6,790			6,790	6,789,737	6,790	0	
Post-retirement benefits	243,965	1,090		242,875	242,875,000	242,875	0	
Other liabilities	9,385			9,385	9,384,708	9,385	0	
Regulatory liabilities	196,809			196,809	196,808,949	196,809	0	
Asset retirement obligations	5,004			5,004	5,004,223	5,004	0	
Total liabilities	2,407,835	39,077	(1,238)	2,369,996	2,369,996,002	2,369,996	0	
Shareholder's equity								
Share capital	556,278	28,461		527,817	527,816,668	527,817	0	
Retained earnings	528,608	(1,996)		530,604	531,737,926	531,738	(1,134)	1
Contributed surplus	12,757			12,757	12,757,392	12,757	0	
Total shareholder's equity	1,097,643	26,465	0	1,071,178	1,072,311,986	1,072,312	(1,134)	
Total liabilities and shareholder's equity	3,505,478	65,541	(1,238)	3,441,175	3,442,307,988	3,442,308	(1,133)	

Notes:
HST Adjustment: In the Financial Statement, THESI has booked the HST to the HST / OVAT Input Tax Credits (ITCs) variance account with offset entry to interest expenses For RRR Reporting, THESI has booked HST to the HST / OVAT Input Tax Credits (ITCs) variance account with offset entry to HST/OVAT Contra Account accounts as per the OEB guidelines. The amount for 2011 is $1,118k and 2012 is $16k. The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,134k, Misc. Interest (Cr.) $16k and Retained Earning (Cr.) 1,118k.

Toronto Hydro-Electric System Limited
Statements of Net Income and Comprehensive Income
Year ended December 31, 2012

	THESL Consolidated Audited 2012 ($,000s) (1)	Unregulated Business ($,000s) (2)	Consolidation Adjustment ($,000s) (3)	Calculated THESL Regulated Business ($,000s) (4)=(1)-(2)-(3)	RRR Filing ($) (5)	RRR Filing ($,000s) (6)	Difference ($,000s) (7)=(4)-(6)	Notes
Revenues								
Sale of electricity	2,799,404			2,799,404	2,313,394,881	2,313,395	486,009	2
Other income	41,057	6,056		35,001	17,424,906	17,425	17,576	3
	2,840,461	6,056	0	2,834,405	2,330,819,787	2,330,820	503,585	
Costs								
Purchased power	2,275,209			2,275,209	1,789,200,443	1,789,200	486,009	2
Operating expenses	236,386	4,436		231,950	214,373,410	214,373	17,576	3
Depreciation and amortization	140,352	1,843		138,509	138,508,981	138,509	0	
	2,651,947	6,278	0	2,645,668	2,142,082,834	2,142,083	503,585	
Income before the following:	188,514	(222)	0	188,736	188,736,952	188,737	(0)	
Net financing charges	76,209	272	r	75,937	75,921,365 r	75,921	r (16) r	1
Gain on disposals of property, plant and equipment	1,805			1,805	1,804,779	1,805	0	
Restructuring costs	27,796	146	r	27,650	27,650,803 r	27,651	r 0 r	
Income before income taxes	86,314	(640)	0	86,954	86,969,563	86,969	(16)	
Income tax expense	3,125			3,125	3,125,406	3,125	(0)	
Net income and comprehensive income	83,189	(640)	0	83,829	83,844,157	83,844	(16)	

Notes:

Note 1: HST Adjustment: In the Financial statement, THESL has booked the HST to the HST / OVAT Input Tax Credits (ITCs) variance account with offset entry to interest expenses. For RRR Reporting, THESL has booked HST to the HST / OVAT Input Tax Credits (ITCs) variance account with offset entry to HST/OVAT Contra Account account as per the OEB guidelines. The amount for 2011 is $1,118k and 2012 is $16k. The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,134k, Misc. Interest (Cr.) $16k and Retained Earning (Cr.) 1,118k.

Note 2: Global Adjustment (GA): Per Corporate Accounting Policy "GA Charge for Regulated Price Plan (RPP) Customers" for regulatory reporting COP expense and COP revenue shall exclude the GA COP charge for RPP customers. The "adjustment" is a decrease to COP expense and a decrease to COP revenue in the amount of $486,009k.

Note 3: Demand Billable Charges: As per USGAAP, THESL book demand billable charges on gross based while for RRR it is shown on net bases.

Toronto Hydro-Electric System Limited
Balance Sheet
As at December 31, 2013

	THESI Consolidated Audited 2013 ($,000s) (1)	Unregulated Business ($,000s) (2)	Consolidation Adjustment ($,000s) (3)	Calculated THESI Regulated Business ($,000s) (4)=(1)-(2)-(3)	RRR Filing ($) (5)	RRR Filing ($,000s) (6)	Difference ($,000s) (7)=(4)-(6)	Notes
ASSETS								
Current								
Cash and cash equivalents	15,677	1,673		14,004	14,003,466	14,003	0	
Accounts receivable, net of allowance for doubtful accounts	199,023	449	(238)	198,812	198,811,870	198,812	0	
Unbilled revenue	326,111	743		325,368	325,368,045	325,368	0	
Income tax receivable	342			342	341,830	342	0	
Inventories	8,566			8,566	8,566,175	8,566	0	
Regulatory assets	7,060			7,060	7,060,239	7,060	0	
Other assets	8,854			8,854	8,853,920	8,854	0	
Total current assets	565,633	2,865	(238)	563,006	563,005,543	563,006	0	
Property, plant and equipment, net	2,640,028	48,949		2,591,079	2,591,078,651	2,591,079	0	
Intangible assets, net	171,489			171,489	171,489,231	171,489	0	
Regulatory assets	234,424			234,424	204,279,550	204,280	30,144	1
Other assets	8,008			8,008	8,008,086	8,008	0	
Deferred income tax assets	155,867			155,867	155,867,403	155,867	0	
Total assets	3,775,449	51,814	(238)	3,723,873	3,693,728,464	3,693,728	30,144	
LIABILITIES AND SHAREHOLDER'S EQUITY								
Current								
Advance from related party	150,000			150,000	150,000,000	150,000	0	
Accounts payable and accrued liabilities	455,752	4,188	(238)	451,802	471,222,890	471,223	(19,421)	2
Customers' advance deposits	37,293			37,293	37,293,279	37,293	0	
Deferred conservation credit	20,020	19,851		169	169,269	169	0	
Post-retirement benefits	8,003	21		7,982	7,982,000	7,982	0	
Other liabilities	2,100			2,100	2,099,943	2,100	0	
Regulatory liabilities	2,516			2,516	2,516,195	2,516	0	
Notes payable to related parties	60,000			60,000	60,000,000	60,000	0	
Total current liabilities	735,684	24,060	(238)	711,862	731,283,576	731,284	(19,421)	
Notes payable to related parties	1,433,199			1,433,199	1,433,199,461	1,433,199	0	
Customers' advance deposits	7,356			7,356	7,355,554	7,356	0	
Post-retirement benefits	230,789	1,058		229,731	229,731,000	229,731	0	
Other liabilities	8,175			8,175	8,174,873	8,175	0	
Regulatory liabilities	180,617			180,617	160,001,344	160,001	20,616	3
Asset retirement obligations	6,247			6,247	6,247,281	6,247	0	
Total liabilities	2,602,067	25,118	(238)	2,577,187	2,575,993,089	2,575,993	1,194	
Shareholder's equity								
Share capital	556,278	28,461		527,817	527,816,668	527,817	0	
Retained earnings	604,347	(1,764)		606,111	577,161,314	577,161	28,950	4
Contributed surplus	12,757			12,757	12,757,392	12,757	0	
Total shareholder's equity	1,173,382	26,697	0	1,146,685	1,117,735,375	1,117,735	28,950	
Total liabilities and shareholder's equity	3,775,449	51,814	(238)	3,723,873	3,693,728,464	3,693,728	30,144	

Toronto Hydro-Electric System Limited
Balance Sheet
As at December 31, 2013

Notes:

Note 1: Difference in "Regulatory assets" of $30,144: Calculated Audited Financial Statement (AFS) Regulated balance of $234,424 & RRR balance of $204,280, a difference of ($30,144), as follows:	
a. A "Smart meter recovery" regulatory asset (RA) was booked for AFS, and is not considered a regulatory asset for purposes of RRR reporting:	$25,230
b. Incremental Capital Model (ICM) revenue and depreciation expense contra account RA were booked for the AFS, and this not considered a regulatory asset for purposes of RRR reporting:	$4,914
Total difference:	$30,144
Note 2: Difference in "Accounts payable and accrued liabilities" of $19,421: Calculated AFS Regulated balance of ($451,802) & RRR balance of ($471,223), a difference of $19,421, as follows:	
a. A "Revision of prior year tax position" regulatory liability (RL) was booked for AFS, and is not considered a regulatory liability for purposes of RRR reporting: For RRR Reporting, the amount was transferred to OEB account 2220 "Miscellaneous Current and Accrued Liabilities" from Regulatory Liabilities.	19,421
Note 3: Difference in "Regulatory liabilities" of ($20,616): Calculated AFS Regulated balance of ($180,617) & RRR balance of ($160,001) a difference of ($20,616), as follows:	
a. A Revision of prior year tax position" regulatory liability (RL) was booked for AFS, and is not considered a regulatory liability for purposes of RRR reporting: For RRR Reporting, the amount was transferred to OEB account 2220 "Miscellaneous Current and Accrued Liabilities" from Regulatory Liabilities.	$19,421
b. HST Contra account adjustment: In prior years' AFS, THESI has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs)' the ITCs savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010. For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established a contra account within Account 1592, "PILs and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. The following adjustment has been made to the AFS to reflect for RRR Reporting the amount in the above mentioned contra account: The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,150k, Misc. Interest (Cr.) $16k and Retained Earnings (Cr.) 1,134k.	$1,150
c. For RRR reporting, THESI has written off to Distribution revenue a credit amount of $44, which was included in regulatory liabilities in the AFS. The amount does not represent a regulatory liability for RRR reporting:	$44
Total difference:	$20,616
Note 4: Difference in "Retained Earnings' of ($28,950): Calculated AFS Regulated balance of ($606,111) & RRR balance of ($577,161) a difference of ($28,950). Adjustments have been made to certain AFS income statement items to arrive at the RRR reporting as follows:	
a. Reduction to AFS Distribution revenue booked for SmartMeter "net revenue requirement" on the disposition of Account 1555 "SmartMeter Capital & Recovery' and 1556 "SmartMeter OM&A Variance account" balances. The amount shall be booked to Distribution revenue for RRR reporting, to OEB account 4080 as the amount is billed to THESI customers in the future:	$25,230
b. Reverse the ICM revenue and related depreciation expense booked in 2013 in the AFS. This ICM revenue and depreciation expense shall be booked for RRR reporting in the future under regulatory prescribed ICM accounting treatment:	$4,914
c. HST Contra account adjustment: In prior years' AFS, THESI has booked to the OEB account 1592, "PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs)' the ITCs savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010. For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established a contra account within Account 1592, "PILs and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592. The following adjustment has been made to the AFS to reflect for RRR Reporting the amount in the above mentioned contra account: The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,150k, Misc. Interest (Cr.) $16k and Retained Earnings (Cr.) 1,134k.	1,150
d. For RRR reporting, THESI has written off to Distribution revenue a credit amount of $44, which was included in regulatory liabilities in the AFS. The amount does not represent a regulatory liability for RRR reporting:	44
Total difference:	$28,950

Toronto Hydro-Electric System Limited
Statements of Net Income and Comprehensive Income
Year ended December 31, 2013

	THESL Consolidated Audited 2013 ($,000s) (1)	Unregulated Business ($,000s) (2)	Consolidation Adjustment ($,000s) (3)	Calculated THESL Regulated Business ($,000s) (4)=(1)-(2)-(3)	RRR Filing ($) (5)	RRR Filing ($,000s) (6)	Difference ($,000s) (7)=(4)-(6)	Notes
Revenues								
Sale of electricity	3,145,455			3,145,455	3,080,217,018	3,080,217	65,238	1
Other income	42,288	6,246		36,042	27,801,322	27,801	8,240	2
	3,187,743	6,246	0	3,181,497	3,108,018,340	3,108,018	73,478	
Costs								
Purchased power	2,567,512			2,567,512	2,534,165,407	2,534,165	33,346	3
Operating expenses	262,304	3,888		258,416	250,176,410	250,176	8,240	4
Depreciation and amortization	171,475	1,988		169,487	167,694,704	167,695	1,792	5
	3,001,291	5,875	0	2,995,415	2,952,036,520	2,952,037	43,378	
Income before the following:	186,452	371	0	186,081	155,981,820	155,981	30,100	
Net financing charges	68,870	139		68,731	68,715,187	68,715	16	6
Gain on disposals of property, plant and equipment	1,280			1,280	1,279,608	1,280	0	
Income before income taxes	118,862	232	0	118,631	88,546,241	88,546	30,085	
Income tax expense	3,123			3,123	3,122,853	3,123	0	
Net income and comprehensive income	115,739	232	0	115,508	85,423,388	85,423	30,085	

Toronto Hydro-Electric System Limited
Statements of Net Income and Comprehensive Income
Year ended December 31, 2013

Notes:

Note 1: Difference in "Sale of electricity" of ($65,238): Calculated Audited Financial Statement (AFS) Regulated balance of ($3,145,455) & RRR balance of ($3,080,217), a difference of ($65,238), as follows:	
a. A "Smart meter recovery" regulatory asset (RA) was booked for AFS, with the offsetting entry to Distribution revenue. This is not considered a regulatory asset for purposes of RRR reporting, and the RA and related distribution revenue have been reversed for RRR reporting:	$25,230
b. For RRR Reporting, THESI booked to "Cost of Power revenue" and "COP expense" the amount of the IESO settlement invoices charge type 142, in the amounts of $33,346 and ($33,346), respectively.	$33,346
For the AFS, THESI does not book IESO settlement invoices charge type 142 to either COP revenue or COP expense.	
c. An Incremental Capital Model (ICM) revenue contra account Regulatory Asset (RA) was booked for the AFS, with an offsetting entry to Distribution revenue. This is not considered a regulatory asset for purposes of RRR reporting. The RA and related Distribution revenue have been reversed for RRR reporting:	$6,706
d. For RRR reporting, THESI has written off to Distribution revenue a credit amount of $44, which was included in regulatory liabilities in the AFS. The amount does not represent a regulatory liability for RRR reporting:	$44
Total difference:	$65,238

Note 2: Difference in "Other income" of ($8,240): Calculated AFS Regulated balance of ($36,042) & RRR balance of ($27,802), a difference of ($8,240), as follows:	
a. Demand Billable Charges. As per USGAAP, THESI booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	$12,194
b. Smart Metering Entity charge: As per USGAAP, THESI books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	$3,954
Total difference:	$8,240

Note 3: Difference in "Purchased power" of $33,346: Calculated AFS Regulated balance of $2,567,512 & RRR balance of $2,534,165 a difference of $33,346, as follows:	
a. For RRR Reporting we booked to "Cost of Power revenue" and "COP expense" the amount of the IESO settlement invoices charge type 142, in the amounts of $33,346 and ($33,346), respectively.	
For the AFS, THESI does not book IESO settlement invoices charge type 142 to either COP revenue or COP expense:	$33,346

Note 4: Difference in "Operating expenses" of $8,240: Calculated AFS Regulated balance of $258,416 and RRR balance of $250,176, a difference of $8,240, as follows:	
a. Demand Billable Charges. As per USGAAP, THESI booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	$12,194
b. Smart Metering Entity charge: As per USGAAP, THESI books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	$3,954
Total difference:	$8,240

Note 5: Difference in "Depreciation and amortization" of $1,792: Calculated AFS Regulated balance of $169,487 & RRR balance of $167,695, a difference of $1,792, as follows:	
a. An Incremental Capital Model (ICM) depreciation contra account Regulatory Asset (RA) was booked for the AFS, with an offsetting entry to Depreciation expense. This is not considered a regulatory asset for purposes of RRR reporting. The RA and related depreciation expense have been reversed for RRR reporting:	$1,792

Note 6: Difference in "Net Financing Charges" of $16: Calculated AFS Regulated balance of $68,731 & RRR balance of $68,715, a difference of $16, as follows:	$16

a. HST Contra account adjustment: In prior years' AFS, THESI has booked to the OEB account 1592, "PILs and Tax Variances" for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax credits (ITCs) 'the ITCs savings arising from the elimination of Provincial Sales Tax and implementation of the HST on July 1, 2010.
For AFS purposes, the offsetting entry was booked to the income statement rather the regulatory sub-account established, a contra account within Account 1592, "PILs and Tax Variances for 2006 and subsequent years - HST/OVAT Contra Account" of Account 1592.
The following adjustment has been made to the AFS to reflect for RRR Reporting the amount in the above-mentioned contra account:
The adjustment entry is, HST/OVAT Contra Account (Dr.) $1,150k, Misc. Interest (Cr.) $16k and Retained Earnings (Cr.) 1,134k.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS FOR THE THREE MONTHS AND YEARS ENDED DECEMBER 31, 2013 AND 2012

Executive Summary

- Net income for the three months and year ended December 31, 2013 was $29.2 million and $121.2 million, compared to net income of $22.8 million and $86.0 million for the comparable periods in 2012;
- capital expenditures were primarily related to the renewal of the electricity infrastructure of LDC and were $151.6 million and $450.3 million for the three months and year ended December 31, 2013, compared to $108.5 million and $292.4 million for the comparable periods in 2012;
- on December 19, 2013, the OEB approved a settlement agreement filed by LDC to allow for the entirety of LDC's requested 2014 capital program;
- on January 16, 2014, the OEB approved LDC's request for disposition of the smart meter deferral account balances, permitting the recovery of $23.9 million and $6.9 million through two separate rate riders effective May 1, 2014;
- in December 2013, the Ice Storm caused damage to the above-ground infrastructure of the Corporation's electricity distribution system resulting in power outages throughout the City;
- on May 22, 2013, the Corporation celebrated the official groundbreaking at Copeland Station, and construction continued during the year;
- on December 17, 2013, the Corporation launched a commercial paper program allowing up to $400.0 million of unsecured short-term promissory notes to be issued in various maturities of no more than one year; and
- on April 9, 2013, the Corporation issued $250.0 million of 2.91% senior unsecured debentures due April 10, 2023 ("Series 8") and $200.0 million of 3.96% senior unsecured debentures due April 9, 2063 ("Series 9"). The net proceeds of the above debentures, together with borrowings under the Corporation's revolving credit facility, were used to repay the Corporation's $225.0 million of 6.11% senior unsecured debentures ("Series 1") and $245.1 million of 6.11% senior unsecured debentures ("Series 5") which matured on May 7, 2013 and May 6, 2013, respectively.

Introduction

The following MD&A should be read in conjunction with:

- the audited consolidated financial statements and accompanying notes of the Corporation as at and for the years ended December 31, 2013 and 2012 ("Consolidated Financial Statements"); and

- the audited consolidated financial statements and accompanying notes of the Corporation as at and for the years ended December 31, 2012 and 2011.

Copies of these documents are available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

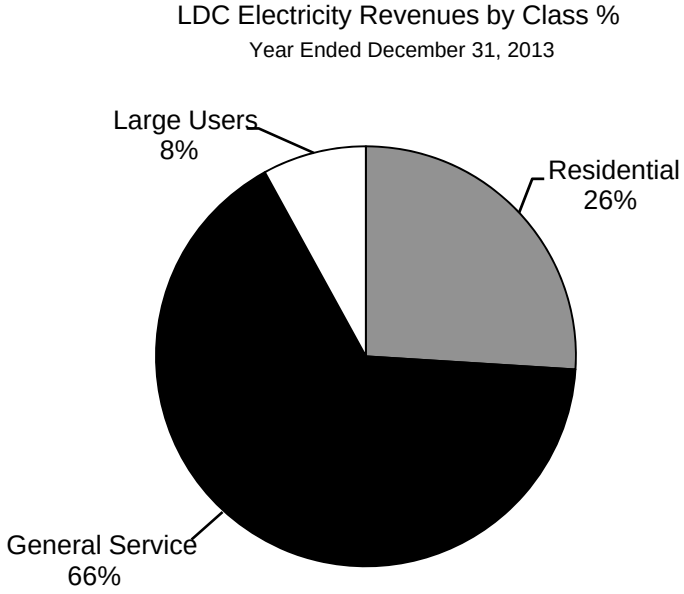
The Corporation's above noted annual consolidated financial statements have been prepared in accordance with US GAAP and are presented in Canadian dollars (see "Significant Accounting Policies" below). The OSC granted an exemption to allow the Corporation to file financial statements under US GAAP for the years commencing on or after January 1, 2012 but before January 1, 2015.

Business of Toronto Hydro Corporation

The Corporation is a holding company which wholly owns two subsidiaries:

- LDC - which distributes electricity and engages in CDM activities; and
- TH Energy- which provides street lighting services.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, which delivers electricity to approximately 730,000 customers located in the City. The City is the sole shareholder of the Corporation. LDC is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in Ontario. The business of LDC is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, and the regulation of electricity distribution rates charged by LDC and other electricity distributors in Ontario. For the year ended December 31, 2013, LDC earned electricity revenues of $3,145.5 million. As illustrated in the accompanying chart, 66% of the revenues were received from general service users[1], 26% from residential service users[2], and 8% from large users[3].



[1] "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of 5,000 kW or less averaged over a twelve-month period.

[2] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

[3] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or more averaged over a twelve-month period.

Electricity Distribution – Industry Overview

In April 1999, the Government of Ontario began restructuring Ontario's electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors purchase electricity from the wholesale market administered by the IESO and recover the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in Ontario. The OEB Act sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for distribution and other activities, and requirements for rate-setting and other legal filings.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

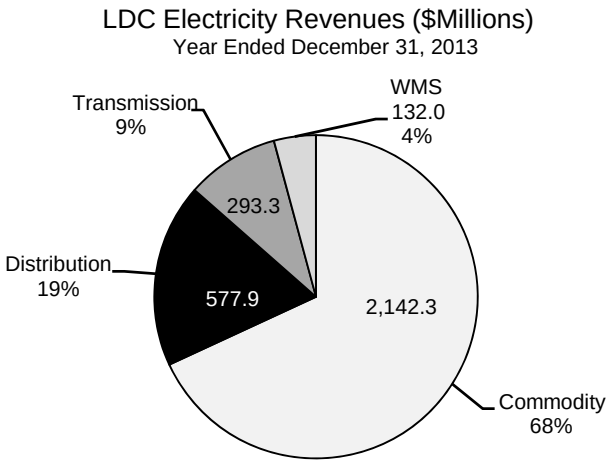
LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

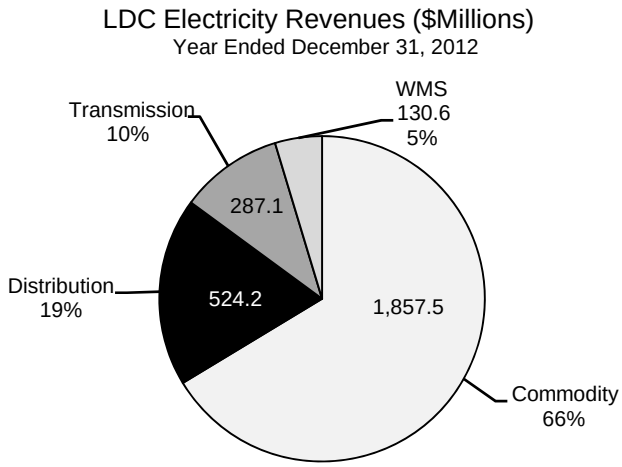
- Commodity Charge – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- Retail Transmission Rate – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through to operators of transmission facilities.

- WMS Charge – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through to the IESO.

- Distribution Rate – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and are comprised of fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.





The electricity revenues for the year ended December 31, 2013 were $3,145.5 million compared to $2,799.4 million for the comparable period in 2012. The increase in electricity revenues for the year ended December 31, 2013 was primarily due to an increase in the commodity charges by the IESO related to higher global adjustment and average energy prices in 2013 compared to 2012 ($284.8 million) and an increase in LDC's distribution revenue for 2013 ($53.7 million) (see "Net Revenues" below in the section entitled "Results of Operations – 2013 compared to 2012").

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The Corporation is exempt from tax under the ITA if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

Corporate Strategy

The Corporation's vision is to "continuously maximize customer and stakeholders' satisfaction by being safe, reliable and environmentally responsible at optimal costs". The Corporation has an ERM framework that helps determine whether the Corporation is well positioned to achieve its strategic objectives. The ERM framework provides a consistent, disciplined methodology for controlling risk by identifying, assessing, managing, monitoring and reporting risks for the Corporation.

The Corporation is focused on the following four strategic pillars:

People – the Corporation aims to maintain an engaged, healthy, productive, and safe workforce to meet changing business requirements, as it strives to:

- Provide a healthy and safe workplace
- Develop a skilled and knowledgeable workforce
- Keep its workforce engaged

The Corporation will continue to strengthen its already strong safety culture through various internal initiatives in order to achieve world-class results. The Corporation is committed to employee safety and will remain persistent in its efforts to mitigate the risk of injury to its workforce. This will be accomplished through ongoing safety inspections, audits, annual policy review and the continuation of the safety programs and standards. The Corporation will continue to use the internal responsibility system to reinforce the importance of safety in the workplace.

Financial – the Corporation aims to meet the financial objectives of its shareholder, as it strives to:

- Provide a fair return to the shareholder
- Continue to increase shareholder value

The Corporation has provided its shareholder with an annual increase in economic value over the last decade. To meet financial objectives of the shareholder, the Corporation seeks to increase shareholder value and is committed to provide a fair return to its shareholder in the future. Along with excellence in corporate financing and financial management, the Corporation will strive to maintain an investment grade credit rating.

Operations – the Corporation aims to improve reliability through sustainable system management, as it strives to:

- Keep the lights on
- Keep the system safe
- Build a grid that supports a modern Toronto

The Corporation is engaging in resource and capital-intensive programs to improve capacity, reliability and quality. The capital program will replace aging assets and accommodate next generation technology to suit the regulatory trends that incent the increased use of distributed generation.

Customer – the Corporation aims to provide value to customers, as it strives to:

- Make it easy to work with
- Help conserve energy
- Provide innovative tools and technology

The Corporation is looking at ways to improve the level of satisfaction that customers experience, whether it is through education and awareness programs, interaction with call centre representatives, their account managers or over the internet. The Corporation continues to undertake initiatives and invest in technology and processes to improve the customer experience. In turn, this focus on customer service will provide long-term value for money.

Performance Measurement

The Corporation measures its performance in relation to the achievement of its strategic objectives by using a balanced scorecard approach. KPIs are monitored throughout the year and appropriate actions are taken as required. The definitions of the 2013 KPIs associated with the previously mentioned four strategic pillars are as follows:

Strategic Pillars	Performance Measure	Definition
People	Safety	x Number of recordable injuries x 200,000 / exposure hours.
	Employee Engagement	› Average number of employee engagement sessions per employee per year, including corporate-wide, divisional and departmental.
Financial	Net Income	x Net income per the Corporation's consolidated financial statements.
Operations	System Average Interruption Duration Index	x Measure of the annual system average interruption duration per customers served, not including MED.
	System Average Interruption Frequency Index	› Measure of the frequency of service interruptions per customers served, not including MED.
	Worst Performing Feeders	› Total number of feeders experiencing seven or more sustained outages in a year, with outages defined as interruptions greater than one minute.
	LDC Regulated Capital	› Achievement of LDC capital work program as approved by the Board of Directors.
Customer	Conservation Demand Management	x Annual summer peak demand savings through year over year megawatt reduction.
	Enhanced Customer Engagement	› Increase in customer self-serve transactions / engagements using various self-serve options.
	Call Centre Service Response	› Average of call centre responses within thirty seconds.

Capability to Deliver Results

The Corporation strives to manage its performance and deliver results. In 2013, the Corporation exceeded all of its corporate and divisional objectives represented by its KPIs. The Corporation's ability to deliver results in each of its strategic pillars is limited by risks inherent in its regulatory environment, business, workforce and in the economic environment. These risks are discussed under the section “Risk Management and Risk Factors” in this MD&A.

Selected Consolidated Financial Data

Consolidated Statements of Net Income and Comprehensive Income
Three months ended December 31
(in thousands of Canadian dollars, except for per share amounts, unaudited)

	2013 $	2012 $	Change $	2011[1] $
Revenues	819,669	691,847	127,822	694,284
Costs				
Purchased power	627,015	551,267	75,748	542,510
Operating expenses	79,319	65,107	14,212	66,880
Depreciation and amortization	66,631	35,900	30,731	43,984
	772,965	652,274	120,691	653,374
Income before the following:	46,704	39,573	7,131	40,910
Net financing charges	(15,074)	(18,640)	3,566	(19,506)
Gain on disposals of PP&E	162	1,805	(1,643)	(1,135)
Income before income taxes	31,792	22,738	9,054	20,269
Income tax expense (recovery)	2,572	(104)	2,676	3,041
Net income and comprehensive income	29,220	22,842	6,378	17,228
Basic and fully diluted net income per share	29,220	22,842	6,378	17,228

[1] The Corporation's consolidated financial statements were prepared in accordance with Part V of Canadian GAAP until December 31, 2011. Selected financial information from comparative consolidated financial statements for 2011 have been adjusted retroactively from the consolidated financial statements previously filed to conform to the presentation of the Corporation's 2012 and 2013 consolidated financial statements prepared in accordance with US GAAP.

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Consolidated Statements of Net Income and Comprehensive Income
Year ended December 31
(in thousands of Canadian dollars, except for per share amounts)

	2013 $	2012 $	Change $	2011[1] $
Revenues	3,202,793	2,852,477	350,316	2,823,470
Costs				
Purchased power	2,567,512	2,275,209	292,303	2,236,541
Operating expenses	271,958	245,173	26,785	262,241
Depreciation and amortization	172,756	141,572	31,184	151,022
	3,012,226	2,661,954	350,272	2,649,804
Income before the following:	190,567	190,523	44	173,666
Net financing charges	(66,273)	(73,977)	7,704	(75,324)
Gain on disposals of PP&E	1,280	1,805	(525)	3,885
Restructuring costs	-	(27,796)	27,796	-
Income before income taxes	125,574	90,555	35,019	102,227
Income tax expense	4,333	4,565	(232)	6,295
Net income and comprehensive income	121,241	85,990	35,251	95,932
Basic and fully diluted net income per share	121,241	85,990	35,251	95,932

[1] The Corporation's consolidated financial statements were prepared in accordance with Part V of Canadian GAAP until December 31, 2011. Selected financial information from comparative consolidated financial statements for 2011 have been adjusted retroactively from the consolidated financial statements previously filed to conform to the presentation of the Corporation's 2012 and 2013 consolidated financial statements prepared in accordance with US GAAP.

Condensed Consolidated Balance Sheet Data
(in thousands of Canadian dollars)

	As at December 31 2013 $	As at December 31 2012 $
Current assets	555,314	552,292
Non-current assets	3,242,217	2,987,062
Total assets	3,797,531	3,539,354
Current liabilities	696,417	937,514
Non-current liabilities	1,882,596	1,461,568
Total liabilities	2,579,013	2,399,082
Shareholder's equity	1,218,518	1,140,272
Total liabilities and shareholder's equity	3,797,531	3,539,354

Results of Operations – 2013 compared to 2012

Net Income

Net income for the three months and year ended December 31, 2013 was $29.2 million and $121.2 million compared to $22.8 million and $86.0 million for the comparable periods in 2012.

The increase in net income for the three months ended December 31, 2013 was primarily due to higher net revenues ($52.1 million) and lower net financing charges ($3.6 million). These favourable variances were partially offset by a higher depreciation expense ($30.7 million), higher operating expenses ($14.2 million), a higher income tax expense ($2.7 million), and lower gains on disposals of surplus properties ($1.6 million).

The increase in net income for the year ended December 31, 2013 was primarily due to higher net revenues ($58.0 million), restructuring costs recognized in the first quarter of 2012 ($27.8 million) related to the cost reduction initiatives at LDC (see "Restructuring Costs" below), lower net financing charges ($7.7 million), and lower income tax expense ($0.2 million). These favourable variances were partially offset by a higher depreciation expense ($31.2 million), higher operating expenses ($26.8 million), and lower gains on disposals of surplus properties ($0.5 million).

Ice Storm

In December 2013, the Ice Storm caused damage to the above-ground infrastructure of the Corporation's electricity distribution system. Approximately 300,000 customers lost power for periods of up to eight days, though strenuous efforts resulted in 75% power restoration within 48 hours. As a result, the Corporation incurred incremental costs consisting of overtime of its own employees, time and equipment costs of other utilities that provided mutual aid, tree clearing services and the replacement of damaged assets. The total costs incurred amounted to $13.8 million, of which $3.6 million were capitalized to PP&E and $10.2 million were charged to operating expenses. In addition, potential distribution revenue of approximately $0.9 million was lost due to the power outage. The Corporation decided not to file a special application with the OEB to seek recovery of incremental operating expenses for the Ice Storm as it was able to absorb the impact from other favourable variances.

Smart Meters

On August 1, 2013, LDC filed an application with the OEB requesting approval for the disposition of balances in its smart meter deferral account related to smart meter installations in 2008, 2009 and 2010, and incremental revenue related to these assets. On January 16, 2014, the OEB approved LDC's request for incremental revenue and disposition of the smart meter deferral account balances.

The OEB ruling on smart meters also permitted the recovery in principle of LDC's allowed cost of capital on smart meters since 2008, with a rate order issued to this effect. Accordingly, a new regulatory asset of $25.2 million has been created to reflect the future amount to be recovered through rates, with a related amount recorded in revenue. For the year ended December 31, 2013, LDC ceased to defer operating and depreciation expenses related to the deployment of the 2008 to 2010 smart meters and recognized revenues as approved by the OEB, resulting in a decrease in the smart meters regulatory asset of $25.0 million, an increase in PP&E of $4.7 million, an increase in intangible assets of $1.1 million, an increase in revenues of $57.5 million, an increase in operating expenses of $7.1 million, and an increase in depreciation and amortization expenses of $28.7 million. See note 9 (c) to the Consolidated Financial Statements for further details.

Net Revenues

Net revenues for the three months and year ended December 31, 2013 were $192.7 million and $635.3 million compared to $140.6 million and $577.3 million for the comparable periods in 2012 (see "Non-GAAP Financial Measures" below).

The increase in net revenues for the three months ended December 31, 2013 was primarily due to higher regulated distribution revenue at LDC ($47.9 million) and higher other income ($4.2 million). The increase in distribution revenue was primarily due to revenue recognition related to the disposition of the 2008-2010 smart meter deferral account balances ($57.5 million) (see "Smart Meters" above), revenue recognition related to the IRM adjustment and the eligible in-service capital expenditures under ICM ($5.1 million), and higher consumption in the fourth quarter of 2013 ($3.7 million). These variances were partially offset by a reduction in distribution revenue related to

the revision of prior year tax positions based on reassessments received and in process, not reflected in applications for electricity distribution rates resulting in an over-recovery of PILs from customers ($19.4 million). The increase in other income for the three months ended December 31, 2013 was primarily due to higher revenue in connection with disposal of scrap material, solar panel installation, and duct rental fees.

The increase in net revenues for the year ended December 31, 2013 was primarily due to higher regulated distribution revenue at LDC ($53.7 million) and higher other income ($4.3 million). The increase in distribution revenue was primarily due to revenue recognition related to the disposition of the 2008-2010 smart meter deferral account balances ($57.5 million) (see “Smart Meters” above), revenue recognition related to the IRM adjustment and the eligible in-service capital expenditures under ICM ($8.2 million), and an unfavourable revenue adjustment recorded in 2012 for PILs variances accumulated in regulatory variance accounts ($4.8 million). These variances were partially offset by a reduction in distribution revenue related to the revision of prior year tax positions based on reassessments received and in process, not reflected in applications for electricity distribution rates resulting in an over-recovery of PILs from customers ($19.4 million). The increase in other income for the year ended December 31, 2013 was primarily due to higher revenue in connection with disposal of scrap material, solar panel installation, and duct rental fees.

Expenses

Operating expenses for the three months and year ended December 31, 2013 were $79.3 million and $272.0 million compared to $65.1 million and $245.2 million for the comparable periods in 2012.

The increase in operating expenses for the three months ended December 31, 2013 was primarily due to the cost of power restoration incurred in 2013 as a result of the Ice Storm that adversely affected the City ($10.2 million) and the recognition of operating expenses related to the disposition of the 2008-2010 smart meter deferral account balances ($7.1 million) (see “Smart Meters” above). These variances were partially offset by lower costs associated with street lighting maintenance and customer demand billable work ($2.7 million).

The increase in operating expenses for the year ended December 31, 2013 was primarily due to the cost of power restoration incurred in 2013 as a result of the Ice Storm that adversely affected the City ($10.2 million), a favourable reassessment for payments in lieu of property taxes to the Ministry of Finance of Ontario recorded in the second quarter of 2012 ($8.7 million), and the recognition of operating expenses related to the disposition of the 2008-2010 smart meter deferral account balances ($7.1 million) (see “Smart Meters” above).

Depreciation and amortization expense for the three months and year ended December 31, 2013 was $66.6 million and $172.8 million compared to $35.9 million and $141.6 million for the comparable periods in 2012.

The increase in depreciation and amortization expense for the three months and year ended December 31, 2013 was primarily due to the recognition of depreciation and amortization expenses related to the disposition of the 2008-2010 smart meter deferral account balances ($28.7 million) (see “Smart Meters” above).

Net Financing Charges

Net financing charges for the three months and year ended December 31, 2013 were $15.1 million and $66.3 million compared to $18.6 million and $74.0 million for the comparable periods in 2012.

The decrease in net financing charges for the three months and year ended December 31, 2013 was primarily due to the refinancing of maturing debentures at a lower interest rate in the second quarter of 2013.

Gain on Disposals of PP&E

Gain on disposals of PP&E for the three months and year ended December 31, 2013 were $0.2 million and $1.3 million compared to $1.8 million and $1.8 million for the comparable periods in 2012.

The decrease in gain on disposals of PP&E for the three months and year ended December 31, 2013 was primarily due to a lower gain realized in connection with the disposals of surplus properties at LDC in 2013.

Restructuring Costs

In the first quarter of 2012, the Corporation’s Board of Directors approved a workforce restructuring program aimed at reducing operating expenditures for LDC. The program was approved following the decision by the OEB to deny

the request of LDC to set its electricity distribution rates for 2012, 2013 and 2014 under the cost of service framework. In preparing its revised application using the IRM framework, LDC concluded that significant cost reductions were necessary to manage its business within the guidelines of the expected allowed electricity distribution rates provided by the IRM framework. The main component of these operating cost reduction initiatives was a workforce restructuring program, which included the severance of management employees and a voluntary exit incentive program for targeted unionized positions.

Restructuring costs for the year ended December 31, 2013 were $nil compared to $27.8 million for the comparable period in 2012.

Income Tax Expense (Recovery)

Income tax expense for the three months and year ended December 31, 2013 was $2.6 million and $4.3 million compared to an income tax recovery of $0.1 million and an income tax expense of $4.6 million for the comparable periods in 2012.

The increase in income tax expense for the three months ended December 31, 2013 was due to higher income before taxes.

The decrease in income tax expense for the year ended December 31, 2013 was due to higher deductions for permanent and temporary differences between accounting and tax treatments ($4.6 million) and favourable resolution of issues identified in prior periods and related assessments by the Ministry of Finance of Ontario ($4.9 million). These variances were partially offset by higher income before taxes ($9.3 million).

Results of Operations – 2012 compared to 2011

Net income was $86.0 million in 2012 compared to $95.9 million in 2011. The decrease in net income was primarily due to restructuring costs recognized in the first quarter of 2012 ($27.8 million) related to the cost reduction initiatives at LDC, lower net revenues ($9.7 million), and lower gains on disposals of surplus properties ($2.1 million). These unfavourable variances were partially offset by lower operating expenses ($17.1 million), lower depreciation expense ($9.5 million), lower income tax expense ($1.7 million), and lower net financing charges ($1.3 million). For further details, see “Selected Consolidated Financial Data” above and the Corporation’s 2012 annual MD&A as filed on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

Quarterly Results of Operations

The table below presents unaudited quarterly consolidated financial information of the Corporation for 2013 and 2012, which has been prepared in accordance with US GAAP.

Quarterly Results of Operations
(in thousands of Canadian dollars, unaudited)

	December 31 2013 $	September 30 2013 $	June 30 2013 $	March 31 2013 $
Revenues	819,669	833,339	792,905	756,880
Costs	772,965	778,240	743,934	717,087
Net income	29,220	35,885	37,555	18,581

	December 31 2012 $	September 30 2012 $	June 30 2012 $	March 31 2012 $
Revenues	691,847	751,270	709,700	699,660
Costs	652,274	693,809	649,831	666,040
Net income (loss)	22,842	34,436	41,538	(12,826)

The Corporation's quarterly results are impacted by changes in revenues resulting from variations in seasonal weather conditions, the fluctuations in electricity prices, and the timing and recognition of regulatory decisions. Consequently, the Corporation's revenues, all other things being equal, would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. A variation in the above trend was noted in 2013 and 2012, evidenced by higher revenue and cost of purchased power in the second quarters of both years, compared to the first quarters of both years. This variation was primarily due to an increase in commodity costs (see "Electricity Distribution – Industry Overview" above).

Financial Position

The following table outlines the significant changes in the consolidated balance sheets as at December 31, 2013 as compared to the consolidated balance sheets as at December 31, 2012.

Consolidated Balance Sheet Data
(in thousands of Canadian dollars)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Assets		
Cash and cash equivalents	(76,592)	See "Liquidity and Capital Resources" below.
Accounts receivable, net of allowance for doubtful accounts	27,555	The increase was primarily due to the timing of billing and collection activities from electricity customers.
Unbilled revenue	48,786	The increase was primarily due to higher pass-through electricity commodity costs and higher consumption in December 2013 compared to December 2012.
Income tax receivable	(7,315)	The decrease was due to a favourable change in prior year reassessments received and in process.
PP&E and intangible assets, net	175,107	The increase was primarily due to the 2013 capital program expenditures and the disposition of the 2008-2010 smart meter deferral account balances (see "Smart Meters" above in the section entitled "Results of Operations – 2013 compared to 2012"), partially offset by depreciation during the period and net eligible in-service capital expenditures under ICM reclassified to regulatory assets per the direction from the OEB.
Regulatory assets	120,270	The increase was primarily due to the reclassification of ICM-related net eligible in-service capital expenditures, partially offset by the net impact of the disposition of the 2008-2010 smart meter deferral account balances (see "Smart Meters" above in the section entitled "Results of Operations – 2013 compared to 2012").

Consolidated Balance Sheet Data
(in thousands of Canadian dollars)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Deferred income tax assets	(36,713)	The decrease was due to lower net deductible temporary differences between tax and accounting values of PP&E.
Liabilities and Shareholder's Equity		
Working capital facility	19,084	The increase was due to funds drawn under the Corporation's working capital facility (see "Liquidity and Capital Resources" below).
Commercial paper	150,000	The increase was due to funds drawn under the Corporation's commercial paper program (see "Liquidity and Capital Resources" below).
Accounts payable and accrued liabilities	73,379	The increase was primarily due to higher electricity commodity cost payable to the IESO, higher capital programs, and the costs related to the Ice Storm (see "Ice Storm" above in the section entitled "Results of Operations – 2013 compared to 2012").
Restructuring accrual	(11,954)	The decrease was due to payments made against the restructuring accrual related to the workforce restructuring program initiated by the Corporation in the first quarter of 2012.
Debentures	(20,258)	The decrease was due to the repayment of $470.1 million senior unsecured debentures, offset by the issuance of $450.0 million senior unsecured debentures during the second quarter of 2013 (see "Liquidity and Capital Resources" below).
Post-retirement benefits	(15,098)	The decrease was primarily due to the actuarial gain recorded in 2013.
Regulatory liabilities	(13,676)	The decrease was primarily due to lower income tax payable to customers in the future.
Retained earnings	78,246	The increase in retained earnings was due to net income for the year ($121.2 million), partially offset by dividends paid ($43.0 million).

Liquidity and Capital Resources

Sources of Liquidity and Capital Resources

The Corporation's current assets and current liabilities amounted to $555.3 million and $696.4 million, respectively, as at December 31, 2013, resulting in a working capital deficit of $141.1 million. The deficit is due to the

Corporation's decision to utilize its commercial paper program and revolving credit facility in lieu of issuing additional debentures to fulfill the Corporation's liquidity requirements, including funding significant capital spending in the current year.

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, issuances of commercial paper, amounts available to be drawn against its credit facilities, and borrowings from debt capital markets. The Corporation's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system of LDC, to purchase power, to meet financing obligations and for prudential requirements.

The Corporation does not believe that equity contributions from the City, its sole shareholder, will constitute a source of capital.

The City has authorized the Corporation to provide financial assistance to its subsidiaries, and LDC to provide financial assistance to other subsidiaries of the Corporation, in the form of guarantees, letters of credit, direct loans or otherwise, for the purpose of enabling them to carry on their businesses, with financial assistance provided to subsidiaries other than LDC not to exceed an aggregate amount of $500.0 million.

On December 17, 2013, the Corporation launched a commercial paper program allowing up to $400.0 million of unsecured short-term promissory notes to be issued in varying maturities of no more than one year. The commercial paper program is supported by liquidity facilities available under the Corporation's revolving credit facility; hence, available borrowing under its revolving credit facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the commercial paper program are being used for general corporate purposes. For the three months ended December 31, 2013, the average outstanding borrowing under the commercial paper program was $33.5 million with a weighted average interest rate of 1.21%. Borrowings under the commercial paper program bear interest based on the prevailing market conditions at the time of issuance.

On September 6, 2013, the Corporation extended the maturity date of its $600.0 million revolving credit facility from October 10, 2017 to October 10, 2018. Borrowings under the revolving credit facility bear interest at short-term floating rates with reference to the Corporation's credit rating.

As at December 31, 2013, no amounts had been drawn under the revolving credit facility and $19.1 million had been drawn under the $20.0 million working capital facility. As at December 31, 2013, $50.1 million of letters of credit had been issued against the $75.0 million prudential facility. For the three months and the year ended December 31, 2013, the average outstanding borrowings on the Corporation's credit facilities, excluding the prudential facility and commercial paper, were $69.2 million and $59.2 million with weighted average interest rates of 1.81% and 2.09 %, respectively. The revolving credit facility, the working capital facility, and the prudential credit facility are summarized in note 11 to the Consolidated Financial Statements.

The Corporation filed a base shelf prospectus dated December 10, 2012 with the securities commissions or similar regulatory authorities in each of the provinces of Canada. These filings allow the Corporation to make offerings of unsecured debt securities of up to $1,500.0 million during the 25-month period following the date of the prospectus.

On April 9, 2013, the Corporation issued Series 8 ($250.0 million) and Series 9 ($200.0 million) debentures, which bear interest payable semi-annually in arrears and contain covenants which, subject to certain exceptions, restrict the ability of the Corporation and LDC to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets. The Corporation may redeem all or part of the Series 8 and Series 9 debentures at any time prior to maturity at a price equal to the greater of the Canada Yield Price (determined in accordance with the terms of the debentures) and par, plus accrued and unpaid interest up to and excluding the date fixed for redemption. The net proceeds of the debentures, together with borrowings under the Corporation's revolving credit facility, were used to repay the Corporation's Series 1 and Series 5 debentures which matured on May 7, 2013 and May 6, 2013, respectively. Debt issuance costs of $2.7 million relating to the Series 8 and Series 9 debentures were deferred as other assets in the second quarter of 2013.

As at December 31, 2013, the Corporation had long-term debentures outstanding in the principal amount of $1,450.0 million. These debentures mature between 2017 and 2063. The Corporation may issue up to $1,050.0 million of additional debentures under the existing base shelf prospectus.

Credit Ratings
As at December 31, 2013

	Debentures	Commercial Paper
DBRS	A (high)	R-1 (low)
Standard & Poor's	A	-

The Corporation believes that it has sufficient availableresou of liquidity and capital to satisfy working capital requirements for the next 12 months.

Consolidated Statements of Cash Flows
(in thousands of Canadian dollars)

	Three months Ended December 31		Year Ended December 31	
	2013 $	2012 $	2013 $	2012 $
Cash and cash equivalents, beginning of perio	-	137,323	76,592	154,256
Net cash provided by operating activities	79,602	54,925	236,123	246,729
Net cash used in investing activities	(126,857)	(104,949)	(411,652)	(265,432)
Net cash provided by (used in) financing activities	47,255	(10,707)	98,937	(58,961)
Cash and cash equivalents, end of period	-	76,592	-	76,592

Net Cash Provided by Operating Activities

Net cash provided by operating activities for the three months and year ended December 31, 2013 was $79.6 and $236.1 million compared to $54.9 million and $246.7 million for the comparable periods in 2012.

The increase in net cash provided by operating activities for the three months ended December 31, 2013 was primarily due to lower working capital and an increase in net income.

The decrease in net cash provided by operating activities for the year ended December 31, 2013 was primarily due to higher working capital, partially offset by an increase in net income.

Net Cash Used in Investing Activities

Net cash used in investing activities for the three months and year ended December 31, 2013 was $126.9 million and $411.7 million compared to $104.9 million and $265.4 million for the comparable periods in 2012.

The increase in net cash used in investing activities for the three months ended December 31, 2013 was primarily due to higher capital expenditures in 2013.

The increase in net cash used in investing activities for the year ended December 31, 2013 was primarily due to higher capital expenditures in 2013 and the sale and maturity of investments in 2012.

Electricity distribution is a capital-intensive business. As the largest municipal electricity distribution company in Canada, LDC continues to invest in rebuilding existing aging infrastructure to address safety, reliability and customer service requirements.

LDC estimates that approximately one-third of its electricity distribution assets are past their expected useful lives. As a strategic response to meet the objective of maximizing customer and stakeholder satisfaction through providing safe and reliable service, LDC is committed to maintenance and capital expenditure requirements for distribution plant refurbishment and replacement.

The following table summarizes the Corporation's capital expenditures for the periods indicated.

Capital Expenditures
(in thousands of Canadian dollars)

	Three months Ended December 31		Year Ended December 31	
	2013 $	2012 $	2013 $	2012 $
Regulated LDC				
Distribution system				
Planned	114,060	84,545	340,347	226,609
Reactive	14,132	11,529	35,002	28,775
Copeland Station	9,515	1,834	45,320	4,065
Technology assets	7,074	7,472	17,118	23,204
Other[1]	5,676	1,788	7,874	5,922
	150,457	107,168	445,661	288,575
Other[2]	1,176	1,362	4,653	3,800
Total Capital Expenditures	151,633	108,530	450,314	292,375

[1] Includes fleet capital and buildings.

[2] Includes unregulated capital expenditures primarily related to TH Energy equipment.

The total regulated capital expenditures were $150.5 million and $445.7 million for the three months and year ended December 31, 2013 compared to $107.2 million and $288.6 million for the comparable periods in 2012. For the year ended December 31, 2013, the increase in regulated capital expenditures was primarily related to planned spending on overhead infrastructure ($52.2 million), Copeland Station ($41.3 million), underground infrastructure ($24.4 million), customer connections ($22.4 million), and network infrastructure and equipment ($13.5 million).

The largest capital initiatives in 2013 include the replacement of overhead infrastructure, the replacement of underground infrastructure, the delivery of customer connections, and the construction of Copeland Station in response to the developing need for distribution solutions in the downtown core of the City.

The replacement of overhead infrastructure includes replacing poles, overhead transformers, overhead switches and other aging overhead infrastructure and equipment. The replacement of underground infrastructure includes replacing direct buried cables, transformers, handwells, and other aging underground infrastructure. Both initiatives will allow LDC to continue to provide ongoing safe and reliable service to its customers. As at December 31, 2013, the year-to-date capital expenditures for the overhead and the underground infrastructure initiatives were $78.2 million and $65.9 million, respectively.

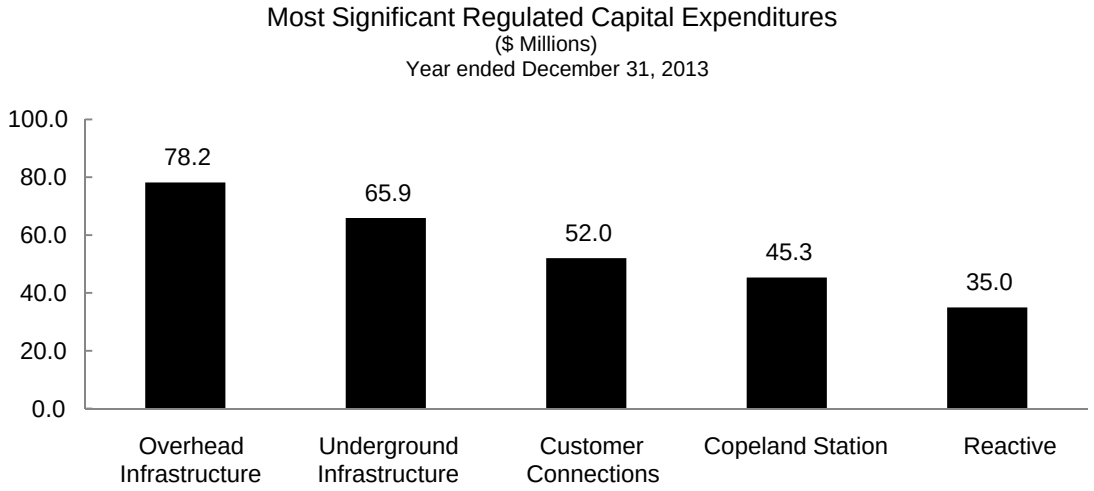
The delivery of customer connections includes spending related to new services and upgrades to existing services for specific commercial customers. For 2013, capital expenditures for the delivery of customer connections were $52.0 million, net of related capital contributions received of $23.6 million.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. When in service, the new station will provide electricity to buildings and neighbourhoods in the central-southwest region of Toronto. Between 2006 and 2011, the population in the City's downtown increased by over 50%[4], and Toronto is now the fourth largest metropolitan area, by population, in North America. Copeland Station will provide much needed additional capacity to serve current and future load requirements in this high-density, high-growth area of Toronto.

On May 22, 2013, the Corporation celebrated the official groundbreaking at the station. On February 1, 2014, the tunnel boring machine arrived on-site and was being prepared to begin tunnelling north to connect the new infrastructure to the grid. As at December 31, 2013, capital expenditures on the Copeland Station project

[4] http://www.toronto.ca/legdocs/mmis/2013/bgrd/backgroundfile-56336.pdf

amounted to $60.5 million of which $45.5 million was recorded in 2013. The total capital expenditures required to complete Copeland Station are expected to be approximately $194.9 million. All capital expenditures related to Copeland Station are recorded to PP&E.



Net Cash Provided by (Used in) Financing Activities

Net cash provided by financing activities for the three month and year ended December 31, 2013 was $47.3 million and $98.9 million compared to net cash used in financing activities of $10.7 million and $59.0 million for the comparable periods in 2012.

The increase in net cash provided by financing activities for the three months ended December 31, 2013 was primarily due to an increase in funds drawn under the Corporation's commercial paper program and working capital facility related to higher capital expenditures in 2013, partially offset by a decrease in funds drawn under the Corporation's revolving credit facility.

The increase in net cash provided by financing activities for the year ended December 31, 2013 was primarily due to funds drawn under the Corporation's commercial paper program and working capital facility related to higher capital expenditures, a decrease in customer deposits in 2012 in compliance with OEB rules and regulations, and lower dividends paid in 2013 compared to 2012. These variances were partially offset by the net effect of the payment in connection with the retirement of $470.1 million of senior unsecured debentures and the issuance of $450.0 million of senior unsecured debentures in the second quarter of 2013.

The shareholder direction adopted by the City with respect to the Corporation provides that the Board of Directors of the Corporation will use its best efforts to ensure that the Corporation meets certain financial performance standards, including those relating to the credit rating and dividends. Subject to applicable law, the shareholder direction provides that the Corporation will pay dividends to the City each year amounting to the greater of $25.0 million or 50% of the Corporation's consolidated net income for the prior fiscal year. The dividends are not cumulative and are payable as follows:

- $6.25 million on the last day of each fiscal quarter of the year; and
- the amount, if any, by which 50% of the Corporation's annual consolidated net income for the year exceeds $25.0 million, within ten days after the approval of the Corporation's audited consolidated financial statements for the year by the Board of Directors of the Corporation.

For the year ended December 31, 2013, the Board of Directors of the Corporation declared and paid dividends totalling $43.0 million to the City.

On March 19, 2014, the Board of Directors of the Corporation declared dividends in the amount of $41.87 million. The dividends are comprised of $35.62 million with respect to net income for the year ended December 31, 2013,

payable to the City on March 28, 2014, and $6.25 million with respect to the first quarter of 2014, payable to the City on March 31, 2014.

Summary of Contractual Obligations and Other Commitments

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments.

Summary of Contractual Obligations and Other Commitments
As at December 31, 2013
(in thousands of Canadian dollars)

	Total $	2014 $	2015/2016 $	2017/2018 $	After 2018 $
Working capital facility	19,084	19,084	-	-	-
Commercial paper	150,000	150,000	-	-	-
Debentures – principal repayment	1,450,000	-	-	250,000	1,200,000
Debentures – interest payments	958,583	60,995	121,990	109,115	666,483
Operating lease obligations	20,268	6,175	11,970	2,123	-
Capital project and other commitments[1,2]	82,569	79,797	2,772	-	-
Capital lease obligations	11,418	2,537	5,074	3,807	-
AROs	7,147	2,417	377	376	3,977
Total contractual obligations and other commitments	2,699,069	321,005	142,183	365,421	1,870,460

[1] Reflect capital project commitments for construction services and estimated capital contributions, with the majority related to Copeland Station.

[2] Subsequent to December 31, 2013, the Corporation entered into capital commitments of approximately $21.0 million for capital contributions payable to Hydro One Networks Inc. over the next year in respect of Copeland Station.

Corporate Developments

Distribution Rates for LDC

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

On May 10, 2012, LDC filed an application for electricity distribution rates for 2012, 2013, and 2014 using the IRM framework, including the filing of an ICM application (the "IRM/ICM Application").

On October 31, 2012, LDC submitted an update to its IRM/ICM Application modifying the requested capital expenditures for 2012 and 2013 to $283.0 million and $579.1 million, respectively, and requesting that consideration for 2014 be deferred to a second phase of the proceeding, once LDC had received a decision from the OEB in respect of phase one. On November 8, 2012, the OEB accepted LDC's request for a two-phase proceeding: phase one comprising LDC's 2012 and 2013 work program proposals and phase two comprising LDC's 2014 work program proposal.

On April 2, 2013, the OEB issued a partial decision and order for phase one of the proceeding comprising LDC's 2012 and 2013 work program proposals. The OEB's decision determined that eligible capital funding under the ICM framework was to be calculated on an in-service basis. This correlates to the approval of capital expenditures amounting to $203.3 million for 2012 and $484.2 million for 2013. New rates became effective June 1, 2013. In 2015, LDC will be allowed to seek recovery for capital spent in 2012 and 2013 that has not yet been approved by the OEB in the current ICM decision due to the standard operation of the regulatory model.

On August 1, 2013, LDC filed an application with the OEB requesting approval for the disposition of balances in its smart meter deferral account related to smart meter installations in 2008, 2009 and 2010. In the application, LDC requested two new rate riders effective May 1, 2014. The first rate rider relates to the recovery of $23.9 million, which represents the cumulative revenue requirement net of recoveries from an existing smart meter rate rider. This

existing smart meter rate rider would be discontinued when the new rate riders become effective. The second rate rider relates to the recovery of $9.6 million, which represents the forecasted 2014 incremental revenue requirement until LDC may be permitted to transfer the smart meter assets into rate base.

On August 19, 2013, LDC submitted an update to its IRM/ICM Application regarding its 2014 work program proposal. The filed update incorporated the OEB's guidance on the ICM methodology provided in the April 2, 2013 partial decision and order with respect to phase one of this proceeding. In phase two, LDC sought approval for total capital expenditures amounting to $398.8 million for 2014.

On December 18, 2013, LDC filed a settlement agreement with the OEB, which allowed for the entirety of LDC's requested 2014 capital program. On December 19, 2013, the OEB approved the settlement agreement. Consistent with the April 2, 2013 partial decision and order with respect to phase one, eligible capital funding under the ICM framework is to be calculated on an in-service basis. This correlates to the approval of capital expenditures amounting to $398.8 million for 2014.

On January 16, 2014, the OEB approved LDC's requested disposition of the smart meter deferral account balances, permitting the recovery of $23.9 million and $9.6 million through two separate rate riders effective May 1, 2014.

CDM Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 GWh of energy savings and 286 MW of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the OPA in the amount of approximately $50.0 million to deliver CDM programs extending from January 1, 2011 to December 31, 2014. As at December 31, 2013, LDC received approximately $45.9 million from the OPA for the delivery of CDM programs. All programs to be delivered are fully funded and paid in advance by the OPA. Amounts received but not yet spent are presented under current liabilities as deferred conservation credits. Upon the expiration of the agreement, LDC is required to repay to the OPA any excess funding received for program administration less any cost efficiency incentives. These programs are expected to support the achievement of the mandatory CDM targets described above.

On December 21, 2012, the Minister of Energy of Ontario issued a direction to the OPA under subsection 25.32(4.1) of the Electricity Act to extend the funding time period for OPA-contracted province-wide CDM initiatives under the Green Energy Act framework to December 31, 2015.

OEB PILs Proceeding

The OEB conducted a review of the PILs variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain MEUs. On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts.

LDC reviewed the balance of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. LDC applied for disposition of the balance as part of its IRM/ICM Application filed on May 10, 2012. The OEB issued its decision and order on April 2, 2013 approving the disposition of the balance. The impact was recorded previously in the Corporation's consolidated financial statements.

Changes to the Corporation's Board of Directors

On April 3, 2013, the City, as the sole shareholder of the Corporation, appointed David Williams, Colum Bastable, Vincent Brescia, Glenna Carr, Derek Cowbourne, Sarah Gee, Paulette Kennedy and Isabel Meharry to the Board of Directors as independent directors of the Corporation. Their appointments were effective April 15, 2013 for a term ending April 14, 2015 or until their successors are appointed. On April 3, 2013, the City also nominated David Williams as Chairman of the Corporation. Mr. Williams was appointed Chairman by the Corporation's Board of Directors effective April 15, 2013 for a term ending April 14, 2015 or until his successor is appointed.

Effective January 1, 2013, the City, as the sole shareholder of the Corporation, appointed councillor Gloria Lindsay Luby to the Board of Directors of the Corporation to replace councillor Rob Metcheser and also re-appointed each of councillor Josh Colle, as the Mayor's designate, and John Shelley Carroll to the Board of Directors of the Corporation. Their appointments are effective for a term ending November 30, 2014 until their successors are appointed.

Labour Agreement

On February 13, 2014, CUPE One ratified collective agreements governing inside and outside employees for a four-year period expiring January 31, 2018. The collective agreements implemented a wage increase of 1.5% on February 1, 2014 and provide for general wage increases of 1.75% effective February 1, 2015, 1.75% effective February 1 2016, and 2% effective February 1, 2017. The collective agreements also contain cost of living escalator clauses that provide for wage adjustments corresponding to the percentage change in the consumer price index. The escalator clauses only become effective if certain prescribed thresholds are exceeded.

Legal Proceedings

In the ordinary course of business, the Corporation is subject to various legal actions and claims with customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these claims, the Corporation and its subsidiaries would make a claim under their liability insurance which the Corporation believes would cover any damages which may become payable by the Corporation and its subsidiaries in connection with these actions. See note 22 (a) to the Consolidated Financial Statements for a discussion of material legal proceedings.

Share Capital

The authorized share capital of the Corporation consists of an unlimited number of common shares without par value, of which 1,000 common shares are issued and outstanding as at the date hereof.

Transactions with Related Parties

As a wholly-owned subsidiary of the City, the Corporation and the City are considered related parties. All transactions with the City are conducted on terms similar to those offered to unrelated parties.

Summary of Transactions with Related Parties
(in thousands of Canadian dollars)

	Year Ended December 31	
	2013 $	2012 $
Revenues	246,894	222,032
Operating expenses and capital expenditures	31,861	26,259
Dividends	42,995	47,966

Summary of Amounts Due to/from Related Parties
(in thousands of Canadian dollars)

	As at December 31	
	2013 $	2012 $
Accounts receivable	5,579	7,810
Unbilled revenue	19,425	17,018
Accounts payable and accrued liabilities	45,472	38,020
Advance deposits	8,816	8,926

Revenues represent amounts charged to the City primarily for electricity, street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends are paid to the City.

Accounts receivable represent receivables from the City primarily for electricity, street lighting and ancillary services. Unbilled revenue represents receivables from the City related to electricity and other services provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services, as well as amounts received from the City for the construction of electricity distribution assets. Advance deposits represent amounts received from the City for future expansion projects.

Controls and Procedures

For purposes of certain Canadian securities regulations, the Corporation is a "Venture Issuer". As such, it is exempt from certain of the requirements of National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. Accordingly, the Chief Executive Officer and Chief Financial Officer have reviewed the Consolidated Financial Statements and the MD&A for the three months and year ended December 31, 2013. Based on their knowledge and exercise of reasonable diligence, they have concluded that these documents fairly present in all material respects the financial condition, results of operations and cash flows of the Corporation for the periods presented.

Risk Management and Risk Factors

The Corporation faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise wide approach to risk management, achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure. The Corporation executes its ERM activities via an ERM framework that is aligned to industry best practices and international guidelines. The Corporation views ERM as a management activity undertaken to add value and improve overall operations. It helps the Corporation by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting risks. Accordingly, ERM is an integral part of the strategic management of the Corporation and is routinely considered in forecasting, planning and executing all aspects of the business.

The ERM framework is operationalized by a consistent, disciplined methodology that clearly defines the risk management process which incorporates subjective elements, risk quantification and risk interdependencies.

While the Corporation's philosophy is that ERM is the responsibility of all business units, at all levels, in matters strategic and operational, the ERM governance structure is comprised of three key levels.

At the top level is the Board of Directors, who works to maintain a general understanding of the risk categories, the types of risks to which the Corporation may be exposed and the practices used to identify, assess, measure and manage those risks. Quarterly, the Board of Directors reviews the Corporation's risk profile, a list of key risks together with treatment activities that represents the greatest threats to meeting the Corporation's strategic objectives.

The second level is the ROC, a lead body to ensure systems are in place to identify, manage, and monitor risks. Through its review of reports from the business and control areas, the ROC assesses the appropriateness and consistent application of systems to manage risks within the Corporation. The ROC also ensures that key risks are brought forward to the attention of the Board and for action by executive management.

Finally, the third level is the Risk Forum. The Risk Forum supports the ROC and is a collection of subject matter experts from across the Corporation who actively engage in the day to day management of risks. Working with the ROC, the Risk Forum oversees the Corporation's risk profile, its performance against the defined risk appetite and determines appropriate risk responses. They also work to ensure effective, efficient, complete and transparent risk reporting to the ROC.

The Corporation is subject to a variety of risks including those described below:

Regulatory Developments

Ontario's electricity industry regulatory developments and policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation and/or its ability to provide reliable service to its customers. In particular, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates under the RRFE, at levels that will permit LDC to carry out its planned capital work programs required to maintain safe and reliable service to its customers and earn the allowed rate of return on the investment in the business;
- the regulatory instruments that arise from the RRFE will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates;
- the OEB will not set a lower recovery for LDC's cost of capital;
- the full cost of providing service to distribution customers will be permitted to be recovered through LDC's electricity distribution rates;
- the OEB will not permit competitors to provide distribution services in LDC's licensed area, or permit loads within LDC's service area to become electrically served by means other than through LDC's electricity distribution system;
- the OEB will allow recovery for revenue lost as a consequence of unanticipated effects of CDM;
- parts of LDC's services will not be separated from LDC and opened to competition; or
- regulatory or other changes will not be made to the PILs regime.

Changes to any of the laws, rules, regulations and policies applicable to the businesses carried on by the Corporation could also have a significant impact on the Corporation. There can be no assurance that the Corporation will be able to comply with applicable future laws, rules, regulations and policies. Failure by the Corporation to comply with applicable laws, rules, regulations and policies may subject the Corporation to civil or regulatory proceedings that may have a material adverse effect on the Corporation.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect.

Condition of Distribution Assets

LDC estimates that approximately one-third of its electricity distribution assets are past their expected useful lives. LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend, among other things, the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

LDC is focused on overcoming the above challenges and executing its maintenance program. However, if LDC is unable to carry out these plans in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of distribution assets, the ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets.

Information Technology Infrastructure

LDC's ability to operate effectively is in part dependent on the development, maintenance and management of complex information technology systems. Computer systems are employed to operate LDC's electricity distribution system and financial, billing and business systems to capture data and to produce timely and accurate information. Failures of any one of the financial, business and operating systems could have a material adverse effect on the Corporation's business, operating results, financial condition and prospects. The Corporation mitigates this risk through various methods including the use of security event management tools on its distribution and business systems, by separating the electricity distribution system from the business systems and by providing company-wide awareness training to personnel.

LDC's electricity distribution infrastructure and technology systems are also potentially vulnerable to damage or interruption from cyber attacks, which could have an adverse impact on its operations, financial conditions, brand and reputation. While LDC has implemented preventative measures to monitor and protect against cyber attacks and mitigate their effects, there can be no assurance that such measures will be completely effective in protecting LDC's electricity distribution infrastructure or assets from a cyber attack or the effects thereof.

Natural and Other Unexpected Occurrences

LDC's operations are exposed to the effects of natural and other unexpected occurrences, such as severe or unexpected weather conditions, terrorism and pandemics. In the current year, the City experienced two severe weather events, one of which (see "Ice Storm" above in the section entitled "Results of Operations – 2013 compared to 2012") had a significant financial impact. Although LDC's facilities and operations are constructed, operated and maintained to withstand such occurrences, there can be no assurance that they will successfully do so in all circumstances. Any major damage to LDC's facilities or interruption of LDC's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although the Corporation has insurance, if it sustained a large uninsured loss caused by natural or other unexpected occurrences, LDC would apply to the OEB for the recovery of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Electricity Consumption

LDC's electricity distribution rates are comprised of a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (e.g., principally sustained periods of hot or cold weather could increase the consumption of electricity, sustained periods of mild weather could decrease the consumption of electricity and general economic conditions could affect overall electricity consumption). Accordingly, there can be no assurance that LDC will earn the revenue requirement approved by the OEB.

Economic conditions could also lead to lower overall electricity consumption, particularly in the commercial customer segment, which is estimated to be the most sensitive to economic changes. Lower electricity consumption from customers could negatively impact LDC's revenue. On an annual basis, the Corporation estimates that a decrease of 1% in electricity consumption would reduce net revenue by approximately $3.5 million.

Market and Credit Risk

LDC is subject to credit risk with respect to customer non-payment of electricity bills. LDC is permitted to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (including letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limit and disconnection. In the event of an actual payment default and a corresponding bad debt expense incurred by LDC, approximately 80% of the expense would be related to commodity and transmission costs and the remainder to LDC's distribution revenue. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the bad debt expense from remaining customers. Established practice in such cases is that the OEB would examine any electricity distributor's application for recovery of extraordinary bad debt expenses on a case-by-case basis.

The Corporation is exposed to fluctuations in interest rates for the valuation of its post-retirement benefit obligations. The Corporation estimates that a 1% (100 basis point) increase in the discount rate used to value these obligations would decrease the accrued benefit obligation, as at December 31, 2013, by approximately $37.0 million, and a 1% (100 basis point) decrease in the discount rate would increase the accrued benefit obligation, as at December 31, 2013, by approximately $45.5 million.

As at December 31, 2013, aside from the valuation of its post-retirement benefit obligations, the Corporation was exposed to interest rate risk predominately from short-term borrowings under its commercial paper program, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. The Corporation estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.1 million to annual net financing charges.

Additional Debt Financing and Credit Rating

Cash generated from operations, after the payment of expected dividends, is not expected to be sufficient to repay existing indebtedness, fund capital expenditures and meet other obligations. The Corporation relies on debt financing through its medium-term note program, commercial paper program or existing credit facilities to repay existing indebtedness, finance the Corporation's daily operations, and fund capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including financial market conditions, the regulatory environment in Ontario, the Corporation's results of operations and financial condition, the ratings assigned to the debentures issued under the Corporation's medium-term note program by credit rating agencies, the current timing to maturity of the Corporation's debentures, the availability of the commercial paper market, and general economic conditions. See notes 11 and 13 to the Consolidated Financial Statements.

Should the Corporation's credit rating from both credit rating agencies fall below "A (minus)" with stable outlook (S&P) and "A (low)" with stable trend (DBRS), the Corporation and its subsidiaries may be required to post additional collateral with the IESO.

Work Force Renewal

Over the next decade, a significant portion of LDC's employees will become eligible for retirement, including potential retirements occurring in supervisory, trades and technical positions. Accordingly, LDC will be required to attract, train and retain skilled employees. There can be no assurance that LDC will be able to attract and retain the required workforce.

Labour Relations

The Corporation's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions to adapt to changing circumstances. The Corporation's ability to make such changes, in turn, will continue to depend in part on its relationship with its labour unions and its ability to develop plans and approaches that are acceptable to its labour unions. There can be no assurance that the Corporation will be able to secure the support of its labour unions.

Insurance

Although the Corporation maintains insurance, there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable or that insurance will continue to be available. In addition, there can be no assurance that liability insurance will cover all losses or liabilities that might arise in the conduct of the Corporation's business. The Corporation self-insures against risks (e.g., business interruption and physical damage to certain automobiles). The occurrence of a significant uninsured claim or a claim in excess of the insurance coverage limits maintained by the Corporation could have a material adverse effect on the Corporation's results of operations and financial position.

Conflicts of Interest

The City owns all of the outstanding shares of the Corporation and has the power to determine the composition of the Board of Directors of the Corporation and influence the Corporation's major business and corporate decisions, including its financing programs and dividend payments. A conflict may arise between the City's role as the sole

shareholder of the Corporation and its role as the administrator of the City's budget and other matters for the residents of the City.

Change of Ownership

The City may decide to sell all or part of the Corporation. In the case of such event, depending on the nature of the transaction, the Corporation's credit ratings could be negatively affected.

Real Property Rights

Certain terminal stations and municipal sub-stations of LDC are located on lands owned by the Province, the City and others. In some cases, LDC does not have and may not be able to obtain formal access agreements with respect to such facilities. Failure to obtain or maintain access agreements could adversely affect LDC's operations.

LDC Competition

In the past, there had been one electricity distributor in each region of Ontario. Under the current regulatory regime, a person must obtain a licence from the OEB in order to own and operate an electricity distribution system. LDC has the right to distribute electricity in the City. Although the distribution licence specifies the area in which the distributor is authorized to distribute electricity, unless otherwise provided, the licence does not provide exclusive distribution rights for such area.

The Corporation believes that the complexities and potential inefficiencies that would be created by having multiple electricity distributors authorized to serve a single area are likely to result in the continuation of the practice of having a single electricity distributor authorized to serve a single area. In addition, the Corporation believes that there are significant barriers to entry with respect to the business of electricity distribution in Ontario, including the cost of maintaining an electricity distribution system, OEB regulation of electricity distribution rates and the level of regulatory compliance required to operate an electricity distribution system. However, the Corporation recognizes that more than one distribution licence could be issued for the same area and there is a possibility that in the future some business functions or activities could be separated from LDC and made open to competition from non-regulated business entities, or that defined geographical areas within LDC's service area may be electrically supplied by a means other than through LDC's electricity distribution system.

Non-GAAP Financial Measures

The Corporation's MD&A includes references to "net revenues", which is a non-GAAP financial measure. The definition of net revenues is revenue minus the cost of purchased power. This measure does not have any standard meaning prescribed by US GAAP and is not necessarily comparable to similarly titled measures of other companies. The Corporation uses this measure to assess its performance and to further make operating decisions. Users of the MD&A utilize this measure to assess the Corporation's financial performance from ongoing operations.

Critical Accounting Estimates

The preparation of the Corporation's Consolidated Financial Statements in accordance with US GAAP requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments under different assumptions or conditions.

The following critical accounting estimates involve significant estimates and judgments used in the preparation of the Consolidated Financial Statements:

Revenue Recognition

Revenue from the sale of electricity is recorded on the basis of cyclical billings and includes an estimated amount for electricity delivered and not yet billed, the amount of which is impacted by energy demand, customer class usage patterns and composition, and weather conditions. Revenue related to eligible capital expenditures under the ICM

framework is recognized on the basis of in-service assets. Other revenues, which include revenues from electricity distribution related services, revenues from the delivery of street lighting services and revenues from demand billable activities, are recognized as the services are rendered.

Regulatory Assets and Liabilities

As at December 31, 2013, regulatory assets amounted to $241.5 million and were primarily related to the reclassification of ICM-related net eligible in-service capital expenditures and timing differences in the recognition of actuarial losses and prior service costs of post-retirement benefits. As at December 31, 2013, regulatory liabilities amounted to $183.1 million and were primarily related to deferred income tax assets payable to customers. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the disposition of these balances was assessed to no longer be probable, the balances would be recorded in the Corporation's consolidated statements of net income and comprehensive income in the period that the assessment is made. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

Employee Future Benefits

Employee future benefits other than pension provided by the Corporation include medical, dental and life insurance benefits, and accumulated sick leave credits. These plans provide benefits to employees when they are no longer providing active service. The accrued benefit obligation and net periodic benefit cost are calculated by independent actuaries using the projected unit credit method and based on assumptions that reflect management's best estimate. The assumptions were determined by management recognizing the recommendations of the Corporation's actuaries. There could be no assurance that actual employee future benefit cost will not differ significantly from the estimates calculated using management's assumptions.

Asset Retirement Obligations

The Corporation recognizes a liability for the future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties. The liability is recognized when an ARO is incurred and when the fair value can be reasonably estimated. AROs amounted to $6.3 million as at December 31, 2013 compared to $5.1 million as at December 31, 2012. See note 4 (n) and 15 to the Consolidated Financial Statements.

Significant Accounting Policies

The Consolidated Financial Statements of the Corporation have been prepared in accordance with US GAAP and are presented in Canadian dollars. In preparing the Consolidated Financial Statements, management makes estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy of Ontario, or the Ministry of Finance of Ontario. The significant accounting policies of the Corporation are summarized in notes 2 and 4 to the Consolidated Financial Statements.

Adoption of New Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities". The amendments require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the consolidated balance sheets. ASU No. 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. Retrospective application is required. The ASU No. 2013-01, "Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities", was issued in January 2013 to amend the scope of ASU No. 2011-11 to clarify that the disclosure requirements are limited to derivatives, repurchase and reverse repurchase agreements, and securities borrowing and lending transactions that are either offset in the consolidated balance sheets or subject to enforceable master netting arrangements or similar agreements. The adoption of these amendments did not have an impact on the Corporation's consolidated balance sheets and related disclosures.

Future Accounting Pronouncements

On July 21, 2011, the OSC granted an exemption to allow the Corporation to prepare its consolidated financial statements in accordance with US GAAP for its fiscal years beginning on or after January 1, 2012 but before January 1, 2015. In the absence of the exemption, the Corporation would have previously been required to adopt IFRS on January 1, 2012. On March 19, 2014, the Board of Directors of the Corporation approved the adoption of IFRS for the year beginning on January 1, 2015 due to the pending expiration of the exemption. Accordingly, the Corporation's consolidated financial statements for 2015 are expected to be prepared in accordance with IFRS and applied retrospectively to the Corporation's opening IFRS consolidated statement of financial position as at January 1, 2014.

The Corporation has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its consolidated financial statements. The Corporation believes that the impact on its financial statements could be material.

IFRS Conversion Project

As a result of above decision, the Corporation has initiated its IFRS conversion project, which was previously suspended as a result of the Corporation's decision to adopt US GAAP. The Corporation established a formal project governance structure. This structure includes a steering committee consisting of senior levels of management from finance, information technology and operations, among others. Regular progress reports are provided to senior executive management.

The Corporation's project consists of two phases:

1) the awareness and assessment phase; and
2) the design and implementation phase.

The Corporation updated its awareness and initial assessment during the fourth quarter of 2013. During the initial assessment it was determined that the areas of accounting differences with the highest potential impact to the Corporation are accounting for PP&E, PILs, employee future benefits, rate regulatory deferral accounts, as well as initial adoption of IFRS under the provisions of IFRS 1, First-time Adoption of IFRS ("IFRS 1"). The Corporation next updated the detailed assessment of accounting and disclosure differences which is expected to be completed in the first quarter of 2014. In parallel, a detailed assessment of the impact of the IFRS conversion on the Corporation's systems, processes and controls as well as other business, regulatory and tax impacts is also in process. During the awareness and assessment phase, the Corporation established a communication plan and a staff-training plan.

The Corporation has not yet started the design and implementation phase of the project. The design phase will involve establishing issue-specific working groups in each of the identified risk areas. The working groups will establish key milestones which include developing recommendations, analyzing financial system and internal control impacts, developing significant accounting policies, and carrying out ongoing discussions with external auditors, in each area. Based on the outcomes of each working group, the Corporation is currently determining the projected impacts of adopting IFRS on its financial statements after considering the options available under IFRS 1.

The roll-out of the changes developed in the design phase will take place during the implementation phase and involve the development of new accounting policies and accounting manuals and the associated training for the finance and operational teams, testing the effectiveness of the changes made to systems, a simulation of the financial reporting process, preparation of opening balance sheet at transition date and related reconciliations, assessing the ongoing impacts on the IFRS financial statements and related disclosures.

The Corporation has revised its project plan to reflect the necessary work involved in determining the impacts of adopting IFRS at the new adoption date of January 1, 2015. The following table provides certain key activities of the changeover plan and an assessment of the Corporation's progress at this time. This information reflects the Corporation's most recent assumptions and expectations. Circumstances may arise such as changes in IFRS, regulations, or economic conditions, which would affect these assumptions or expectations.

Key Activities	Status
Accounting policies & procedures:	
x High level review of major differences between US GAAP and IFRS x Establish issue-specific working groups in the identified risk areas x Detailed assessment of accounting and disclosure differences, accounting policy choices and IFRS 1 elections available x Develop recommendations and accounting policies through ongoing discussions with external auditors x Finalize new accounting policies and accounting manuals	x All accounting policy positions are in process x Final approval of the policies will be finalized in 2014 x Continue to monitor ongoing IASB projects and assess potential impacts x Accounting policies and procedure manuals continue to be updated based on the IASB project developments
Financial statements preparation:	
x Identify US GAAP to IFRS financial statements presentation differences and design interim and annual financial statements formats and related notes disclosures x Simulate the financial reporting process under IFRS x Prepare the opening balance sheet at the date of transition and IFRS 1 related reconciliations and disclosures x Assess ongoing impacts on the IFRS financial statements and related disclosures	x Developed drafted financial statements formats x Started testing of system related modifications to IFRS generated financial statements x Preparation of the opening balance sheet on transition date is in progress
Training & communication:	
x Provide training to affected finance and operational teams, management and the Board of Directors, and relevant committees thereof, including the audit committee x Develop and execute staff training plan, and roll out communication initiatives x Continue to update audit committee and senior management on a quarterly basis for key developments in IFRS and the potential impacts to the Corporation's financial statements	x Completed detailed training for resources directly engaged in the changeover and general awareness training to broader group of finance employees x Started topic-specific and relevant training to finance and operational teams on all finalized positions. Key areas include PP&E, PILs, employee benefits, provisions, capital contributions, borrowing cost and financial statement presentation x Continue ongoing, periodic internal and external communications on the Corporation's progress on the IFRS project and direction x Develop staff training plans with respect to regulatory deferral accounts

Key Activities	Status
Business impacts:	
x Evaluate impacts and implement necessary changes to debt covenants, internal performance measures, contracts and processes	x Impacts to debt covenants, regulatory and other business processes are being assessed
Information technology systems:	
x Analysis of financial system to identify required modifications x Test the effectiveness of the changes made to systems x Ensure solution captures financial information under US GAAP and IFRS during the year of transition for comparative reporting purposes	x Completed system changes for reporting purposes including subledger configurations for derecognition and depreciation on a component level. Further changes to information systems are to be made based upon the changes required to meet the regulatory deferral account standard x Complete the modifications to the system to accommodate the new transition date of January 1, 2014 and begin to accumulate IFRS data for reporting comparative information x Continue to implement remaining required modifications to financial systems
Control environment:	
x Detailed assessment of the impact of IFRS conversion on people, systems, processes and internal controls x Analyze and update internal control processes and documentation x Implement related controls and procedures to ensure the integrity and effectiveness of internal controls over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P")	x Based on the accounting policies and procedures developed, the Corporation continues to evaluate and document the impacts on new and existing controls to ensure the integrity and effectiveness of ICFR and DC&P x Additional controls may be required to address first-time IFRS adoption and new processes implemented to support ongoing IFRS reporting requirements. These controls will be implemented and tested on a timely basis for reporting under IFRS in 2015.

In general, a first-time adopter is required to apply the IFRS standards retrospectively and recognize any consequential adjustments in retained earnings. IFRS 1 sets out all of the transitional requirements applicable for the first-time adoption of IFRS. Several mandatory and optional exemptions to the retrospective application are available. The Corporation has considered the impacts of IFRS 1 and an initial assessment has been made as to which exemptions would be elected upon transition. At this time, the impact on the Corporation's future financial position and results of operations is not reasonably determinable. In addition, during the year of 2014 until the transition, changes to IFRS may impact exemptions available for first-time adopters, and in turn, may change the Corporation's original assessments and policy selections.

The Corporation has completed a detailed assessment of the accounting and disclosure differences between US GAAP and IFRS and identified the following areas as having the potential to materially impact the consolidated financial statements on the date of transition to IFRS and post-IFRS implementation.

Risk Areas	Key Differences IFRS vs. US GAAP	Potential Key Impacts
IAS 12 - Income Taxes	IAS 12 requires that a deferred tax asset is recognized to the extent it is probable that it will be realized - i.e. a net approach, whereas US GAAP allows all deferred tax assets being recognized and a valuation allowance being recognized to the extent that it is more likely than not that the deferred tax assets will not be realized - i.e. a gross approach.	Currently a valuation allowance has been established for certain capital loss carryforwards and allowed tax depreciation under US GAAP. All other deferred tax assets are considered more likely than not to be realized. The impact of adopting IAS 12 is one of disclosure only as the net deferred tax assets recorded would be similar under both standards.
IAS 16 - PP&E	IAS 16 requires that the estimates of useful life and residual value, and the method of depreciation, are reviewed at a minimum at each annual reporting period. Any changes are accounted for prospectively as a change in estimate. The carrying amount of an item of PP&E shall be derecognized upon disposal or when no future economic benefits are expected. The gain or loss arising from the derecognition of an item of PP&E shall be included in profit or loss (unless IAS 17 requires otherwise on a sale and leaseback). Gains shall not be classified as revenue.	As a result of adoption of IAS 16, useful lives and residual value will need to be reviewed annually. The Corporation will be derecognizing all items of PP&E as soon as they are taken out of service. PP&E will decrease with a corresponding increase to depreciation expense.

Risk Areas	Key Differences IFRS vs. US GAAP	Potential Key Impacts
IAS 19 - Employee Benefits	IAS 19 does not specify whether an entity should distinguish current and non-current portions related to post-employment benefits. Under US GAAP, the amount of the actuarial present value of benefits included in the benefit obligation which is expected to be paid in the next 12 months is classified as current. Actuarial gains or losses of defined benefit plans are recognized immediately in OCI and cannot be recycled into profit or loss. The corridor method, which is permitted under US GAAP has been eliminated under IFRS. For other long-term benefits other than post-employment benefits, IAS 19 requires benefits that are expected to be settled wholly before twelve months after the end of the annual reporting period in which the employees render the related service to be classified as current. Under IFRS, short-term benefits that accumulate are recognized even when the benefit is non-vested, as opposed to US GAAP, in which recognition of such benefits is permitted but not mandatory.	Based on preliminary assessments, the Corporation will elect to account for all post-employment benefits as non-current under IFRS. All actuarial gains and losses related to post-employment benefits will be recognized immediately into OCI under IFRS and will not be allowed to be recycled to profit or loss. The Corporation's long-term benefits are not expected to be wholly settled within 12 months and therefore will remain as non-current under IFRS. As a result of adoption of IAS 19, the Corporation will need to accrue for the required employee benefits liability.
IAS 23- Borrowing Costs	The core principle of IAS 23 is that borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset form part of the cost of that asset. Other borrowing costs are recognized as an expense in the period in which they are incurred. Borrowing costs under IFRS are calculated using the weighted average interest rate of the Corporation's general borrowings, including borrowing costs previously capitalized, as opposed to the OEB prescribed rate on a simple interest basis permitted under US GAAP. Borrowing costs should also be capitalized as soon as the asset meets the conditions of commencement date as opposed to the current practice, in which costs can be capitalized after the 6 month mark.	Based on preliminary assessments, it is expected that additional borrowing costs would be capitalized as a result of the adoption of IAS 23.
IAS 37 - Provisions, Contingent Assets and Liabilities	IAS 37 requires a discount rate that reflects current market assessments of the time value of money and risks specific to the liability, whereas US GAAP requires the use of a credit-adjusted risk-free rate.	Based on preliminary assessments, the impact on the date of transition when using the IFRS 1 optional exemption is an increase to decommissioning provisions, a decrease to PP&E, and a decrease to opening retained earnings.
IFRIC 18 - Transfer Assets from Customers (Capital Contributions)	IFRIC 18 does not allow for the netting of capital contributions received against items of PP&E.	Based on preliminary assessments, there will be a reclassification between PP&E, and unearned revenue liability. The capital contribution will be amortized, and recognized into revenue opposed to against depreciation under US GAAP. Presentation differences will have no impact on the net income reported.
IFRS 14 – Regulatory Deferral Accounts	The Corporation is in the process of determining key differences.	The Corporation is in the process of determining key differences.

Forward-Looking Information

The Corporation includes forward-looking information in its MD&A within the meaning of applicable securities laws in Canada. The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "aims", "anticipates", "believes", "budgets", "committed", "could", "estimates", "expects", "focus", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "strives", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management.

The forward-looking information in the MD&A includes, but is not limited to, statements regarding the Corporation's achievement of its strategic pillars as described in the section entitled "Corporate Strategy", the Corporation's plans to borrow funds to repay maturing debentures and to finance the investment in LDC's infrastructure and the Corporation's available sources of liquidity and capital resources and the sufficiency thereof to satisfy working capital requirements for the next 12 months as described in the sections entitled "Liquidity and Capital Resources" and "Additional Debt Financing and Credit Rating", the anticipated capacity to be provided by Copeland Station and the expected capital expenditures required to complete Copeland Station as described in the section entitled "Liquidity and Capital Resources", the ability to pay any damages in connection with legal actions and claims as described in the section entitled "Legal Proceedings", the impact of market volatility on the Corporation's consolidated results of operations, performance, business prospects and opportunities as described in the section entitled "Quarterly Results of Operations", the effect of changes in energy consumption on future revenue as described in the section entitled "Electricity Consumption", the effect of changes in interest rates and discount rates on future revenue requirements and future post-retirement benefit obligations, respectively, as described in the section entitled "Market and Credit Risk", changes in accounting estimates as described in the section entitled "Significant Accounting Policies", and the plan in connection with the IFRS conversion project and progress of the regulatory deferral account project as described in the section entitled "Future Accounting Pronouncements". The statements that make up the forward-looking information are based on assumptions that include, but are not limited to, the future course of the economy and financial markets, the receipt of applicable regulatory approvals and requested rate orders, the receipt of favourable judgments, the level of interest rates and the Corporation's ability to borrow, and the effectiveness of the potential future transition to IFRS by the Corporation.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, market liquidity and the quality of the underlying assets and financial instruments, the timing and extent of changes in prevailing interest rates, inflation levels, legislative, judicial and regulatory developments that could affect revenues and the results of borrowing efforts.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

Selected Annual Information

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2013, 2012 and 2011. This information has been derived from the Consolidated Financial Statements.

Selected Annual Consolidated Financial Information
(in thousands of Canadian dollars)

	2013 $	2012 $	2011[1] $
Year Ended December 31,			
Net revenues[2]	635,281	577,268	586,929
Operating expenses[2]	271,958	245,173	262,241
Net income[2]	121,241	85,990	95,932
Capital expenditures[3]	450,314	292,375	437,067
As at December 31,			
Total assets[4]	3,797,531	3,539,354	3,527,507
Total debentures[4,5]	1,449,332	1,469,590	1,469,527
Other non-current financial liabilities[6]	15,531	16,175	27,101
Shareholder's equity[4]	1,218,518	1,140,272	1,102,248
Dividends[3]	42,995	47,966	33,063
Total debt to capitalization ratio[7]	57.0%	56.3%	57.1%
Return on equity[8]	10.3%	7.7%	9.0%

[1] The Corporation's consolidated financial statements were prepared in accordance with Part V of Canadian GAAP until December 31, 2011. Selected financial information from comparative consolidated financial statements for 2011 have been adjusted retroactively from the consolidated financial statements previously filed to conform to the presentation of the Corporation's 2012 and 2013 consolidated financial statements prepared in accordance with US GAAP.

[2] See "Results of Operations" for further details on net revenues, operating expenses and net income.

[3] See "Liquidity and Capital Resources" for further details on capital expenditures and dividends.

[4] See "Financial Position" for further details of significant changes in assets, debentures and shareholder's equity.

[5] Total debentures include current and long-term debentures.

[6] Other non-current financial liabilities include non-current obligations under capital lease and non-current customers' deposits. Under US GAAP, deposits that are due or will become due on demand within one year from the end of the reporting period have been reclassified to other current financial liabilities.

[7] Total debt to capitalization ratio = (total debt) / (total debt + total shareholder's equity), where total debt = (working capital facility + commercial paper + revolving credit facility + current portion of debentures + long-term portion of debentures).

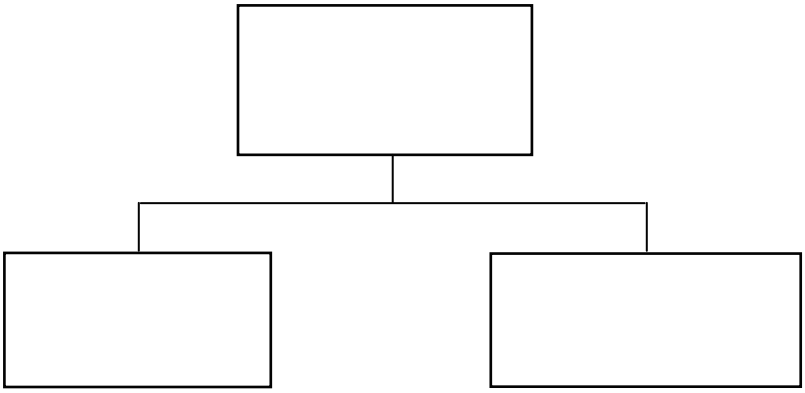
[8] Return on equity = net income / average total shareholder's equity. Return on equity is measured over a 12-month period.

Additional Information

Additional information with respect to the Corporation, including its annual information form) is available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com

Toronto, Canada

March 19, 2014



Toronto Hydro is subject to extensive federal, provincial and local regulation relating to the protection of the environment. The principal federal legislation is the Canadian Environmental Protection Act which regulates the use, import, export and storage of toxic substances, including PCBs and ozone-depleting substances. Toronto Hydro is also subject to the federal Transportation of Dangerous Goods Act which prescribes safety standards and requirements for the handling and transportation of hazardous goods including PCBs and sets out reporting, training and inspection requirements relating thereto.

The principal provincial legislation is the Environmental Protection Act which regulates releases and spills of contaminants, including PCBs, ozone-depleting substances and other halocarbons, contaminated soil management, and the monitoring and reporting of and liability for contaminant discharge. The provincial Technical Standards and Safety Act also applies to Toronto Hydro's operations with respect to the handling of and training related to compressed gas, propane and liquid fuels. The provincial Fire Protection and Prevention Act requires Toronto Hydro to incorporate procedures and training for dealing with any spills of flammable or combustible liquids. The provincial Dangerous Goods Transportation Act prescribes safety standards and requirements for transportation of dangerous goods on provincial highways and sets out inspection requirements related thereto.

Municipal by-laws regulate discharges of industrial sewage and storm water run-off to the municipal sewer system and the reporting of the release of certain toxic substances into the atmosphere.

In 2013, LDC spent approximately $4.4 million to meet environmental protection requirements. These costs are not anticipated to significantly increase for future years, and do not currently have a material impact on the Corporation's financial and operational results.

The Corporation recognizes a liability for the future environmental remediation of certain properties and for future removal and handling costs for contamination in electricity distribution equipment in service and in storage. The liability is recognized when the asset retirement obligation is incurred and when the fair value is determined. As at December 31, 2013, the Corporation's asset retirement obligations amounted to $6.3 million. See notes 4 and 15 to the Consolidated Financial Statements.

PUBLIC OFFERING INFORMATION

In accordance with section 2.4.3 of the OEB Filing Requirements (July 17, 2013), this schedule includes the following information about Toronto Hydro's recent public offerings:

- Appendix A: Prospectus, issued 10 December 2012;
- Appendix B: 8th Supplemental Trust Indenture, issued November 2011;
- Appendix C: 9th Supplemental Trust Indenture, issued April 2013; and
- Appendix D: 10th Supplemental Trust Indenture, issued April 2013.

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. The securities to be issued hereunder have not been and will not be registered under the United States Securities Act of 1933, as amended, and, subject to certain exceptions, may not be offered or sold within the United States or to United States persons. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer, Toronto Hydro Corporation, 14 Carlton Street, Toronto, Ontario, M5B 1K5, (416) 542-3100 and are also available electronically at www.sedar.com.

SHORT FORM BASE SHELF PROSPECTUS

New Issue December 10, 2012

TORONTO HYDRO CORPORATION

$1,500,000,000 DEBENTURES
(unsecured)

Toronto Hydro Corporation (the "Corporation") may offer and issue from time to time unsecured debentures (the "Debentures") in one or more series in an aggregate principal amount of up to $1,500,000,000 (or the equivalent thereof in foreign currencies or currency units if any of the Debentures are denominated in foreign currencies or currency units) during the twenty-five months from the date of this prospectus. The Debentures will be offered pursuant to an MTN program established by the Corporation.

The Debentures will be issued under a trust indenture dated May 7, 2003 (as supplemented from time to time by supplemental indentures), will be direct unsecured obligations of the Corporation and will rank equally (except as to sinking funds and to the extent prescribed by law) with all other unsecured and unsubordinated indebtedness of the Corporation. The Debentures will have a term to maturity of not less than one year and will be issuable in denominations of $1,000 or more. The Debentures may be issued in Canadian dollars or any foreign currency or currency unit determined at the time of issue.

The specific terms of an offering of Debentures (including the aggregate principal amount of the Debentures being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate, the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling the Corporation to extend the maturity date of the Debentures, the name(s) of the dealer(s) offering the Debentures, the commission payable to such dealer(s), the method of distribution and the net proceeds to the Corporation) will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. The Corporation reserves the right to set forth in a pricing supplement specific terms of Debentures which are not within the parameters set forth in this prospectus.

The sole shareholder of the Corporation is the City of Toronto. The Debentures will not be obligations of, and will not be guaranteed in any manner by, the City of Toronto.

There is no market through which the Debentures may be sold and purchasers may not be able to resell Debentures purchased under this prospectus. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures and the extent of issuer regulation. See "Risk Factors". Unless otherwise indicated in a pricing supplement, the Debentures will not be listed on any securities exchange.

RATES ON APPLICATION

(continued on next page)

(continued from cover)

The Debentures may be offered by one or more dealers as selected from time to time by the Corporation (collectively, the "Dealers"), in each case, acting as agent of the Corporation or as principal. Where the Debentures are offered by the Dealer(s) as agent(s), the commissions payable by the Corporation in connection with sales of such Debentures shall be agreed from time to time between the Corporation and any such Dealer(s). Where the Debentures are purchased by the Dealer(s) as principal, the Debentures shall be purchased at such prices and with such commissions as may be agreed from time to time between the Corporation and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Debentures by purchasers exceeds or is less than the price paid by the Dealer, acting as principal, to the Corporation. The commissions payable in connection with sales of Debentures will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. The Corporation may also offer the Debentures directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and the Corporation. The Corporation and, if applicable, the Dealers, may reject any offer to purchase the Debentures in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify the offering of the Debentures under this prospectus without notice. The Dealers may over-allot or effect transactions which stabilize or maintain the market price of the Debentures offered at a level above that which might otherwise prevail in the open market. See "Plan of Distribution".

The offering of the Debentures is subject to the approval of certain legal matters on behalf of the Corporation by McMillan LLP.

The registered and head office of the Corporation is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

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DOCUMENTS INCORPORATED BY REFERENCE

The following documents of the Corporation filed with the provincial securities regulatory authorities in Canada are incorporated by reference in this prospectus for the purposes of the offering of Debentures hereunder:

(a) the annual information form (the "AIF") of the Corporation dated March 29, 2012;

(b) the comparative audited consolidated financial statements of the Corporation together with the auditors' report thereon and the notes thereto as at and for the years ended December 31, 2011 and December 31, 2010;

(c) management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2011;

(d) the comparative unaudited interim consolidated financial statements of the Corporation together with the notes thereto as at and for the three-month and nine-month periods ended September 30, 2012 and September 30, 2011 and management's discussion and analysis relating thereto;

(e) earnings coverage ratios for the twelve-month periods ended December 31, 2011 and September 30, 2012; and

(f) the Ernst & Young LLP auditors' report on the financial statements as at and for the year ended December 31, 2010 referred to in item (b).

All material change reports, business acquisition reports and unaudited interim consolidated financial statements of the Corporation (and management's discussion and analysis relating thereto) filed by the Corporation after the date of this prospectus with the securities regulatory authorities in Canada will be deemed to be incorporated by reference in this prospectus for the purposes of the offering of Debentures hereunder.

Updated earnings coverage ratios will be filed quarterly with the provincial securities regulatory authorities in Canada and will be deemed to be incorporated by reference in this prospectus for the purposes of the offering of Debentures hereunder.

When new documents of the type referred to in paragraphs (a), (b) and (c) above are filed by the Corporation with and, where required, accepted by the provincial securities regulatory authorities in Canada during the currency of this prospectus, such documents will be deemed to be incorporated by reference in this prospectus and the previous documents of the type referred to in paragraphs (a), (b) and (c) above and all material change reports, business acquisition reports, unaudited interim consolidated financial statements (and management's discussion and analysis relating thereto) and prospectus supplements filed by the Corporation with the provincial securities regulatory authorities in Canada before the commencement of the Corporation's financial year in which the new documents are

filed will no longer be deemed to be incorporated by reference in this prospectus for the purposes of the future offering of Debentures hereunder.

A pricing supplement containing the specific variable terms for an issue of Debentures will be delivered to purchasers of such Debentures together with this prospectus and will be deemed to be incorporated by reference in this prospectus as of the date of the pricing supplement, solely for the purposes of the Debentures issued under that pricing supplement.

Any statement contained in this prospectus or in a document incorporated or deemed to be incorporated by reference herein will be deemed to be modified or superseded, for purposes of this prospectus, to the extent that a statement contained herein or in a document incorporated or deemed to be incorporated by reference herein modifies or supersedes such prior statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded will not constitute a part of this prospectus, except as so modified or superseded.

FORWARD-LOOKING INFORMATION

Certain information included or incorporated by reference in this prospectus constitutes "forward-looking information". The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information. The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management considers to be reasonable in the circumstances. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information, including, without limitation, the following factors: the outcome of outstanding rate applications and other proceedings before the OEB, the timing and amount of future cash flows generated by the Corporation's investments, market liquidity and the quality of the underlying assets and financial instruments; the timing and extent of changes in prevailing interest rates; inflation levels; legislative, judicial and regulatory developments that could affect revenues, accounting policies or the business carried on by Toronto Hydro; LDC's ability to continue to maintain and operate the distribution system reliably and safely in the future; LDC's ability to develop, maintain and manage a complex information technology systems infrastructure; the volume of electricity consumed by LDC's customers; credit risk with respect to customer non-payment; the Corporation's ability to arrange sufficient and cost-effective debt financing; Toronto Hydro's ability to attract and retain the required workforce; the effects of natural and other unexpected occurrences; Toronto Hydro's ability to obtain or maintain adequate insurance to cover losses or liabilities that might arise at rates it considers reasonable; Toronto Hydro's compliance with Canadian, federal, provincial and municipal environmental regulation (changes in environmental regulation or enforcement may impose material additional costs on Toronto Hydro); material changes in Toronto Hydro's assessment of the estimated fair value of its investments; a credit rating change; Toronto Hydro's ability to develop plans and approaches that are acceptable to its labour unions; the risks associated with being controlled by the City of Toronto as well as potential conflicts of interest that may arise between Toronto Hydro, the City of Toronto and related parties; Toronto Hydro's ability to obtain formal access agreements with respect to certain terminal stations and municipal substations located on lands owned by the Province of Ontario, the City of Toronto and others; and more than one distribution licence could be issued for the same area and there is a possibility that in the future some business functions or activities could be separated from LDC and made open to more competition from non-regulated business entities, or that defined geographical areas within LDC's service area may be electrically supplied by a means other than through LDC's system. All of the forward-looking information included or incorporated by reference in this prospectus is qualified by these cautionary statements and those made in the "Risk Factors" section of this prospectus and the comparable sections of the documents incorporated or deemed to be incorporated by reference in this prospectus (including the Corporation's annual information form and the management's discussion and analysis of financial condition and results of operations accompanying the financial statements of the Corporation). These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information

made herein or in the documents incorporated by reference. The Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Capitalized terms used in this section without definition, have the meanings given to them elsewhere in this prospectus.

CURRENCY

Unless otherwise specified, all references to dollars contained in this prospectus are to Canadian dollars.

TORONTO HYDRO

Toronto Hydro Corporation (the "Corporation" and, together with its subsidiaries, "Toronto Hydro") is a holding company which, through its wholly-owned subsidiaries:

- Toronto Hydro-Electric System Limited ("LDC") – distributes electricity and engages in conservation and demand management activities; and
- Toronto Hydro Energy Services Inc. – provides street lighting services.

The principal business of Toronto Hydro is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system located in the City of Toronto. LDC is the largest municipal electricity distribution company in Canada. The business of LDC is regulated by the Ontario Energy Board ("OEB") which has broad powers relating to licensing and standards of conduct and service and the regulation of rates charged by LDC and other electricity distributors.

The sole shareholder of the Corporation is the City of Toronto.

USE OF PROCEEDS

The net proceeds from the sale of Debentures will be used by the Corporation for general corporate purposes. Proceeds from the sale of the Debentures may also be used to reduce indebtedness that the Corporation may have with the bank affiliates of one or more of the Dealers (as defined below).

PLAN OF DISTRIBUTION

The Debentures may be offered by one or more dealers as selected from time to time by the Corporation (collectively, the "Dealers"), in each case, acting as agent of the Corporation or as principal. Where the Debentures are offered by the Dealer(s) as agent(s), the commissions payable by the Corporation in connection with sales of such Debentures shall be agreed from time to time between the Corporation and any such Dealer(s). Where the Debentures are purchased by the Dealer(s) as principal, the Debentures shall be purchased at such prices and with such commissions as may be agreed from time to time between the Corporation and any such Dealer(s). Resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Debentures by purchasers exceeds or is less than the price paid by such Dealer, acting as principal, to the Corporation. The commissions payable in connection with sales of Debentures will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. The Corporation may also offer the Debentures directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and the Corporation.

The Corporation may enter into one or more dealer agreements with the Dealers relating to the sale of Debentures under this prospectus. A copy of the dealer agreement(s) will be filed with the securities regulatory authorities in each of the provinces of Canada following its execution.

The Corporation and, if applicable, the Dealers, may reject any offer to purchase the Debentures in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify the offering of the Debentures under this prospectus without notice.

In connection with any offering of Debentures, the Dealers may over-allot or effect transactions which stabilize or maintain the market price of the Debentures offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time. In addition, the Dealers may, from time to time purchase and sell the Debentures in the secondary market but are not obliged to do so. There can be no assurance that there will be a secondary market for the Debentures. The offering price and other terms for such sales in the secondary market may, from time to time, be varied by the Dealers.

The Debentures have not and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), or any state securities laws, and may not be offered or sold within the United States or to United States persons unless registered under the U.S. Securities Act and applicable state securities laws or an exemption therefrom is available. Each of the Dealers will agree not to buy or offer to buy, to sell or offer to sell, or

solicit any offer to buy any Debentures in the United States of America, its territories or possessions, or to or for the account or benefit of United States persons, except to "qualified institutional buyers" in accordance with Rule 144A under the U.S. Securities Act. Debentures issued to qualified institutional buyers pursuant to Rule 144A under the U.S. Securities Act will be represented by definitive certificates and will be subject to certain restrictions on transfer set forth therein and in the supplemental indenture and will bear a legend regarding such restrictions as set forth in the supplemental indenture. This prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of the Debentures in the United States. In addition, until 40 days after the commencement of the offering of an issue of Debentures, an offer or sale of that issue within the United States by any Dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A under the U.S. Securities Act.

RATINGS

The Debentures have been assigned a rating of "A (high)" with a stable trend by DBRS Limited ("DBRS") and "A" by Standard &Poor's ("S&P").

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". A DBRS rating may be modified by the addition of "high" or "low" to indicate relative standing within the major rating categories. Long-term debt instruments which are rated in the "A" category by DBRS are considered to be of "good credit quality", with substantial capacity for the payment of financial obligations. Entities in the "A" category, however, are considered to be more vulnerable to future events, but qualifying negative factors are considered manageable. An A rating is the second of the three sub-categories within the third of the ten rating categories. S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". An S&P rating may be modified by the addition of a plus or minus sign to indicate relative standing within the major rating categories. Long-term debt instruments which are rated in the "A" category by S&P are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitment on the obligation is still strong. An A rating is the second of the three sub-categories within the third of the ten rating categories.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating agency.

DESCRIPTION OF THE DEBENTURES

The Debentures will be issued in one or more series under a trust indenture dated May 7, 2003 between the Corporation and BNY Trust Company of Canada (the "Trustee", which term shall include, unless the context requires otherwise, its successors), as supplemented from time to time by supplemental indentures (together, the "Indenture"). The Indenture permits the issuance of an unlimited principal amount of debentures of the Corporation in one or more series. The terms of each series of debentures issued pursuant to the Indenture will be specified in a supplemental indenture to the Indenture. A copy of the Indenture is available electronically at www.sedar.com.

The specific terms of an offering of Debentures (including the aggregate principal amount of the Debentures being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate, the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling the Corporation to extend the maturity date of the Debentures, the name(s) of the Dealer(s) offering the Debentures, the commission payable to such Dealer(s), the method of distribution and the net proceeds to the Corporation) will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. Unless otherwise indicated in a pricing supplement, the Debentures will not be listed on any securities exchange. The Corporation reserves the right to set forth in a pricing supplement specific terms of Debentures which are not within the parameters set forth in this prospectus.

The following is a summary of the material attributes of the Debentures. This summary does not purport to be complete. For a complete description of the Debentures, reference should be made to the Indenture. Certain capitalized terms used in this summary are defined below under "Definitions".

Term, Denomination and Currency

The Debentures will have a term to maturity of not less than one year and will be issuable in denominations of $1,000 or more. The Debentures may be issued in Canadian dollars or any foreign currency or currency unit determined at the time of issue.

Interest

The Debentures will bear interest at fixed or floating rates as set out in the applicable pricing supplement to this prospectus.

Rank

The Debentures will be direct unsecured obligations of the Corporation and will rank equally (except as to sinking funds and to the extent prescribed by law) with all other unsecured and unsubordinated indebtedness of the Corporation, including indebtedness of the Corporation under a $600 million revolving credit facility with a syndicate of Canadian banks (the "THC Revolving Credit Facility"), two bilateral credit facilities under which up to $95 million is available from two Canadian banks (the "Bilateral Credit Facilities") and debentures of every other series issued pursuant to the Indenture.

The Debentures will not be obligations of, and will not be guaranteed in any manner by, the City of Toronto.

Redemption

If so specified in the applicable pricing supplement, a series of Debentures may be redeemed, at the Corporation's option, in whole at any time or in part from time to time, prior to maturity, on not more than 60 and not less than 15 business days prior notice, at the redemption price, together in each case with accrued and unpaid interest to, but not including, the date fixed for redemption. The applicable pricing supplement will specify the redemption price (or the manner of calculating the redemption price), if any, for the series of Debentures.

If less than all Debentures of any series of Debentures are to be redeemed, the Debentures to be redeemed will be selected by the Trustee on a pro rata basis or by lot or such other means as the Trustee may deem equitable and expedient.

Purchase for Cancellation

The Corporation may, at any time, purchase Debentures for cancellation, in the open market, by tender or by private contract, at any price.

Covenants

Negative Pledge

The Corporation will not, and will not permit any Designated Subsidiary to, create, assume or suffer to exist any Security Interest, other than Permitted Encumbrances, over any of its assets (present or future) to secure any Obligation, unless at the same time it shall secure equally and rateably therewith all the Debentures issued pursuant to the Indenture then outstanding.

Limitation on Funded Indebtedness

The Corporation will not, and will not permit any Designated Subsidiary to, directly or indirectly, issue, incur, assume or otherwise become liable for or in respect of any Funded Indebtedness unless, after giving effect thereto, Consolidated Funded Indebtedness would not exceed 75% of Total Consolidated Capitalization. This covenant will not operate to prevent the Corporation or a Designated Subsidiary from issuing, incurring, assuming or otherwise becoming liable for or in respect of any Inter-Company Indebtedness and Non-Speculative Financial Instrument Obligations. This covenant will operate to prevent the Corporation or a Designated Subsidiary from assigning any Inter-Company Indebtedness to a person other than the Corporation or a Designated Subsidiary.

Limitation on Designated Subsidiary Indebtedness

The Corporation will not permit a Designated Subsidiary to, directly or indirectly, issue, incur, assume or otherwise become liable for or in respect of any Indebtedness except:

(a) Inter-Company Indebtedness of the Designated Subsidiary;

(b) Non-Recourse Debt of the Designated Subsidiary;

(c) Non-Speculative Financial Instrument Obligations of the Designated Subsidiary;

(d) Permitted Capital Lease Obligations of the Designated Subsidiary;

(e) Prudential and Bilateral Credit Support Obligations of the Designated Subsidiary;

(f) Purchase Money Obligations of the Designated Subsidiary; and

(g) any other Indebtedness of the Designated Subsidiary (in addition to the Indebtedness referred to in paragraphs (a) to (f)) if, after giving effect to the Indebtedness, the aggregate amount of all Indebtedness of all Designated Subsidiaries incurred by this paragraph (g) only would not exceed 5% of Consolidated Net Worth.

For the purposes of this covenant, the assignment by the Corporation to a third party of Inter-Company Indebtedness owing by a Designated Subsidiary will be considered to be an incurrence of Indebtedness by such Designated Subsidiary.

Designation of Subsidiaries as Designated Subsidiaries

LDC is a Designated Subsidiary. The board of directors of the Corporation may designate a subsidiary of the Corporation in addition to LDC as a Designated Subsidiary if:

(a) at the time of and after giving effect to the designation, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing;

(b) after giving effect to the designation, the Corporation would be entitled under the Indenture to issue Funded Indebtedness in the amount of at least $1.00; and

(c) none of the shares of the subsidiary is owned by another subsidiary of the Corporation that is not a Designated Subsidiary.

The board of directors of the Corporation may terminate the designation of a subsidiary of the Corporation other than LDC as a Designated Subsidiary if:

(a) at the time of and after giving effect to the termination, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing;

(b) after giving effect to the termination, the Corporation would be entitled under the Indenture to issue Funded Indebtedness in the amount of at least $1.00; and

(c) the subsidiary does not own any Funded Indebtedness of the Corporation or any shares or Funded Indebtedness of any other Designated Subsidiary.

Restriction on Mergers and Dispositions

The Corporation will not, directly or indirectly through a Designated Subsidiary, enter into a transaction or series of transactions in which all or substantially all of the undertaking, property and assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis would become the property of any other person, whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale, lease or otherwise, unless:

(a) the person is a corporation organized and existing under the laws of Canada or a province or territory thereof and expressly assumes, by a supplemental indenture satisfactory in form to the Trustee and its counsel and executed and delivered to the Trustee, all of the covenants and obligations of the Corporation under the Indenture and all debentures issued pursuant to the Indenture; and

(b) at the time of and after giving effect to the reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale, lease or other transaction, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing.

Events of Default

The following are Events of Default applicable to a series of debentures, including each series of Debentures, issued pursuant to the Indenture:

(a) failure to pay principal or premium (if any) on the debentures when due;

(b) failure to pay interest on the debentures when due if such failure continues for a period of 30 days;

(c) the sale, transfer, lease or other disposition of all or substantially all of the property and assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis other than in accordance with the covenants described above under "– Covenants – Restriction on Mergers and Dispositions";

(d) failure to observe or perform any other covenant or condition contained in the Indenture if such failure continues for a period of 60 days after written notice thereof has been given to the Corporation by the Trustee or the holders of at least 25% in principal amount of the debentures of any affected series then outstanding;

(e) failure by the Corporation or any Material Subsidiary to pay principal, premium (if any) or interest due on any Indebtedness, the principal amount of which is more than $50 million in the aggregate, beyond the applicable grace period;

(f) failure by the Corporation or any Material Subsidiary to observe or perform any provision of any agreement under which Indebtedness is created if such failure has the effect of causing more than $50 million of such Indebtedness in the aggregate to become due and payable or to be required to be redeemed or repurchased before its stated maturity;

(g) the rendering by a court of competent jurisdiction of one or more judgments against the Corporation or any Material Subsidiary in an aggregate amount of more than $50 million if the judgments remain undischarged or unstayed for more than 30 days; and

(h) specified events of bankruptcy, insolvency or reorganization affecting the Corporation or any Material Subsidiary.

Default

If an Event of Default described in paragraphs (a) to (g) above occurs and is continuing, the Trustee or the holders of not less than 25% of the principal amount of debentures of a series of debentures issued pursuant to the Indenture then outstanding may declare the principal amount of, and the premium (if any) and accrued and unpaid interest on all debentures of that series then outstanding to be due and payable immediately.

If an Event of Default described in paragraph (h) above occurs and is continuing, the principal amount of and the premium (if any) and accrued and unpaid interest on all debentures issued pursuant to the Indenture then outstanding shall be due and payable immediately without any declaration or other action by the Trustee or the holders of the debentures.

Protection of Trustee

Subject to the provisions of the Indenture relating to the duties of the Trustee, if an event of default applicable to a series of debentures issued pursuant to the Indenture occurs and is continuing, the Trustee will be under no

obligation to exercise any of its rights or powers under the Indenture at the request or direction of any holders of such debentures unless the Trustee is sufficiently indemnified in accordance with the provisions of the Indenture. Subject to the provisions of the Indenture providing for the indemnification of the Trustee, the holders of the requisite principal amount of such debentures will have the right to direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any rights or powers of the Trustee in respect of such debentures.

Modification

The Indenture provides that certain rights, privileges, restrictions and conditions of debentures issued and outstanding under the Indenture may be modified if such modifications are authorized by extraordinary resolution.

The term "extraordinary resolution" is defined in the Indenture to mean:

(a) in the case of modifications which affect a particular series of debentures issued pursuant to the Indenture, a resolution passed by the affirmative votes of the holders of not less than 66⅔% of the principal amount of debentures of that series then outstanding represented and voting at a meeting or an instrument in writing signed by the holders of not less than 66⅔% of the principal amount of debentures of that series then outstanding; and

(b) in the case of modifications which affect all debentures issued pursuant to the Indenture, a resolution passed by the affirmative votes of the holders of not less than 66⅔% of the principal amount of all debentures then outstanding represented and voting at a meeting or an instrument in writing signed by the holders of not less than 66⅔% in principal amount of all debentures then outstanding, treated in each case as a single class.

Defeasance

The Indenture requires the Trustee to release the Corporation from its obligations in respect of a series of debentures issued pursuant to the Indenture if specified conditions are met, including the deposit by the Corporation of cash or certain cash-equivalent securities for the payment of all principal and interest and any other amounts on the debentures of such series and the payment of the expenses of the Trustee.

Form, Transfer and Payment Mechanics

Except as described under "Plan of Distribution" or as set out in a pricing supplement, the Debentures will be represented by one or more global Debentures (collectively, the "Global Debenture") registered in the name of CDS Clearing and Depository Services Inc. or a successor thereof (the "Depository") or its nominee and held by or on behalf of the Depository as custodian for institutions (including Dealers) which participate directly or indirectly in the Depository's book-entry only registration system ("BEO Participants"). Interests in the Debentures represented by the Global Debenture will be evidenced by credits to book-entry accounts of BEO Participants maintained with the Depository. Interests of the owners of Debentures represented by the Global Debenture will be evidenced by credits to accounts maintained with such BEO Participants on behalf of such owners.

Except as described under "Plan of Distribution" and as described below or as set out in a pricing supplement, purchasers of Debentures represented by the Global Debenture will not be entitled to certificates or other instruments from the Corporation or the Depository evidencing their ownership of Debentures. Beneficial owners of Debentures represented by the Global Debenture will not be shown on the registers maintained by the Trustee or the records maintained by the Depository but will be shown through the book-entry accounts of BEO Participants. The rights of beneficial owners of Debentures represented by the Global Debenture may be exercised only through the BEO Participants with which such book-entry accounts are maintained. Purchasers of Debentures represented by the Global Debenture will receive a customer confirmation of purchase from the selling Dealer.

Purchasers of Debentures represented by the Global Debenture will receive definitive Debentures registered in their name only:

(a) if the Corporation determines that the Depository is no longer willing, able or qualified to discharge properly its responsibilities as holder of the Global Debenture in connection with the Debentures and the Corporation is unable to locate a qualified successor;

(b) if the Corporation elects to terminate the book-only registration of Debentures through the Depository; or

(c) in certain other specified circumstances.

Transfers of interests in Debentures represented by the Global Debenture will be effected through records maintained by the Depository or its nominee (with respect to interests of BEO Participants) and on the records of BEO Participants (with respect to interests of persons other than BEO Participants). Beneficial owners of Debentures represented by the Global Debenture who are not BEO Participants but who desire to transfer any interest in Debentures may do so only through BEO Participants.

Payments of interest and principal on the Global Debenture will be made to the Depository or its nominee as registered holder of the Global Debenture. As long as the Depository or its nominee is the registered owner of the Global Debenture, the Depository or its nominee will be considered the sole owner of the Global Debenture for the purposes of receiving payment on the Global Debenture and for all other purposes under the Indenture and the Global Debenture.

The Corporation expects that the Depository or its nominee, upon receipt of any payment of principal or interest in respect of the Global Debenture, will credit the accounts of BEO Participants, on the date principal or interest is payable, with payments in amounts proportionate to their respective interests in the principal amount of the Global Debenture as shown on the records of the Depository or its nominee. The Corporation also expects that payments of principal and interest by BEO Participants to the owners of interests in the Debentures represented by the Global Debenture held through accounts maintained with BEO Participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name", and will be the responsibility of BEO Participants. The responsibility and liability of the Corporation and the Trustee in respect of Debentures represented by the Global Debenture is limited to making payment of any principal and interest due on the Global Debenture to the Depository or its nominee.

Governing Law

The Indenture is and the Debentures will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

Definitions

The following defined terms used in this section of the prospectus are defined in the Indenture substantially as set out below.

"Capital Lease" means, with respect to a person, a lease or other arrangement in respect of real or personal property that is required to be classified and accounted for as a capital lease on a balance sheet of the person in accordance with GAAP.

"Capital Lease Obligation" means, with respect to a person, the obligation of the person to pay rent or other amounts under a Capital Lease.

"Consolidated Funded Indebtedness" means the aggregate amount of all Funded Indebtedness of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP.

"Consolidated Net Worth" means the shareholder's equity of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP. For greater certainty, the shareholder's equity of a subsidiary of the Corporation that is not a Designated Subsidiary will not be included in making such determination.

"Contingent Liability" means, with respect to a person, any agreement, undertaking or arrangement by which the person guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the obligation, debt, or other liability of any other person (other than by endorsements of instruments in the course of collection), or guarantees the payment of dividends or other distributions upon the shares of any other person. The amount of any Contingent Liability will, subject to any limitation contained therein, be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the obligation, debt or other liability to which the Contingent Liability relates.

"Deferred Purchase Price Obligation" means, with respect to a person, any obligation issued, incurred or assumed by the person in connection with the acquisition by the person of an asset in respect of the deferred purchase price of the asset.

"Designated Subsidiary" means Toronto Hydro-Electric System Limited and, until such designation is terminated in accordance with the covenants described above under "Covenants – Designation of Subsidiaries as Designated Subsidiaries", any other subsidiary of the Corporation designated as a Designated Subsidiary by the board of directors of the Corporation in accordance with the covenants described above under "Covenants – Designation of Subsidiaries as Designated Subsidiaries".

"Event of Default" means an event of default under the Indenture.

"Financial Instrument Obligations" means, with respect to any person, obligations arising under:

(a) interest rate swap agreements, forward rate agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is interest rates or the price, value or amount payable thereunder is dependent or based upon interest rates or fluctuations in interest rates in effect from time to time (but excluding conventional floating rate indebtedness);

(b) currency swap agreements, cross-currency agreements, forward agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is currency exchange rates or the price, value or amount payable thereunder is dependent or based upon currency exchange rates or fluctuations in currency exchange rates in effect from time to time; and

(c) any agreement for the making or taking of any commodity (including coal, natural gas, oil and electricity), swap agreement, floor, cap or collar agreement or commodity future or option or other similar agreement or arrangement, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is any commodity or the price, value or amount payable thereunder is dependent or based upon the price or fluctuations in the price of any commodity;

or any other similar transaction, including any option to enter into any of the foregoing, or any combination of the foregoing, in each case to the extent that the net amount due or accruing due by the person under the obligations determined by marking the obligations to market in accordance with their terms.

"Funded Indebtedness" means Indebtedness (other than Subordinated Indebtedness) that, on the date of issue or assumption of liability, has a term to maturity (including any right of extension or renewal) of greater than 18 months.

"GAAP" means at any date of determination:

(a) accounting principles which are generally recognized as being generally accepted in Canada, if the Corporation is then preparing its financial statements in accordance with such principles; or

(b) accounting principles which are generally recognized as being generally accepted in the United States, if the Corporation is then preparing its financial statements in accordance with such principles.

"Indebtedness" means, with respect to a person, without duplication:

(a) all obligations of the person for borrowed money, including obligations with respect to bankers' acceptances and contingent reimbursement obligations relating to letters of credit and other financial instruments;

(b) all Financial Instrument Obligations of the person;

(c) all Deferred Purchase Price Obligations of the person;

(d) all Capital Lease Obligations and Purchase Money Obligations of the person;

(e) all Prudential and Bilateral Credit Support Obligations of the person; and

(f) all Contingent Liabilities of the person with respect to obligations of another person if such obligations are of the type referred to in paragraphs (a) to (e).

"Inter-Company Indebtedness" means, with respect to the Corporation, Indebtedness of the Corporation to a Designated Subsidiary and, with respect to a Designated Subsidiary, Indebtedness of the Designated Subsidiary to the Corporation or to another Designated Subsidiary.

"Material Subsidiary" means a Designated Subsidiary and any other subsidiary of the Corporation:

(a) the total assets of which represent more than 10% of the total assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP; or

(b) the total revenues of which represent more than 10% of the total revenues of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP.

For greater certainty, the assets and revenues of a subsidiary of the Corporation that is not a Designated Subsidiary will not be included in making such determinations.

"Non-Recourse Debt" means, with respect to a person, any indebtedness incurred to finance the creation, development, construction or acquisition of an asset of the person (and any extensions, renewals or refunding of any such indebtedness) provided that the recourse of the obligee thereof against the person is limited in all circumstances (other than in respect of false or misleading representations or warranties) to the asset (including all rights and benefits related to or arising out of the asset).

"Non-Speculative Financial Instrument Obligations" means, with respect to a person, Financial Instrument Obligations of the person entered into by the person in the ordinary course of business for risk management purposes and not for speculative or capital raising purposes.

"Obligations" means, with respect to a person, without duplication, all items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of the person and all Contingent Liabilities of the person.

"Permitted Capital Lease Obligations" means, with respect to a Designated Subsidiary, the obligation of the Designated Subsidiary to pay rent or other amounts under a Capital Lease, other than a Capital Lease entered into as part of a Sale and Leaseback Transaction unless:

(a) the property which is the subject matter of the Sale and Leaseback Transaction is owned by the Designated Subsidiary;

(b) the proceeds of sale of such property have been determined by the board of directors of the Designated Subsidiary to be at least equal to its fair value; and

(c) either of the following is applicable:

(1) at the time of the Sale and Leaseback Transaction, the cost of acquiring such property could have been financed pursuant to a Purchase Money Obligation; or

(2) within 120 days after completion of the Sale and Leaseback Transaction, the Designated Subsidiary reduces its Indebtedness, other than Indebtedness permitted pursuant to paragraphs (a) to (e) above under "– Covenants – Limitation on Designated Subsidiary Indebtedness", by an amount at least equal to the net proceeds from the Sale and Leaseback Transaction.

"Permitted Encumbrances" means:

(a) any Security Interest securing Obligations of a Designated Subsidiary that:

(1) exists before and at the time that the Designated Subsidiary becomes a Designated Subsidiary;

(2) was not created or assumed in contemplation or as a result of the Designated Subsidiary becoming a Designated Subsidiary; and

(3) immediately before and after the Designated Subsidiary becomes a Designated Subsidiary, does not attach to the assets or secure Obligations of the Corporation or any other Designated Subsidiary;

(b) any Purchase Money Mortgage or Capital Lease of the Corporation or a Designated Subsidiary;

(c) any Security Interest in an asset created or assumed by the Corporation or a Designated Subsidiary to secure Non-Recourse Debt of the Corporation or the Designated Subsidiary in respect of such asset;

(d) any Security Interest in cash, marketable debt securities or accounts receivable created or assumed by the Corporation or a Designated Subsidiary to or in favour of a bank or other lending institution to secure indebtedness of the Corporation or the Designated Subsidiary that is payable on demand or that, on the date of issue or assumption of liability, has a term to maturity (including any right of extension or renewal) of 18 months or less and that is incurred by the Corporation or the Designated Subsidiary in the ordinary course of business and for the purpose of carrying on the same;

(e) any Security Interest in cash or marketable debt securities created or assumed by the Corporation to secure Non-Speculative Financial Instrument Obligations of the Corporation if the aggregate value of such cash and marketable debt securities is not more than 105% of the aggregate amount of the Non-Speculative Financial Instrument Obligations;

(f) any Security Interest created or assumed by a Designated Subsidiary in favour of the Corporation or any Wholly-Owned Designated Subsidiary;

(g) any Security Interest in an asset acquired by the Corporation or a Designated Subsidiary that secures Obligations of any other person, whether or not such Obligations are assumed by the Corporation or the Designated Subsidiary provided that the Security Interest:

(1) exists before and at the time that the asset is acquired by the Corporation or the Designated Subsidiary;

(2) was not created or assumed in contemplation of or as a result of the asset being acquired by the Corporation or the Designated Subsidiary; and

(3) immediately before and after the asset is acquired by the Corporation or the Designated Subsidiary, does not attach to the assets or secure Obligations of the Corporation or any other Designated Subsidiary;

(h) any Security Interest in cash or marketable debt securities in a sinking fund account established by the Corporation in support of a series of debentures issued pursuant to the Indenture;

(i) any Security Interest or deposit under workers' compensation, social security or similar legislation or in connection with bids, tenders, leases, contracts or expropriation proceedings or to secure public or statutory obligations, surety and appeal bonds or costs of litigation where required by law;

(j) any Security Interest or privilege imposed by law, such as builders', mechanics, material men's, carriers', warehousemen's and landlords' liens and privileges; or any Security Interest or privilege arising out of judgments or awards with respect to which the Corporation or a Designated Subsidiary at the time is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending such appeal or proceedings for review; or any Security Interest for taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Corporation or a Designated Subsidiary in good faith; or any undetermined or inchoate Security Interest or privilege incidental to current operations that has not been filed pursuant to law against the Corporation or a Designated Subsidiary or that relates to obligations not due or delinquent; or the deposit of cash or securities in connection with any Security Interest or privilege referred to in this paragraph (j);

(k) any right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, licence, franchise, grant or permit held or acquired by the Corporation or a Designated Subsidiary, or by any statutory provision, to terminate the lease, licence, franchise, grant or permit or to purchase assets used in connection therewith or to require annual or other periodic payments as a condition of the continuance thereof;

(l) any Security Interest or right of distress reserved in or exercisable under any lease for rent to which the Corporation or a Designated Subsidiary is a party and for compliance with the terms of the lease;

(m) any Security Interest created or assumed by the Corporation or a Designated Subsidiary in favour of a public utility or any municipality or governmental or other public authority when required by the utility, municipality or other authority in connection with the operations of the Corporation or a Designated Subsidiary;

(n) any reservations, limitations, provisos and conditions expressed in original grants from the Crown;

(o) any minor encumbrances, such as easements, rights-of-way, servitudes or other similar rights in land granted to or reserved by other persons, rights-of-way for sewers, electric lines, telegraph and telephone lines, oil and natural gas pipelines and other similar purposes, or zoning or other restrictions applicable to the Corporation's or a Designated Subsidiary's use of real property, that do not in the aggregate materially detract from the value of the property or materially impair its use in the operation of the business of the Corporation or the Designated Subsidiary;

(p) any extension, renewal, alteration, substitution or replacement, in whole or in part, of a Security Interest referred to in paragraphs (a) to (o) provided that the Security Interest is limited to all or part of the same assets, the principal amount of the secured Obligations is not increased by that action, the term of the secured Obligations is not shortened and the terms and conditions of the Security Interest are no more restrictive in any material respect than the Security Interest so extended; and

(q) any other Security Interest created or assumed by the Corporation or a Designated Subsidiary (in addition to the Security Interests referred to in paragraphs (a) to (p)) if, after giving effect to the Security Interest, the aggregate amount of all Indebtedness secured by Security Interests permitted by this paragraph only does not at that time exceed 5% of Consolidated Net Worth.

"Prudential and Bilateral Credit Support Obligations" means, without duplication, the following obligations:

(a) all contingent reimbursement obligations of the Corporation relating to letters of credit and other financial instruments and all Contingent Liabilities of the Corporation in respect of Obligations of a subsidiary of the Corporation for the purchase or sale of electricity or natural gas; and

(b) all obligations of a Designated Subsidiary for borrowed money, including contingent reimbursement obligations relating to letters of credit and other financial instruments under credit facilities established for participants in the wholesale market for electricity administered by the Independent Electricity System Operator ("IESO"), in respect of the Obligations of the Designated Subsidiary for the purchase or sale of electricity or natural gas;

if such obligations were incurred or assumed to satisfy:

(x) prescribed prudential requirements in the wholesale market for electricity administered by the IESO;

(y) credit support arrangements required by electricity distribution companies under the terms of the Retail Settlement Code established by the OEB; or

(z) credit support requirements of counterparties under bilateral contracts or customers under purchase contracts.

"Purchase Money Mortgage" means, with respect to a person, any Security Interest created or assumed by the person to secure a Purchase Money Obligation provided that such Security Interest is limited to the asset financed by such Purchase Money Obligation and is created or assumed not later than three months after such Purchase Money Obligation is issued, incurred or assumed.

"Purchase Money Obligation" means, with respect to a person, indebtedness of the person issued, incurred or assumed to finance all or part of the cost of acquiring any asset for the person, other than shares, bonds and other securities, or constructing, installing or improving any real property or fixtures of the person, provided that the indebtedness is issued, incurred or assumed within twelve months after such acquisition, construction, installation or improvement, and includes any extension, renewal or refunding of such indebtedness so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased.

"Sale and Leaseback Transaction" means, with respect to a person, a transaction or series of transactions pursuant to which the person sells or transfers real or personal property owned by the person to a third party and subsequently leases such real or personal property.

"Security Interest" means any security interest, assignment by way of security, mortgage, charge (whether fixed or floating), hypothec, pledge, lien or other encumbrance on or in respect of property or assets that secures the payment of Obligations.

"Subordinated Indebtedness" means all indebtedness of the Corporation in respect of which, upon any distribution of assets of the Corporation upon any dissolution, winding-up, liquidation or reorganization of the Corporation (whether in bankruptcy, insolvency or receivership proceedings or upon an assignment for the benefit of creditors, or any other marshalling of the assets and liabilities of the Corporation or otherwise), the payment of all indebtedness and liabilities of the Corporation in connection with all debentures issued pursuant to the Indenture including principal, interest, fees and expenses, must be satisfied in full prior to any amount being applied to such indebtedness.

"Total Consolidated Capitalization" means, without duplication, the sum of:

(a) the principal amount of all Consolidated Funded Indebtedness;

(b) the principal amount of all Subordinated Indebtedness; and

(c) the Consolidated Net Worth;

in each case, as determined by the Corporation and its Designated Subsidiaries.

"Wholly-Owned Designated Subsidiary" means a Designated Subsidiary all of the outstanding shares in the capital of which are owned by the Corporation or one or more Wholly-Owned Designated Subsidiaries.

RISK FACTORS

In addition to the risks described in the documents incorporated or deemed to be incorporated by reference in this prospectus (including the Corporation's annual information form and the management's discussion and analysis of financial condition and results of operations accompanying the financial statements of the Corporation) and the section entitled "Forward-Looking Information" in each such document and this prospectus, prospective purchasers should consider the risks described below before purchasing Debentures.

Rank of Debentures and Holding Company Structure

The Debentures will be direct unsecured obligations of the Corporation and will rank equally with all other unsecured and unsubordinated indebtedness of the Corporation, including indebtedness of the Corporation under the THC Revolving Credit Facility and the Bilateral Credit Facilities. A default by the Corporation under the Indenture will constitute an event of default under the THC Revolving Credit Facility and an event of default or repayment event under the Bilateral Credit Facilities. There can be no assurance that sufficient funds would be available at the time of any such default to make any required payment under the Debentures.

The Corporation is a holding company and substantially all of its business activities are carried on by its subsidiaries. Because the Corporation is a holding company, the Debentures will be effectively subordinated to all existing and future liabilities, including trade payables and other indebtedness, of the Corporation's subsidiaries. In addition, as a holding company, the Corporation's ability to meet its financial obligations is dependent primarily upon the receipt of interest and principal, management fees, cash dividends and other payments from its subsidiaries, together with proceeds raised by the Corporation through the issuance of debt. The Corporation is wholly-owned by the City of Toronto and does not currently raise funds through the issuance of share capital. The Corporation's subsidiaries are distinct legal entities and have no legal obligation, contingent or otherwise, to pay any amount due under the Debentures

or to make any amounts available therefor. In addition, the payment of dividends and the making of loans, advances and other payments to the Corporation by its subsidiaries may be subject to statutory or contractual restrictions, will depend on the earnings of the subsidiaries and will be subject to various business and other considerations.

Absence of Public Market for the Debentures

The Debentures will be newly issued securities for which there is no existing trading market. The Corporation does not intend to list the Debentures on any Canadian, U.S. or other securities exchange. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures and the extent of issuer regulation. There can be no assurance that a secondary market will develop for the Debentures or that any secondary market that does develop will continue. Accordingly, purchasers may not be able to sell the Debentures. In addition, if a trading market does develop for the Debentures, the Debentures could trade at prices that may be higher or lower than their initial offering price, depending on many factors, including prevailing interest rates, the Corporation's results of operations and financial position, the ratings assigned to the Debentures and the Corporation's other debt securities and the markets for similar debt securities.

Ratings

There is no assurance that any rating assigned to the Debentures issued hereunder will remain in effect for any given period of time or that any rating will not be lowered or withdrawn entirely by the relevant rating agency. A lowering or withdrawal of such rating may have an adverse effect on the market value of the Debentures.

Interest Rate Risks

Prevailing interest rates will affect the market price or value of the Debentures. Generally, the market price or value of the Debentures will decline as prevailing interest rates for comparable debt instruments rise and increase as prevailing interest rates for comparable debt instruments decline. Fluctuations in interest rates may also impact borrowing costs of the Corporation which may adversely affect its creditworthiness.

Risks Associated with Floating Rate Notes

The Debentures will bear interest at fixed or floating rates as set out in the applicable pricing supplement to this prospectus. Investments in floating rate Debentures entail risks not associated with investments in fixed rate Debentures. The resetting of the applicable rate on a floating rate Debenture may result in a lower interest rate as compared to a fixed rate Debenture issued at the same time. The applicable rate on a floating rate Debenture will fluctuate in accordance with fluctuations in the instrument or obligation or other measure on which the applicable rate is based, which in turn may fluctuate and be affected by a number of interrelated factors, including economic, financial and political events over which the Corporation has no control.

Foreign Currency Risks

An investment in Debentures that are denominated or payable in other than Canadian dollars entails significant risks that are not associated with a similar investment in a security denominated in Canadian dollars. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the Canadian dollar and the applicable foreign currency unit, the possibility of the imposition or modification of foreign exchange controls by either the Canadian or foreign governments and potential illiquidity in the secondary market. These risks will vary depending upon the currency or currencies involved and, where appropriate, will be more fully described in a pricing supplement.

This prospectus does not describe all the risks of an investment in the Debentures denominated or payable other than in Canadian dollars and prospective investors should consult their own financial and legal advisor as to the risk entailed with respect thereto. Debentures denominated in other than Canadian dollars are not appropriate investments for investors who are unfamiliar with foreign currency transactions.

The Debentures will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. A judgment by a Canadian court relating to any Debenture may be awarded only in Canadian currency and such judgment may be based on a rate of exchange in existence on a day other than the day of payment.

Additional Debt Financing

The Corporation expects to borrow to repay the Debentures when required to do so under the terms of the Debentures and to finance the renewal of LDC's electricity infrastructure. The Corporation's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including financial market conditions, the regulatory environment in Ontario, the Corporation's results of operations and financial condition, the ratings assigned to the Corporation and its securities by credit rating agencies, the current timing of debt maturities and general economic conditions.

Shareholder Direction

Council of the City of Toronto has adopted a shareholder direction (the "Shareholder Direction") which sets out certain corporate governance principles with respect to Toronto Hydro. The Shareholder Direction is summarized in the AIF under "Relationship with the City". The Shareholder Direction is not for the benefit of, or enforceable by, the holders of the Debentures.

LEGAL MATTERS

Certain legal matters relating to the offering will be passed on for the Corporation by McMillan LLP. The partners and associates of McMillan LLP beneficially own, directly or indirectly, less than one per cent of the securities of the Corporation or any associate or affiliate of the Corporation.

AUDITORS

The auditors of the Corporation are KPMG LLP, Chartered Accountants ("KPMG LLP"), at their office at Bay Adelaide Centre, 333 Bay Street, Suite 4600, Toronto, Ontario, M5H 2S5. KPMG LLP have been the auditors of the Corporation since April 12, 2011. KPMG LLP is independent in Ontario in accordance with its rules of professional conduct.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus, the accompanying prospectus supplement and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some provinces, revision of the price or damages if the prospectus, the accompanying prospectus supplement and any amendment contain a misrepresentation or are not delivered to the purchaser, provided that the remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal advisor.

AUDITORS' CONSENT

We have read the short form base shelf prospectus (the "Prospectus") of Toronto Hydro Corporation (the "Corporation") dated December 10, 2012 relating to the issuance in an aggregate principal amount of up to $1,500,000,000 of Debentures of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the Prospectus of our report to the shareholder of the Corporation on the consolidated balance sheet of the Corporation as at December 31, 2011, and the consolidated statements of income, retained earnings and cash flows for the year ended December 31, 2011. Our report is dated March 2, 2012.

(Signed) KPMG LLP
Chartered Accountants
Licensed Public Accountants

Toronto, Canada
December 10, 2012

AUDITORS' CONSENT

We have read the short form base shelf prospectus (the "Prospectus") of Toronto Hydro Corporation (the "Corporation") dated December 10, 2012 relating to the issuance in an aggregate principal amount of up to $1,500,000,000 of Debentures of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the Prospectus of our report to the shareholder of the Corporation on the consolidated balance sheet of the Corporation as at December 31, 2010, and the consolidated statements of income, retained earnings and cash flows for the year ended December 31, 2010. Our report is dated March 11, 2011.

(Signed) ERNST & YOUNG LLP
Chartered Accountants
Licensed Public Accountants

Toronto, Canada
December 10, 2012

CERTIFICATE OF THE CORPORATION

Dated: December 10, 2012

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all the provinces of Canada.

(Signed) ANTHONY HAINES
President and Chief Executive Officer

(Signed) JEAN-SEBASTIEN COUILLARD
Chief Financial Officer

On behalf of the Board of Directors

(Signed) CLARE R. COPELAND
Director

(Signed) BRIAN CHU
Director

EIGHTH SUPPLEMENTAL TRUST INDENTURE

Made as of November 18, 2011

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

3.54% Senior Unsecured Debentures
due 2021 (Series 7)

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EIGHTH SUPPLEMENTAL TRUST INDENTURE

THIS EIGHTH SUPPLEMENTAL TRUST INDENTURE made as of November 18, 2011,

B E T W E E N:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "Corporation")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "Trustee")

RECITALS

A. BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

B. The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "Trust Indenture") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

C. The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

D. The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

E. The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

F. The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

G. The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

H. The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

I. The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

J. The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture; and

K. This Eighth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures.

NOW THEREFORE THIS EIGHTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

SECTION 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Eighth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Eighth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Eighth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation hereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Eighth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Eighth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 7 Debentures by this Eighth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Eighth Supplemental Trust Indenture, the meaning given to the term in this Eighth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Eighth Supplemental Trust Indenture and in the Series 7 Debentures, the following terms have the following meanings:

(1) Canada Yield on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to maturity of the Series 7 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(2) Canada Yield Price means the price equal to the present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 7 Debentures, using a discount rate equal to the sum of the Canada Yield and 34 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) on the Business Days prior to the Redemption Date of the Series 7 Debentures.

(3) Series 7 Debentures means the 3.54% Senior Unsecured Debentures due 2021 (Series 7) referred to in Section 2.1.

(4) Series 7 Debentures Debt Account means the deposit account established in respect of the Series 7 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 7 Debentures Debt Account".

(5) Series 7 Debentures Interest Payment Date means May 18 and November 18 in each year that the Series 7 Debentures are outstanding.

(6) Series 7 Debentures Interest Period means the period commencing on and including the later of the date of issue of the Series 7 Debentures and the immediately preceding Series 7 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 7 Debentures Interest Payment Date to occur in respect of which interest is payable.

(7) Trust Indenture means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

SECTION 2 SERIES 7 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Eighth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "3.54% Senior Unsecured Debentures due 2021 (Series 7)", having the terms set out in this Eighth Supplemental Trust Indenture.

2.2 Limitation on Issue

The aggregate principal amount of Series 7 Debentures which may be issued under this Eighth Supplemental Trust Indenture including any supplement hereto will be limited to $1,000,000,000.

2.3 Date of Issue and Maturity

The Series 7 Debentures shall be dated November 18, 2011 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on November 18, 2021 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 7 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 3.54% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments on each Series 7 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 7 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 7 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 7 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 7 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 7 Debentures on maturity, by or prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 7 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 7 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 7 Debentures

(a) The Series 7 Debentures may be redeemed at the Corporation's option when not in default under the Trust Indenture, in whole at any time prior to Stated Maturity, or in part at any time and from time to time prior to Stated Maturity, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 7 Debentures in accordance with Section 5.5 of the Trust Indenture.

(c) The Series 7 Debentures will not be subject to purchase pursuant to any sinking fund provisions.

2.8 Form of Series 7 Debentures

(a) Except as set out in 2.8(b) below, the Series 7 Debentures and the registration panel and the certificate of the Trustee to be endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 7 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 7 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 7 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "U.S. SECURITIES ACT") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 7 Debentures are to be sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may

be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

> "The undersigned (A) acknowledges that the sale of the securities to which this declaration relates is being made in reliance upon Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such securities was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such securities. Terms used herein have the meaning given to them by Regulation S under the U.S. Securities Act."

If any Series 7 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 7 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 7 Debentures are to be certified and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 7 Debentures.

2.9 Signatures on Series 7 Debentures

The Series 7 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 7 Debenture issued shall be obligatory or shall entitle the Holder of such Series 7 Debenture to the benefits of this Eighth Supplemental Trust Indenture until it has been certified by manual signature by or on behalf of the Trustee by execution of the certificate of the Trustee endorsed thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 7 Debenture shall be conclusive evidence that such Series 7 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 7 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Eighth Supplemental Trust Indenture, and such Series 7 Debenture.

(b) The certificate of the Trustee on any Series 7 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Eighth

Supplemental Trust Indenture or of the Series 7 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 7 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 7 Debentures, the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 7 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 7 Debentures.

SECTION 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Eighth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Eighth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Eighth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Eighth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Eighth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: Anthony Haines
Name: Anthony Haines
Title: President and
Chief Executive Officer

By: Jean-Sebastien Couillard
Name: Jean-Sebastien Couillard
Title: Chief Financial Officer

BNY TRUST COMPANY OF CANADA

By: Ismail Bawa
Name: Ismail Bawa
Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 7

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Debenture is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any debentures issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO. or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this debenture herein and it is a violation of its rights for another person to hold, transfer or deal with this debenture.

No. 7-000

$ z

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE 2021 (SERIES 7)

ISIN CA 89119ZAD56
CUSIP 89119ZAD5

Issue Date	z, 2011
Stated Maturity	z, 2021
Interest Rate Per Annum	z%
Interest Payment Dates	z and z in each year
Initial Interest Payment Date	z, 2012
Principal Amount	$z

TORONTO HYDRO CORPORATION (the "Corporation") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this z% Senior Unsecured Debenture due z, 2021 (Series 7) (the "Series 7 Debenture"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 7 Debenture, at the

address of the registered holder hereof appearing on the register of Series 7 Debentures maintained by or at the direction of the Trustee (the "Register"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Date in each year, and if the Corporation at any time defaults in the payment of any principal or interest, it will pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque, by same day delivery, to the address of the registered holder hereof appearing on the Register of interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 7 Debenture is presented to and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 7 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 7 Debenture is one of an authorized issue of debentures designated as 2.% Senior Unsecured Debentures due, 2021 (Series 7) and forming the series of debentures created and issued under an eighth supplemental trust indenture made as of 2011 (the "Eighth Supplemental Trust Indenture") to a trust indenture (the "Indenture") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "Trustee"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the Eighth Supplemental Trust Indenture and the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "Trust Indenture"). The Trust Indenture specifies the terms and conditions upon which the Series 7 Debentures are created and issued and may be created, issued and held and the rights of the registered holders of the Series 7 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 7 Debenture and to each of which the registered holder of this Series 7 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 7 Debentures that may be created and issued under the Trust Indenture is limited to $1,000,000,000 in lawful money of Canada. Series 7 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 7 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated indebtedness of the Corporation.

This Series 7 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 7 Debentures in the open market, by tender or by private contract, at any price. Series 7 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 7 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 7 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 7 Debenture to be signed by its z and its z.

TORONTO HYDRO CORPORATION

By: _____
Name: z
Title: z

By: _____
Name: z
Title: z

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 7 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EX CEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE 2021 (SERIES 7)

ISIN CA 89119ZAD56
CUSIP 89119ZAD5

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 7 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 7

THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "U.S. SECURITIES ACT") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM *BNY TRUST COMPANY OF CANADA* UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO *BNY TRUST COMPANY OF CANADA* AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.

No. 7-000

$ z

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE z (SERIES 7)

Issue Date	z, 2011
Stated Maturity	z, 2021
Interest Rate Per Annum	z%
Interest Payment Dates	z and z in each year
Initial Interest Payment Date	z, 2012
Principal Amount	$ z

TORONTO HYDRO CORPORATION (the "Corporation") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this z% Senior Unsecured Debenture due z, 2021 (Series 7) (the "Series 7 Debenture"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay

Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 7 Debenture, at the address of the registered holder hereof appearing on the register of Series 7 Debentures maintained by or at the direction of the Trustee (the "Register"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation, on the day that is two Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 7 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 7 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 7 Debenture is one of an authorized issue of debentures designated as 2.0% Senior Unsecured Debentures due December 2, 2021 (Series 7) and forming the series of debentures created and issued under a eighth supplemental trust indenture made as of December 2, 2011 (the "Eighth Supplemental Trust Indenture") to a trust indenture (the "Indenture") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "Trustee"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the Eighth Supplemental Trust Indenture and the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "Trust Indenture"). The Trust Indenture specifies the terms and conditions upon which the Series 7 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 7 Debentures, the Corporation and the Trustee, all of which rights and conditions are incorporated by reference in this Series 7 Debenture and to each of which the registered holder of this Series 7 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 7 Debentures that may be created and issued under the Trust Indenture is limited to $1,000,000,000 lawful money of Canada. Series 7 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 7 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated indebtedness of the Corporation.

This Series 7 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 7 Debentures in the open market, by tender or by private contract, at any price. Series 7 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 7 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 7 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 7 Debenture to be signed by its z and its z.

TORONTO HYDRO CORPORATION

By: _____
Name: z
Title: z

By: _____
Name: z
Title: z

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 7 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA

Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EX CEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE 2021 (SERIES 7)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

NINTH SUPPLEMENTAL TRUST INDENTURE

Made as of April 9, 2013

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

2.91% Senior Unsecured Debentures
due 2023 (Series 8)

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NINTH SUPPLEMENTAL TRUST INDENTURE

THIS NINTH SUPPLEMENTAL TRUST INDENTURE made as of April 9, 2013,

B E T W E E N:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "Corporation")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "Trustee")

RECITALS

A. BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

B. The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "Trust Indenture") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

C. The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

D. The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

E. The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

F. The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

G. The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

H. The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

I. The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

J. The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

K. The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures; and

L. This Ninth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures.

NOW THEREFORE THIS NINTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

SECTION 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Ninth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Ninth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Ninth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation hereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Ninth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Ninth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 8 Debentures by this Ninth Supplemental Trust Indenture. In the event of any inconsistency between the meaning

given to a term in the Trust Indenture and the meaning given to the same term in this Ninth Supplemental Trust Indenture, the meaning given to the term in this Ninth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Ninth Supplemental Trust Indenture and in the Series 8 Debentures, the following terms have the following meanings:

(1) Canada Yield on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to maturity of the Series 8 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(2) Canada Yield Price means the price equal to the present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 8 Debentures, using a discount rate equal to the sum of the Canada Yield and 28 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) on the Business Days prior to the Redemption Date of the Series 8 Debentures.

(3) Series 8 Debentures means the 2.91% Senior Unsecured Debentures due 2023 (Series 8) referred to in Section 2.1 below.

(4) Series 8 Debentures Debt Account means the deposit account established in respect of the Series 8 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 8 Debentures Debt Account".

(5) Series 8 Debentures Interest Payment Date means October 10 and April 10 in each year that the Series 8 Debentures are outstanding with the exception of the first payment of interest which will be due on October 10, 2013 as provided in Section 2.4(a) below.

(6) Series 8 Debentures Interest Period means the period commencing on and including the later of the date of issue of the Series 8 Debentures and the immediately preceding Series 8 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 8 Debentures Interest Payment Date to occur in respect of which interest is payable.

(7) Trust Indenture means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

SECTION 2 SERIES 8 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Ninth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "2.91% Senior Unsecured Debentures due 2023 (Series 8)", having the terms set out in this Ninth Supplemental Trust Indenture.

2.2 Limitation on Issue

The aggregate principal amount of Series 8 Debentures which may be issued under this Ninth Supplemental Trust Indenture including any supplement hereto will be limited to $500,000,000.

2.3 Date of Issue and Maturity

The Series 8 Debentures shall be dated April 9, 2013 (being the applicable date of issue) and will become due and payable, together with accrued interest and unpaid interest thereon, on April 10, 2023 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 8 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 2.91% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments on each Series 8 Debentures Interest Payment Date, with the exception of the first payment of interest which will be due on October 10, 2013 and which will be $14.62972604 per $1,000 principal amount of Series 8 Debentures.

(b) Interest shall be payable in respect of each Series 8 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 8 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 8 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 8 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 8 Debentures on maturity, by, or prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 8 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 8 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 8 Debentures

(a) The Series 8 Debentures may be redeemed at the Corporation's option when not in default under the Trust Indenture, in whole at any time, or in part at any time and from time to time, prior to January 10, 2023, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid

interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 8 Debentures may be redeemed at the Corporation's option when not in default under the Trust Indenture, in whole, but not in part, at any time on or after January 10, 2023, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to 100% of the principal amount of the Series 8 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 8 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 8 Debentures will not be subject to purchase pursuant to any sinking fund provisions.

2.8 Form of Series 8 Debentures

(a) Except as set out in Section 2.8(b) below, the Series 8 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 8 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 8 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 8 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "U.S. SECURITIES ACT") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE

U.S. SECURITIES ACT, OR (2) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY" MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 8 Debentures are to be sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "U.S. Securities Act") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 8 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 8 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 8 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 8 Debentures.

2.9 Signatures on Series 8 Debentures

The Series 8 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 8 Debenture issued shall be obligatory or shall entitle the Holder of such Series 8 Debenture to the benefits of this Ninth Supplemental Trust Indenture until it has been certified by manual signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 8 Debenture shall be conclusive evidence that such Series 8 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 8 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Ninth Supplemental Trust Indenture, and such Series 8 Debenture.

(b) The certificate of the Trustee on any Series 8 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Ninth Supplemental Trust Indenture or of the Series 8 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 8 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 8 Debentures, the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 8 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 8 Debentures.

SECTION 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Ninth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Ninth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Ninth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Ninth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Ninth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: Anthony Haines
Name: Anthony Haines
Title: President and
Chief Executive Officer

By: Jean-Sebastien Couillard
Name: Jean-Sebastien Couillard
Title: Chief Financial Officer

BNY TRUST COMPANY OF CANADA

By: Ismail Bawa
Name: Ismail Bawa
Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 8

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Debenture is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any debentures issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO. or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this debenture herein and it is a violation of its rights for another person to hold, transfer or deal with this debenture.

No. 8-000

$ z

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE 20" (SERIES 8)

ISIN CA 89119ZAE30
CUSIP 89119ZAE3

Issue Date	z, 2013
Stated Maturity	z, 20"
Interest Rate Per Annum	z%
Interest Payment Dates	z and z in each year
Initial Interest Payment Date	z, 2013
Principal Amount	$z

TORONTO HYDRO CORPORATION (the "Corporation") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this z% Senior Unsecured Debenture due z, 20" (Series 8) (the "Series 8 Debenture"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 8 Debenture (with the

exception of the first payment of interest which will be due "on 20" and which will be $" per $1,000 principal amount of Series 8 Debentures, to the address of the registered holder hereof appearing on the register of Series 8 Debentures maintained by or at the direction of the Trustee (the "Register"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 8 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 8 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 8 Debenture is one of an authorized issue of debentures designated as "% Senior Unsecured Debentures due, 20" (Series 8) and forming a series of debentures created and issued under a ninth supplemental trust indenture made as of, 2013 (the "Ninth Supplemental Trust Indenture") to a trust indenture (the "Indenture") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "Trustee"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the Ninth Supplemental Trust Indenture and the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "Indenture"). The Trust Indenture specifies the terms and conditions upon which the Series 8 Debentures are created and issued or may be created, issued and held, the rights of the registered holders of the Series 8 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 8 Debenture and to each of which the registered holder of this Series 8 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 8 Debentures that may be created and issued under the Trust Indenture is limited to $ in lawful money of Canada. Series 8 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof

and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 8 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated indebtedness of the Corporation.

This Series 8 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time, or in part at any time and from time to time, prior to ", 20", subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 8 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole, but not in part, at any time on or after ", 20", subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 8 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 8 Debentures in the open market, by tender or by private contract, at any price. Series 8 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 8 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 8 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 8 Debenture to be signed by its z and its z.

TORONTO HYDRO CORPORATION

By: _____
Name: z
Title: z

By: _____
Name: z
Title: z

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 8 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EX CEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE 20’ (SERIES 8)

ISIN CA 89119ZAE30
CUSIP 89119ZAE3

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 8 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 8

THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "U.S. SECURITIES ACT") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY" MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT

No. 8-000

$ z

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE z (SERIES 8)

Issue Date	z, 2013
Stated Maturity	z, 20"
Interest Rate Per Annum	z%
Interest Payment Dates	z and z in each year
Initial Interest Payment Date	z, 2013
Principal Amount	$z

TORONTO HYDRO CORPORATION (the "Corporation") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this z% Senior Unsecured Debenture due z, 20" (Series 8) (the "Series 8 Debenture"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest

Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 8 Debenture (with the exception of the first payment of interest which will be due on "[redacted], 20" and which will be $" per $1,000 principal amount of Series 8 Debentures), at the address of the registered holder hereof appearing on the register of Series 8 Debentures maintained by or at the direction of the Trustee (the "Register"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder appearing on the Register. The Corporation, on the day that is two Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 8 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 8 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 8 Debenture is one of an authorized issue of debentures designated as "[redacted]% Senior Unsecured Debentures due [redacted], 20" (Series 8) and forming the series of debentures created and issued under a ninth supplemental trust indenture made as of [redacted], 2013 (the "Ninth Supplemental Trust Indenture") to a trust indenture (the "Indenture") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "Trustee"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 21, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the Ninth Supplemental Trust Indenture and the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "Trust Indenture"). The Trust Indenture specifies the terms and conditions upon which the Series 8 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 8 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 8 Debenture and to each of which the registered holder of this Series 8 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 8 Debentures that may be created and issued under the Trust Indenture is limited to $[ ] in lawful money of Canada. Series 8 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 8 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated indebtedness of the Corporation.

This Series 8 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part at any time and from time to time, prior to [ ], 20[ ], subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 8 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole, but not in part, at any time on or after [ ], 20[ ], subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 8 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 8 Debentures in the open market, by tender or by private contract, at any price. Series 8 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 8 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 8 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 8 Debenture to be signed by its z and its z.

TORONTO HYDRO CORPORATION

By: _____
Name: z
Title: z

By: _____
Name: z
Title: z

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 8 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EX CEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE 20’ (SERIES 8)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

TENTH SUPPLEMENTAL TRUST INDENTURE

Made as of April 9, 2013

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

3.96% Senior Unsecured Debentures
due 2063 (Series 9)

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TENTH SUPPLEMENTAL TRUST INDENTURE

THIS TENTH SUPPLEMENTAL TRUST INDENTURE made as of April 9, 2013,

B E T W E E N:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "Corporation")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "Trustee")

RECITALS

A. BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

B. The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "Trust Indenture") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

C. The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

D. The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

E. The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

F. The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

G. The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

H. The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

I. The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

J. The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

K. The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

L. The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures; and

M. This Tenth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures.

NOW THEREFORE THIS TENTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

SECTION 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Tenth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Tenth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Tenth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Tenth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Tenth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 9 Debentures by this Tenth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Tenth Supplemental Trust Indenture, the meaning given to the term in this Tenth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Tenth Supplemental Trust Indenture and in the Series 9 Debentures, the following terms have the following meanings:

(1) Canada Yield on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to maturity of the Series 9 Debentures, such yield to maturity being the average of the yields quoted by two major Canadian investment dealers specified by the Corporation.

(2) Canada Yield Price means the price equal to the present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 9 Debentures, using a discount rate equal to the sum of the Canada Yield and 38 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) on the Business Days prior to the Redemption Date of the Series 9 Debentures.

(3) Series 9 Debentures means the 3.96% Senior Unsecured Debentures due 2063 (Series 9) referred to in Section 2.1.

(4) Series 9 Debentures Debt Account means the deposit account established in respect of the Series 9 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 9 Debentures Debt Account".

(5) Series 9 Debentures Interest Payment Date means October 9 and April 9 in each year that the Series 9 Debentures are outstanding.

(6) Series 9 Debentures Interest Period means the period commencing on and including the later of the date of issue of the Series 9 Debentures and the immediately preceding Series 9 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 9 Debentures Interest Payment Date to occur in respect of which interest is payable.

(7) Trust Indenture means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

SECTION 2 SERIES 9 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Tenth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "3.96% Senior Unsecured Debentures due 2063 (Series 9)", having the terms set out in this Tenth Supplemental Trust Indenture.

2.2 Limitation on Issue

The aggregate principal amount of Series 9 Debentures which may be issued under this Tenth Supplemental Trust Indenture including any supplement hereto will be limited to $500,000,000.

2.3 Date of Issue and Maturity

The Series 9 Debentures shall be dated April 9, 2013 (being the applicable date of issue) and will become due and payable, together with accrued interest and unpaid interest thereon, on April 9, 2063 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 9 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 3.96% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments on each Series 9 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 9 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 9 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 9 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 9 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 9 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 9 Debentures. The deposit of funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 9 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 9 Debentures

(a) The Series 9 Debentures may be redeemed at the Corporation's option when not in default under the Trust Indenture, in whole at any time, or in part at any time and from time to time, prior to October 9, 2062, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 9 Debentures may be redeemed at the Corporation's option when not in default under the Trust Indenture, in whole, but not in part, at any time on or after October 9, 2062, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to 100% of the principal amount of the Series 9 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 9 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 9 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

2.8 Form of Series 9 Debentures

(a) Except as set out in 2.8(b) below, the Series 9 Debentures and the registration panel and the certificate of the Trustee to be endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 9 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 9 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto with the definitive certificate, and each Series 9 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF

1933, AS AMENDED (THE "U.S. SECURITIES ACT") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY" MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 9 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "U.S. Securities Act") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 9 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 9 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 9 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 9 Debentures.

2.9 Signatures on Series 9 Debentures

The Series 9 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 9 Debenture issued shall be obligatory or shall entitle the Holder of such Series 9 Debenture to the benefits of this Tenth Supplemental Trust Indenture until it has been certified by manual signature by or on behalf of the Trustee by execution of the certificate of the Trustee endorsed thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 9 Debenture shall be conclusive evidence that such Series 9 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 9 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Tenth Supplemental Trust Indenture, and such Series 9 Debenture.

(b) The certificate of the Trustee on any Series 9 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Tenth Supplemental Trust Indenture or of the Series 9 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 9 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 9 Debentures, the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 9 Debentures in respect of any tax, assessment or governmental charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 9 Debentures.

SECTION 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Tenth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Tenth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Tenth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Tenth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Tenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: Anthony Haines
Name: Anthony Haines
Title: President and
Chief Executive Officer

By: Jean-Sebastien Couillard
Name: Jean-Sebastien Couillard
Title: Chief Financial Officer

BNY TRUST COMPANY OF CANADA

By: Ismail Bawa
Name: Ismail Bawa
Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 9

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Debenture is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any debentures issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO. or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this debenture herein and it is a violation of its rights for another person to hold, transfer or deal with this debenture.

No. 9-000

$ z

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE 20" (SERIES 9)

ISIN CA 89119ZAF05
CUSIP 89119ZAF0

Issue Date	z, 2013
Stated Maturity	z, 20"
Interest Rate Per Annum	z%
Interest Payment Dates	z and z in each year
Initial Interest Payment Date	z, 2013
Principal Amount	$z

TORONTO HYDRO CORPORATION (the "Corporation") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this z% Senior Unsecured Debenture due z, 20" (Series 9) (the "Series 9 Debenture"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 9 Debenture, at the

address of the registered holder hereof appearing on the register of Series 9 Debentures maintained by or at the direction of the Trustee (the "Register"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Date in each year, and if the Corporation at any time defaults in the payment of any principal or interest, it will pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque, by same day delivery, to the address of the registered holder hereof appearing on the Register of interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 9 Debenture is presented to and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 9 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 9 Debenture is one of an authorized issue of debentures designated as 4.2% Senior Unsecured Debentures due [redacted], 20" (Series 9) and forming the series of debentures created and issued under a tenth supplemental trust indenture made as of [redacted], 2013 (the "Tenth Supplemental Trust Indenture") to a trust indenture (the "Indenture") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "Trustee"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April [redacted], 2013 between the Corporation and the Trustee, the Tenth Supplemental Trust Indenture and the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "Trust Indenture"). The Trust Indenture specifies the terms and conditions upon which the Series 9 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 9 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 9 Debenture and to each of which the registered holder of this Series 9 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 9 Debentures that may be created and issued under the Trust Indenture is limited to "[redacted]" in lawful money of Canada. Series 9 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof

and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 9 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated indebtedness of the Corporation.

This Series 9 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time, or in part at any time and from time to time, prior to ", 20", subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 9 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole, but not in part, at any time on or after ", 20", subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 9 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 9 Debentures in the open market, by tender or by private contract, at any price. Series 9 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 9 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 9 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 9 Debenture to be signed by its z and its z.

TORONTO HYDRO CORPORATION

By: _____
Name: z
Title: z

By: _____
Name: z
Title: z

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 9 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EX CEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE 20’ (SERIES 9)

ISIN CA 89119ZAF05
CUSIP 89119ZAF0

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 9 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 9

THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "U.S. SECURITIES ACT") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY" MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT

No. 9-000

$ z

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE z (SERIES 9)

Issue Date	z, 2013
Stated Maturity	z, 20"
Interest Rate Per Annum	z%
Interest Payment Dates	z and z in each year
Initial Interest Payment Date	z, 2013
Principal Amount	$z

TORONTO HYDRO CORPORATION (the "Corporation") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this z% Senior Unsecured Debenture due z, 20" (Series 9) (the "Series 9 Debenture"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 11th Floor, 320 Bay Street, Toronto, Ontario M5H 4A6, and to pay interest on the Principal Amount at the Interest

Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 9 Debenture, at the address of the registered holder hereof appearing on the register of Series 9 Debentures maintained by or at the direction of the Trustee (the "Register"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation, on the day that is two Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 9 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 9 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 9 Debenture is one of an authorized issue of debentures designated as 4.2% Senior Unsecured Debentures due [redacted], 20" (Series 9) and forming the series of debentures created and issued under a tenth supplemental trust indenture made as of [redacted], 2013 (the "Tenth Supplemental Trust Indenture") to a trust indenture (the "Indenture") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "Trustee"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 20, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April [redacted], 2013 between the Corporation and the Trustee, the Tenth Supplemental Trust Indenture and the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "Trust Indenture"). The Trust Indenture specifies the terms and conditions upon which the Series 9 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 9 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 9 Debenture and to each of which the registered holder of this Series 9 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 9 Debentures that may be created and issued under the Trust Indenture is limited to "[redacted]" in lawful money of Canada. Series 9 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 9 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated indebtedness of the Corporation.

This Series 9 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time, or in part at any time and from time to time, prior to ", 20", subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 9 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole, but not in part, at any time on or after ", 20", subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 9 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 9 Debentures in the open market, by tender or by private contract, at any price. Series 9 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 9 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 9 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 9 Debenture to be signed by its z and its z.

TORONTO HYDRO CORPORATION

By: _____
Name: z
Title: z

By: _____
Name: z
Title: z

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 9 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA

Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EX CEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
z% SENIOR UNSECURED DEBENTURES DUE 20’ (SERIES 9)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

RATING AGENCY REPORTS

In accordance with section 2.4.3 of the OEB Filing Requirements (July 17, 2013), this schedule includes the following rating agency reports:

- Appendix A: Standard and Poor's, 8 May 2014; and
- Appendix B: DBRS, 13 May 2014.

RatingsDirect®

Summary:

Toronto Hydro Corp.

Primary Credit Analyst:
Stephen R Goltz, Toronto (1) 416-507-2592; stephen.goltz@standardandpoors.com

Secondary Contact:
Andrew Ng, Toronto 416.507.2545; andrew.ng@standardandpoors.com

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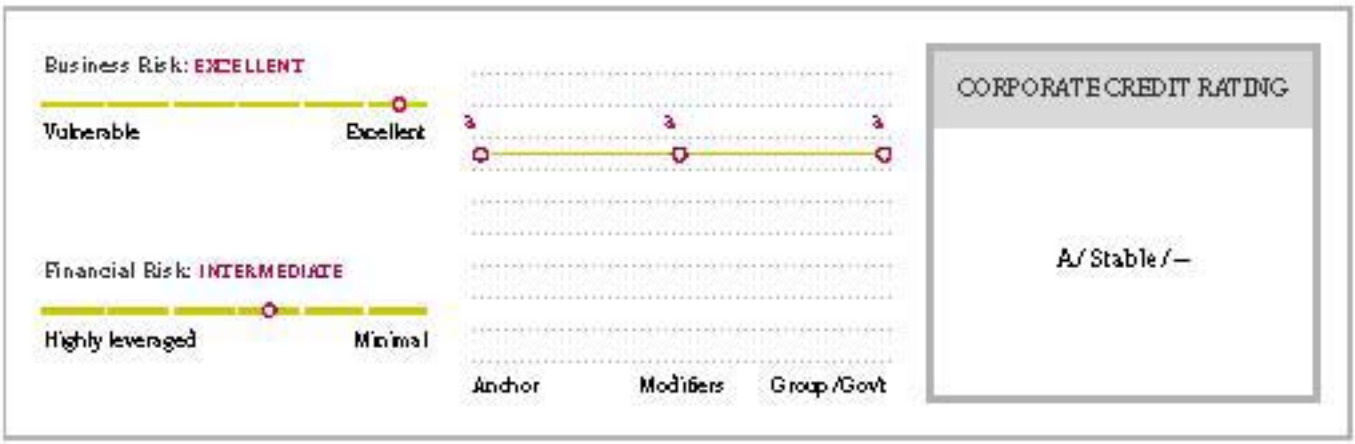
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Ratings Score Snapshot

Related Criteria And Research

Summary:

Toronto Hydro Corp.



Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• Transparent, predictable and stable regulatory regime • No input cost risks, because tariffs allow the pass-through of major expenses to customers • Stable customer base with no meaningful customer concentration risk	• Stable regulated cash flow • Sizable capital programs related to aging infrastructure • High leverage

Outlook: Stable

The stable outlook reflects Standard & Poor's Ratings Services' expectation that Toronto Hydro Corp. will continue to focus on the regulated utility business, which provides a stable and predictable stream of cash flow during our two-year outlook horizon. In addition, we believe the company will manage its capital expenditure cost to be within the approved amount set forth by the Ontario Energy Board (OEB) and maintain the deemed capital structure.

Downside scenario

We could downgrade the rating as a result of a material adverse regulatory decision, severe operational inefficiencies, or other changes that we believe might lead to long-term financial deterioration resulting in adjusted funds from operations [AFFO]-to-debt falling below 13%.

Upside scenario

We could upgrade the rating if we expect Toronto Hydro to demonstrate sustainable long-term financial growth or to improve its financial position that results in AFFO-to-debt of 23%-25%. This could require the utility to deviate from its financial policy, which we believe is highly unlikely. As a result, the prospect of an upgrade is limited during our two-year outlook horizon.

Standard & Poor's Base-Case Scenario

The key drivers in our analysis continue to be the regulatory framework and the performance of the utility operator within the regulatory framework.

Assumptions

- The regulatory system will be stable and Toronto Hydro will not experience any material, adverse regulatory decisions
- The utility will earn a standard return on equity of approximately 9.58%, operate within the deemed capital structure with 60% debt, and not spend any unapproved capital
- The company will have its rate base reset in 2015 under the new custom incentive rate-making (IR) method

Key Metrics

	2013A	2014E	2015E
AFFO/debt	16.7%	13%-16%	13%-15%
AFFO/interest	3.68x	3.3x-4.0x	3.3x-4.0x

AFFO--Adjusted funds from operations. A--Actual. E--Estimate.

Business Risk: Excellent

In our view, Toronto Hydro's business risk profile is "excellent." The main positive driver continues to be the OEB. The

regulator continues to provide a transparent regulatory framework that supports a stable and predictable cash flow model, which we view as a key credit strength. Historically, electricity rates are established under a cost-of-service framework with rates for subsequent three years under an incentive-rate mechanism. In 2012, the OEB proposed additional alternatives to electricity rate settings. We believe Toronto Hydro will adapt the custom IR method to reflect the revenue requirement based on the large multiyear capital programs the company is committed to in the next few years. Toronto Hydro most recently had its cost-of-service hearing in 2011 and is scheduled for a rate reset in 2015. The regulatory framework also limits the utility's exposure to commodity risk and associated cash flow volatility because price fluctuations in the commodity flow through directly to customers.

Further supporting the excellent business risk profile is Toronto Hydro's large and diverse customer base with no meaningful concentration risk Residential and small businesses account for more than 90% of the total. In our view this customer profile is less sensitive to macroeconomic stress and business cycles. Nevertheless, the residential customer base has some sensitivity to volume fluctuations, primarily weather-driven, although we do not believe the fluctuations would pressure credit metrics at the rating. We do not expect Toronto Hydro's customer composition to change materially over the next two-year horizon.

We believe the utility carries relatively low operating risk because it has no obligation to ensure an adequate supply of electricity and is not burdened with the procurement process or power purchase agreement, which reduces operating risks. We expect operational efficiency and reliability to remain within provincial industry norms to avoid regulatory risk linked to poor sustained performance.

Financial Risk: Intermediate

When evaluating the "intermediate" financial risk profile for Toronto Hydro, we take into the consideration of the company's lower-risk regulated business model and apply the low-volatility table. We expect the utility will continue generating stable cash flow, a key credit strength. The company has large capital programs in the next few years and relies on the combination of internal FFO and external debt to fund these capital expenditures. As a result, this has a downward pressure on the credit metrics, especially the AFFO-to-debt metric. However we believe the company will be able to maintain the AFFO-to-debt metric above the 13% threshold.

To further support the intermediate financial profile risk is that we expect Toronto Hydro to maintain its deemed capital structure established by the regulator, which includes about 60% debt. Furthermore, the company has a C$400 million commercial paper (CP) program with C$150 million outstanding. Supporting the CP program are liquidity facilities available under the utility's C$600 million revolving credit facility; hence, available borrowing under the credit facility is reduced by the amount of CP outstanding. In our opinion, the credit facility provides sufficient backup liquidity to protect Toronto Hydro in the event the company is unable to roll over the maturing paper with new notes.

Liquidity: Adequate

In our view, Toronto Hydro's liquidity "adequate". The company has sufficient liquidity sources to cover more than 1.1x its uses. Moreover, in the event of a 10% EBITDA decline, Toronto Hydro's sources of funds would still exceed its

uses. In our opinion, the company has sound relationships with its banks, generally satisfactory standing in credit markets and generally prudent financial risk management.

Principal Liquidity Sources	Principal Liquidity Uses
• FFO of approximately C$290 million • Undrawn committed credit facility of C$450 million expiring in October 2018, and two smaller facilities with total capacity of C$95 million, of which C$26 million is available	• A broad range of capital spending in 2014 that is estimated in the range of C$280 million to C$540 million • CP of C$150 million that matures in 2014 • Cash dividends of approximately C$61 million

Covenants

We expect Toronto Hydro to maintain sizable headroom below its 75% debt-to-capital covenant.

Other Modifiers

The modifying factors had no impact on the rating.

Ratings Score Snapshot

Corporate Credit Rating

A/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: a

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Financial policy:** Neutral (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan. 2, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- 2008 Corporate Criteria: Commercial Paper, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

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EB-2014-0166Toronto Hydro-Electric System Limit

Toronto Hydro Corporation

Report Date:
May 13, 2014

Rating Considerations

Strengths

(1) **Reasonable regulatory environment.** THC is predominantly a regulated electric distribution company that RSHUDWHV LQ D UHDVRQDEOH UHJXODWRU\ HQYLURQPHQW 7KH degree of stability to earnings and cash flow over the long term.

(2) **Strong franchise area.** THC is one of the largest municipally owned local distribution companies (LDCs) in Canada, serving a customer base of approximately 730,000 customers. Almost all RI 7+&¶V HOHF throughput is distributed to residential and general service customers, ZKR DFFRXQW IRU RI revenue (approximately 18% of the market in the Province of Ontario (rated AA (low)). Demand from these customers is relatively stable year over year, as they are less sensitive to economic cycles. Toronto is now the fourth-largest metropolitan area, by population, in North America.

(3) **Reasonable financial profile.** The Company¶V NH\ FUHGLW PHWULFV UHPDLQ consistent with the rating category. 7KH FRQILUPDWLRQ LQFRUSRUDWHV '%56¶V H[SHFWDWLRQV WKDW debt-to-capital ratio in line with the /'&¶V regulatory 60% debt-to-40% equity structure, and that in the event that debt leverage rises above the regulated capital structure, the Company will take necessary measures to restore its structure to the 60% debt level in a timely manner.

Challenges

(1) **Balance sheet pressure due to high capex.** Significant capital expenditure is needed to replace the &RPSDQ\¶V DJLQJ LQIUDVWUXFWXUH DSSURPLPDWHO\ $403 million planned in 2013), resulting in higher free cash flow deficits. In recent years, THC funded free cash flow deficits with a combination of proceeds from asset sales and debt, maintaining leverage close to the regulatory deemed capital structure (60% debt to 40% equity). However, as WKH &RPSDQ\¶V FDVK EDODQFHV going forward it will need to depend entirely on debt to fund its cash flow deficits. DBRS is concerned that this might DIIHFW WKH &RPSDQ\¶V IILQDQFLDO IOH[LELOLW\ DQG LWV DELOLW capital structure.

(2) **Earnings sensitive to volume.** Earnings and cash flow for electricity distribution companies are partially dependent on the volume of electricity sold, given that rates typically include a variable charge component. Seasonality, economic cyclicality and weather variability have a direct impact on the volume of electricity sold and, therefore, on revenue earned from electricity sales.

(3) **Limited access to equity markets.** 7+&¶V RZQHUVKLS VWUXFWXUH (the City; rated AA)) limits its ability to access the equity markets. As a result, 7+&¶V FDVK deficits are being financed largely through debt.

Earnings and Outlook

(CA$ millions where applicable)	For the year ended December 31 2013	2012	2011	2010	2009
Net Sales	578	577	587	549	504
EBITDA	323	332	325	326	295
EBIT	179	191	174	157	132
Gross interest expense	72	78	81	75	77
Earning before taxes	113	117	98	86	62
Net income before non-recurring items	112	105	93	61	43
Reported net income	121	86	96	66	42
Return on equity	9.5%	9.4%	8.7%	6.0%	4.3%
Rate base	2,298	2,298	2,298	2,141	2,035

(1) 2011 to 2013 financials based on USGAAP.

2013 Summary

- 7+&¶V HDUQLQJV DUH VXSSRUWHG E\ D UHDVRQDEOH UHJXODWHG diversified customer base.
- Net earnings before recurring items were higher due to lower operating costs resulting from cost reductions and staff restructuring in 2012, as well as lower financial charges.
- Reported net income was higher in 2013 due to: (1) OEB¶V -DQXDU\ disposition of the smart meter deferral account balances, permitting the recovery of return on assets since 2008 and providing for a one-time, non-recurring gain of $21 million in 2013, offset by higher operating expenses due to storm costs of $10.2 million; and (2) lower net income in 2012, resulting from a non-recurring restructuring charge of $27.8 million related to cost-reduction initiatives. DBRS has adjusted net sales and earnings to reflect these non-recurring items.

Electricity Throughputs (million kWh)	%	2013	2012	2011	2010	2009	2008	2007	2006
Residential	21%	5,073	5,174	5,204	5,209	5,037	5,216	5,332	5,352
General service	70%	17,027	17,206	17,148	17,318	16,855	17,415	17,837	17,583
Large users	10%	2,326	2,182	2,355	2,219	2,462	2,508	2,591	2,592
Total (million kWh)	100%	24,426	24,562	24,708	24,746	24,354	25,139	25,760	25,527
Growth in electricity throughputs		(0.6%)	(0.6%)	(0.2%)	1.6%	(3.1%)	(2.4%)	0.9%	(3.2%)

Customers	%	2013	2012	2011	2010	2009	2008	2007	2006
Residential	89%	648,380	637,910	629,049	620,501	611,357	605,509	601,515	599,080
General service	11%	81,137	80,699	80,222	79,836	78,840	78,589	78,349	78,978
Large users	0%	51	52	52	50	47	47	49	49
Total	100%	729,568	718,661	709,323	700,387	690,244	684,145	679,913	678,107
Growth in customer base		1.5%	1.3%	1.3%	1.5%	0.9%	0.6%	0.3%	0.2%

As of December 31, 2013

2014 Outlook

- 2014 is the final year the LDC will use a third-generation IRM (2012-2014). 8QGHU WKH ,50 WKH earnings and ROE could be negatively affected if it is unable to meet the efficiency targets.

Financial Profile and Outlook

(CA$ millions where applicable)	For the year ended December 31 2013	2012	2011	2010	2009
Net income before non-recurring items	112	105	93	61	43
Depreciation & amortization	173	142	151	169	163
Deferred income taxes and other	16	(7)	43	22	16
Cash flow from operations	301	239	287	253	222
Dividends paid	(43)	(48)	(33)	(25)	(25)
Capital expenditures	(413)	(302)	(437)	(391)	(249)
Free cash flow (bef. working cap. changes)	(156)	(111)	(183)	(163)	(53)
Changes in non-cash work. cap. items	(45)	(4)	59	27	(31)
Changes in regulatory assets & liabilities	(20)	11	(66)	(16)	(59)
Net Free Cash Flow	(220)	(103)	(191)	(151)	(142)
Acquisitions & long-term investments	0	0	0	0	0
Short-term investments	0	34	(34)	50	0
Proceeds on asset sales	2	3	5	9	1
Net equity change	0	0	0	0	0
Net debt change	147	(2)	54	198	3
Other	(5)	(9)	(10)	13	9
Change in cash	(77)	(78)	(176)	119	(129)
Total debt	1,618	1,470	1,470	1,410	1,211
Cash and cash equivalents	0	77	154	330	211
Total debt in capital structure (1)	57.6%	57.2%	59.7%	58.5%	55.4%
Cash flow/Total debt	18.6%	16.3%	19.5%	17.9%	18.3%
EBIT gross interest coverage (times)	2.50	2.44	2.16	2.10	1.73
Dividend payout ratio	38.4%	45.6%	35.5%	40.8%	59.2%

(1) Including operating leases. (2) 2011 to 2013 financials based on USGAAP.

2013 Summary

- 7+&¶V LQDQFLDO credit metrics remained reasonable for the assigned rating category.
- Capex has been steadily rising due to the replacement of aging electricity infrastructure, resulting in free cash flow deficits. Capital expenditures for the Copeland project were $43.5 million for 2013 (Total of $60.5 million spent on the project). The deficit in 2013 was financed with debt and cash on hand.
- Dividends are paid as per policy adopted by the City, that THC will pay the greater of $25 million per year (in segments throughout the year) or, if applicable, 50% of its consolidated net income for the year.

2014 Outlook

- In December 2013, the OEB approved a settlement agreement which correlates to the approval of capital expenditures amounting to $398.8 million for 2014.
- In February 2014, THC commenced tunneling for the Copeland Station project. The total capital expenditure required for the project is expected to be approximately $195 million.
- DBRS expects the Company to manage its balance sheet prudently, so that it continues to maintain its leverage in line with WKH /'& deemed capital structure. Should leverage rise above the deemed capital VWUXFWXUH RYHU RU LI NH\ FUHGLW PHWULFV ZHDNHQ DQG financial profile could deteriorate to a level that is no longer commensurate with the current A (high) rating.
- ,W UHPDLQV WR EH VHHQ ZKHWKHU 7+&¶V GLYLGHQG SROLF potentially weakening its financial profile.

Long-Term Debt Maturities and Bank Lines

(CA$ millions)	Amount	Drawn/CPs/LOCs	Available	Expiry
Cash & Cash Equivalents	-	-	-	-
Revolving Credit Facility	600.0	150.0	450.0	Oct 10, 2018
Prudential Facility	75.0	50.1	24.9	Demand
Working Capital Facility	20.0	19.1	0.9	Demand
		Total	**475.9**	

As at December 31, 2013

- On September 6, 2013, Toronto Hydro extended its $600 million committed credit facility by an additional year, to now mature in October 2018. As at December 31, 2013, $150 million was drawn under this facility.
- On December 17, 2013, Toronto Hydro launched a Commercial Paper program (DBRS rated R-1 (low)) for $400 million backstopped by its credit facility.
- The Company's liquidity profile remained strong and sufficient to cover all near- to medium-term obligations, with approximately $477 million of available funds.
- THC also has a $75 million Prudential Facility and $20 million Working Capital Facility.

Debentures

(CA$ millions)	Maturity	Outstanding
Series 2 - 5.15%	Nov 14, 2017	250.0
Series 3 - 4.49%	Nov 12, 2019	250.0
Series 6 - 5.54%	May 21, 2040	200.0
Series 7 - 3.54%	Nov 18, 2021	300.0
Series 8 - 2.91%	Apr 10, 2023	250.0
Series 9 - 3.96%	Apr 9, 2063	200.0
Total debentures		**1,450.0**
Less: Current portion of debentures		(0.7)
Long-term portion of debentures		**1,449.3**

As at December 31, 2013

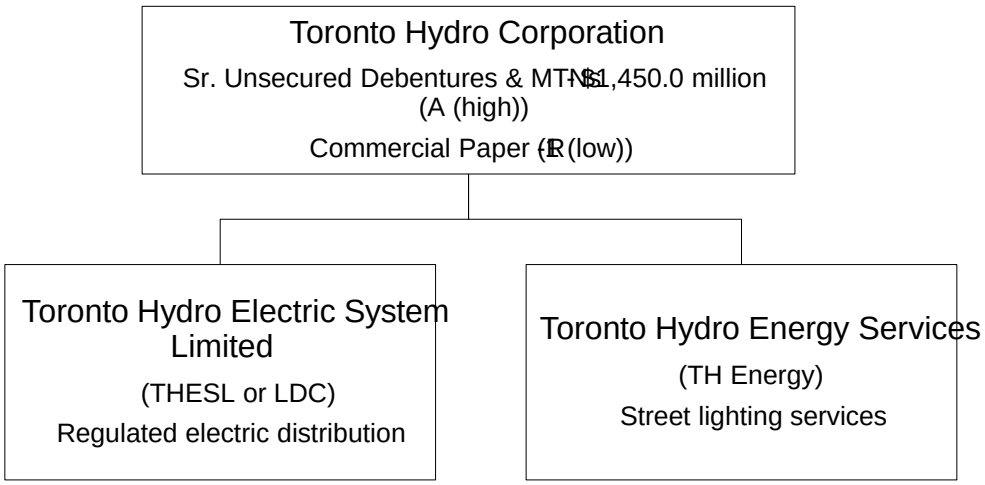
Debentures Maturities

(CA$ millions)	2014	2015	2016	2017	2018+	Total
Amount	-	-	-	250.0	1200.0	1450.0
% of Total	0.0%	0.0%	0.0%	17.2%	82.8%	100.0%

As at December 31, 2013

- Debt maturities are reasonably staggered and THC continues to have good access to debt capital markets. The Company has access to a base shelf prospectus filed on December 10, 2012, for the issuance of up to $1.5 billion (approximately, $1.05 billion available as at December 31, 2013), active for 25 months following this prospectus date.
- On April 9, 2013, THC issued $250 million of 2.91% senior unsecured debentures due April 10, 2023 (Series 8), and $200 million of 3.96% senior unsecured debentures due April 9, 2063 (Series 9). Net proceeds from the issuances were used to repay a $300 million debenture that matured on May 7, 2013, and $200 million of debentures that matured on May 7, 2003 and May 6, 2013, respectively.

Corporate Structure



- THC is a holding company with the following two subsidiaries operating exclusively in the Toronto area:
  - Toronto Hydro Electric System Limited, one of the largest municipal distribution utilities in Canada, is responsible for regulated electricity distribution (99% of revenue).
  - Toronto Hydro Energy Services Inc., which has a contractual relationship with the City, owns and operates street lighting services (1% of revenue).
- Most of the energy produced in Ontario is generated by Ontario Power Generation Inc. (rated A (low)), then WUDQVPLWWHG WR 7+&¶V QHWZRUNV E\ +\GUR 2QH ,QF UDWHG to its customers via overhead and underground lines.
- The Company currently employs approximately 1,540 people, has a peak load of approximately 5,000 megawatts and distributes electricity to approximately 730,000 customers (approximately 18% of the market in the Province of Ontario (rated AA (low)).

Regulation

- THC operates under a reasonable regulatory environment regulated by the OEB (refer to Page 8), whose mandate is to approve and set rates for the distribution and transmission of electricity, as set out by the *Electricity Act, 1998*.
- The LDC operates with a deemed capital structure of 60% debt (divided into 56% long-term and 4% short-term) and 40% equity, and an allowed ROE of 9.58%.
- For rate setting, the Company currently operates under the third-generation IRM framework for the 2012-2014 rate years.
- For 2015 and onward, THC is expected to operate under a CIR, which is a hybrid between cost of service (COS) and IRM (minimum five-year term). 7KH UDWH VHWWLQJ IRU WKH WHUP LV and OEB ¶V R analysis, using productivity benchmarking.
- CIR is suited to distributors with large, broad, multi-year investment needs over a five-year period or more and distributors who require certainty of funding several years in advance.
- CIR requires THC to provide five-year histories and five-year forecasts, with emphasis on how the plan will vary from one application type to another. Benchmarking will likely include a combination of service quality, financial performance, asset management and Conservation and Demand Management (CDM) inflation factors. 3 2ff- U D P SfV +/- 300 basis points will be allowed and additional funding is available to compensate for unforeseen events costing over $1 million.
- In January 2014, the OEB approved the disposition of balances in its smart meter deferral account related to installations in 2008, 2009 and 2010. The two new rate riders approved are effective May 1, 2014.
- In 2015, the LDC will be allowed to seek recovery for capital spent in 2012 and 2013 that has not yet been approved by the OEB in the current ICM decision, due to the standard operation of the regulatory model.

Assessment of Regulatory Environment

Criteria	Score	Analysis
(1) Deemed Equity	Excellent Good Satisfactory Below Average Poor	The OEB allows LDC to have a deemed equity of 40%, which has been consistent historically.
(2) Allowed ROE	Excellent Good Satisfactory Below Average Poor	7KH 2(%¶V DOORZHG UHWXUQ RC LDC has been 9.58% in the past few years.
(3) Energy Cost Recovery	Excellent Good Satisfactory Below Average Poor	No power price risk, as the Company is allowed to pass through the entire cost of purchased power used by its customers.
(4) Capital Cost Recovery	Excellent Good Satisfactory Below Average Poor	Major capital costs are pre-approved by the OEB and added to rate base after project completion.
(5) COS vs. IRM	Excellent Good Satisfactory Below Average Poor	LDC is regulated under an incentive rate mechanism (IRM), with three years in between the COS rebasing year.

Criteria	Score	Analysis
(6) Political Interference	Excellent Good Satisfactory Below Average Poor	After years of a relatively stable political and regulatory environment, the utility sector in Ontario could face growing challenges. As generation costs potentially rise above and ultimately test the political ceiling (10% increase of the total bill annually), it may be difficult for the utilities to pass costs onto the ratepayers.
(7) Retail Rate	Excellent Good Satisfactory Below Average Poor	Retail rates in Ontario are at the mid-range of rates in other Canadian provinces. 7RURQWR +\GUR range between 11.2 cents/kWh to 13.5 cent/kWh on peak rates from May 2014. The economic environment in Ontario is stable (real GDP grew by 2.3% in 2013).
(8) Stranded Cost Recovery	Excellent Good Satisfactory Below Average Poor	Toronto Hydro has a limited history of stranded costs. Most prudently incurred or budgeted capital expenditures are approved by the OEB. DBRS notes that there can be some regulatory lag in the approval of capital expenditures under the renewed regulatory framework.
(9) Rate Freeze	Excellent Good Satisfactory Below Average Poor	)URP WR GXH WR ULVLQ experimental utility deregulation phase, a distribution rate freeze was imposed province-wide. There have been no subsequent province-wide rate freezes.
(10) Market Structure (Deregulation)	Excellent Good Satisfactory Below Average Poor	Electricity distribution in Ontario is largely regulated and the structure provides for stability and low risk associated with purchased energy costs and counterparty risk.

Toronto Hydro Corporation

Balance Sheet

(CA$ millions)	Dec. 31 2013	Dec. 31 2012	Dec. 31 2011		Dec. 31 2013	Dec. 31 2012	Dec. 31 2011
Assets				**Liabilities & Equity**			
Cash & equivalents	0	77	154	Bank indebtedness	169	0	0
Accounts receivable	203	175	183	Accounts payable	457	383	412
Inventories	9	8	7	Current portion L.T.D.	0	470	0
Unbilled revenue	327	278	262	Customer advanced deposits	37	40	40
Prepaid expenses & other	17	15	51	Deferred revenue	21	20	13
				Other current liab.	13	24	17
Total Current Assets	555	552	657	**Total Current Liab.**	696	938	483
Net fixed assets	2,664	2,527	2,399	Long-term debt	1,449	1,000	1,470
Future income tax assets	158	194	202	Deferred income taxes	175	193	200
Goodwill & intangibles	171	134	113	Provisions	237	249	241
Regulatory assets	234	120	143	Regulatory liabilities	5	4	3
Investments & others	14	12	12	Other L.T. liab.	16	16	27
				Shareholders' equity	1,219	1,140	1,102
Total Assets	3,798	3,539	3,528	**Total Liab. & SE**	3,798	3,539	3,528

	For the year ended December 31				
Liquidity & Capital Ratios	**2013**	**2012**	**2011**	**2010**	**2009**
Current ratio	0.80	0.59	1.36	1.26	2.02
Total debt in capital structure	57.0%	56.3%	57.1%	57.6%	54.8%
Total debt in capital structure (1)	57.6%	57.2%	59.7%	58.5%	55.4%
Cash flow/Total debt	18.6%	16.3%	19.5%	17.9%	18.3%
Cash flow/Total debt (1)	18.2%	15.7%	17.6%	17.3%	17.9%
(Cash flow-dividends)/Capex (times)	0.62	0.63	0.58	0.58	0.79
Dividend payout ratio	38.4%	45.6%	35.5%	40.8%	59.2%
Coverage Ratios (times)					
EBIT gross interest coverage	2.50	2.44	2.16	2.10	1.73
EBITDA gross interest coverage	4.50	4.25	4.03	4.37	3.86
Fixed-charges coverage	2.53	2.46	2.16	2.10	1.77
EBIT gross interest coverage (1)	2.51	2.46	2.24	2.13	1.76
Profitability Ratios					
EBITDA margin	55.9%	57.5%	55.3%	59.4%	58.6%
EBIT margin	31.0%	33.0%	29.6%	28.5%	26.3%
Profit margin	19.4%	18.2%	15.9%	11.1%	8.4%
Return on equity	9.5%	9.4%	8.7%	6.0%	4.3%
Return on capital	5.9%	6.0%	5.6%	4.5%	4.1%

(1) Including operating leases. (2) 2011 to 2013 financials based on USGAAP.

Toronto Hydro Corporation

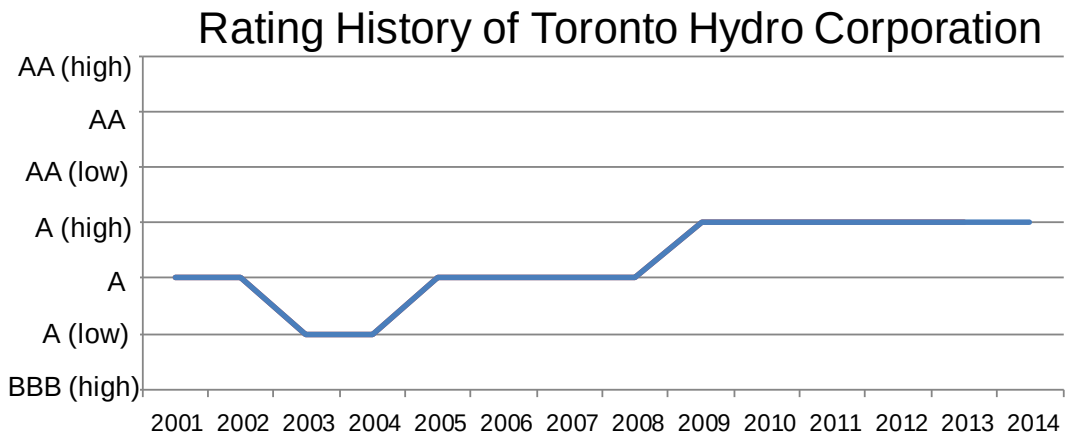
Report Date:
May 13, 2014

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Senior Unsecured Debentures & MTNs	A (high)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating History

	Current	2013	2012	2011	2009 - 2010
Issuer Rating	A (high)	A (high)	NR	NR	NR
Senior Unsecured Debentures & MTNs	A (high)	A (high)	A (high)	A (high)	A (high)
Commercial Paper	R-1 (low)	R-1 (low)	NR	NR	NR



Note:
All figures are in Canadian dollars unless otherwise noted.

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RATE BASE OVERVIEW

In accordance with s. 2.5.1.1 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements"), this schedule provides an overview of Toronto Hydro's rate base and year-over year variance analysis of rate base and distribution assets for the following years: 2011 OEB-approved, 2011 to 2013 historical actuals, 2014 bridge year forecast, and 2015 test year forecasts. Continuity statements for Toronto Hydro's fixed assets, including interest during construction and all overheads, are filed at Exhibit 2A, Tab 1, Schedule 2.

1. RATE BASE

Table 1 below summarizes Toronto Hydro's rate base values for the historical (2011 to 2013), bridge (2014), and test year (2015), including opening and closing balances, the average of opening and closing balances for gross assets and accumulated depreciation, and the utility's working capital allowance.

Table 1: Rate Base Overview ($ Millions)

	2011 OEB Approved	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2015 Test MIFRS
Opening PP&E NBV	1,897.8	1,895.8	2,183.5	2,251.9	2,356.0	2,436.6
ICM	-	-	-	-	-	372.6
Street Lighting	-	-	-	-	-	39.8
Opening PP&E NBV Adjusted	1,897.8	1,895.8	2,183.5	2,251.9	2,356.0	2,849.0
Closing PP&E NBV	2,105.1	2,183.5	2,251.9	2,356.0	2,456.3[1]	3,161.0
Average PP&E NBV	2,001.5	2,039.7	2,217.7	2,304.0	2,406.1	3,005.0
Working Capital Allowance	296.7	318.1	316.6	354.4	369.5	241.5
Rate Base	2,298.2	2,357.7	2,534.3	2,658.4	2,775.6	3,246.5

/C

[1] The 2014 financial results have not been closed out and audited. However, Toronto Hydro's assessment is that the 2014 closing PP&E NBV is within approximately 1% of the forecast.

For the purpose of the test year revenue requirement (Exhibit 6, Tab 1, Schedule 1),[1] rate base includes the average of the opening and closing balances for the net book value of property, plant and equipment plus a working capital allowance. The net book value of property, plant and equipment ("PP&E") includes only assets that are associated with activities that enable the distribution of electricity ("distribution assets") and excludes non distribution assets. Working capital allowance is based on the cost of power and controllable expenses such as operations and maintenance, billing, collections and administration expenses. /C

1.1. Fixed Asset Continuity Statements

The continuity statements are filed at Exhibit 2A, Tab 1, Schedule 2. Toronto Hydro confirms that:

- the continuity statements provide year-end balance and include interest during construction, and all overheads;
- the opening and closing balances of gross assets and accumulated depreciation that are used to calculate the fixed asset component of rate base correspond to the respective balances in the fixed asset continuity statements; and
- continuity statements reconcile to calculated depreciation expenses (Exhibit 4B, Tab 1, Schedule 1) and are presented by asset account.

1.2. Working Capital Allowance ("WCA")

As can be seen in Table 1, WCA rises from $296.7 million in 2011 to $369.5 million in 2014, and then drops to $241.7 million in 2015. The main driver of the WCA increase from 2011 to 2014 is the cost of power expense. In 2015, Toronto Hydro forecasts a lower WCA due to a reduction in the allowance percentages based on the utility's latest /C /C

[1] Due to a last minute revision that could not be reflected in the Revenue Requirement Work Form (RRWF) (Exhibit 6, Tab 1, Schedule 2), the rate base value shown in the RRWF is $ 1.1M higher than the Rate Base Overview table above and the Fixed Asset Continuity statements (Exhibit 2A, Tab 1, Schedule 2). The impact on the Revenue Requirement is less than $0.1 million. /C

lead lag study conducted by Navigant Consulting Inc. Further details on WCA are provided at Exhibit2A, Tab 3 and Schedules 1 and 2.

2. RATE BASE VARIANCE ANALYSIS

2.1. 2011 OEB Approved vs. 2015 Test Year

Toronto Hydro's requested rate base for the 2015 test year is $3,246.7 million, which represents an increase of $948.5 million or 41.3 percent from the rate base amount of $2,298.2 million approved by the OEB in the utility's last rebasing application (EB-2010-0142). The average net book value ("NBV") of PP&E increased by $1,003.5 million and the WCA component of rate base decreased by approximately $55.0 million from that approved by the OEB. **/C** **/C** **/C**

2.2. 2011 OEB Approved vs. 2011 Actual

Toronto Hydro's 2011 actual rate base was $38.2 million less than the 2011 OEB-approved amount. Average NBV of PP&E in 2011 was $38.2 million higher than the OEB-approved level, primarily due to higher in-service additions than originally assumed and additional 2011 capital expenditure. Toronto Hydro's actual 2011 WCA was $21.4 million higher than OEB-approved because the cost of power expenses were $170.2 million higher than the original forecast, with most of the increase being attributable to commodity price increases.

2.3. 2011 Actual vs. 2012 Actual

Toronto Hydro's rate base increased by $176.6 million from 2011 to 2012. The net increase in average PP&E was $178.1 million. Continued investment in distribution assets contributed to this increase. WCA decreased by $1.5 million in 2012 primarily due to reduction in OM&A in 2012 compared to 2011.

2.4. 2013 Actual vs. 2012 Actual

In 2013, rate base increased by $124.1 million over 2012 levels. In 2013, the average PP&E NBV increased by $86.2 million. Continued investment in distribution assets contributed to this increase. In addition, in 2013, Toronto Hydro applied for and received approval for final disposition of its smart metering costs and investments. As a result of this decision, a total of $46.8 million in smart meter assets were transferred to rate base. The net book value of stranded meters related to the deployment of smart meters was also reclassified to regulatory assets resulting in a decrease in net assets of $17.3 million. WCA increased by $37.8 million due to cost of power expenses, which were $292.3 million higher in 2013 than the 2012, with most of the increase being attributable to commodity price increases.

2.5. 2013 Actual vs. 2014 Bridge Year

In 2014, rate base is forecasted to increase by $117.2 million. Average NBV of PP&E is expected to increase by $102.1 million due to increased investment in the distribution system. The level of increases in average NBV of PP&E is offset by the 2013 removal of the NBV of stranded meters related to Toronto Hydro's smart metering program. In this application, Toronto Hydro is proposing disposition of its stranded meter assets (Exhibit 2B, Tab 4, Schedule 1) and therefore has removed the amounts from the ending 2013 (opening 2014) NBV of PP&E. WCA increases by $15.1 million, primarily due to rising commodity costs. /C /C

2.6. 2014 Bridge Year vs. 2015 Test Year

In 2015 rate base is forecasted to increase by $471.1 million. Average NBV of PP&E increases by $598.9 million, while WCA decreases by $127.8 million. The increase in PP&E includes $372.6 million towards board approved ICM of 2013-2014 and $39.8 /C /C /C

million towards street lighting assets. Toronto Hydro has included ICM and street lighting in the opening balance of PP&E to capture the full year return.

3. DISTRIBUTION ASSETS

Table 2A below presents a summary of Toronto Hydro's distribution assets net of accumulated depreciation (excluding construction work-in-progress), based on the OEB's minimum reporting groups for the historical (2011 to 2013), bridge (2014), and test (2015) years.

Table 2A: Net Assets (2011-2015) – Years Ending December 31 ($ millions)

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Land and Buildings	61.3	63.1	67.3	69.1	68.7	110.0
TS Primary Above 50	10.5	11.0	11.0	11.1	11.1	12.3
Distribution System	222.6	226.5	229.3	245.5	244.2	291.4
Poles and Wires	2,893.6	3,037.9	3,179.0	3,300.4	3,253.5	3,824.2
Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
Services and Meters	303.7	317.2	278.1	298.7	298.7	349.0
General Plant	130.1	134.4	141.6	167.2	167.1	153.3
Equipment	180.1	178.5	181.8	189.7	189.7	197.1
IT Assets	44.6	50.5	56.3	87.4	87.4	98.9
Other Distribution Assets	323.9	348.9	380.2	402.4	404.9	477.3
Contributions and Grants	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
Gross Assets	**4,607.8**	**4,809.0**	**4,977.7**	**5,227.6**	**5,150.5**	**5,976.5**
Accumulated Depreciation	(2,424.2)	(2,557.1)	(2,621.7)	(2,771.3)	(2,713.9)	(2,815.6)
Net Assets	**2,183.5**	**2,251.9**	**2,356.0**	**2,456.3**	**2,436.6**	**3,161.0**

/C

The major drivers of the changes from 2011 to 2015 include:

- Continued investment in distribution assets;
- Inclusion of OEB-approved smart meter expenditures in net assets;
- Reclassification of stranded meters from net assets to regulatory assets;
- Inclusion of 2013 and 2014 ICM eligible in-service capital expenditures;

- Adjustments to decrease net assets related to the transition from UGAAP to MIFRS; and
- Completion of the Phase 1 Copeland TS project.

As directed by the OEB in its Partial Decision and Order in EB-2012-0064, Toronto Hydro transferred Incremental Capital Module ("ICM") in-service capital additions in the year 2013 and 2014 to a regulatory asset account. For the purpose of 2015 opening rate base, Toronto Hydro has included forecasted ICM in-service assets as at the end of 2014. To illustrate, Tab 2B below provides a separate view of net assets which includes ICM in-service additions in 2013 and 2014. For more information about Toronto Hydro's ICM True-Up process proposal, please refer to Exhibit 2A, Tab 9, Schedule 1.

Table 2B: Net Assets (2011-2015) – Years Ending December 31 ($ millions) Including Eligible ICM In-Service Capital Expenditures

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Land and Buildings	61.3	63.1	67.8	69.8	69.3	110.0
TS Primary Above 50	10.5	11.0	11.0	11.4	11.4	12.3
Distribution System	222.6	226.5	234.7	264.6	263.3	291.4
Poles and Wires	2,893.6	3,037.9	3,312.1	3,599.0	3,552.4	3,824.2
Line Transformers	731.7	757.4	813.3	860.2	829.6	835.5
Services and Meters	303.7	317.2	282.6	314.9	315.0	349.0
General Plant	130.1	134.4	141.6	167.2	167.1	153.3
Equipment	180.1	178.5	181.8	189.7	189.7	197.1
IT Assets	44.6	50.5	56.3	87.7	87.7	98.9
Other Distribution Assets	323.9	348.9	381.2	402.2	404.7	477.3
Contributions and Grants	(294.5)	(316.6)	(339.6)	(357.2)	(357.2)	(372.5)
Gross Assets	**4,607.8**	**4,809.0**	**5,142.9**	**5,609.5**	**5,532.9**	**5,976.5**
Accumulated Depreciation	(2,424.2)	(2,557.1)	(2,623.7)	(2,781.1)	(2,723.8)	(2,815.6)
Net Assets	**2,183.5**	**2,251.9**	**2,519.1**	**2,828.4**	**2,809.2**	**3,161.0**

/C

3.1. 2011 OEB-Approved vs. 2011 Actual

Toronto Hydro reached a settlement with intervenors in its last rebasing application in 2011 (EB-2010-0142), which resulted in the OEB approving the utility's capital expenditures for 2011 on an envelope basis.[2] Toronto Hydro therefore provides its variance analysis between 2011 OEB-approved and actual net fixed assets at a total level. 2011 OEB-approved net assets were $2,001.5 million compared to $2,183.5 million historical actual net assets. As explained in more detail below, the variance of $182.0 million of actuals over the OEB-approved amounts is attributable to higher in-service additions than originally assumed and additional capital expenditures in 2011:

- In-Service Additions: Consistent with previous years, the in-service amounts forecasted in the 2011 rebasing application were determined based on assumptions using historical averages. Actual in-service amounts were greater than assumed resulting in a higher value of actual ending 2011 net assets than the OEB-approved amount.
- Additional Capital Expenditures: 2011 capital expenditures exceeded the OEB-approved amount by $66.7 million. The related 2011 in-service amounts included unanticipated amounts related to a capital lease with Canadian Power Survey Corporation for the use of stray voltage scanning equipment, the purchase of land at 715 Milner and civil construction projects. These amounts contributed to higher actual net assets in 2011 compared to amounts approved by the OEB in Toronto Hydro's last rebasing application (EB-2010-0142).

3.2. 2011 Actual vs. 2012 Actual

As table 3 below illustrates, 2012 net assets were $2,251.9 million compared to 2011 net assets of $2,183.5 million, representing an increase of $68.4 million. Capital additions were $209.4 million and depreciation expense was $140.1 million in 2012. For more

[2] EB-2010-0142, Partial Decision and Order (July 7, 2011) at pages 2 and 3.

information, refer to the fixed asset continuity statement for 2012 UGAAP (Exhibit 2A, Tab 2, Schedule 1, Appendix A). Continued investment in distribution assets contributed to this increase. The primary driver contributing to the increase is poles and wires assets.

Table 3: 2011 Historical (CGAAP) versus 2012 Historical (UGAAP) ($ millions)

	2011 Historical CGAAP	2012 Historical UGAAP	Variance ($)	Variance (%)
Land and Buildings	61.3	63.1	1.8	2.9
TS Primary Above 50	10.5	11.0	0.5	4.6
Distribution System	222.6	226.5	4.0	1.8
Poles and Wires	2,893.6	3,037.9	144.3	5.0
Line Transformers	731.7	757.4	25.7	3.5
Services and Meters	303.7	317.2	13.5	4.4
General Plant	130.1	134.4	4.3	3.3
Equipment	180.1	178.5	(1.6)	(0.9)
IT Assets	44.6	50.5	5.9	13.2
Other Distribution Assets	323.9	348.9	25.0	7.7
Contributions and Grants	(294.5)	(316.6)	(22.1)	7.5
Gross Assets	**4,607.8**	**4,809.0**	**201.2**	**4.4**
Accumulated Depreciation	(2,424.2)	(2,557.1)	(132.8)	5.5
Net Assets	**2,183.5**	**2,251.9**	**68.4**	**3.1**

Note: Variances due to rounding may exist

3.3. 2012 Actual vs. 2013 Actual

As Table 4 below illustrates, 2013 net assets were $2,356.0 million compared to historical 2012 net assets of $2,251.9 million, representing an increase of $104.1 million or 4.6 percent. Capital additions were $381.3 million and depreciation expense was $143.1 million in 2013. For more information, refer to the fixed asset continuity statement for 2013 UGAAP (Exhibit 2A, Tab 2, Schedule 1, Appendix A). Continued investment in distribution assets contributed to this increase. The primary driver contributing to the increase is poles and wires assets. The net book value of stranded meters related to the deployment of smart meters was also reclassified to regulatory assets resulting in a decrease in net assets of $17.8 million. These reductions to net assets

were offset by an increase in net assets of $46.8 million related to the OEB ruling on smart meters permitting the recovery of the utility's allowed cost of capital on smart meters since 2008.

Table 4: 2012 Historical (UGAAP) versus 2013 Historical (UGAAP) ($ millions)

	2012 Historical UGAAP	2013 Historical UGAAP	Variance ($)	Variance (%)
Land and Buildings	63.1	67.3	4.1	6.6
TS Primary Above 50	11.0	11.0	(0.0)	(0.0)
Distribution System	226.5	229.3	2.8	1.2
Poles and Wires	3,037.9	3,179.0	141.0	4.6
Line Transformers	757.4	791.9	34.5	4.6
Services and Meters	317.2	278.1	(39.2)	(12.3)
General Plant	134.4	141.6	7.2	5.4
Equipment	178.5	181.8	3.3	1.9
IT Assets	50.5	56.3	5.8	11.5
Other Distribution Assets	348.9	380.2	31.2	9.0
Contributions and Grants	(316.6)	(338.8)	(22.2)	7.0
Gross Assets	**4,809.0**	**4,977.7**	**168.7**	**3.5**
Accumulated Depreciation	(2,557.1)	(2,621.7)	(64.6)	2.5
Net Assets	**2,251.9**	**2,356.0**	**104.1**	**4.6**

Note: Variances due to rounding may exist

Table 4 above reflects a reduction in net assets by $163.1 million related to ICM in-service capital expenditures, which were transferred to a regulatory asset account, as directed by the OEB in EB-2012-0064.[4]

3.4. 2013 Actual vs. 2014 Bridge

As Table 5 below illustrates, Toronto Hydro forecasts 2014 net assets at $2,456.3 million compared to historical 2013 net assets of $2,356.0 million, representing an increase of $100.3 million or 4.3 percent. Capital additions are forecasted at $470.6 million and accumulated depreciation additions are forecasted at $158.2 million in 2014. For more information,

/C

/C

[4] EB-2012-0064, Partial Decision and Order (April 2, 2013).

refer to the fixed asset continuity statement for 2014 USGAAP (Exhibit 2A, Tab 1, Schedule 2, Appendix 2-BA). Continued investment in distribution assets contributed to this increase. The primary driver contributing to the increase is poles and wires assets. /C

Table 5: 2013 Historical (UGAAP) versus 2014 Bridge (UGAAP) ($ millions)

	2013 Historical UGAAP	2014 Bridge UGAAP	Variance ($)	Variance (%)
Land and Buildings	67.3	69.1	1.9	2.8
TS Primary Above 50	11.0	11.1	0.2	1.4
Distribution System	229.3	245.5	16.1	7.0
Poles and Wires	3,179.0	3,300.4	121.5	3.8
Line Transformers	791.9	810.3	18.3	2.3
Services and Meters	278.1	298.7	20.7	7.4
General Plant	141.6	167.2	25.6	18.1
Equipment	181.8	189.7	7.8	4.3
IT Assets	56.3	87.4	31.1	55.2
Other Distribution Assets	380.2	402.4	22.2	5.8
Contributions and Grants	(338.8)	(354.3)	(15.5)	4.6
Gross Assets	**4,977.7**	**5,227.6**	**249.9**	**5.0**
Accumulated Depreciation	(2,621.7)	(2,771.3)	(149.6)	5.7
Net Assets	**2,356.0**	**2,456.3**	**100.2**	**4.3**

Note: Variances due to rounding may exist

/C

Table 5 above, reflects a reduction in net assets by $214.6 million related to forecasted ICM eligible in-service capital expenditures, which were transferred to a regulatory asset account as directed by the OEB. /C

3.5. 2014 Bridge vs. 2015 Test Year

Toronto Hydro forecasts 2015 net assets under MFIRS at $3,161.0 million compared to forecasted 2014 net assets of $2,456.3 million under UGAAP, representing an increase of $704.7 million or 28.7 percent. The 2015 opening balance net assets are adjusted for the following items, representing $393.3 million of the total net asset increase: /C

- \$372.6 million increase related to the addition of 2013 and 2014 ICM eligible in-service capital expenditures presented in the regulatory asset account for the duration of the IRM period. /C
- \$39.8 million increase for the transfer of former street lighting assets, which as proposed in Exhibit 2A, Tab 5, Schedule 1, will have a neutral effect on the utility's test year revenue requirement;
- \$19.1 million decrease related to the transition from UGAAP to MIFRS.

Table 5A: 2014 Bridge (UGAAP) versus 2015 Test (MIFRS) (\$ millions)

	2014 Bridge UGAAP	2015 Test MIFRS	Variance (\$)	Variance (%)
Land and Buildings	69.1	110.0	40.9	59.1
TS Primary Above 50	11.1	12.3	1.2	10.4
Distribution System	245.5	291.4	45.9	18.7
Poles and Wires	3,300.4	3,824.2	523.8	15.9
Line Transformers	810.3	835.5	25.3	3.1
Services and Meters	298.7	349.0	50.2	16.8
General Plant	167.2	153.3	(13.9)	(8.3)
Equipment	189.7	197.1	7.4	3.9
IT Assets	87.4	98.9	11.4	13.1
Other Distribution Assets	402.4	477.3	75.0	18.6
Contributions and Grants	(354.3)	(372.5)	(18.2)	5.1
Gross Assets	**5,227.6**	**5,976.5**	**749.0**	**14.3**
Accumulated Depreciation	(2,771.3)	(2,815.6)	(44.3)	1.6
Net Assets	**2,456.3**	**3,161.0**	**704.7**	**28.7**

Note: Variances due to rounding may exist

/C

Capital additions are forecasted at \$539.7 million. The increase in net assets is driven by the capital investments outlined in the Distribution System Plan (Exhibit 2B, Section E). /C

Land and Buildings are expected to increase \$40.9 million or 59.1 percent and TS Primary Above 50 assets are expected to increase \$1.2 million or 10.4 percent. The /C /C

increase in both of these major plant accounts is primarily due to the Phase 1 Copeland TS project which includes the station facility construction and installation of high voltage transmission connections. The Copeland TS project was approved by the OEB under the Toronto Hydro's 2012-2014 ICM application.[5] Refer to the Station Expansion Program (Exhibit 2B, E7.9) for additional details relating to this project.

Distribution System assets are expected to increase $45.9 million or 18.7 percent. The increase in distribution system assets is primarily due to the forecasted in-service stations switchgear projects. Municipal Station Switchgear and Transformer Switchgear work was filed and approved as part of Toronto Hydro's 2012-2014 ICM application and will continue as a program in 2015 to replace existing obsolete switchgear with a modern arc-resistant design. Refer to the Switchgear Renewal Program (Exhibit 2B, E6.13) for more information about this project. **/C**

Capital investment in poles and wires is expected to increase by $523.8 million or 15.9 percent and investment in line transformer assets are expected to increase by $25.3 million or 3.1 percent. The increase in these major plant categories is primarily attributed to the Underground Circuit Renewal (Exhibit 2B, E6.1), Overhead Circuit Renewal (Exhibit 2B, E6.4), Reactive Capital (Exhibit 2B, E6.20) and Customer Connections (Exhibit 2B, E5.2) programs. **/C**

- The Underground and Overhead Circuit Renewal programs are required to replace end of life and obsolete assets to mitigate failure and safety risks.
- The Reactive Capital program is required to restore power to customers and maintain system performance and reliability when assets fail.

[5] EB-2012-0064, Partial Decision and Order (April 2, 2013) at page 53.

- The Customer Connection program allows Toronto Hydro to satisfy its obligation to connect new customers in its service area.

Net additions to poles and wires and line transformers includes the 2013 and 2014 ICM eligible in-service capital expenditures presented in the regulatory asset account for the duration of the IRM period. Former street lighting assets are also included as part of the net addition increase to poles and wires.

Services and meter assets are expected to increase $50.2 million or 16.8 percent. The increase in services and meter assets is primarily related to the Metering program (Exhibit 2B, E6.1), the objective of which is to ensure compliance with Measurement Canada, OEB and IESO rules and regulations. **/C**

Equipment assets are expected to increase $7.4 million or 3.9 percent. The increase in equipment is primarily due to fleet. Refer to the Fleet and Equipment Services program (Exhibit 2B, E8.1) for additional details. **/C** **/C**

IT assets are expected to increase $11.4 million or 13.1 percent primarily due to computer hardware equipment investment which enables Toronto Hydro to efficiently and effectively plan and execute capital and operational programs and fulfill its obligations to customers and regulatory bodies. Refer to the IT Hardware program (Exhibit 2B, E8.4) for more information.

Other distribution assets are expected to increase $75.0 million or 18.6 percent primarily due to the in-service amount for computer software additions. For additional details related to the computer software investments refer to the IT Software program (Exhibit 2B, E8.5). **/C**

Contributions and grants are expected to increase $18.2 million or 5.1 percent related to realized contributions related to in-service assets.

The forecasted accumulated depreciation additions is $208.1 million in 2015, and includes $33.9 million of losses on derecognition of assets. For more information about Toronto Hydro's depreciation expense and derecognition losses, refer to Exhibit 4B, Tab 1, Schedules 1 and 2, respectively. /C

Net assets were reduced by $4.6 million related to eligible investment for the purpose of enabling the connection of a renewable energy generation facility to its distribution system. In accordance with s. 79.1 of the *Ontario Energy Board Act, 1998* and s. 2.5.2.5 of the OEB's Filing Requirements (July 17, 2013), Toronto Hydro proposes to recover the cost incurred for these investments from all provincial ratepayers. Refer to Exhibit 2A, Tab 8, Schedule 1 for more information about Toronto Hydro's proposed treatment of renewable enabling eligible investments.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - CGAAP

Year 2011

CCA Class	OEB	Description	Cost					Accumulated Depreciation					Net Book Value
			Opening Balance	Additions	Retirement	Transfers	Closing Balance	Opening Balance	Additions	Retirement	Transfers	Closing Balance	
12	1611	Computer Software (Formally known as Account 1925)	$ 172,691,847	$ 53,066,537	$ r	($ 3,159,693)	$ 222,598,691	($ 129,292,640)	($ 24,893,304)	$ r	$ r	($ 154,185,944)	$ 68,412,747
N/A	1805	Land	$ 7,670,263	($ 1,535)	($ 58,892)	$ r	$ 7,609,837	$ r	$	$ r	$ r	$ r	$ r 7,609,837
1	1808	Buildings	$ 45,857,359	$ 2,530,944	($ 3,761,399)	($ 45,048)	$ 44,581,856	($ 17,441,185)	($ 1,550,177)	$ 1,151,042	$ 6,334	($ 17,833,986)	$ 26,747,870
47	1815	TransformerStation Equipment >50 kV	$ 9,869,059	$ 623,021	$ r	$ r	$ 10,492,080	($ 3,945,111)	($ 380,940)	$ r	$ r	($ 4,326,051)	$ 6,166,029
47	1820	Distribution Station Equipment <50 kV	$ 199,481,416	$ 23,105,699	$ r	$ r	$ 222,587,114	($ 88,643,689)	($ 7,083,676)	$ r	$ r	($ 95,727,365)	$ 126,859,750
47	1830	Poles,Towers&Fixtures	$ 350,090,188	$ 28,998,242	$ r	$ r	$ 379,088,430	($ 171,015,223)	($ 5,824,614)	$ r	$ r	($ 176,839,838)	$ 202,248,592
47	1835	OverheadConductors &Devices	$ 378,085,017	$ 34,893,995	$ r	$ r	$ 412,979,013	($ 240,607,561)	($ 4,341,875)	$ r	$ r	($ 244,949,436)	$ 168,029,576
47	1840	UndergroundConduit	$ 1,178,820,486	$ 134,109,241	$ r	$ r	$ 1,312,929,727	($ 588,742,455)	($ 31,948,117)	$ r	$ r	($ 620,690,572)	$ 692,239,156
47	1845	UndergroundConductors &Devices	$ 722,435,297	$ 66,209,802	$ r	$ r	$ 788,645,099	($ 377,725,469)	($ 13,844,464)	$ r	$ r	($ 391,569,933)	$ 397,075,166
47	1850	LineTransformers	$ 682,649,674	$ 49,044,127	$ r	$ r	$ 731,693,800	($ 356,892,831)	($ 21,426,917)	$ r	$ r	($ 378,319,748)	$ 353,374,052
47	1855	Services(Overhead &Underground)	$ 72,596,667	$ 2,896,736	$ r	$ r	$ 75,493,402	($ 13,025,365)	($ 1,433,856)	$ r	$ r	($ 14,459,221)	$ 61,034,181
47	1860	Meters	$ 210,553,546	$ 17,674,856	$ r	$ r	$ 228,228,402	($ 115,000,783)	($ 9,162,626)	$ r	$ r	($ 124,163,409)	$ 104,064,992
N/A	1905	Land	$ 1,889,782	$ 7,261,212	$ r	$ r	$ 9,150,994	$ r	$	$ r	$ r	$ r	$ r 9,150,994
1	1908	Buildings&Fixtures	$ 105,685,557	$ 4,619,112	$ r	$ 45,048	$ 110,349,717	($ 38,167,505)	($ 6,395,106)	$ r	($ 6,334)	($ 44,568,945)	$ 65,780,772
13	1910	LeaseholdImprovements	$ 19,460,717	$ 294,610	$ r	$ r	$ 19,755,328	($ 12,768,075)	($ 5,993,705)	$ r	$ r	($ 18,761,779)	$ 993,548
8	1915	OfficeFurniture &Equipment	$ 16,398,277	$ 4,106,766	$ r	$ r	$ 20,505,043	($ 7,024,507)	($ 1,452,357)	$ r	$ r	($ 8,476,864)	$ 12,028,179
52	1920	ComputerEquipment rHardware	$ 40,633,537	$ 3,991,660	$ r	$ r	$ 44,625,197	($ 31,228,484)	($ 4,373,915)	$ r	$ r	($ 35,602,399)	$ 9,022,798
10	1930	TransportationEquipment	$ 73,748,754	$ 11,490,148	($ 7,257,634)	$ 34,362	$ 78,015,630	($ 43,208,343)	($ 7,074,141)	$ 7,185,827	($ 57,374)	($ 43,154,031)	$ 34,861,599
8	1935	StoresEquipment	$ 5,506,283	$ r	$ r	$ r	$ 5,506,283	($ 5,476,091)	($ 7,709)	$ r	$ r	($ 5,483,800)	$ 22,484
8	1940	Tools,Shop & Garage Equipment	$ 36,736,912	$ 2,646,528	$ r	($ 192,000)	$ 39,191,440	($ 25,431,593)	($ 1,924,584)	$ r	$ r	($ 27,356,177)	$ 11,835,262
8	1945	Measurement&TestingEquipment	$ 4,866,897	$ 13,567,209	$ r	($ 13,417,930)	$ 5,016,176	($ 4,300,071)	($ 1,086,963)	$ r	$ 958,424	($ 4,428,611)	$ 587,566
8	1955	CommunicationsEquipment	$ 26,817,595	$ 1,368,039	$ r	$ 3,351,693	$ 31,537,327	($ 21,012,708)	($ 2,899,180)	$ r	$ r	($ 23,911,888)	$ 7,625,439
8	1960	Miscellaneous Equipment	$ 170,801	$ 197,257	$ r	$ r	$ 368,058	($ 2,911)	($ 25,285)	$ r	$ r	($ 28,196)	$ 339,863
47	1970	LoadManagement Controls Customer Premises	$ 15,181,181	($ 338,086)	$ r	$ r	$ 14,843,095	($ 8,630,378)	($ 1,025,729)	$ r	$ r	($ 9,656,107)	$ 5,186,988
47	1975	LoadManagement Controls Utility Premises	$ 554,382	$ r	$ r	$ r	$ 554,382	($ 554,382)	$ r	$ r	$ r	($ 554,382)	$ r
47	1980	SystemSupervisor Equipment	$ 56,427,608	$ 1,154,182	$ r	$ r	$ 57,581,790	($ 36,171,073)	($ 1,763,841)	$ r	$ r	($ 37,934,914)	$ 19,646,876
47	1995	Contributions&Grants	($ 258,098,313)	($ 36,381,079)	$ r	$ r	($ 294,479,391)	$ 53,243,868	$ 8,200,745	$ r	$ r	$ 61,444,613	($ 233,034,778)
N/A	1609	CapitalContributions Paid	$ 2,042,507	$ 12,016,399	$ r	$ r	$ 14,058,906	($ 524,244)	($ 916,010)	$ r	$ r	($ 1,440,253)	$ 12,618,653
N/A	2005	PropertyUnderCapital Leases	$ 885,800	$ r	$ r	$ 13,383,568	$ 14,269,368	($ 350,415)	$ r	$ r	($ 901,049)	($ 1,251,464)	$ 13,017,904
							$ r					$ r	$ r
		Sub-Total	**$ 4,179,709,098**	**$ 439,145,621**	**($ 11,077,924)**	**$ -**	$ 4,607,776,794	**($ 2,283,939,224)**	**($ 148,628,347)**	**$ 8,336,869**	**$ -**	**($ 2,424,230,701)**	**$ 2,183,546,093**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ **r**					$ r	$ r
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ ***r***					$ r	$ r
		Total PP&E	**$ 4,179,709,098**	**$ 439,145,621**	**($ 11,077,924)**	**$ -**	$ 4,607,776,794	**($ 2,283,939,224)**	**($ 148,628,347)**	**$ 8,336,869**	**$ -**	**($ 2,424,230,701)**	**$ 2,183,546,093**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							$ **r**			$ r	
		Total							**($ 148,628,347)**				

10		Transportation
8		StoresEquipment

Less: *Fully Allocated Depreciation*

Transportation	($ 2,189,844)
StoresEquipment	
Net Depreciation	($ 146,438,503)

Notes:

1 Thebelow CCAclasseshavebeenupdated oradded fortheseOEBAccounts:

CCAClass	OEB	Description	ExplanationforChange
N/A	1612	LandRights	Fortaxpurposes,theland rights/easementsare treated aseligible capital expenditures["ECE"] and are recorded in Schedule 10oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1808	Buildings	Fortaxpurposes,theland rights/easementsare treated aseligible capital expenditures["ECE"] and are recorded in Schedule 10oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1908	Buildings&Fixtures	Perdefinition ofCCAClass 1in Schedule IIofIncomeTaxRegulations
52	1920	ComputerEquipment rHardware	Class52(with 100% CCArate with no half ryearrule)wasadded toSchedule IIofIncomeTaxRegulations on April 30, 2009 rforeligible computersacquired after January27, 2009 and beforeFebruary, 2011.
N/A	1609	CapitalContributions Paid	Fortaxpurposes,thecapital contributions paid are treated asECE and are recorded in Schedule 10oftheincometaxreturn(perparagraph30ofInterpretationBulletin ITr143R3)
N/A	2005	PropertyUnderCapital Leases	NotCapitalized fortax purposes,actual paymentin theyear is deductible fortax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - UGAAP

Year 2012

			Cost					Accumulated Depreciation					
CCA Class	OEB	Description	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 222,598,691	$ 19,655,588	$ r	$ r	$ 242,254,279	($ 154,185,944)	($ 20,224,259)	$ r	$ r	($ 174,410,203)	$ 67,844,075
N/A	1805	Land	$ 7,609,837	$ r	($ 13,989)	$ r	$ 7,595,848	$ r	$ r	$ r	$ r	$ r	$ 7,595,848
1	1808	Buildings	$ 44,581,856	$ 2,314,871	($ 566,615)	$ 45,048	$ 46,375,160	($ 17,833,986)	($ 1,495,626)	$ 247,655	($ 3,983)	($ 19,085,940)	$ 27,289,220
47	1815	TransformerStation Equipment >50kV	$ 10,492,080	$ 525,966	$ r	($ 43,688)	$ 10,974,359	($ 4,326,051)	($ 402,730)	$ r	$ r	($ 4,728,781)	$ 6,245,578
47	1820	Distribution Station Equipment <50 kV	$ 222,587,114	$ 3,874,905	$ r	$ 77,169	$ 226,539,188	($ 95,727,365)	($ 6,499,970)	$ r	$ r	($ 102,227,335)	$ 124,311,853
47	1830	Poles,Towers&Fixtures	$ 379,088,430	$ 13,535,315	$ r	$ r	$ 392,623,745	($ 176,839,838)	($ 6,469,781)	$ r	$ r	($ 183,309,619)	$ 209,314,126
47	1835	OverheadConductors &Devices	$ 412,979,013	$ 20,008,279	$ r	$ 84,573	$ 433,071,865	($ 244,949,436)	($ 5,152,543)	$ r	$ r	($ 250,101,980)	$ 182,969,885
47	1840	UndergroundConduit	$ 1,312,929,727	$ 65,155,008	$ r	($ 424,660)	$ 1,377,660,076	($ 620,690,572)	($ 32,737,980)	$ r	($ 1,119)	($ 653,429,670)	$ 724,230,405
47	1845	UndergroundConductors &Devices	$ 788,645,099	$ 45,810,001	$ r	$ 134,998	$ 834,590,098	($ 391,569,933)	($ 14,554,813)	$ r	($ 1,599)	($ 406,126,346)	$ 428,463,752
47	1850	LineTransformers	$ 731,693,800	$ 25,553,462	$ r	$ 184,160	$ 757,431,422	($ 378,319,748)	($ 20,415,257)	$ r	$ 1,599	($ 398,733,406)	$ 358,698,016
47	1855	Services(Overhead &Underground)	$ 75,493,402	$ 4,880,163	$ r	$ 119,394	$ 80,492,959	($ 14,459,221)	($ 1,552,305)	$ r	$ r	($ 16,011,525)	$ 64,481,434
47	1860	Meters	$ 228,228,402	$ 8,583,433	$ r	($ 71,512)	$ 236,740,323	($ 124,163,409)	($ 9,461,636)	$ r	$ r	($ 133,625,046)	$ 103,115,277
N/A	1905	Land	$ 9,150,994	$ r	$ r	$ r	$ 9,150,994	$ r	$ r	$ r	$ r	$ r	$ 9,150,994
1	1908	Buildings&Fixtures	$ 110,349,717	$ 3,688,811	$ r	($ 45,048)	$ 113,993,480	($ 44,568,945)	($ 5,597,338)	$ r	$ 3,983	($ 50,162,300)	$ 63,831,180
13	1910	LeaseholdImprovements	$ 19,755,328	$ 628,396	$ r	$ r	$ 20,383,723	($ 18,761,779)	($ 604,412)	$ r	$ r	($ 19,366,191)	$ 1,017,532
8	1915	OfficeFurniture &Equipment	$ 20,505,043	$ 1,213,915	$ r	$ r	$ 21,718,959	($ 8,476,864)	($ 1,695,701)	$ r	$ r	($ 10,172,565)	$ 11,546,394
50	1920	ComputerEquipment rHardware	$ 44,625,197	$ 5,897,757	$ r	($ 20,079)	$ 50,502,876	($ 35,602,399)	($ 4,401,165)	$ r	$ 418	($ 40,003,146)	$ 10,499,730
10	1930	TransportationEquipment	$ 78,015,630	$ 2,116,290	($ 7,623,507)	$ 731,156	$ 73,239,570	($ 43,154,031)	($ 7,499,760)	$ 7,039,462	($ 220,097)	($ 43,834,426)	$ 29,405,144
8	1935	StoresEquipment	$ 5,506,283	$ r	$ r	$ r	$ 5,506,283	($ 5,483,800)	($ 7,709)	$ r	$ r	($ 5,491,508)	$ 14,775
8	1940	Tools,Shop &Garage Equipment	$ 39,191,440	$ 1,104,891	$ r	$ r	$ 40,296,331	($ 27,356,177)	($ 2,006,371)	$ r	$ r	($ 29,362,549)	$ 10,933,782
8	1945	Measurement&TestingEquipment	$ 5,016,176	$ 298,172	$ r	$ r	$ 5,314,349	($ 4,428,611)	($ 2,061,676)	$ r	$ 1,916,847	($ 4,573,439)	$ 740,910
8	1955	CommunicationsEquipment	$ 31,537,327	$ 522,839	$ r	$ 20,079	$ 32,080,245	($ 23,911,888)	($ 2,684,558)	$ r	($ 418)	($ 26,596,864)	$ 5,483,380
8	1960	Miscellaneous Equipment	$ 368,058	$ 1,043	$ r	$ r	$ 369,101	($ 28,196)	($ 36,918)	$ r	$ r	($ 65,113)	$ 303,988
47	1970	LoadManagement Controls Customer Premises	$ 14,843,095	$ r	$ r	$ r	$ 14,843,095	($ 9,656,107)	($ 1,082,077)	$ r	$ r	($ 10,738,184)	$ 4,104,911
47	1975	LoadManagement Controls Utility Premises	$ 554,382	$ r	$ r	$ r	$ 554,382	($ 554,382)	$ r	$ r	$ r	($ 554,382)	$ r
47	1980	SystemSupervisor Equipment	$ 57,581,790	$ 526,532	$ r	($ 19,082)	$ 58,089,239	($ 37,934,914)	($ 1,761,636)	$ r	$ r	($ 39,696,550)	$ 18,392,689
47	1995	Contributions&Grants	($ 294,479,391)	($ 22,061,046)	$ r	($ 41,353)	($ 316,581,790)	$ 61,444,613	$ 9,011,788	$ r	$ 1,119	$ 70,457,520	($ 246,124,270)
N/A	1609	CapitalContributions Paid	$ 14,058,906	$ 5,590,059	$ r	$ r	$ 19,648,965	($ 1,440,253)	($ 734,850)	$ r	$ r	($ 2,175,104)	$ 17,473,861
N/A	2005	PropertyUnderCapital Leases	$ 14,269,368	$ r	$ r	($ 731,156)	$ 13,538,213	($ 1,251,464)	$ r	$ r	($ 1,696,751)	($ 2,948,215)	$ 10,589,998
							$ r					$ r	$ r
		Sub-Total	**$ 4,607,776,794**	**$ 209,424,649**	**($ 8,204,110)**	**$ -**	$ 4,808,997,333	**($ 2,424,230,701)**	**($ 140,129,282)**	**$ 7,287,117**	**$ -**	**($ 2,557,072,867)**	**$ 2,251,924,467**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ **r**					$ r	$ r
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ ***r***					$ r	$ r
		Total PP&E	**$ 4,607,776,794**	**$ 209,424,649**	**($ 8,204,110)**	**$ -**	$ 4,808,997,333	**($ 2,424,230,701)**	**($ 140,129,282)**	**$ 7,287,117**	**$ -**	**($ 2,557,072,867)**	**$ 2,251,924,467**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							$ **r**			$ r	
		Total							**($ 140,129,282)**				

10		Transportation
8		StoresEquipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,620,301)
StoresEquipment	
Net Depreciation	($ 138,508,981)

Notes:

1 Thebelow CCAclasseshavebeenupdated fortheseOEBAccounts :

CCAClass	OEB	Description	ExplanationforChange
N/A	1612	LandRights	Fortaxpurposes,theland rights/easementsare treated aseligible capital expenditures["ECE"] and are recorded in Schedule 10oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1808	Buildings	Fortaxpurposes, theland rights/easementsare treated aseligible capital expenditures["ECE"] and are recorded in Schedule 10oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1908	Buildings&Fixtures	Perdefinition ofCCAClass 1in Schedule IIofIncomeTaxRegulations
50	1920	ComputerEquipment rHardware	Class50(with 55% CCArate and subjecttohalfryear rule)wasadded toSchedule IIofIncomeTaxRegulations on April 23, 2009 rforeligible computersand softwareacquired after March18, 2007, but not including property thatis included in Class 52.
N/A	1609	CapitalContributions Paid	Fortaxpurposes,thecapital contributions paid are treated asECE and are recorded in Schedule10oftheincometaxreturn(perparagraph30ofInterpretationBulletin ITr143R3)
N/A	2005	PropertyUnderCapital Leases	NotCapitalized fortaxpurposes,actual paymentin theyear is deductible fortax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - UGAAP

Year 2013

			Cost					Accumulated Depreciation					
CCA Class	OEB	Description	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 242,254,279	$ 17,872,360	$ r	$ 8,261,966	$ 268,388,604	($ 174,410,203)	($ 17,210,554)	$ r	($ 7,195,178)	($ 198,815,935)	$ 69,572,669
N/A	1805	Land	$ 7,595,848	$ r	($ 7,317)	$ r	$ 7,588,531	$ r	$ r	$ r	$ r	$ r	$ 7,588,531
1	1808	Buildings	$ 46,375,160	$ 4,942,504	($ 246,793)	($ 541,000)	$ 50,529,871	($ 19,085,940)	($ 1,866,209)	$ 37,334	$ 225,417	($ 20,689,399)	$ 29,840,472
47	1815	TransformerStation Equipment >50kV	$ 10,974,359	$ 4,172	$ r	($ 5,874)	$ 10,972,657	($ 4,728,781)	($ 404,101)	$ r	$ 180	($ 5,132,702)	$ 5,839,955
47	1820	Distribution Station Equipment <50 kV	$ 226,539,188	$ 8,271,011	$ r	($ 5,464,410)	$ 229,345,789	($ 102,227,335)	($ 6,699,017)	$ r	$ 182,105	($ 108,744,247)	$ 120,601,543
47	1830	Poles,Towers&Fixtures	$ 392,623,745	$ 30,383,301	$ r	($ 16,170,543)	$ 406,836,503	($ 183,309,619)	($ 6,883,833)	$ r	$ 87,033	($ 190,106,418)	$ 216,730,084
47	1835	OverheadConductors &Devices	$ 433,071,865	$ 43,696,424	$ r	($ 14,172,386)	$ 462,595,902	($ 250,101,980)	($ 5,922,635)	$ r	$ 90,213	($ 255,934,401)	$ 206,661,501
47	1840	UndergroundConduit	$ 1,377,660,076	$ 100,436,340	$ r	($ 57,235,826)	$ 1,420,860,590	($ 653,429,670)	($ 34,220,426)	$ r	$ 582,669	($ 687,067,427)	$ 733,793,163
47	1845	UndergroundConductors &Devices	$ 834,590,098	$ 99,691,661	$ r	($ 45,594,739)	$ 888,687,020	($ 406,126,346)	($ 16,600,725)	$ r	$ 578,583	($ 422,148,488)	$ 466,538,532
47	1850	LineTransformers	$ 757,431,422	$ 55,799,337	$ r	($ 21,304,392)	$ 791,926,367	($ 398,733,406)	($ 21,501,170)	$ r	$ 228,732	($ 420,005,844)	$ 371,920,523
47	1855	Services(Overhead &Underground)	$ 80,492,959	$ 6,704,765	$ r	($ 3,072,213)	$ 84,125,511	($ 16,011,525)	($ 1,651,822)	$ r	$ 13,170	($ 17,650,177)	$ 66,475,334
47	1860	Meters	$ 236,740,323	$ 13,604,147	$ r	($ 56,391,064)	$ 193,953,406	($ 133,625,046)	($ 9,864,020)	$ r	$ 83,356,734	($ 60,132,332)	$ 133,821,074
N/A	1905	Land	$ 9,150,994	$ r	$ r	$ r	$ 9,150,994	$ r	$ r	$ r	$ r	$ r	$ 9,150,994
1	1908	Buildings&Fixtures	$ 113,993,480	$ 7,241,269	$ r	$ r	$ 121,234,749	($ 50,162,300)	($ 5,715,814)	$ r	$ r	($ 55,878,114)	$ 65,356,634
13	1910	LeaseholdImprovements	$ 20,383,723	($ 31,233)	$ r	$ r	$ 20,352,491	($ 19,366,191)	($ 284,866)	$ r	$ r	($ 19,651,057)	$ 701,434
8	1915	OfficeFurniture &Equipment	$ 21,718,959	$ 577,423	$ r	$ r	$ 22,296,381	($ 10,172,565)	($ 2,321,386)	$ r	$ r	($ 12,493,951)	$ 9,802,431
50	1920	ComputerEquipment rHardware	$ 50,502,876	$ 5,275,147	$ r	$ 550,474	$ 56,328,497	($ 40,003,146)	($ 4,595,199)	$ r	($ 537,522)	($ 45,135,867)	$ 11,192,631
10	1930	TransportationEquipment	$ 73,239,570	$ 337,366	($ 832,365)	$ 120,283	$ 72,864,854	($ 43,834,426)	($ 7,148,702)	$ 773,987	($ 72,944)	($ 50,282,085)	$ 22,582,769
8	1935	StoresEquipment	$ 5,506,283	$ r	$ r	$ r	$ 5,506,283	($ 5,491,508)	($ 7,709)	$ r	$ r	($ 5,499,217)	$ 7,066
8	1940	Tools,Shop &Garage Equipment	$ 40,296,331	$ 2,291,332	$ r	$ r	$ 42,587,663	($ 29,362,549)	($ 2,188,127)	$ r	$ r	($ 31,550,676)	$ 11,036,987
8	1945	Measurement&TestingEquipment	$ 5,314,349	$ 304,913	($ 194,000)	($ 304,913)	$ 5,120,349	($ 4,573,439)	($ 2,081,814)	$ 54,843	$ 1,960,406	($ 4,640,005)	$ 480,344
8	1955	CommunicationsEquipment	$ 32,080,245	$ 1,011,467	$ r	$ r	$ 33,091,712	($ 26,596,864)	($ 1,901,560)	$ r	$ r	($ 28,498,424)	$ 4,593,288
8	1960	Miscellaneous Equipment	$ 369,101	$ r	$ r	$ r	$ 369,101	($ 65,113)	($ 36,918)	$ r	$ r	($ 102,031)	$ 267,071
47	1970	LoadManagement Controls Customer Premises	$ 14,843,095	$ r	$ r	$ r	$ 14,843,095	($ 10,738,184)	($ 1,082,077)	$ r	$ r	($ 11,820,262)	$ 3,022,834
47	1975	LoadManagement Controls Utility Premises	$ 554,382	$ r	$ r	$ r	$ 554,382	($ 554,382)	$ r	$ r	$ r	($ 554,382)	$ r
47	1980	SystemSupervisor Equipment	$ 58,089,239	$ 3,405,676	$ r	($ 1,013,175)	$ 60,481,740	($ 39,696,550)	($ 1,814,662)	$ r	$ 14,286	($ 41,496,926)	$ 18,984,815
47	1995	Contributions&Grants	($ 316,581,790)	($ 23,083,937)	$ r	$ 858,765	($ 338,806,962)	$ 70,457,520	$ 9,836,203	$ r	($ 13,004)	$ 80,280,719	($ 258,526,243)
N/A	1609	CapitalContributions Paid	$ 19,648,965	$ 2,532,156	$ r	$ r	$ 22,181,121	($ 2,175,104)	($ 901,706)	$ r	$ r	($ 3,076,809)	$ 19,104,312
N/A	2005	PropertyUnderCapital Leases	$ 13,538,213	$ r	$ r	$ 184,630	$ 13,722,843	($ 2,948,215)	$ r	$ r	($ 1,887,462)	($ 4,835,677)	$ 8,887,166
							$ r					$ r	$ r
		Sub-Total	**$ 4,808,997,333**	**$ 381,267,602**	**($ 1,280,474)**	**($ 211,294,417)**	$ 4,977,690,044	**($ 2,557,072,867)**	**($ 143,068,846)**	**$ 866,164**	**$ 77,613,418**	($ 2,621,662,131)	**$ 2,356,027,913**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ r					$ r	$ r
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ r					$ r	$ r
		Total PP&E	**$ 4,808,997,333**	**$ 381,267,602**	**($ 1,280,474)**	**($ 211,294,417)**	$ 4,977,690,044	**($ 2,557,072,867)**	**($ 143,068,846)**	**$ 866,164**	**$ 77,613,418**	($ 2,621,662,131)	**$ 2,356,027,913**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							$ r			$ r	
		Total							**($ 143,068,846)**				

10		Transportation
8		StoresEquipmen t

Less: *Fully Allocated Depreciation*

Transportation	($ 2,314,931)
StoresEquipmen t	
Net Depreciation	($ 140,753,915)

Notes:

1 Thebelow CCAclasseshavebeenupdated fortheseOEBAccounts

CCAClass	OEB	Description	ExplanationforChange
N/A	1612	LandRights	Fortaxpurposes,theland rights/easementsare treated aseligible capital expenditures[“ECE”] and are recorded in Schedule 10oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1808	Buildings	Fortaxpurposes,theland rights/easementsare treated aseligible capital expenditures[“ECE”] and are recorded in Schedule 10oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1908	Buildings&Fixtures	Perdefinition ofCCAClass 1in Schedule IIofIncomeTaxRegulations
50	1920	ComputerEquipment rHardware	Class50(with 55% CCArate and subjecttohalf ryearrule)wasadded toSchedule IIofIncomeTaxRegulations on April 23, 2009 rfor eligiblecomputersand softwareacquired after March18, 2007, but not including propertythatis included in Class 52.
N/A	1609	CapitalContributions Paid	Fortaxpurposes,thecapital contributions paid are treated asECE and are recorded in Schedule 10oftheincometaxreturn(perparagraph30ofInterpretationBulletin ITr143R3)
N/A	2005	PropertyUnderCapital Leases	NotCapitalized for taxpurposes,actual paymentin theyear is deductible fortax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - UGAAP

Year **2014**

			Cost					AccumulatedDepreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 268,388,604	$ 15,168,023	$ r	($ 330,435)	$ 283,226,192	($ 198,815,935)	($ 19,182,023)	$ r	$ 17,128	($ 217,980,830)	$ 65,245,361
N/A	1805	Land	$ 7,588,531	$ r	($ 3,288)	$ r	$ 7,585,243	$ r	$ r	$ r	$ r	$ r	$ 7,585,243
1	1808	Buildings	$ 50,529,871	$ 4,340,259	($ 2,379,439)	($ 78,322)	$ 52,412,370	($ 20,689,399)	($ 2,023,489)	$ 381,380	$ 316,955	($ 22,014,552)	$ 30,397,818
47	1815	TransformerStation Equipment >50kV	$ 10,972,657	$ 473,723	$ r	($ 321,055)	$ 11,125,325	($ 5,132,702)	($ 410,092)	$ r	$ 3,623	($ 5,539,171)	$ 5,586,154
47	1820	Distribution Station Equipment <50 kV	$ 229,345,789	$ 29,848,866	$ r	($ 13,711,927)	$ 245,482,729	($ 108,744,247)	($ 7,040,253)	$ r	$ 342,531	($ 115,441,968)	$ 130,040,760
47	1830	Poles,Towers&Fixtures	$ 406,836,503	$ 36,083,610	($ 1,575,844)	($ 26,984,374)	$ 414,359,894	($ 190,106,418)	($ 7,596,852)	$ 421,813	$ 603,230	($ 196,678,227)	$ 217,681,668
47	1835	OverheadConductors &Devices	$ 462,595,902	$ 49,556,844	$ r	($ 25,230,128)	$ 486,922,618	($ 255,934,401)	($ 6,901,315)	$ r	$ 518,672	($ 262,317,044)	$ 224,605,574
47	1840	UndergroundConduit	$ 1,420,860,590	$ 143,831,357	$ r	($ 84,834,206)	$ 1,479,857,741	($ 687,067,427)	($ 36,940,621)	$ r	$ 2,658,269	($ 721,349,779)	$ 758,507,962
47	1845	UndergroundConductors &Devices	$ 888,687,020	$ 58,960,887	$ r	($ 28,340,892)	$ 919,307,016	($ 422,148,488)	($ 17,590,134)	$ r	$ 1,777,485	($ 437,961,137)	$ 481,345,879
47	1850	LineTransformers	$ 791,926,367	$ 46,968,875	$ r	($ 28,636,422)	$ 810,258,820	($ 420,005,844)	($ 22,171,293)	$ r	$ 1,181,371	($ 440,995,767)	$ 369,263,053
47	1855	Services(Overhead &Underground)	$ 84,125,511	$ 17,455,197	$ r	($ 9,502,810)	$ 92,077,897	($ 17,650,177)	($ 1,874,227)	$ r	$ 154,401	($ 19,370,003)	$ 72,707,894
47	1860	Meters	$ 193,953,406	$ 14,882,921	$ r	($ 2,182,077)	$ 206,654,251	($ 60,132,332)	($ 12,464,057)	$ r	$ 139,433	($ 72,456,955)	$ 134,197,295
N/A	1905	Land	$ 9,150,994	$ r	$ r	$ r	$ 9,150,994	$ r	$ r	$ r	$ r	$ r	$ 9,150,994
1	1908	Buildings&Fixtures	$ 121,234,749	$ 25,218,362	$ r	$ 3,515	$ 146,456,626	($ 55,878,114)	($ 6,377,509)	$ r	$ 143	($ 62,255,481)	$ 84,201,145
13	1910	LeaseholdImprovements	$ 20,352,491	$ 387,591	$ r	$ r	$ 20,740,081	($ 19,651,057)	($ 314,340)	$ r	$ r	($ 19,965,397)	$ 774,685
8	1915	OfficeFurniture &Equipment	$ 22,296,381	$ 2,347,858	$ r	$ r	$ 24,644,239	($ 12,493,951)	($ 2,128,106)	$ r	$ r	($ 14,622,057)	$ 10,022,182
50	1920	ComputerEquipment rHardware	$ 56,328,497	$ 31,340,289	$ r	($ 252,540)	$ 87,416,246	($ 45,135,867)	($ 7,028,006)	$ r	$ 16,303	($ 52,147,569)	$ 35,268,677
10	1930	TransportationEquipment	$ 72,864,854	$ 4,223,323	$ r	($ 1,307)	$ 77,086,870	($ 50,282,085)	($ 6,558,032)	$ r	$ 218	($ 56,839,900)	$ 20,246,970
8	1935	StoresEquipment	$ 5,506,283	$ r	$ r	$ r	$ 5,506,283	($ 5,499,217)	($ 7,066)	$ r	$ r	($ 5,506,283)	$ r
8	1940	Tools,Shop &Garage Equipment	$ 42,587,663	$ 472,026	$ r	$ r	$ 43,059,688	($ 31,550,676)	($ 2,216,738)	$ r	$ r	($ 33,767,414)	$ 9,292,274
8	1945	Measurement&TestingEquipment	$ 5,120,349	$ 2,101,186	$ r	($ 2,092,578)	$ 5,128,956	($ 4,640,005)	($ 3,744,776)	$ r	$ 3,744,029	($ 4,640,751)	$ 488,205
8	1955	CommunicationsEquipment	$ 33,091,712	$ 773,912	$ r	$ r	$ 33,865,625	($ 28,498,424)	($ 1,855,881)	$ r	$ r	($ 30,354,306)	$ 3,511,319
8	1960	Miscellaneous Equipment	$ 369,101	$ r	$ r	$ r	$ 369,101	($ 102,031)	($ 36,918)	$ r	$ r	($ 138,948)	$ 230,153
47	1970	LoadManagement Controls Customer Premises	$ 14,843,095	$ r	$ r	$ r	$ 14,843,095	($ 11,820,262)	($ 1,082,077)	$ r	$ r	($ 12,902,339)	$ 1,940,757
47	1975	LoadManagement Controls Utility Premises	$ 554,382	$ r	$ r	$ r	$ 554,382	($ 554,382)	$ r	$	$ r	($ 554,382)	$ r
47	1980	SystemSupervisor Equipment	$ 60,481,740	$ 1,924,300	$ r	($ 215,829)	$ 62,190,211	($ 41,496,926)	($ 2,048,691)	$ r	$ 72,158	($ 43,473,459)	$ 18,716,753
47	1995	Contributions&Grants	($ 338,806,962)	($ 17,584,653)	$ r	$ 2,123,873	($ 354,267,741)	$ 80,280,719	$ 10,351,884	$ r	($ 18,199)	$ 90,614,404	($ 263,653,337)
N/A	1609	CapitalContributions Paid	$ 22,181,121	$ 1,798,200	$ r	$ 1,761,108	$ 25,740,429	($ 3,076,809)	($ 955,031)	$ r	($ 36,296)	($ 4,068,136)	$ 21,672,292
N/A	2005	PropertyUnderCapital Leases	$ 13,722,843	$ r	$ r	$ 2,092,578	$ 15,815,421	($ 4,835,677)	$ r	$ r	($ 3,744,029)	($ 8,579,706)	$ 7,235,715
				$ r		$ r	$ r		$ r		$ r		
		Sub-Total	**$ 4,977,690,044**	**$ 470,572,957**	**($ 3,958,571)**	**($ 216,733,828)**	**$ 5,227,570,601**	**($ 2,621,662,131)**	**($ 158,195,645)**	**$ 803,193**	**$ 7,747,425**	**($ 2,771,307,158)**	**$ 2,456,263,443**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ **r**					$ r	$ r
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ ***r***					$ r	$ r
		Total PP&E	**$ 4,977,690,044**	**$ 470,572,957**	**($ 3,958,571)**	**($ 216,733,828)**	**$ 5,227,570,601**	**($ 2,621,662,131)**	**($ 158,195,645)**	**$ 803,193**	**$ 7,747,425**	**($ 2,771,307,158)**	**$ 2,456,263,443**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							$ **r**			$ r	
		Total							**($ 158,195,645)**				

10		Transportation
8		StoresEquipment

Less: *Fully Allocated Depreciation*

Transportation	($ 2,342,979)
StoresEquipment	
Net Depreciation	($ 155,852,666)

Notes:

1 Thebelow CCAclasseshasbeenupdated oradded fortheseOEBAccounts:

CCAClass	OEB	Description	**Explanation for Change**
N/A	1612	Land Rights	Fortaxpurposes,theland rights/easementsare treated aseligible capital expenditures["ECE"] and are recorded in Schedule 10oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1808	Buildings	Fortaxpurposes,theland rights/easementsare treated aseligible capital expenditures["ECE"] and are recorded in Schedule 10 oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1908	Buildings&Fixtures	Perdefinition ofCCAClass 1in Schedule IIofIncomeTaxRegulations
50	1920	ComputerEquipment rHardware	Class50(with 55% CCArate and subjecttohalf ryearrule)wasadded toSchedule IIofIncomeTaxRegulations on April 23, 2009 rfor eligible computersand softwareacquired after March18, 2007, but not including property thatis included in Class 52.
N/A	1609	CapitalContributions Paid	Fortaxpurposes,thecapital contributions paid are treated asECE and are recorded in Schedule 10oftheincometaxreturn(perparagraph30ofInterpretationBulletin ITr143R3)
N/A	2005	PropertyUnderCapital Leases	NotCapitalized fortaxpurposes,actual paymentin theyear is deductible fortax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Retirement	Cost: Transfers	Cost: Derecognition	Cost: Closing Balance	AccumulatedDepreciation: Opening Balance	AccumulatedDepreciation: Additions	AccumulatedDepreciation: Retirement	AccumulatedDepreciation: Transfers	AccumulatedDepreciation: Derecognition	AccumulatedDepreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 268,388,604	$ 15,177,636	$ r	($ 331,236)	$ r	$ 283,235,005	($ 198,815,935)	($ 19,182,937)	$ r	$ 17,170	$ r	($ 217,981,703)	$ 65,253,302
N/A	1612	Land Rights	$ 7,191,090	$ r	$ r	$ r	$ r	$ 7,191,090	$ r	($ 89,423)	$ r	$ r	$ r	($ 89,423)	$ 7,101,667
N/A	1805	Land	$ 7,588,531	$ r	($ 3,288)	$ r	$ r	$ 7,585,243	$ r	$ r	$ r	$ r	$ r	$ r	$ 7,585,243
1	1808	Buildings	$ 50,051,442	$ 4,342,809	($ 2,379,439)	($ 80,876)	$ r	$ 51,933,935	($ 20,689,399)	($ 2,034,879)	$ 381,380	$ 316,976	$ r	($ 22,025,922)	$ 29,908,013
47	1815	TransformerStation Equipment >50kV	$ 10,972,657	$ 474,187	$ r	($ 321,661)	$ r	$ 11,125,183	($ 5,132,702)	($ 410,099)	$ r	$ 3,630	$ r	($ 5,539,171)	$ 5,586,012
47	1820	Distribution Station Equipment <50 kV	$ 229,345,789	$ 29,862,940	$ r	($ 13,738,605)	($ 1,289,203)	$ 244,180,921	($ 108,744,247)	($ 7,040,476)	$ r	$ 342,783	$ 1,211,150	($ 114,230,790)	$ 129,950,132
47	1830	Poles,Towers&Fixtures	$ 406,937,426	$ 36,102,639	($ 1,575,844)	($ 27,039,814)	($ 19,700,692)	$ 394,723,714	($ 190,106,418)	($ 7,597,440)	$ 421,813	$ 603,611	$ 10,481,739	($ 186,196,694)	$ 208,527,020
47	1835	OverheadConductors &Devices	$ 462,595,902	$ 49,585,933	$ r	($ 25,282,689)	($ 5,667,212)	$ 481,231,934	($ 255,934,401)	($ 6,906,901)	$ r	$ 519,020	$ 3,244,682	($ 259,077,600)	$ 222,154,334
47	1840	UndergroundConduit	$ 1,420,860,590	$ 143,930,570	$ r	($ 85,058,238)	($ 744,800)	$ 1,478,988,122	($ 687,067,427)	($ 36,952,150)	$ r	$ 2,660,137	$ 419,968	($ 720,939,472)	$ 758,048,650
47	1845	UndergroundConductors &Devices	$ 888,938,892	$ 59,003,468	$ r	($ 28,397,701)	($ 20,974,613)	$ 898,570,047	($ 422,148,488)	($ 17,441,988)	$ r	$ 1,777,944	$ 17,708,268	($ 420,104,264)	$ 478,465,783
47	1850	LineTransformers	$ 791,192,942	$ 47,004,173	$ r	($ 28,690,543)	($ 29,945,614)	$ 779,560,959	($ 420,005,844)	($ 22,237,759)	$ r	$ 1,181,907	$ 20,438,401	($ 420,623,295)	$ 358,937,664
47	1855	Services(Overhead &Underground)	$ 84,125,511	$ 17,465,910	$ r	($ 9,521,934)	$ r	$ 92,069,487	($ 17,650,177)	($ 1,874,323)	$ r	$ 154,539	$ r	($ 19,369,961)	$ 72,699,526
47	1860	Meters	$ 193,953,406	$ 14,890,821	$ r	($ 2,186,247)	$ r	$ 206,657,980	($ 60,132,332)	($ 12,464,374)	$ r	$ 139,514	$ r	($ 72,457,191)	$ 134,200,789
N/A	1905	Land	$ 9,150,994	$ r	$ r	$ r	$ r	$ 9,150,994	$ r	$ r	$ r	$ r	$ r	$ r	$ 9,150,994
1	1908	Buildings&Fixtures	$ 121,234,749	$ 25,218,671	$ r	$ 3,506	($ 125,000)	$ 146,331,925	($ 55,878,114)	($ 6,377,517)	$ r	$ 143	$ 112,500	($ 62,142,988)	$ 84,188,937
13	1910	LeaseholdImprovements	$ 20,352,491	$ 387,591	$ r	$ r	$ r	$ 20,740,081	($ 19,651,057)	($ 314,340)	$ r	$ r	$ r	($ 19,965,397)	$ 774,685
8	1915	OfficeFurniture &Equipment	$ 22,296,381	$ 2,347,871	$ r	$ r	($ 3,842)	$ 24,640,411	($ 12,493,951)	($ 2,128,107)	$ r	$ r	$ 3,485	($ 14,618,572)	$ 10,021,839
50	1920	ComputerEquipment rHardware	$ 56,328,497	$ 31,345,390	$ r	($ 253,152)	$ r	$ 87,420,735	($ 45,135,867)	($ 7,028,569)	$ r	$ 16,343	$ r	($ 52,148,093)	$ 35,272,642
10	1930	TransportationEquipment	$ 72,864,854	$ 4,225,151	$ r	($ 1,307)	$ r	$ 77,088,698	($ 50,282,085)	($ 6,558,138)	$ r	$ 218	$ r	($ 56,840,005)	$ 20,248,692
8	1935	StoresEquipment	$ 5,506,283	$ r	$ r	$ r	$ r	$ 5,506,283	($ 5,499,217)	($ 7,066)	$ r	$ r	$ r	($ 5,506,283)	$ r
8	1940	Tools,Shop &Garage Equipment	$ 42,587,663	$ 472,378	$ r	$ r	$ r	$ 43,060,041	($ 31,550,676)	($ 2,216,753)	$ r	$ r	$ r	($ 33,767,429)	$ 9,292,612
8	1945	Measurement&TestingEquipment	$ 5,120,349	$ 2,101,189	$ r	($ 2,092,578)	$ r	$ 5,128,960	($ 4,640,005)	($ 3,744,776)	$ r	$ 3,744,029	$ r	($ 4,640,751)	$ 488,208
8	1955	CommunicationsEquipment	$ 33,091,712	$ 773,912	$ r	$ r	$ r	$ 33,865,625	($ 28,498,424)	($ 1,855,881)	$ r	$ r	$ r	($ 30,354,306)	$ 3,511,319
8	1960	Miscellaneous Equipment	$ 369,101	$ r	$ r	$ r	$ r	$ 369,101	($ 102,031)	($ 36,918)	$ r	$ r	$ r	($ 138,948)	$ 230,153
47	1970	LoadManagement Controls Customer Premises	$ 14,843,095	$ r	$ r	$ r	$ r	$ 14,843,095	($ 11,820,262)	($ 1,082,077)	$ r	$ r	$ r	($ 12,902,339)	$ 1,940,757
47	1975	LoadManagement Controls Utility Premises	$ 554,382	$ r	$ r	$ r	$ r	$ 554,382	($ 554,382)	$ r	$ r	$ r	$ r	($ 554,382)	$ r
47	1980	SystemSupervisor Equipment	$ 60,481,740	$ 1,925,700	$ r	($ 216,297)	($ 4,680,597)	$ 57,510,547	($ 41,496,926)	($ 2,048,748)	$ r	$ 72,168	$ 3,775,638	($ 39,697,869)	$ 17,812,678
47	1995	Contributions&Grants	($ 338,806,962)	($ 17,605,144)	$ r	$ 2,129,381	$ r	($ 354,282,725)	$ 80,280,719	$ 10,369,809	$ r	($ 18,239)	$ r	$ 90,632,289	($ 263,650,436)
N/A	1609	CapitalContributions Paid	$ 22,181,121	$ 1,803,632	$ r	$ 1,761,108	$ r	$ 25,745,861	($ 3,076,809)	($ 955,180)	$ r	($ 36,296)	$ r	($ 4,068,286)	$ 21,677,575
N/A	2005	PropertyUnderCapital Leases	$ 13,722,843	$ r	$ r	$ 2,092,578	$ r	$ 15,815,421	($ 4,835,677)	$ r	$ r	($ 3,744,029)	$ r	($ 8,579,706)	$ 7,235,715
				$ r		$ r		$ r		$ r		$ r			
		Sub-Total	**$ 4,984,022,075**	**$ 470,837,428**	**($ 3,958,571)**	**($ 217,226,307)**	**($ 83,131,571)**	**$ 5,150,543,054**	**($ 2,621,662,131)**	**($ 158,217,010)**	**$ 803,193**	**$ 7,751,568**	**$ 57,395,830**	**($ 2,713,928,550)**	**$ 2,436,614,504**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ r						$ r	$ r
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*						$ r						$ r	$ r
		Total PP&E	**$ 4,984,022,075**	**$ 470,837,428**	**($ 3,958,571)**	**($ 217,226,307)**	**($ 83,131,571)**	**$ 5,150,543,054**	**($ 2,621,662,131)**	**($ 158,217,010)**	**$ 803,193**	**$ 7,751,568**	**$ 57,395,830**	**($ 2,713,928,550)**	**$ 2,436,614,504**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)								$ r				$ r	
		Total								**($ 158,217,010)**					

10		Transportation
8		StoresEquipment

Less: *Fully Allocated Depreciation*

Transportation	($ 2,342,979)
StoresEquipment	
Net Depreciation	($ 155,874,031)

Notes:

1 Thebelow CCAclasseshasbeenupdated oradded fortheseOEBAccounts:

CCA Class	OEB	Description	Explanation for Change
N/A	1612	LandRi ghts	Fortax purposes,theland ri ghts/easementsare treated aseli gibleca pitalex penditures ["ECE"]and are recorded in Schedule 10oftheincometaxreturn (per paragraph29ofInter pretationBulletin ITr143R3)
1	1808	Buildings	Fortaxpurposes,theland rights/easementsare treated aseligible capital expenditures["ECE"] and are recorded in Schedule 10oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1908	Buildings&Fixtures	Perdefinition ofCCAClass 1in Schedule IIofIncomeTaxRegulations
50	1920	ComputerEquipment rHardware	Class50(with 55% CCArate and subjecttohalf ryearrule)wasadded toSchedule IIofIncomeTaxRegulations on April 23, 2009 rforeligible computersand softwareacquired after March18, 2007, but not including property thatis included in Class 52.
N/A	1609	CapitalContributions Paid	Fortaxpurposes,thecapital contributions paid are treated asECE and are recorded in Schedule 10oftheincometaxreturn(perparagraph30ofInterpretationBulletin ITr143R3)
N/A	2005	PropertyUnderCapital Leases	NotCapitalized fortaxpurposes,actual paymentin theyear is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year **2015**

			Cost								
CCA Class	**OEB**	**Description**	**Original Opening Balance**	**STL Transfer**	**ICM Transfer**	**Revised Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Derecognition**	**Closing Balance**
12	1611	Computer Software (Formally known as Account 1925)	$ 283,235,005	$ r	$ 331,236	$ 283,566,240	$ 25,707,753	$ r	$	$ r	$ 309,273,993
N/A	1612	Land Rights	$ 7,191,090	$ r	$ r	$ 7,191,090	$ r	$ r	$ r	$ r	$ 7,191,090
N/A	1805	Land	$ 7,585,243	$ r	$ r	$ 7,585,243	$ r	$ r	$ r	$ r	$ 7,585,243
1	1808	Buildings	$ 51,933,935	$ r	$ 621,876	$ 52,555,812	$ 42,675,695	($ 1,449,701)	$ r	$ r	$ 93,781,805
47	1815	TransformerStation Equipment >50kV	$ 11,125,183	$ r	$ 321,661	$ 11,446,844	$ 928,991	$ r	$ r	($ 94,141)	$ 12,281,694
47	1820	Distribution Station Equipment <50 kV	$ 244,180,921	$ r	$ 19,117,868	$ 263,298,789	$ 30,196,781	$ r	($ 470,712)	($ 1,630,381)	$ 291,394,477
47	1830	Poles,Towers&Fixtures	$ 394,723,714	$ 36,121,302	$ 43,211,408	$ 474,056,425	$ 42,285,278	$ r	$ 0	($ 27,184,232)	$ 489,157,471
47	1835	OverheadConductors &Devices	$ 481,231,934	$ 341,869	$ 39,460,264	$ 521,034,068	$ 50,220,187	$ r	$ r	($ 14,001,761)	$ 557,252,494
47	1840	UndergroundConduit	$ 1,478,988,122	$ 3,457,400	$ 142,264,440	$ 1,624,709,962	$ 124,467,391	$ r	$ r	$ r	$ 1,749,177,353
47	1845	UndergroundConductors &Devices	$ 898,570,047	$ 4,697,187	$ 73,974,813	$ 977,242,048	$ 70,084,398	$ r	($ 0)	($ 18,693,747)	$ 1,028,632,698
47	1850	LineTransformers	$ 779,560,959	$ r	$ 50,042,828	$ 829,603,786	$ 36,538,578	$ r	$ 0	($ 30,603,146)	$ 835,539,218
47	1855	Services(Overhead &Underground)	$ 92,069,487	$ r	$ 12,595,308	$ 104,664,795	$ 15,347,254	$ r	$ r	($ 7,152)	$ 120,004,896
47	1860	Meters	$ 206,657,980	$ r	$ 3,644,325	$ 210,302,305	$ 19,717,726	$ r	$ 0	($ 1,071,386)	$ 228,948,645
N/A	1905	Land	$ 9,150,994	$ r	$ r	$ 9,150,994	$ r	($ 477,212)	$ r	$ r	$ 8,673,782
1	1908	Buildings&Fixtures	$ 146,331,925	$ r	($ 3,506)	$ 146,328,420	$ 17,921,294	($ 30,471,343)	$ r	($ 1,287,428)	$ 132,490,943
13	1910	LeaseholdImprovements	$ 20,740,081	$ r	$ r	$ 20,740,081	$ 43,066	$ r	$ r	$ r	$ 20,783,147
8	1915	OfficeFurniture &Equipment	$ 24,640,411	$ r	$ r	$ 24,640,411	$ 210,700	$ r	$ r	($ 63,647)	$ 24,787,464
50	1920	ComputerEquipment rHardware	$ 87,420,735	$ r	$ 253,152	$ 87,673,888	$ 11,191,364	$ r	$ r	$ r	$ 98,865,251
10	1930	TransportationEquipment	$ 77,088,698	$ r	$ 1,307	$ 77,090,005	$ 3,877,748	$ r	$ r	$ r	$ 80,967,753
8	1935	StoresEquipment	$ 5,506,283	$ r	$ r	$ 5,506,283	$ r	$ r	$ r	$ r	$ 5,506,283
8	1940	Tools,Shop &Garage Equipment	$ 43,060,041	$ r	$ r	$ 43,060,041	$ 1,832,094	$ r	$ r	$ r	$ 44,892,135
8	1945	Measurement&TestingEquipment	$ 5,128,960	$ r	$ r	$ 5,128,960	$ r	$ r	($ 0)	$ r	$ 5,128,960
8	1955	CommunicationsEquipment	$ 33,865,625	$ r	$ r	$ 33,865,625	$ 1,571,175	$ r	$ r	$ r	$ 35,436,800
8	1960	MiscellaneousEquipment	$ 369,101	$ r	$ r	$ 369,101	$ 7,831	$ r	$ r	$ r	$ 376,932
47	1970	LoadManagement Controls Customer Premises	$ 14,843,095	$	$ r	$ 14,843,095	$r 99,273	$ r	$	$ r	$ 14,942,368
47	1975	LoadManagement Controls Utility Premises	$ 554,382	$	$ r	$ 554,382	$	$ r	$	$r r	$ 554,382
47	1980	SystemSupervisor Equipment	$ 57,510,547	$ r	$ 1,229,472	$ 58,740,019	$ 7,707,664	$ r	($ 4,096,668)	($ 7,296,713)	$ 55,054,301
47	1995	Contributions&Grants	($ 354,282,725)	$ r	($ 2,902,453)	($ 357,185,178)	($ 15,280,038)	$ r	($ 0)	$ r	($ 372,465,216)
N/A	1609	CapitalContributions Paid	$ 25,745,861	$ r	($ 1,761,108)	$ 23,984,753	$ 52,373,679	$ r	($ 1,853,428)	$ r	$ 74,505,004
N/A	2005	PropertyUnderCapital Leases	$ 15,815,421	$ r		$ 15,815,421	$ r	$ r	$ 0	$ r	$ 15,815,421
		Sub-Total	**$ 5,150,543,054**	**$ 44,617,759**	**$ 382,402,893**	**$ 5,577,563,706**	**$ 539,725,880**	**($ 32,398,256)**	**($ 6,420,808)**	**($ 101,933,734)**	**$ 5,976,536,788**
		Less Socialized Renewable Energy Generation Investments (input as negative)									$ r
		Less Other Non Rate-Regulated Utility Assets (input as negative)									$ r
		Total PP&E	**$ 5,150,543,054**	**$ 44,617,759**	$ 382,402,893	**$ 5,577,563,706**	**$ 539,725,880**	**($ 32,398,256)**	**($ 6,420,808)**	**($ 101,933,734)**	**$ 5,976,536,788**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total									

10		Transportation
8		StoresEquipment

Notes:

1 Thebelow CCAclasseshasbeenupdated oradded fortheseOEBAccounts:

CCA Class	**OEB**	**Description**	**Explanation for Change**
N/A	1612	LandRi ghts	Fortax purposes,theland ri ghts/easementsare treated aseli gibleca pitalex penditures ["ECE"]and are recorded in Schedule 10oftheincometaxreturn (per paragraph29ofInter pretationBulletin ITr143R3)
1	1808	Buildings	Fortaxpurposes,theland rights/easementsare treated aseligible capital expenditures["ECE"] and are recorded in Schedule 10oftheincometaxreturn(perparagraph29ofInterpretationBulletin ITr143R3)
1	1908	Buildings&Fixtures	Perdefinition ofCCAClass 1in Schedule IIofIncomeTaxRegulations
50	1920	ComputerEquipment rHardware	Class50(with 55% CCArate and subjecttohalf ryearrule)wasadded toSchedule IIofIncomeTaxRegulations on April 23, 2009 rforeligible computersand softwareacquired after March18, 2007, but not including propertythatis included i
N/A	1609	CapitalContributions Paid	Fortaxpurposes,thecapital contributions paid are treated asECE and are recorded in Schedule 10oftheincometaxreturn(perparagraph30ofInterpretationBulletin ITr143R3)
N/A	2005	PropertyUnderCapital Leases	NotCapitalized fortaxpurposes,actual paymentin theyear is deductible fortax.

				AccumulatedDepreciation								
CCA Class	**OEB**	**Description**	**Original Opening Balance**	**STL Transfer**	**ICM Transfer**	**Revised Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Derecognition**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	($ 217,981,703)	$ r	($ 17,170)	($ 217,998,872)	($ 21,011,750)	$ r	$	$	($ 239,010,622)	$ 70,263,371
N/A	1612	Land Rights	($ 89,423)	$ r	$ r	($ 89,423)	($ 89,423)	$ r	$ r	$ r	($ 178,846)	$ 7,012,244
N/A	1805	Land	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ 7,585,243
1	1808	Buildings	($ 22,025,922)	$ r	($ 542,392)	($ 22,568,314)	($ 2,164,056)	$ 130,522	$ 0	$ r	($ 24,601,849)	$ 69,179,957
47	1815	TransformerStation Equipment >50kV	($ 5,539,171)	$ r	($ 3,630)	($ 5,542,801)	($ 433,082)	$ r	$ 3	$ 55,292	($ 5,920,589)	$ 6,361,105
47	1820	Distribution Station Equipment <50 kV	($ 114,230,790)	$ r	($ 522,081)	($ 114,752,870)	($ 8,071,762)	$ r	$ 4,124	$ 1,547,522	($ 121,272,987)	$ 170,121,490
47	1830	Poles,Towers&Fixtures	($ 186,196,694)	($ 3,536,803)	($ 690,647)	($ 190,424,144)	($ 9,383,299)	$ r	$ 1,211	$ 14,391,300	($ 185,414,933)	$ 303,742,539
47	1835	OverheadConductors &Devices	($ 259,077,600)	($ 25,769)	($ 609,398)	($ 259,712,767)	($ 8,010,517)	$ r	$ 2,508	$ 11,597,279	($ 256,123,497)	$ 301,128,997
47	1840	UndergroundConduit	($ 720,939,472)	($ 273,033)	($ 3,242,546)	($ 724,455,051)	($ 40,909,577)	$ r	$ 28,132	$ r	($ 765,336,496)	$ 983,840,857
47	1845	UndergroundConductors &Devices	($ 420,104,264)	($ 976,046)	($ 2,357,313)	($ 423,437,622)	($ 18,874,495)	$ r	$ 8,037	$ 12,366,339	($ 429,937,742)	$ 598,694,956
47	1850	LineTransformers	($ 420,623,295)	$ r	($ 1,434,826)	($ 422,058,121)	($ 22,574,248)	$ r	$ 1,019	$ 20,848,109	($ 423,783,240)	$ 411,755,978
47	1855	Services(Overhead &Underground)	($ 19,369,961)	$ r	($ 167,709)	($ 19,537,670)	($ 2,235,152)	$ r	$ 169	$ 6,706	($ 21,765,946)	$ 98,238,950
47	1860	Meters	($ 72,457,191)	$ r	($ 198,422)	($ 72,655,613)	($ 13,258,376)	$ r	$ 1	$ 524,830	($ 85,389,159)	$ 143,559,487
N/A	1905	Land	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ 8,673,782
1	1908	Buildings&Fixtures	($ 62,142,988)	$ r	($ 143)	($ 62,143,131)	($ 6,162,152)	$ 18,990,375	$ 0	$ 691,012	($ 48,623,896)	$ 83,867,047
13	1910	LeaseholdImprovements	($ 19,965,397)	$ r	$ r	($ 19,965,397)	($ 305,716)	$ r	$ r	$ r	($ 20,271,113)	$ 512,034
8	1915	OfficeFurniture &Equipment	($ 14,618,572)	$ r	$ r	($ 14,618,572)	($ 1,988,900)	$ r	$ r	$ 51,630	($ 16,555,842)	$ 8,231,621
50	1920	ComputerEquipment rHardware	($ 52,148,093)	$ r	($ 16,343)	($ 52,164,436)	($ 12,430,692)	$ r	$ r	$ r	($ 64,595,128)	$ 34,270,123
10	1930	TransportationEquipment	($ 56,840,005)	$ r	($ 218)	($ 56,840,223)	($ 6,376,745)	$ r	$ r	$ r	($ 63,216,968)	$ 17,750,785
8	1935	StoresEquipment	($ 5,506,283)	$ r	$ r	($ 5,506,283)	$ r	$ r	$ r	$ r	($ 5,506,283)	$ r
8	1940	Tools,Shop &Garage Equipment	($ 33,767,429)	$ r	$ r	($ 33,767,429)	($ 2,220,076)	$ r	$ r	$ r	($ 35,987,505)	$ 8,904,630
8	1945	Measurement&TestingEquipment	($ 4,640,751)	$ r	$ r	($ 4,640,751)	($ 2,218,623)	$ r	$ 2,222,154	$ r	($ 4,637,220)	$ 491,739
8	1955	CommunicationsEquipment	($ 30,354,306)	$ r	$ r	($ 30,354,306)	($ 1,924,002)	$ r	$ r	$ r	($ 32,278,308)	$ 3,158,491
8	1960	MiscellaneousEquipment	($ 138,948)	$ r	$ r	($ 138,948)	($ 37,146)	$ r	$ r	$ r	($ 176,094)	$ 200,838
47	1970	LoadManagement Controls Customer Premises	($ 12,902,339)	$ r	$ r	($ 12,902,339)	($ 1,070,206)	$ r	$	$	($ 13,972,544)	$ 969,824
47	1975	LoadManagement Controls Utility Premises	($ 554,382)	$ r	$ r	($ 554,382)	$ r	$	$	$ r	($ 554,382)	$ r r
47	1980	SystemSupervisor Equipment	($ 39,697,869)	$ r	($ 86,454)	($ 39,784,323)	($ 2,137,803)	$ r	$ 23,305	$ 5,921,324	($ 35,977,498)	$ 19,076,803
47	1995	Contributions&Grants	$ 90,632,289	$ r	$ 30,491	$ 90,662,780	$ 10,852,528	$ r	($ 17,051)	$ r	$ 101,498,257	($ 270,966,959)
N/A	1609	CapitalContributions Paid	($ 4,068,286)	$ r	$ 36,296	($ 4,031,989)	($ 1,150,182)	$ r	$ r	$ r	($ 5,182,171)	$ 69,322,833
N/A	2005	PropertyUnderCapital Leases	($ 8,579,706)	$ r	$ r	($ 8,579,706)	$ r	$ r	($ 2,222,154)	$ r	($ 10,801,861)	$ 5,013,560
		Sub-Total	**($ 2,713,928,550)**	**($ 4,811,651)**	**($ 9,822,504)**	**($ 2,728,562,705)**	**($ 174,185,452)**	**$ 19,120,897**	**$ 51,457**	**$ 68,001,341**	**($ 2,815,574,461)**	**$ 3,160,962,327**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ r								$ r	$ r
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ r								$ r	$ r
		Total PP&E	**($ 2,713,928,550)**	**($ 4,811,651)**	($ 9,822,504)	**($ 2,728,562,705)**	**($ 174,185,452)**	**$ 19,120,897**	**$ 51,457**	**$ 68,001,341**	**($ 2,815,574,461)**	**$ 3,160,962,327**
		Depreciation Expense adj. from gain or los					$ r				$ r	
		Total					**($ 174,185,452)**					

10		Transportation
8		StoresEquipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,671,045)
StoresEquipment	
Net Depreciation	($ 172,514,406)

Notes:

1 Thebelow CCAclasseshasbeenupdated oradded forthese

CCA Class	**OEB**	**Description**	
N/A	1612	LandRi ghts	
1	1808	Buildings	
1	1908	Buildings&Fixtures	
50	1920	ComputerEquipment rHardware	nClass 52.
N/A	1609	CapitalContributions Paid	
N/A	2005	PropertyUnderCapital Leases	

GROSS ASSETS

1. BREAKDOWN BY FUNCTION

In accordance with section 2.5.1.2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements"), Table 1 below provides a breakdown of gross assets by function from 2011 historical actuals through to 2015 test year forecast. The amount for construction work-in-progress ("CWIP") has also been provided. The amounts for CWIP have not been included in gross assets for rate base.

In accordance with the Uniform System of Accounts ("USoA"), Toronto Hydro has included asset accounts 1805 to 1860 in the category of distribution plant, accounts 1905 to 1980, accounts 1609 to 1612 and account 2005 in the category of general plant, and account 1995 in the category of capital contributions.

Table 1: Breakdown of Gross Assets by Function

Gross Assets	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Distribution Plant	4,214.3	4,404.1	4,547.4	4,726.0	4,646.6	5,413.8
General Plant	687.9	721.5	769.2	855.8	858.2	935.2
Capital Contributions	(294.5)	(316.6)	(338.9)	(354.3)	(354.3)	(372.5)
Total Before CWIP	**4,607.8**	**4,809.0**	**4,977.7**	**5,227.6**	**5,150.5**	**5,976.5**
CWIP	257.8	336.9	401.3	515.5	516.1	507.4
Total Including CWIP	**4,865.6**	**5,145.9**	**5,379.0**	**5,743.1**	**5,666.6**	**6,483.9**

Note: Variances due to rounding may exist

/C

2. BREAKDOWN BY MAJOR PLANT ACCOUNT

In accordance with section 2.5.1.2 of the OEB's Filing Requirements (July 17, 2013), Table 2 below provides a breakdown of gross assets by major plant account from 2011 to 2015.

Table 2: Gross Assets Breakdown by Major Plant Account Summary

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Land and Buildings	61.3	63.1	67.3	69.1	68.7	110.0
TS Primary Above 50	10.5	11.0	11.0	11.1	11.1	12.3
Distribution System	222.6	226.5	229.3	245.5	244.2	291.4
Poles and Wires	2,893.6	3,037.9	3,179.0	3,300.4	3,253.5	3,824.2
Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
Services and Meters	303.7	317.2	278.1	298.7	298.7	349.0
General Plant	130.1	134.4	141.6	167.2	167.1	153.3
Equipment	180.1	178.5	181.8	189.7	189.7	197.1
IT Assets	44.6	50.5	56.3	87.4	87.4	98.9
Other Distribution Assets	323.9	348.9	380.2	402.4	404.9	477.3
Contributions and Grants	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
Gross Assets	**4,607.8**	**4,809.0**	**4,977.7**	**5,227.6**	**5,150.5**	**5,976.5**

Note: Variances due to rounding may exist

/C

In accordance with the Uniform System of Accounts ("USoA"), Toronto Hydro's major plant categories are comprised of the following USoA accounts:

- **Land and Building**: 1805 Land; 1808 Buildings and Fixtures; 1810 Leasehold Improvements; 1905 Land
- **TS Primary Above 50**: 1815 Transformer Station Equipment
- **Distribution System**: 1820 Distribution Station Equipment
- **Poles and Wires**: 1830 Poles, Towers and Fixtures; 1835 O/H Conductors and Devices; 1840 U/G Conduit; 1845 U/G Conductors and Devices
- **Line Transformers**: 1850 Line Transformers
- **Services and Meters**: 1855 Services; 1860 Meters (including Smart Meters)
- **General Plant**: 1908 Buildings and Fixtures; 1910 Leasehold Improvements
- **Equipment**: 1915 Office Furniture and Equipment; 1930 Transportation Equipment; 1935 Stores Equipment; 1940 Tools, Shop and Garage Equipment; 1945 Measures & Test Equipment; 1955 Communication Equipment; 1960 Miscellaneous Equipment
- **IT Assets**: 1610 Miscellaneous Intangible Plant; 1920 Computer Equipment

- Other Distribution Assets: 1609 Capital Contributions Paid; 1611 Computer Software; 1612 Land Rights; 1970 Load Management-Customer; 1975 Load Management-Utility; 1980 System Supervisory Equipment; 2005 Property Under Capital Leases
- Contributions and Grants: 1995 Contributed Capital

Appendix A to this schedule provides a breakdown of gross assets by major plant account and USofA Account from 2011 to 2015.

Appendix A. Table 2 - Gross Assets Breakdown by Major Plant Account - Detailed by Uniform System of Account

	Description	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
1905	Land	9.2	9.2	9.2	9.2	9.2	8.7
1805	Land	7.6	7.6	7.6	7.6	7.6	7.6
1808	Buildings and Fixtures	44.6	46.4	50.5	52.4	51.9	93.8
1810	Leasehold Improvements	-	-	-	-	-	-
	Subtotal Land and Buildings	61.3	63.1	67.3	69.1	68.7	110.0
1815	Transformer Station Equipment	10.5	11.0	11.0	11.1	11.1	12.3
	Subtotal TS Primary Above 50	10.5	11.0	11.0	11.1	11.1	12.3
1820	Distribution Station Equipment	222.6	226.5	229.3	245.5	244.2	291.4
	Subtotal Distribution System	222.6	226.5	229.3	245.5	244.2	291.4
1830	Poles, Towers and Fixtures	379.1	392.6	406.8	414.4	394.7	489.2
1835	O/H Conductors and Devices	413.0	433.1	462.6	486.9	481.2	557.3
1840	U/G Conduit	1,312.9	1,377.7	1,420.9	1,479.9	1,479.0	1,749.2
1845	U/G Conductors and Devices	788.6	834.6	888.7	919.3	898.6	1,028.6
	Subtotal Poles and Wires	2,893.6	3,037.9	3,179.0	3,300.4	3,253.5	3,824.2
1850	Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
	Subtotal Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
1855	Services	75.5	80.5	84.1	92.1	92.1	120.0
1860	Meters (includes Smart Meters)	228.2	236.7	194.0	206.7	206.7	229.0
	Subtotal Services and Meters	303.7	317.2	278.1	298.7	298.7	349.0
1908	Buildings and Fixtures	110.3	114.0	121.2	146.5	146.3	132.5
1910	Leasehold Improvements	19.8	20.4	20.4	20.7	20.7	20.8
	Subtotal General Plant	130.1	134.4	141.6	167.2	167.1	153.3
1915	Office Furniture and Equipment	20.5	21.7	22.3	24.6	24.6	24.8
1930	Transportation Equipment	78.0	73.2	72.9	77.1	77.1	81.0
1935	Stores Equipment	5.5	5.5	5.5	5.5	5.5	5.5
1940	Tools, Shop and Garage Equipment	39.2	40.3	42.6	43.1	43.1	44.9
1945	Measurement & Test Equipment	5.0	5.3	5.1	5.1	5.1	5.1
1955	Communication Equipment	31.5	32.1	33.1	33.9	33.9	35.4
1960	Miscellaneous Equipment	0.4	0.4	0.4	0.4	0.4	0.4
	Subtotal Equipment	180.1	178.5	181.8	189.7	189.7	197.1
1610	Miscellaneous Intangible Plant	-	-	-	-	-	-
1920	Computer Equipment	44.6	50.5	56.3	87.4	87.4	98.9
	Subtotal IT Assets	44.6	50.5	56.3	87.4	87.4	98.9
1609	Capital Contributions Paid	14.1	19.6	22.2	25.7	25.7	74.5
1611	Computer Software	222.6	242.3	268.4	283.2	283.2	309.3
1612	Land Rights	-	-	-	-	7.2	7.2
1970	Load Management-Customer	14.8	14.8	14.8	14.8	14.8	14.9
1975	Load Management-Utility	0.6	0.6	0.6	0.6	0.6	0.6
1980	System Supervisory Equipment	57.6	58.1	60.5	62.2	57.5	55.1
2005	Property Under Capital Leases	14.3	13.5	13.7	15.8	15.8	15.8
	Subtotal Other Distribution Assets	323.9	348.9	380.2	402.4	404.9	477.3
1995	Contributed Capital	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
	Subtotal Contributions and Grants	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
	GROSS FIXED ASSETS	**4,607.8**	**4,809.0**	**4,977.7**	**5,227.6**	**5,150.5**	**5,976.5**
2055	Construction Work in Process	257.8	336.9	401.3	515.5	516.1	507.4
	GROSS INCLUDING CWIP	**4,865.6**	**5,145.9**	**5,379.0**	**5,743.1**	**5,666.6**	**6,483.9**

WORKING CAPITAL ALLOWANCE (WCA)

Toronto Hydro determined the Working Capital Allowance ("WCA") included in its 2015 ratebase based on an updated Lead-Lag Study performed by Navigant Consulting Inc. ("Navigant"), which is filed as Exhibit 2A, Tab 3, Schedule 2. Navigant used Toronto Hydro's 2012 financial information to determine the revenue lead and expense lag for various detailed revenue and cost components. The methodology employed by Navigant in the current study is generally the same as that employed in the last Lead-Lag study which was filed in EB-2007-0680. Toronto Hydro confirms that for the purposes of the Lead-Lag Study, leads and lags were measured in days, and were dollar weighted.

The result of the Lead-Lag Study is a significant decrease in the WCA rate approved in the utility's last rebasing application (EB-2010-0142) from 12.88% of controllable expenses plus cost of power to 7.99% for the 2015 test year. The reduction was achieved primarily as a result of two changes: /C

1) a significant decrease in the revenue lag due to improved billing and collection activities, and
2) a change in the weightings applied to revenue lag days from customers to class revenues.

Table 1 below presents a detailed calculation of the WCA for 2015. To calculate the WCA, the Cost of Power was determined by using: the split between RPP and non-RPP customers, 2015 forecast RPP, HOEP, and UTR.

Table 1: Working Capital Allowance Calculation

	2015 Expenses ($ millions)	Working Capital Factor		Expenses * Working Capital Factor ($ millions)	
Cost of Power	2,751.9	6.1%		167.0	
OM&A	269.5	5.8%		15.6	
Interest on Long Term Debt	82.0	2.4%		2.0	
Income and Capital Taxes	24.0	28.4%		6.8	/C
DRC	171.2	5.9%		10.2	
SubrTotal Working Capital Requirement				201.7	/C
HST at 13%		Net Lag Days	Expenses * Net Lag Days/365 * 13% HST		
Revenue	3,403.1	r5.5	r6.6		
Cost of Power	2,751.9	45.9	45.0		
OM&A Expenses	103.2	41.5	1.5		
HST Working Capital Requirement				39.9	
Total Working Capital				241.5	/C
Working Capital as % of Cost of Power and Controllable Expenses				7.99%	

Table 2 below provides a comparison of the Working Capital Requirements for the 2015 test year which have been included in the utility's rate base calculations (Exhibit 2A, Tab 1, Schedule 1), and the last OEB-approved WCA in 2011. This table shows that since 2011, Toronto Hydro has achieved a reduction of just under $60M in its WCA.

Table 2: Working Capital Allowance ($millions)

	2011 OEB Approved	2015 Test Year	
Working Capital Allowance	296.7	241.5	/C

Working Capital Requirements of Toronto Hydro Electric System Limited's Distribution Business

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June 27, 2014

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Section 1: Executive Summary

Summary

This report provides the results of the working capital requirements of THESL's distribution business.

Performing a lead/lag study requires two key undertakings:

1. Developing an understanding of how the regulated distribution business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

Results from the lead/lag study using 2012 data identify the following working capital amount in Table 1-1, below.

Table 1-1: Summary of Working Capital Requirements

Year	2012
Percentage of OMA	7.91%
Working Capital Requirement	$218,720,393

The results of the study indicate a lower working capital requirement compared to THESL's EB-2007-0680 distribution lead/lag study. A considerable amount of time has lapsed between the two studies. The primary reason for the difference is the decrease in retail revenue lag days due to the upgrade of THESL's Customer Information System since the prior study. The retail revenue lag days have decreased by approximately 20 percent. Table 2-1, below summarizes the detailed working capital requirements for 2012 calculated in the study.

Table 2-1: THESL Distribution Working Capital Requirements (2012)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses	Working Capital Requirements
Cost of Power	55.04	32.84	22.20	6.07%	$2,450,597,565	$148,654,316
OM&A Expenses	55.04	33.86	21.19	5.79%	$312,961,220	$18,115,434
PILS	55.04	(48.95)	103.99	28.41%	$7,831,100	$2,225,034
Interest Expense	55.04	46.17	8.87	2.42%	$176,173,950	$4,264,550
DRC	55.04	33.31	21.74	5.94%	$162,416,324	$9,645,577
Total					$3,009,980,059	$180,485,912
HST						$38,234,481
Total Including HST						$218,720,393
Working Capital as a Percent of OM&A (incl. Cost of Power)						7.91%

Organization of the Report

Section II of the report discusses the lag times associated with THESL's collections of revenues. The section includes a description of the sources of revenues and how an overall revenue lag is derived.

Section III presents the lead times associated with THESL's expenses. The section includes a description of the types of expenses incurred by THESL's distribution operations and how expenses are treated for the purposes of deriving an overall provincial expense lead.

Section IV presents a summary of the results from the study.

Section 4: Revenue Lags

A distribution utility providing service to its customers generally derives its revenue from bills paid for service by its customers. A revenue lag represents the number of days from the date service is rendered by THESL until the date payments are received from customers and funds are available to THESL.

Interviews with THESL personnel indicate that its distribution business receives funds from the following funding streams:

1. Retail Customers;
2. Other Sources (revenues from electricity retailers and revenues for miscellaneous services such as jobbing and contracting work performed by THESL); and,
3. The Ontario Clean Energy Benefit (OCEB).

The lag times associated with the funding streams above were weighted and combined to calculate an overall revenue lag time as shown below. Detailed data tables are provided in Appendix B.

Table 3: Summary of Revenue Lag

Description	Lag Days	Revenues	Weighting	Weighted Lag
Retail Revenue	54.78	$ 3,265,502,197	94.18%	51.59
Other Revenue	33.93	$ 25,540,425	0.74%	0.25
Ontario Clean Energy Benefit	62.98	$ 176,156,432	5.08%	3.20
Total		$ 3,467,199,054	100.00%	55.04

Retail Revenue Lag

Retail Revenue lag consists of the following components:

1. Service Lag;
2. Billing Lag;
3. Collections Lag; and,
4. Payment Processing Lag.

The lag times for each of the above components, when added together, results in the Retail Revenue Lag for the purpose of calculating the working capital requirements for THESL's distribution business. The components are intended to represent a continuous process from the end date of the customer's previous billing cycle to the date in which the payment is available to THESL. Figure 1 illustrates the start and end point for each component of THESL's retail revenue lag.

Figure 1: Retail Revenue Lag

Table 3, below summarizes the total Retail Revenue Lag.

Table 4: Summary of Retail Revenue Lag

Description	Lag Days
Service Lag	18.72
Billing Lag	12.52
Collections Lag	22.21
Payment Processing Lag	1.32
Total	54.78

The estimation of each component of the Retail Revenue Lag is described below.

Service Lag

The Service Lag is the time from THESL's provision of electricity to a customer, to the time the customer's service period ends, which is typically defined as when the meter is read. Customer Service staff at THESL provided data which documented that approximately 78% of revenues are billed monthly and 22% of revenues are billed bi-monthly. Using the information provided, the Service Lag was estimated to be 18.72 days.

Billing Lag

The Billing Lag is the time period from when the customer's service period ends, which is typically defined as when the meter is read, and the time that the customer's bill is generated in the customer information system (CIS). Interviews with billing staff at THESL and analysis of meter billing data indicated that THESL customers have an average billing lag of 12.52 days, which is significantly shorter than billing lag in the prior study due to the implementation of a new CIS.

Collections Lag

The Collections Lag is the time period from when the bill is generated in the CIS, until the time when the customer provides a payment to THESL. The Collections Lag is measured by analyzing the receivables aging data provided by THESL. THESL's Collection lag was calculated to be 22.21 days was determined for THESL's distribution operations.

Payment Processing Lag

The Payment Processing lag is the time period from when the customer provides a payment to THESL until such time as the funds associated with that payment are available to the company. The Payment Processing Lag is measured by analyzing the payment methods used by THESL customers. Some examples of the payment methods used include credit card, pre-authorized payment and branch payment. THESL provided the processing time associated with each method of payment and the number of customers using each method of payment. Using such data provided by THESL for the calendar year 2012, a customer-weighted average payment processing lag of 1.32 days was determined for THESL's distribution operations.

Section III: Expense Leads

Expense Leads are defined as the time period between when a service is provided to THESL and when payment is required for that service. Typically services are provided in advance of payment which reduces the capital requirement of the company. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

1. Cost of Power;
2. OM&A Expenses;
3. Interest on Long Term Debt;
4. Payments in Lieu of Taxes; and,
5. Harmonized Sales Tax.

Cost of Power

For the purpose of the distribution lead lag study, cost of power expenses were considered to consist of payments made by THESL to its vendors in the following categories:

1. Independent Electricity System Operator (IESO) Cost of Power Expenses;
2. Hydro One Low Voltage Charges;
3. Payments to Non Utility Generators; and,
4. Payments to Renewable Energy Standard Offer Program (RESOP), Micro Feed in Tariff (MFIT), and Feed in Tariff (FIT) customers.

Expense lead times were calculated individually for each of the items listed above and then dollar weighted to derive a composite expense lead time of 32.84 days for cost of power expenses.

Table 5: Summary of Cost of Power Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
IESO Cost of Power	$ 2,442,084,555	99.65%	32.80	32.68
Hydro One Low Voltage Charges	$ 352,519,111	0.01%	32.22	0.00
Payments to Non Utility Generators	$ 2,933,301,111	0.01%	32.26	0.00
Payments to RESOP, MFIT, and FIT customers	$ 7,186,760,111	0.32%	46.29	0.15
Total	$ 2,450,597,565	100.00%		32.84

IESO Cost of Power Expenses

THESL purchases its power supply requirements on a monthly basis from the IESO and pays for such supplies on a schedule defined by the IESO's billing and settlement procedures. Taking the information on actual payments made by THESL in 2012, a dollar weighted Cost of Power expense lead time of 32.801 days was calculated. Table 6 below summarizes the components of the Cost of Power expense lead calculation.

Table 6: Summary of IESO Cost of Power Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 201,741,673	8.26%	2/21/2012	15.50	21.00	31.50	2.60
Feb-12	$ 189,300,906	7.75%	3/20/2012	14.50	20.00	30.50	2.36
Mar-12	$ 201,593,695	8.21%	4/23/2012	15.50	23.00	34.50	2.83
Apr-12	$ 182,265,321	7.46%	5/18/2012	15.00	18.00	31.00	2.31
May-12	$ 202,835,582	8.31%	6/20/2012	15.50	20.00	33.50	2.78
Jun-12	$ 217,612,164	8.91%	7/20/2012	15.00	20.00	33.00	2.94
Jul-12	$ 220,868,561	9.04%	8/21/2012	15.50	21.00	32.50	2.94
Aug-12	$ 231,368,962	9.47%	9/21/2012	15.50	21.00	34.50	3.27
Sep-12	$ 195,552,497	8.01%	10/19/2012	15.00	19.00	32.00	2.56
Oct-12	$ 198,526,123	8.13%	11/21/2012	15.50	21.00	34.50	2.80
Nov-12	$ 204,231,158	8.36%	12/20/2012	15.00	20.00	33.00	2.76
Dec-12	$ 197,187,913	8.07%	1/21/2013	15.50	21.00	32.50	2.62
Total	$ 2,442,084,555	100.00%				32.801	

Hydro One Low Voltage Charges

THESL provides payment to Hydro One for low voltage charges on a monthly basis and pays for such charges on a monthly basis. Based upon information on payments made by THESL in 2012, a dollar-weighted Hydro One Low Voltage Charges Cost of Power expense lead time of 32.221 days was calculated. Table 7, below summarizes the components of the Hydro One Low Voltage Charges expense lead calculation.

Table 7: Summary of Hydro One Low Voltage Charges

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ [illegible]	7.77%	2/16/2012	15.50	16.00	31.50	2.45
Feb-12	$ [illegible]	10.60%	3/16/2012	14.50	16.00	30.50	3.23
Mar-12	$ [illegible]	7.38%	4/19/2012	15.50	19.00	34.50	2.55
Apr-12	$ [illegible]	7.04%	5/16/2012	15.00	16.00	31.00	2.18
May-12	$ [illegible]	7.05%	6/16/2012	15.50	16.00	31.50	2.22
Jun-12	$ [illegible]	7.46%	7/18/2012	15.00	18.00	33.00	2.46
Jul-12	$ [illegible]	8.94%	8/17/2012	15.50	17.00	32.50	2.90
Aug-12	$ [illegible]	8.26%	9/19/2012	15.50	19.00	34.50	2.85
Sep-12	$ [illegible]	10.88%	10/17/2012	15.00	17.00	32.00	3.48
Oct-12	$ [illegible]	10.25%	11/17/2012	15.50	17.00	32.50	3.33
Nov-12	$ [illegible]	7.16%	12/16/2012	15.00	16.00	31.00	2.22
Dec-12	$ [illegible]	7.20%	1/17/2013	15.50	17.00	32.50	2.34
Total	$ [illegible]	100.00%				32.221	

Payments to Non-Utility Generators

THESL purchases power supply from Non-Utility Generators on a monthly basis and pays for such supplies on a monthly basis. For the year 2012, a dollar-weighted expense lead time of 32.26 days was calculated. Table 8 below summarizes the components of the Non-Utility Generator payments expense lead calculation.

Table 8: Summary of Non-Utility Generator Payments

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$	11.59%	2/16/2012	15.50	16.00	31.50	3.65
Feb-12	$	6.26%	3/16/2012	14.50	16.00	30.50	1.91
Mar-12	$	4.63%	4/19/2012	15.50	19.00	34.50	1.60
Apr-12	$	4.63%	5/16/2012	15.00	16.00	31.00	1.44
May-12	$	4.85%	6/16/2012	15.50	16.00	31.50	1.53
Jun-12	$	4.71%	7/18/2012	15.00	18.00	33.00	1.56
Jul-12	$	10.74%	8/17/2012	15.50	17.00	32.50	3.49
Aug-12	$	9.93%	9/19/2012	15.50	19.00	34.50	3.42
Sep-12	$	13.08%	10/17/2012	15.00	17.00	32.00	4.19
Oct-12	$	12.32%	11/17/2012	15.50	17.00	32.50	4.00
Nov-12	$	8.60%	12/16/2012	15.00	16.00	31.00	2.67
Dec-12	$	8.65%	1/17/2013	15.50	17.00	32.50	2.81
Total	$	100.00%				32.26	

Payments to RESOP, MFIT, and FIT Customers

THESL purchases power supply from RESOP, MFIT and FIT customers. Using payment information in 2012 and the service and billing lag values determined from the revenue analysis, a dollar weighted expense lead time of 46.29 days was calculated. Table 9 below summarizes the components of the RESOP, MFIT, and FIT payments expense lead calculation. Additional detail can be found in Appendix B.

Table 9: RESOP, MFIT, and FIT Customer Payments

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
RESOP	$ 113,497,711	1.44%	38.41	0.55
MFIT	$ 1,843,520	23.43%	43.31	10.15
FIT	$ 5,910,143	75.12%	47.38	35.59
Total	$ 7,867,160	100.00%	1	46.29

OM&A Expenses

For the purpose of the distribution lead lag study, OM&A expenses were considered to consist of payments made by THESL to its vendors in the following categories:

1. Payroll & Benefits;
2. Property Taxes;
3. Non-Resident Withholding Tax;
4. Corporate Procurement Card;
5. Lease Payments;
6. Outside Services; and,
7. Miscellaneous OM&A.

Expense lead times were calculated individually for each of the items listed above and then dollar weighted to derive a composite expense lead time of 33.86 days for OM&A expenses.

Table 10: Summary of OM&A Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
Payroll & Benefits	$ 207,829,884	66.41%	27.30	18.13
Property Taxes	$ 6,494,693	2.08%	(27.57)	(0.57)
Non-Resident Withholding Tax	$ 249,209	0.08%	29.44	0.02
Corporate Procurement Card	$ 187,473	0.06%	26.21	0.02
Lease Payments	$ 8,971,928	2.87%	12.85	0.37
Outside Services	$ 49,864,366	15.93%	53.51	8.53
Miscellaneous OM&A	$ 39,363,668	12.58%	58.56	7.37
Total	$ 312,961,220	100.00%	1	33.86

Payroll & Benefits

The following items were considered to be expenses related to the Payroll & Benefits of THESL:

1. Two types of payroll including basic and board of directors payroll;
2. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings;
3. Contributions made by THESL to the THESL Pension Plan;
4. Group Health, Dental, and Life Insurance related administrative fees and claims, long term disability, accidental death and dismemberment, and employee assistance program;
5. Payments made by THESL on account of the Employer Health Tax (EHT); and,
6. Payments made by THESL to the Workplace Safety and Insurance Board (WSIB).

When all Payroll, Withholdings and Benefits were dollar weighted using actual payment data, the weighted average expense lead time associated with Payroll & Benefits was determined to be 27.30 days as shown in Table 11, below. Additional detail can be found in Appendix B.

Table 11: Summary of Payroll & Benefits Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
Payroll	$ 102,963,943	19.68	49.54%	9.75
Withholdings	$ 152,044,775	33.58	25.04%	8.41
Pensions	$ 129,800,561	56.83	14.34%	8.15
Group Life Insurance	$ 2,760,101	(4.25)	1.33%	(0.06)
Group Medical & Dental Claims	$ 33,286,318	0.50	6.39%	0.03
Long Term Disability	$ 2,160,197	(4.25)	1.04%	(0.04)
Accidental Death and Dismemberment	$ 287,471	(4.25)	0.01%	(0.00)
Employee Assistance Program	$ 818,870	(4.10)	0.06%	(0.00)
EHT	$ 3,167,626	42.39	1.52%	0.65
WSIB	$ 1,498,062	57.96	0.72%	0.42
Total	$ 207,829,884	1	100.00%	27.30

Property Taxes

THESL makes property tax payments to the City of Toronto and taxing authorities in the Province of Ontario. These payments are made in the current year for the current year and are typically made in installments. Using the payment dates and amounts associated with THESL's distribution business for calendar year 2012, a dollar weighted expense lead (lag) time of negative 27.57 days was determined. Table 12, below summarizes the components of the property tax expense lead calculation. Additional detail can be found in Appendix B.

Table 12: Summary of Property Tax Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
PIL Property Tax	$ 135,851	0.83%	(15.39)	(0.13)
Property Tax	$ 16,140,842	99.17%	(27.67)	(27.44)
Total	$ 16,294,693	100.00%		(27.57)

Non-Resident Withholding Tax

THESL makes non-resident withholding tax payments to the relevant taxing authority. These payments are made on a monthly basis. Using actual payment dates and amounts provided by THESL, a dollar weighted expense lead time of 29.44 days was determined. Table 13, below summarizes the components of the non-resident withholding tax expense lead calculation.

Table 13: Summary of Non-Resident Withholding Tax Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 17,156,611	7.05%	1/13/2012	15.50	13.00	28.50	2.01
Feb-12	$ 32,228,111	12.93%	2/15/2012	15.50	15.00	30.50	3.94
Mar-12	$ 15,623,111	2.26%	3/15/2012	14.00	16.00	30.00	0.68
Apr-12	$ 56,377,111	22.62%	4/13/2012	15.50	13.00	28.50	6.45
May-12	$ 9,885,111	3.97%	5/15/2012	15.00	15.00	30.00	1.19
Jun-12	$ 12,593,111	5.05%	6/15/2012	15.50	15.00	30.50	1.54
Jul-12	$ 16,577,111	6.65%	7/13/2012	15.00	13.00	28.00	1.86
Aug-12	$ 4,793,111	1.92%	8/15/2012	15.50	15.00	30.50	0.59
Sep-12	$ 23,459,111	9.41%	9/14/2012	15.50	14.00	29.50	2.78
Oct-12	$ 37,550,111	15.07%	10/15/2012	15.00	15.00	30.00	4.52
Nov-12	$ 15,812,111	6.34%	11/15/2012	15.50	15.00	30.50	1.94
Dec-12	$ 16,751,111	6.72%	12/14/2012	15.00	14.00	29.00	1.95
Total	$ 249,120,911	100.00%				29.44	

Corporate Procurement Card

Procurement (or charge) cards are used by the THESL's employees for a variety of company related reasons including, and not limited to, purchases of materials in the field, incidental expenses, and to settle charges for travel and accommodation. Based on invoice and payment information provided by THESL, a dollar weighted expense lead time of 26.21 days was determined. Table 14 below summarizes the components of the corporate procurement card expense lead calculation.

Table 14: Summary of Corporate Procurement Card Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 1,115,917	8.50%	1/13/2012	15.50	11.00	26.50	2.25
Feb-12	$ 1,111,782	6.28%	2/15/2012	14.50	11.00	25.50	1.60
Mar-12	$ 1,114,624,111	2.47%	3/15/2012	15.50	11.00	26.50	0.65
Apr-12	$ 1,115,756,111	3.07%	4/13/2012	15.00	11.00	26.00	0.80
May-12	$ 1,112,882	6.87%	5/15/2012	15.50	11.00	26.50	1.82
Jun-12	$ 1,114,794	7.89%	6/15/2012	15.00	11.00	26.00	2.05
Jul-12	$ 1,114,246,111	2.27%	7/13/2012	15.50	11.00	26.50	0.60
Aug-12	$ 1,115,776,111	3.08%	8/15/2012	15.50	11.00	26.50	0.82
Sep-12	$ 1,116,420,111	3.42%	9/14/2012	15.00	11.00	26.00	0.89
Oct-12	$ 1,113,849	7.39%	10/15/2012	15.50	11.00	26.50	1.96
Nov-12	$ 1,159,012	31.48%	11/15/2012	15.00	11.00	26.00	8.18
Dec-12	$ 1,132,403	17.28%	12/14/2012	15.50	11.00	26.50	4.58
Total	$ 1,187,473	100.00%				26.21	

Lease Payments

Using actual payment dates and amounts provided by THESL, a dollar weighted lease expense lead time of 12.85 days was determined. Table 15, below summarizes the components of the lease expense lead calculation.

Table 15: Summary of Lease Expenses

Delivery Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 1,844,861	9.42%	48.81	0.51	49.32	4.64
Feb-12	$ 1,740,722	8.26%	14.93	5.63	20.56	1.70
Mar-12	$ 1,740,722	8.26%	15.07	(7.91)	7.16	0.59
Apr-12	$ 1,740,722	8.26%	15.21	(7.35)	7.86	0.65
May-12	$ 1,740,722	8.26%	15.29	(9.35)	5.94	0.49
Jun-12	$ 1,740,722	8.26%	15.21	(2.36)	12.86	1.06
Jul-12	$ 1,719,847	8.02%	15.28	(3.25)	12.03	0.97
Aug-12	$ 1,740,722	8.26%	15.50	(6.91)	8.59	0.71
Sep-12	$ 1,740,722	8.26%	15.21	(10.48)	4.73	0.39
Oct-12	$ 1,740,722	8.26%	15.29	(4.20)	11.08	0.91
Nov-12	$ 1,740,722	8.26%	15.21	(10.76)	4.45	0.37
Dec-12	$ 1,740,722	8.26%	15.29	(10.77)	4.52	0.37
Total	$ 21,971,928	100.00%				12.85

Outside Services

THESL engages outside services to provide assistance in the areas of engineering, information technology, receivables management, accounting, and general consulting. Based on 2012 transactions in THESL's accounts payable system under the outside services category, a dollar weighted expense lead time of 53.51 days was determined. Table 16, below summarizes the components of outside services expense lead calculation.

Table 16: Summary of Outside Services Expenses

Delivery Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 14,612,817	9.25%	14.38	37.70	52.08	4.82
Feb-12	$ 12,781,515	5.58%	14.58	43.98	58.56	3.27
Mar-12	$ 13,033,721	6.08%	12.29	41.93	54.22	3.30
Apr-12	$ 12,865,796	5.75%	14.44	46.31	60.75	3.49
May-12	$ 16,084,596	12.20%	28.24	13.45	41.68	5.09
Jun-12	$ 15,110,106	10.25%	14.48	47.74	62.22	6.38
Jul-12	$ 13,904,682	7.83%	29.29	13.85	43.14	3.38
Aug-12	$ 13,800,454	7.62%	13.96	35.58	49.54	3.78
Sep-12	$ 14,129,948	8.28%	19.05	33.91	52.97	4.39
Oct-12	$ 15,325,608	10.68%	30.95	32.32	63.28	6.76
Nov-12	$ 14,810,172	9.65%	13.73	44.26	57.98	5.59
Dec-12	$ 13,404,952	6.83%	13.81	34.29	48.10	3.28
Total	$ 149,864,366	100.00%	11	1		53.51

Miscellaneous O&M&A

The Miscellaneous O&M&A category includes items such as product purchases, equipment rentals, and provision of general services to THESL. Based on 2012 transactions in THESL's accounts payable system under the Miscellaneous O&M&A category, a dollar weighted expense lead time of 58.56 days was derived. Table 17, below summarizes the components of miscellaneous O&M&A expense lead calculation.

Table 17: Summary of Miscellaneous O&M&A Expenses

Delivery Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 15,024,613	12.76%	74.53	(17.64)	56.88	7.26
Feb-12	$ 13,197,116	8.12%	57.20	(49.67)	7.53	0.61
Mar-12	$ 13,513,623	8.93%	39.78	(0.92)	38.86	3.47
Apr-12	$ 14,245,067	10.78%	60.99	62.93	123.92	13.36
May-12	$ 13,438,457	8.74%	59.78	(30.27)	29.51	2.58
Jun-12	$ 12,285,298	5.81%	15.80	35.12	50.92	2.96
Jul-12	$ 13,326,833	8.45%	49.06	(0.03)	49.03	4.14
Aug-12	$ 13,235,973	8.22%	60.64	(6.81)	53.84	4.43
Sep-12	$ 12,390,997	6.07%	16.04	42.90	58.94	3.58
Oct-12	$ 12,283,193	5.80%	15.93	36.91	52.84	3.06
Nov-12	$ 13,132,224	7.96%	56.56	18.42	74.98	5.97
Dec-12	$ 13,290,273	8.36%	66.50	18.88	85.38	7.14
Total	$ 159,363,668	100.00%				58.56

Interest on Short-Term and Long-Term Debt

THESL makes interest payments on long-term and short-term intercompany promissory notes out of current year revenues. Payments on long-term debt are generally made twice a year. Though short-term debt was not part of THESL's financing in the base year of the analysis (2012), discussions with THESL staff indicate that short-term debt is expected to be a part of THESL's financing in the 2015-2019 period. Payments for short-term intercompany promissory notes in 2013 were included to reflect a known and measurable change from the base year of the analysis. Table 18, below summarizes the components of the interest expense lead calculation. Taking into account the various long-term and short-term debt instruments, a dollar-weighted expense lead time of 46.17 days was determined for the 2012 calendar year.

Table 18: Summary of Interest Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
2012 Long-term debt	$ 175,272,180	98.82%	46.38	45.83
2013 Short-term debt	$ 101,769	1.18%	28.84	0.34
Total	$ 176,173,950	100.00%		46.17

Debt Retirement Charge (DRC)

THESL makes payments for the debt retirement charge on a monthly basis to the Ontario Electricity Financial Corporation. Using payment amounts that were made in calendar year 2012, a dollar-weighted expense lead time of 33.31 days was determined for DRC. Table 19, below summarizes the components of the DRC expense lead calculation.

Table 19: Summary of DRC Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 12,414,868	7.64%	1/18/2012	15.50	18.00	33.50	2.56
Feb-12	$ 13,362,129	8.23%	2/17/2012	15.50	17.00	32.50	2.67
Mar-12	$ 13,574,039	8.36%	3/16/2012	14.00	17.00	31.00	2.59
Apr-12	$ 14,210,958	8.75%	4/18/2012	15.50	18.00	33.50	2.93
May-12	$ 12,537,844	7.72%	5/18/2012	15.00	18.00	33.00	2.55
Jun-12	$ 12,721,780	7.83%	6/18/2012	15.50	18.00	33.50	2.62
Jul-12	$ 12,952,542	7.97%	7/18/2012	15.00	18.00	33.00	2.63
Aug-12	$ 14,352,950	8.84%	8/20/2012	15.50	20.00	35.50	3.14
Sep-12	$ 15,787,738	9.72%	9/18/2012	15.50	18.00	33.50	3.26
Oct-12	$ 14,192,275	8.74%	10/18/2012	15.00	18.00	33.00	2.88
Nov-12	$ 13,282,921	8.18%	11/19/2012	15.50	19.00	34.50	2.82
Dec-12	$ 13,026,281	8.02%	12/18/2012	15.00	18.00	33.00	2.65
Total	$ 162,416,324	100.00%					33.31

Payment in Lieu of Taxes (PILs)

THESL makes payments in lieu of taxes in installments to the relevant taxing authorities. Using payment amounts that were made in calendar year 2012, a dollar weighted expense lead time of negative 48.95 days was determined for PILs. Table 20, below summarizes the components of the PILS expense lead calculation.

Table 20: Summary of PILs Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
2012	$ 11,665,000	21.26%	1/31/2012	183.00	(335.00)	(152.00)	(32.32)
2012	$ 11,665,000	21.26%	2/29/2012	183.00	(306.00)	(123.00)	(26.15)
2012	$ 11,822,000	23.27%	4/30/2012	183.00	(245.00)	(62.00)	(14.43)
2012	$ 1,914,000	11.67%	5/31/2012	183.00	(214.00)	(31.00)	(3.62)
2012	$ 1,541,000	6.91%	9/28/2012	183.00	(94.00)	89.00	6.15
2012	$ 1,612,000	7.82%	10/31/2012	183.00	(61.00)	122.00	9.53
2012	$ 1,612,000	7.82%	11/30/2012	183.00	(31.00)	152.00	11.88
Total	$ 17,831,000	100.00%					(48.95)

Harmonized Sales Tax (HST)

The expense lead times associated with the following items that attract HST were considered in THESL's distribution lead/lag study.

1. Revenues;
2. Cost of Power; and,
3. OM&A [1].

A summary of the expense lead times and working capital amounts associated with each of the above items is provided in Table 21. Note that the statutory approach described at the outset was used to determine the expense lead times associated with THESL's remittances and disbursements of HST (i.e., remittances are generally on the last day of the month following the date of the applicable return).

Table 21: Summary of HST Working Capital Amounts

Description	HST Lead Time	Working Capital Factor	2012
Revenues	(5.47)	1.50%	$ (6,347,016)
Cost of Power	45.92	12.55%	$ 67,966
OM&A Expenses	41.50	11.34%	$ 13,513,531
Total			$ 7,234,481

[1] Costs within OM&A that attract HST include Corporate Procurement Card, Outside Services, and Miscellaneous OM&A.

Section IV: Conclusions

Using the results described under the discussion of revenue lags and expense leads, and applying them to THESL's distribution expenses for 2012, THESL's working capital requirements were determined. Table 22, below summarizes the working capital requirements for 2012 calculated in the study.

Table 22: THESL Distribution Working Capital Requirements (2012)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses	Working Capital Requirements
Cost of Power	55.04	32.84	22.20	6.07%	$ 2,450,597,565	$ 148,654,316
OM&A Expenses	55.04	33.86	21.19	5.79%	$ 312,961,220	$ 18,115,434
PILS	55.04	(48.95)	103.99	28.41%	$ 7,831,001	$ 2,225,034
Interest Expense	55.04	46.17	8.87	2.42%	$ 176,173,950	$ 4,265,501
DRC	55.04	33.31	21.74	5.94%	$ 162,416,324	$ 9,645,577
Total					$ 3,009,980,059	$ 180,485,912
HST						$ 38,234,481
Total Including HST						$ 218,720,393
Working Capital as a Percent of OM&A incl. Cost of Power						7.91%

The results of the study indicate a lower working capital requirement compared to THESL's EB-2007-0680 distribution lead/lag study. A considerable amount of time has elapsed between the two studies. The primary reason for the difference is the decrease in retail revenue lag days, due to the upgrade of THESL's Customer Information System since the prior study. The retail revenue lag days have decreased by approximately 20 percent.

Appendix A: Working Capital Methodology

Working capital is the amount of funds that are required to finance the day to day operations of a regulated utility and which are included as part of a rate base for ratemaking purposes. A lead lag study is the most accurate basis for determination of working capital and was used by Navigant for this purpose.

A lead lag study analyzes the time between the date customers receive service and the date that customers' payments are available to THESL (or "lag") together with the time between which THESL receives goods and services from its vendors and pays for them at a later date (or "lead") [2]. "Leads" and "Lags" are both measured in days and are dollar weighted where appropriate. [3] The dollar weighted net lag (lag minus lead) days is then divided by 365 (or 366 for leap years) and then multiplied by the annual test year expenses to determine the amount of working capital required. The resulting amount of working capital is then included in THESL's rate base for the purpose of deriving revenue requirements.

Key Concepts

Two key concepts need to be defined as they appear throughout the report:

Mid Point Method

When a service is provided to (or by) THESL over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid point of a service period can be calculated using the formula:

$$\text{Mid Point} = X + \frac{(Y - X + 1)}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the mid point of a period, an alternative formula that is generally used is shown below. The formula uses the number of days in a year (A) and the number of periods in a year (B):

$$\text{Mid Point} = \frac{1}{2} \times \frac{A}{B}$$

Statutory Approach

In conjunction with the mid point method, it is important to note that not all areas of the study may utilize dates on which actual payments were made to (or by) THESL. In some instances, particularly for the HST, the due dates for payments are established by statute or by regulation with significant penalties for late payments. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

Expense Lead Components

As used in the study, Expense Leads are defined to consist of two components:

[2] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

[3] The notion of dollar weighting is pursued further in the sub section titled "Key Concepts".

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1. Service Lead component (services are assumed to be provided to THESL evenly around the mid point of the service period), and
2. Payment Lead component (the time period from the end of the service period to the time payment was made and when funds have left THESL's possession).

Dollar Weighting

Both leads and lags should be dollar weighted where appropriate and where data is available to accurately reflect the flow of dollars. For example, suppose that a particular transaction has a lead time of 100 days and has a dollar value of $100. Further, suppose that another transaction has a lead time of 30 days with a dollar value of $1 Million. A simple (un-weighted) average of the two transactions would give us a lead time of 65 days ([100+30]/2). However, when these two transactions are dollar weighted, the resulting lead time would be closer to 30 days which is more representative of how the dollars actually flow.

Methodology

Performing a Lead/Lag study requires two key undertakings:

1. Developing an understanding of how the regulated distribution business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of THESL's operations, interviews with personnel within THESL's Accounts Payable, Customer Service, Wholesale Market Operations, Human Resources, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the course of the interviews included:

1. What is being sold (or purchased)? If a service is being provided to (or by) THESL, over what time period was this service provided;
2. Who are the buyers (or sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes to the terms for payment expected? Are these terms driven by industry or internally? What is the basis for any such changes;
5. Are there any new rules or regulations governing transactions relating to distribution operations that are expected to materialize over the time frame considered in this report; and,
6. How are payments made (or received)? Payment types have different payment lead times (i.e., internet payments have shorter deposit times than cheque deposit times)

Appendix B: Detailed Data Tables

Other Revenues

Table 23: Summary of Other Revenues

Description	Amounts	Weighting	Revenue Lag Time	Weighted Lag Time
Hydro One Sub Station	$ 11,143,151	1.69%	273.00	4.61
Demand Billable	$ 625,109,273	98.31%	29.83	29.32
Total	$ 636,540,425	100.00%		33.93

OCEB

Table 24: Summary of OCEB

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 14,777,518	8.39%	3/16/2012	15.50	45.00	60.50	5.08
Feb-12	$ 16,082,331	9.13%	4/18/2012	14.50	49.00	63.50	5.80
Mar-12	$ 15,985,774	9.07%	5/16/2012	15.50	46.00	61.50	5.58
Apr-12	$ 14,762,648	8.38%	6/18/2012	15.00	49.00	64.00	5.36
May-12	$ 14,085,387	8.00%	7/18/2012	15.50	48.00	63.50	5.08
Jun-12	$ 13,976,849	7.93%	8/17/2012	15.00	48.00	63.00	5.00
Jul-12	$ 16,150,445	9.17%	9/19/2012	15.50	50.00	65.50	6.01
Aug-12	$ 18,228,456	10.35%	10/17/2012	15.50	47.00	62.50	6.47
Sep-12	$ 14,618,252	8.30%	11/16/2012	15.00	47.00	62.00	5.15
Oct-12	$ 12,904,170	7.33%	12/18/2012	15.50	48.00	63.50	4.65
Nov-12	$ 12,919,262	7.33%	1/16/2013	15.00	47.00	62.00	4.55
Dec-12	$ 11,665,341	6.62%	2/18/2013	15.50	49.00	64.50	4.27
Total	$ 176,156,432	100.00%					62.98

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RESOP 1

Table 25: Summary of Payments to RESOP Customers 1

Payment Period 1	Amounts 1	Weighting Factor 1	Service Lead Time 1	Payment Lead Time 1	Total Lead Time 1	Weighted Lead Time 1
Jan 12 1	$ 1 12,254 1	1.99% 1	15.79 1	22.43 1	38.21 1	0.76 1
Feb 12 1	$ 1 14,998 1	4.40% 1	16.29 1	22.43 1	38.71 1	1.70 1
Mar 12 1	$ 1 16,013 1	5.30% 1	16.29 1	22.43 1	38.71 1	2.05 1
Apr 12 1	$ 1 11,184 1	9.85% 1	15.29 1	22.43 1	37.71 1	3.72 1
May 12 1	$ 1 13,375 1	11.78% 1	16.11 1	22.43 1	38.54 1	4.54 1
Jun 12 1	$ 1 12,914 1	11.38% 1	15.90 1	22.43 1	38.33 1	4.36 1
Jul 12 1	$ 1 9,305 1	8.20% 1	16.29 1	22.43 1	38.71 1	3.17 1
Aug 12 1	$ 1 19,542 1	17.22% 1	15.79 1	22.43 1	38.21 1	6.58 1
Sep 12 1	$ 1 8,905 1	7.85% 1	16.29 1	22.43 1	38.71 1	3.04 1
Oct 12 1	$ 1 12,650 1	11.15% 1	16.28 1	22.43 1	38.71 1	4.31 1
Nov 12 1	$ 1 8,856 1	7.80% 1	15.79 1	22.43 1	38.21 1	2.98 1
Dec 12 1	$ 1 3,500 1	3.08% 1	16.29 1	22.43 1	38.71 1	1.19 1
Total 1	$ 111 113,497 1	100.00%	1	1	38.41 1	

MFIT 1

Table 26: Summary of Payments to MFIT Customers 1

Payment Period 1	Amounts 1	Weighting Factor 1	Service Lead Time 1	Payment Lead Time 1	Total Lead Time 1	Weighted Lead Time 1
Jan 12 1	$ 1 13 4,183 1	1.89% 1	15.98 1	27.09 1	43.07 1	0.81 1
Feb 12 1	$ 1 14 5,164 1	2.48% 1	16.46 1	27.09 1	43.54 1	1.08 1
Mar 12 1	$ 1 17 7,317 1	3.97% 1	16.43 1	27.09 1	43.52 1	1.73 1
Apr 12 1	$ 1 12 5,175 1	6.82% 1	15.46 1	27.09 1	42.54 1	2.90 1
May 12 1	$ 1 14 5,149 1	7.89% 1	16.44 1	27.09 1	43.53 1	3.44 1
Jun 12 1	$ 1 14 4,917 1	8.12% 1	15.96 1	27.09 1	43.05 1	3.50 1
Jul 12 1	$ 1 26 11,612 1	14.19% 1	16.44 1	27.09 1	43.53 1	6.18 1
Aug 12 1	$ 1 30 8,102 1	16.71% 1	15.96 1	27.09 1	43.05 1	7.19 1
Sep 12 1	$ 1 24 7,177 1	13.44% 1	16.46 1	27.09 1	43.54 1	5.85 1
Oct 12 1	$ 1 21 8,174 1	11.87% 1	16.45 1	27.09 1	43.54 1	5.17 1
Nov 12 1	$ 1 12 2,961 1	6.58% 1	15.96 1	27.09 1	43.04 1	2.83 1
Dec 12 1	$ 1 11 1,465 1	6.05% 1	16.46 1	27.09 1	43.54 1	2.63 1
Total 1	$ 1 181 43,520 1	100.00%	1	1	43.31 1	

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FIT 1 1

Table 27: Summary of Payments to FIT Customers

Payment Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 115,154,711	0.87%	15.88	31.24	47.12	0.41
Feb-12	$ 106,102,291	1.79%	16.38	31.24	47.62	0.85
Mar-12	$ 154,121,181	2.61%	16.38	31.24	47.62	1.24
Apr-12	$ 339,175,631	5.75%	15.38	31.24	46.62	2.68
May-12	$ 411,111,741	6.96%	15.65	31.24	46.89	3.26
Jun-12	$ 680,191,171	11.52%	16.09	31.24	47.34	5.45
Jul-12	$ 607,111,741	10.27%	16.38	31.24	47.62	4.89
Aug-12	$ 785,119,931	13.29%	16.03	31.24	47.28	6.28
Sep-12	$ 885,135,621	14.98%	16.38	31.24	47.62	7.13
Oct-12	$ 757,172,231	12.82%	16.38	31.24	47.62	6.11
Nov-12	$ 631,104,451	10.74%	15.88	31.24	47.12	5.06
Dec-12	$ 496,101,191	8.39%	16.38	31.24	47.62	4.00
Total	$ 5,910,143	100.00%				47.38

Payroll

Table 28: Summary of Payroll Expenses

Delivery Period (Pay Period)	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
12/18/2011 to 12/31/2011	$ 3,743,615	3.64%	1/4/2012	7.00	4.00	11.00	0.40
01/01/2012 to 01/14/2012	$ 3,685,570	3.58%	1/18/2012	7.00	4.00	11.00	0.39
01/15/2012 to 01/28/2012	$ 3,637,840	3.53%	2/1/2012	7.00	4.00	11.00	0.39
01/29/2012 to 02/11/2012	$ 3,951,309	3.84%	2/15/2012	7.00	4.00	11.00	0.42
02/12/2012 to 02/25/2012	$ 3,939,521	3.83%	2/29/2012	7.00	4.00	11.00	0.42
02/26/2012 to 03/10/2012	$ 3,593,195	3.49%	3/14/2012	7.00	4.00	11.00	0.38
03/11/2012 to 03/24/2012	$ 3,448,774	3.35%	3/28/2012	7.00	4.00	11.00	0.37
03/25/2012 to 04/07/2012	$ 3,323,462	3.23%	4/11/2012	7.00	4.00	11.00	0.36
04/08/2012 to 04/21/2012	$ 3,638,829	3.53%	4/25/2012	7.00	4.00	11.00	0.39
04/22/2012 to 05/05/2012	$ 3,722,814	3.62%	5/9/2012	7.00	4.00	11.00	0.40
05/06/2012 to 05/19/2012	$ 3,674,061	3.57%	5/23/2012	7.00	4.00	11.00	0.39
05/20/2012 to 06/02/2012	$ 3,737,336	3.63%	6/6/2012	7.00	4.00	11.00	0.40
06/03/2012 to 06/16/2012	$ 3,721,799	3.61%	6/20/2012	7.00	4.00	11.00	0.40
06/17/2012 to 06/30/2012	$ 3,750,644	3.64%	7/4/2012	7.00	4.00	11.00	0.40
07/01/2012 to 07/14/2012	$ 3,863,603	3.75%	7/18/2012	7.00	4.00	11.00	0.41
07/15/2012 to 07/28/2012	$ 3,823,881	3.71%	8/1/2012	7.00	4.00	11.00	0.41
07/29/2012 to 08/11/2012	$ 3,908,038	3.80%	8/15/2012	7.00	4.00	11.00	0.42
08/12/2012 to 08/25/2012	$ 3,880,714	3.77%	8/29/2012	7.00	4.00	11.00	0.41
08/26/2012 to 09/08/2012	$ 3,841,950	3.73%	9/12/2012	7.00	4.00	11.00	0.41
09/09/2012 to 09/22/2012	$ 3,811,314	3.70%	9/26/2012	7.00	4.00	11.00	0.41
09/23/2012 to 10/06/2012	$ 3,802,499	3.69%	10/10/2012	7.00	4.00	11.00	0.41
10/07/2012 to 10/20/2012	$ 3,934,557	3.82%	10/24/2012	7.00	4.00	11.00	0.42
10/21/2012 to 11/03/2012	$ 4,193,257	4.07%	11/7/2012	7.00	4.00	11.00	0.45
11/04/2012 to 11/17/2012	$ 4,329,636	4.21%	11/21/2012	7.00	4.00	11.00	0.46
11/18/2012 to 12/01/2012	$ 4,121,857	4.00%	12/5/2012	7.00	4.00	11.00	0.44
12/02/2012 to 12/15/2012	$ 4,157,888	4.04%	12/19/2012	7.00	4.00	11.00	0.44
01/01/2011 to 12/31/2011	$ 3,416,730	3.32%	3/28/2012	182.50	88.00	270.50	8.98
01/01/2012 to 03/31/2012	$ 92,750	0.09%	3/15/2012	45.50	(16.00)	29.50	0.03
04/01/2012 to 06/30/2012	$ 87,750	0.09%	7/5/2012	45.50	5.00	50.50	0.04
07/01/2012 to 09/30/2012	$ 65,875	0.06%	9/13/2012	46.00	(17.00)	29.00	0.02
10/01/2012 to 12/31/2012	$ 62,875	0.06%	12/6/2012	46.00	(25.00)	21.00	0.01
Total	$ 102,963,943	100.00%	1	1	1	1	19.68

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Withholdings 1

Table 29: Summary of Withholdings Expenses 1

Delivery Period 1 1 (Pay Period) 1	Amounts 1	Weighting 1 Factor % 1	Payment 1 Date 1	Service 1 Lead 1 Time 1	Payment 1 Lead 1 Time 1	Total 1 Lead 1 Time 1	Weighted 1 Lead 1 Time 1
12/18/2011 to 12/31/2011	$ 1 1 2,371,111 1	4.48% 1	1/4/2012 1	7.00 1	11.00 1	18.00 1	0.82 1
01/01/2012 to 01/14/2012 1	$ 1 1 2,314,472 1	4.37% 1	1/18/2012 1	7.00 1	11.00 1	18.00	0.80 1
01/15/2012 to 01/28/2012	$ 1 1 2,291,856 1	4.33% 1	2/1/2012 1	7.00 1	13.00 1	20.00 1	0.88 1
01/29/2012 to 02/11/2012 1	$ 1 1 2,472,835 1	4.67% 1	2/15/2012 1	7.00 1	13.00 1	20.00	0.95 1
02/12/2012 to 02/25/2012	$ 1 1 2,397,001 1	4.53% 1	2/29/2012 1	7.00 1	16.00 1	23.00 1	1.06 1
02/26/2012 to 03/10/2012 1	$ 1 1 2,173,168 1	4.99% 1	3/14/2012 1	7.00 1	16.00 1	23.00	0.96 1
03/11/2012 to 03/24/2012	$ 1 1 2,827,668 1	10 6.63% 1	3/28/2012 1	7.00 1	11.00 1	18.00 1	0.98 1
03/25/2012 to 04/07/2012 1	$ 1 1 1,922,646 1	4.45% 1	4/11/2012 1	7.00 1	11.00 1	18.00	0.66 1
04/08/2012 to 04/21/2012	$ 1 1 2,153,758 1	4.07% 1	4/25/2012 1	7.00 1	12.00 1	19.00 1	0.79 1
04/22/2012 to 05/05/2012 1	$ 1 1 2,102,368 1	3.97% 1	5/9/2012 1	7.00 1	12.00 1	19.00	0.77 1
05/06/2012 to 05/19/2012	$ 1 1 1,942,826 1	3 1.67% 1	5/23/2012 1	7.00 1	17.00 1	24.00 1	0.90 1
05/20/2012 to 06/02/2012 1	$ 1 1 1,981,111 1	3.74% 1	6/6/2012 1	7.00 1	10.00 1	17.00	0.65 1
06/03/2012 to 06/16/2012	$ 1 1 1,863,961 1	3 1.52% 1	6/20/2012 1	7.00 1	10.00 1	17.00 1	0.61 1
06/17/2012 to 06/30/2012 1	$ 1 1 1,734,066 1	3.28% 1	7/4/2012 1	7.00 1	11.00 1	18.00	0.60 1
07/01/2012 to 07/14/2012	$ 1 1 1,710,896 1	3 1.23% 1	7/18/2012 1	7.00 1	11.00 1	18.00 1	0.59 1
07/15/2012 to 07/28/2012 1	$ 1 1 1,560,219 1	2.95% 1	8/1/2012 1	7.00 1	13.00 1	20.00	0.60 1
07/29/2012 to 08/11/2012	$ 1 1 1,564,785 1	2 1.96% 1	8/15/2012 1	7.00 1	13.00 1	20.00 1	0.60 1
08/12/2012 to 08/25/2012 1	$ 1 1 1,476,121 1	2.79% 1	8/29/2012 1	7.00 1	12.00 1	19.00	0.54 1
08/26/2012 to 09/08/2012	$ 1 1 1,432,966 1	2 1.71% 1	9/12/2012 1	7.00 1	11.00 1	18.00 1	0.50 1
09/09/2012 to 09/22/2012 1	$ 1 1 1,404,023 1	2.65% 1	9/26/2012 1	7.00 1	11.00 1	18.00	0.49 1
09/23/2012 to 10/06/2012	$ 1 1 1,383,932 1	2 1.61% 1	10/10/2012 1	7.00 1	11.00 1	18.00 1	0.48 1
10/07/2012 to 10/20/2012 1	$ 1 1 1,480,491 1	2.80% 1	10/24/2012 1	7.00 1	16.00 1	23.00	0.65 1
10/21/2012 to 11/03/2012	$ 1 1 1,661,792 1	3 1.14% 1	11/7/2012 1	7.00 1	16.00 1	23.00 1	0.73 1
11/04/2012 to 11/17/2012 1	$ 1 1 1,788,194 1	3.38% 1	11/21/2012 1	7.00 1	18.00 1	25.00	0.86 1
11/18/2012 to 12/01/2012	$ 1 1 1,604,248 1	3 1.03% 1	12/5/2012 1	7.00 1	11.00 1	18.00 1	0.55 1
12/02/2012 to 12/15/2012 1	$ 1 1 1,626,355 1	3.07% 1	12/19/2012 1	7.00 1	13.00 1	20.00	0.62 1
Total 1	$ 1 52,044,775 1 1	100.00%	1		1		33.58 1 1

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Pensions

Table 30: Summary of Pension Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Feb-12	$ 12,207,160	7.41%	2/28/2012	7.00	51.49	58.49	4.33
Mar-12	$ 12,379,281	7.98%	3/31/2012	7.00	55.99	62.99	5.03
Apr-12	$ 15,293,218	17.76%	4/30/2012	7.00	46.61	53.61	9.52
May-12	$ 12,398,137	18.05%	5/31/2012	7.00	47.01	54.01	4.35
Jun-12	$ 12,397,522	8.05%	6/30/2012	7.00	49.02	56.02	4.51
Jul-12	$ 12,372,761	7.96%	7/31/2012	7.00	51.94	58.94	4.69
Aug-12	$ 12,346,717	7.87%	8/31/2012	7.00	55.02	62.02	4.88
Sep-12	$ 13,505,145	11.76%	9/30/2012	7.00	50.00	57.00	6.70
Oct-12	$ 12,310,456	7.75%	10/31/2012	7.00	46.04	53.04	4.11
Nov-12	$ 12,301,748	17.72%	11/30/2012	7.00	48.01	55.01	4.25
Dec-12	$ 12,288,416	7.68%	12/31/2012	7.00	51.00	58.00	4.45
Total	$ 29,800,561	100.00%			1		56.83

Group Life Insurance

Table 31: Summary of Group Life Insurance Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 1,225,021	8.15%	1/11/2012	15.50	(20.00)	(4.50)	(0.37)
Feb-12	$ 1,225,814	8.18%	2/11/2012	14.50	(18.00)	(3.50)	(0.29)
Mar-12	$ 1,228,422	18.28%	3/11/2012	15.50	(20.00)	(4.50)	(0.37)
Apr-12	$ 1,243,951	8.84%	4/11/2012	15.00	(19.00)	(4.00)	(0.35)
May-12	$ 1,246,579	18.93%	5/11/2012	15.50	(20.00)	(4.50)	(0.40)
Jun-12	$ 1,226,522	8.21%	6/11/2012	15.00	(19.00)	(4.00)	(0.33)
Jul-12	$ 1,225,714	8.18%	7/11/2012	15.50	(20.00)	(4.50)	(0.37)
Aug-12	$ 1,226,913	8.22%	8/11/2012	15.50	(20.00)	(4.50)	(0.37)
Sep-12	$ 1,226,673	8.21%	9/11/2012	15.00	(19.00)	(4.00)	(0.33)
Oct-12	$ 1,229,813	8.31%	10/11/2012	15.50	(20.00)	(4.50)	(0.37)
Nov-12	$ 1,228,291	18.27%	11/11/2012	15.00	(19.00)	(4.00)	(0.33)
Dec-12	$ 1,226,797	8.22%	12/11/2012	15.50	(20.00)	(4.50)	(0.37)
Total	$ 2,760,011	100.00%				(4.25)	

Group Medical and Dental Claims

Table 32: Summary of Group Medical and Dental Claims Expenses

Delivery Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 1,125,344	8.37%	0.50	0.00	0.50	0.04
Feb-12	$ 1,052,741	7.97%	0.50	0.00	0.50	0.04
Mar-12	$ 1,125,344	8.76%	0.50	0.00	0.50	0.04
Apr-12	$ 1,089,042	7.97%	0.50	0.00	0.50	0.04
May-12	$ 1,125,344	8.76%	0.50	0.00	0.50	0.04
Jun-12	$ 1,089,042	8.37%	0.50	0.00	0.50	0.04
Jul-12	$ 1,125,344	8.37%	0.50	0.00	0.50	0.04
Aug-12	$ 1,125,344	8.76%	0.50	0.00	0.50	0.04
Sep-12	$ 1,089,042	7.57%	0.50	0.00	0.50	0.04
Oct-12	$ 1,125,344	8.76%	0.50	0.00	0.50	0.04
Nov-12	$ 1,089,042	8.76%	0.50	0.00	0.50	0.04
Dec-12	$ 1,125,344	7.57%	0.50	0.00	0.50	0.04
Total	$ 13,286,318	100.00%			0.50	

Long-term Disability

Table 33: Summary of Long-term Disability Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 193,181	8.94%	1/11/2012	15.50	(20.00)	(4.50)	(0.40)
Feb-12	$ 191,492	8.86%	2/11/2012	14.50	(18.00)	(3.50)	(0.31)
Mar-12	$ 190,374	18.81%	3/11/2012	15.50	(20.00)	(4.50)	(0.40)
Apr-12	$ 179,311	8.30%	4/11/2012	15.00	(19.00)	(4.00)	(0.33)
May-12	$ 177,478	8.21%	5/11/2012	15.50	(20.00)	(4.50)	(0.37)
Jun-12	$ 177,478	8.21%	6/11/2012	15.00	(19.00)	(4.00)	(0.33)
Jul-12	$ 176,332	8.16%	7/11/2012	15.50	(20.00)	(4.50)	(0.37)
Aug-12	$ 176,177	8.15%	8/11/2012	15.50	(20.00)	(4.50)	(0.37)
Sep-12	$ 175,007	8.10%	9/11/2012	15.00	(19.00)	(4.00)	(0.32)
Oct-12	$ 174,191	8.06%	10/11/2012	15.50	(20.00)	(4.50)	(0.36)
Nov-12	$ 174,702	8.08%	11/11/2012	15.00	(19.00)	(4.00)	(0.32)
Dec-12	$ 175,247	8.11%	12/11/2012	15.50	(20.00)	(4.50)	(0.36)
Total	$ 2,160,971	100.00%				(4.25)	

Accidental Death and Dismemberment

Table 34: Summary of Accidental Death and Dismemberment Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 2,498	8.69%	1/11/2012	15.50	(20.00)	(4.50)	(0.39)
Feb-12	$ 2,440	8.49%	2/11/2012	14.50	(18.00)	(3.50)	(0.30)
Mar-12	$ 2,324	8.08%	3/11/2012	15.50	(20.00)	(4.50)	(0.36)
Apr-12	$ 2,376	8.27%	4/11/2012	15.00	(19.00)	(4.00)	(0.33)
May-12	$ 2,401	8.35%	5/11/2012	15.50	(20.00)	(4.50)	(0.38)
Jun-12	$ 2,374	8.26%	6/11/2012	15.00	(19.00)	(4.00)	(0.33)
Jul-12	$ 2,506	8.72%	7/11/2012	15.50	(20.00)	(4.50)	(0.39)
Aug-12	$ 2,356	8.20%	8/11/2012	15.50	(20.00)	(4.50)	(0.37)
Sep-12	$ 2,554	8.89%	9/11/2012	15.00	(19.00)	(4.00)	(0.36)
Oct-12	$ 2,302	8.01%	10/11/2012	15.50	(20.00)	(4.50)	(0.36)
Nov-12	$ 2,305	8.02%	11/11/2012	15.00	(19.00)	(4.00)	(0.32)
Dec-12	$ 2,310	8.04%	12/11/2012	15.50	(20.00)	(4.50)	(0.36)
Total	$ 28,747	100.00%				(4.25)	

Employee Assistance Program

Table 35: Summary of Employee Assistance Program Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 1,100,911	9.41%	1/11/2012	15.50	(20.00)	(4.50)	0.00
Feb-12	$ 1,403,403	19.69%	2/11/2012	14.50	(18.00)	(3.50)	(0.69)
Mar-12	$ 1,100,911	9.41%	3/11/2012	15.50	(20.00)	(4.50)	0.00
Apr-12	$ 1,175,756	14.94%	4/11/2012	15.00	(19.00)	(4.00)	(0.60)
May-12	$ 1,100,911	9.41%	5/11/2012	15.50	(20.00)	(4.50)	0.00
Jun-12	$ 1,175,755	14.94%	6/11/2012	15.00	(19.00)	(4.00)	(0.60)
Jul-12	$ 1,100,911	9.41%	7/11/2012	15.50	(20.00)	(4.50)	0.00
Aug-12	$ 1,193,328	16.26%	8/11/2012	15.50	(20.00)	(4.50)	(0.73)
Sep-12	$ 1,059,321	4.99%	9/11/2012	15.00	(19.00)	(4.00)	(0.20)
Oct-12	$ 1,192,341	16.18%	10/11/2012	15.50	(20.00)	(4.50)	(0.73)
Nov-12	$ 1,071,781	6.04%	11/11/2012	15.00	(19.00)	(4.00)	(0.24)
Dec-12	$ 1,083,284	6.97%	12/11/2012	15.50	(20.00)	(4.50)	(0.31)
Total	$ 11,818,870	100.00%				(4.10)	

EHT

Table 36: Summary of EHT Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Dec-11	$ 1,256,358	8.09%	2/15/2012	7.00	39.05	46.05	3.73
Jan-12	$ 1,258,387	8.16%	3/15/2012	7.00	39.91	46.91	3.83
Feb-12	$ 1,257,282	8.12%	4/16/2012	7.00	43.94	50.94	4.14
Mar-12	$ 1,387,857	12.24%	4/16/2012	7.00	27.85	34.85	4.27
Apr-12	$ 1,251,921	7.95%	5/15/2012	7.00	32.48	39.48	3.14
May-12	$ 1,249,372	7.87%	6/15/2012	7.00	35.60	42.60	3.35
Jun-12	$ 1,248,325	7.86%	7/16/2012	7.00	37.95	44.95	3.53
Jul-12	$ 1,250,312	7.90%	8/15/2012	7.00	41.41	48.41	3.83
Aug-12	$ 1,246,973	7.80%	9/17/2012	7.00	30.03	37.03	2.89
Sep-12	$ 1,243,255	7.68%	10/15/2012	7.00	30.03	37.03	2.84
Oct-12	$ 1,245,346	7.75%	11/15/2012	7.00	32.87	39.87	3.09
Nov-12	$ 1,271,737	8.58%	12/17/2012	7.00	36.86	43.86	3.76
Total	$ 15,167,626	100.00%				42.39	

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WSIB 1

Table 37: Summary of WSIB Expenses1

Delivery Period 1	Amounts 1	Weighting Factor % 1	Payment Date 1	Service Lead Time 1	Payment Lead Time 1	Total Lead Time 1	Weighted Lead Time 1
Jan-12	$ 1,138,266	9.23%	2/28/2012	14.00	45.00	59.00	5.45
Feb-12	$ 1,139,473	9.31%	3/31/2012	14.00	49.00	63.00	5.87
Mar-12	$ 2,210,991	18.09%	4/30/2012	21.00	37.00	58.00	10.49
Apr-12	$ 1,132,178	8.82%	5/31/2012	14.00	40.00	54.00	4.76
May-12	$ 1,129,106	8.67%	6/30/2012	14.00	42.00	56.00	4.86
Jun-12	$ 1,129,136	8.62%	7/31/2012	14.00	45.00	59.00	5.09
Jul-12	$ 1,123,585	8.25%	8/31/2012	14.00	48.00	62.00	5.11
Aug-12	$ 1,165,165	11.06%	9/30/2012	21.00	36.00	57.00	6.30
Sep-12	$ 1,191,769	6.13%	10/31/2012	14.00	39.00	53.00	3.25
Oct-12	$ 1,172,821	5.16%	11/30/2012	14.00	41.00	55.00	2.84
Nov-12	$ 1,159,741	3.99%	12/31/2012	14.00	44.00	58.00	2.31
Dec-12	$ 1,140,831	2.68%	1/31/2013	14.00	47.00	61.00	1.63
Total	$ 12,498,062	100.00%			1		57.96	1

PILs Property Tax 1

Table 38: Summary of PILs Property Tax Expenses1

Delivery Period 1	Amounts 1	Weighting Factor % 1	Payment Date 1	Service Lead Time 1	Payment Lead Time 1	Total Lead Time 1	Weighted Lead Time 1
2012	$ 1,361,101	67.43%	4/16/2012	183.00	(258.00)	(75.00)	(50.57)
2012	$ 1,171,541	32.57%	10/16/2012	183.00	(75.00)	108.00	35.18
Total	$ 2,018,511	100.00%			1		(15.39)	1

Property Tax 1

Table 39: Summary of Property Tax Expenses1

Delivery Period 1	Amounts 1	Weighting Factor % 1	Payment Date 1	Service Lead Time 1	Payment Lead Time 1	Total Lead Time 1	Weighted Lead Time 1
2012	$ 1,106,974	16.53%	3/1/2012	183.00	(304.00)	(121.00)	(20.01)
2012	$ 1,106,869	16.53%	4/2/2012	183.00	(272.00)	(89.00)	(14.71)
2012	$ 1,106,792	16.53%	5/1/2012	183.00	(243.00)	(60.00)	(9.92)
2012	$ 1,082,192	16.80%	7/3/2012	183.00	(180.00)	3.00	0.50
2012	$ 1,082,063	16.80%	8/1/2012	183.00	(151.00)	32.00	5.38
2012	$ 1,081,952	16.80%	9/4/2012	183.00	(117.00)	66.00	11.09
Total	$ 6,440,842	100.00%			1		(27.67)	1

TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

In accordance with section 2.5.1.4 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) ("the Filing Requirements"), this schedule provides information about Toronto Hydro's proposed treatment of stranded assets related to smart meter deployment, which conforms with the guidance provided by the OEB in s. 2.5.1.4 of the Filing Requirements, and in section 3.7 and Appendix A-1 of the Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition (December 15, 2011). A completed copy of OEB Appendix 2-S is filed as Exhibit 2A, Tab 3, Schedule 2.

1. BACKGROUND

Toronto Hydro began its Smart Meter program in 2006 and substantially completed installation of all smart meters by the end of 2010. In 2012, Toronto Hydro applied for and was granted approval by the OEB for recovery of all remaining Smart Meter costs.[1]

2. NET BOOK VALUE ("NBV")

As of December 31, 2014, the net value of the Stranded Meters is estimated at $15.8 million. This value reflects the NBV of the assets ($16.3 million) less recovery amounts through scrap sales ($0.5 million). No carrying costs have been calculated on the Stranded Meter assets.

3. RECORDED AMOUNTS

For the conventional meters stranded through the Smart Meter program, Toronto Hydro continued to record these amounts in Account 1860 – Meters, until they were transferred

[1] EB-2013-0287, Decision and Order, January 16, 2014.

to Account 1555 – Sub-account Stranded Meter Costs in 2013. Depreciation was recorded on these meters since the beginning of the program.

4. RATE RIDER RECOVERY

For the purposes of 2015 Revenue Requirement (Exhibit 6, Tab 1, Schedule 1), the NBV of the stranded smart meter assets is not included in the utility's rate base. Toronto Hydro is seeking recovery of this amount through a separate rate rider. Toronto Hydro confirms that the associated cost recovery from the separate rate rider will be recorded in Account 1555 – Sub-account Stranded Meter Costs to reduce the balance of the sub-account.

For more information about the proposed rate rider, and an explanation of Toronto Hydro's approach to allocating the NBV of the stranded meters to the applicable customer rate classes, please refer to Exhibit 9, Tab 1, Schedule 1.

OEB Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2007	(2)	$ 67,097,235	$ 47,207,275		$ 19,889,960		$ 19,889,960
2008	(2)	$ 93,973,448	$ 68,107,443		$ 25,866,004		$ 25,866,004
2009	(2)	$ 103,875,474	$ 78,528,568		$ 25,346,906		$ 25,346,906
2010	(2)	$ 108,015,264	$ 84,895,573		$ 23,119,691		$ 23,119,691
2011	(2)	$ 109,231,835	$ 88,865,762		$ 20,366,073		$ 20,366,073
2012	(2)	$ 109,696,939	$ 92,049,602		$ 17,647,337		$ 17,647,337
2013	(2)	$ 121,654,750	$ 104,292,705		$ 17,362,045	$ 485,160	$ 16,876,884
2014	(1)(2)	$ 121,654,750	$ 105,377,923		$ 16,276,827	$ 485,160	$ 15,791,667

Notes:

(1) *For 2014 Depercation, it is provided based on forecast basis.*

(2) *For the period of 2007 to 2012, Stranded Meters were included in Account 1860. Stranded Meters were moved to Account 1555*

STREET LIGHTING ASSET TRANSFER

In two decisions relating to the utility's Street Lighting Transfer Application (EB-2009-0180 et al.), the OEB found that a portion of the street lighting assets in the City of Toronto can be considered distribution assets. In a Decision and Order dated February 11, 2010, the OEB made a principled determination about the categories of street lighting assets which could be considered to serve a distribution function and could be transferred to Toronto Hydro (the "Classification Decision"). In a subsequent Decision and Order, /C dated August 3, 2011, the OEB approved a value of $28.9 million of the assets that were /C found to be eligible to be transferred (the "Valuation Decision").

This schedule provides information to support Toronto Hydro's proposal to transfer former street lighting assets into the utility's rate base effective January 1, 2015, at the revised value of $39.8 million. Toronto Hydro submits that the revised transfer value of /C the street lighting assets has no effect on the utility's revenue requirement for all rate classes other than the Street Lighting and Unmetered Scattered Load ("USL") rate classes because the costs associated with the street lighting assets are directly allocated to the Streetlighting (95%) and the USL (5%) rate classes. For the Streetlighting class, these costs are offset by revenues from a Service Agreement with the City of Toronto. For the USL class, the effects are minimal. In addition, Toronto Hydro notes that for the purpose of this application, the effect of the proposed transfer has been fully integrated into the utility's operating and capital expenses, and cost allocation model; this schedule provides a summary of those effects.

The evidence is organized as follows:

1) Background
2) Post Filing Assessment
3) Asset Transfer Valuation

/C

4) Summary of Capital and OM&A Programs relating to Street Lighting
5) Revenue Requirement and Cost Allocation

1. BACKGROUND

On June 15, 2009, Toronto Hydro together with Toronto Hydro Energy Services Inc. ("TH Energy") and related legal entities (collectively, the "Applicants") applied jointly to the OEB for authorization to effectively transfer the streetlighting and expressway lighting assets held by TH Energy to Toronto Hydro.

In the Classification Decision, the OEB found that only certain assets are appropriately considered distribution assets (based on purpose, functional or intended use) and are eligible to be transferred to Toronto Hydro. Essentially, the OEB found that assets which are dedicated only to the streetlighting function per se (including luminaires, brackets and conductors on the bracket, and poles, related pole foundations and conductors along poles on local roads fed by underground circuits) do not serve a distribution function, and therefore were ineligible to be transferred. However, other assets (including poles, related pole foundations and conductors fed by overhead distribution lines or by underground circuits in mixed use urban areas) were found to have, or be capable of having, a distribution function. These assets were eligible to be transferred, as were underground conductors in residential areas, and all handwells that formed part of the street lighting system.

In the Classification Decision, the OEB rejected, for regulatory purposes, the discounted cash flow valuation that underpinned the original purchase of the streetlighting assets by TH Energy from the City of Toronto in 2006, and found that the depreciated historic cost ("DHC") method was more appropriate for rate setting purposes. However, as described in the Applicant's evidence and acknowledged by the OEB in the Valuation Decision,

/C

DHC information on the existing street lighting assets did not exist and was too costly to create.[1] The OEB therefore directed Toronto Hydro to bring forward further evidence enumerating the assets that were eligible for transfer according to the principles and categories set out in the Classification Decision, and provide a "physical valuation" of those assets.[2]

In addition, the OEB found that it was unable to determine on the evidence the proper classification of expressway lighting. The Applicants subsequently withdrew their request for the transfer of the expressway lighting assets in light of the principles set out in the Classification Decision.

In response to the Classification Decision, Toronto Hydro and TH Energy undertook two studies. The first was an exhaustive cataloguing of the streetlighting (and expressway lighting) assets, carried out by their staff and contract resources. This cataloguing (the "Inventory Study") recorded asset location, condition, and other parameters (including street type with respect to type of supply) necessary to properly classify the assets according to the terms of the Classification Decision. Toronto Hydro then used the data collected in the Inventory Study to determine the classification of all individual assets according to the criteria set out in the Classification Decision.

The second study was a valuation study conducted by ValuQuest Limited (the "ValuQuest Study"), which used the Depreciated Replacement Cost ("DRC") method to provide a "physical valuation" of the assets based on information from the Inventory Study. The ValuQuest Study found a DRC value of $83.7 million for the streetlighting assets, and $99.1 million for the total of streetlighting and expressway lighting assets.

[1] Valuation Decision, at page 14. The information does exist for assets installed after the purchase.
[2] Classification Decision, at page 20.

The Applicants filed evidence including the ValuQuest Study on January 31, 2011 in response to the OEB's direction in the Classification Decision. The Applicants proposed a 2010 year end valuation for the transferable assets of $28.9 million. This value was arrived at by scaling the DRC amounts in each asset class by the ratio of the 2010 year-end total net book value ("NBV") of $63.5 million. TH Energy's financial records the DRC total of $99.1 million. The basis of this valuation is explained in further detail below.

In the Valuation Decision, the OEB accepted the figure of $28.9 million as the 2010 year-end value of the transferable assets; however, the OEB noted that it did not specifically endorse the scaling of the DRC values so that their total matched the 2010 year-end NBV value. The OEB decided that rate base, revenue requirement, and the consequences of the transfer would be determined in Toronto Hydro's next cost of service application.[4]

On November 7, 2011, Toronto Hydro filed evidence in its EB-2011-0144 cost of service application relating to the incorporation of the street lighting assets into the utility's rate base.[5] In that application Toronto Hydro proposed a slightly lower transfer price for the assets of $28.5 million, reflecting the forecast evolution of the assets (principally additions and depreciation) over 2011. However, the OEB ultimately dismissed the EB-2011-0144 application so the matter remained unresolved.

The Applicants proceeded as authorized by the OEB to complete the transaction effective January 1, 2012. At that time an Agreement of Purchase and Sale (the "Sale Agreement") was executed between the parties which initially provided for a transfer price of $28.5 million, subject to a detailed analysis of the NBV of the transferred assets, which analysis would then underpin an adjustment to the transfer price, if necessary.

[4] Valuation Decision, at page 15.
[5] EB-2011-0144, Application and Evidence, Exhibit P3 (November 7, 2011).

By February of 2012, Toronto Hydro and TH Energy completed the detailed analysis of the NBV of the transferred assets, and found that the true NBV of the transferred assets was in fact $44.2 million. The methodology of the detailed analysis is explained in detail below. As a result, the value of the assets transferred was recorded at $44.2 million in Toronto Hydro's books. There was no change to the total valuation of the combined streetlighting and expressway lighting assets, so the amount that remained un-transferred in TH Energy was correspondingly lower.

2. POST FILING ASSESSMENT

Toronto Hydro filed a previous version of this evidence on July 31, 2014. After the filing, Toronto Hydro conducted an assessment of the assumptions and methodology underlying the transfer, and determined that the evidence must be revised. The revised description below does not affect the proposed value of the asset transfer into Toronto Hydro's rate base.

Toronto Hydro determined that an additional data point was used in the detailed analysis of the NBV of the transferred assets. This data point was the Optimal Investment Portfolio ("OIP") study, which was conducted in 2004 to assess the vintages of all major assets in Toronto Hydro's system, and to implement IFRS-consistent changes related to the manner in which Toronto Hydro records and accounts for its assets. For the purpose of the street lighting transfer, the OIP Study was used to determine the vintages of the poles, pole foundations and handwells and to allocate these assets between Toronto Hydro and TH Energy. The OIP Study provided better information about the vintages of the street lighting assets than the Inventory Study which was used for the purpose of the Valuation Decision in 2011. To illustrate, the original valuation assumed that approximately 49% of poles which did not have an associated year, were fully

depreciated. The OIP Study, however, revealed that only 5% of poles were without an associated year. Similarly, the original valuation assumed that nearly 58% of poles were older than 1970 and were thus fully depreciated, but the OIP Study shows that there were less than half of this number of poles, approximately 27% of poles, in that vintage band.[6]

In addition, Toronto Hydro assessed the classification of assets into the transferable and non-transferable categories and determined that: 1) approximately 5900 poles and related assets transferred from TH Energy were not *prima facie* eligible to be transferred because they were located on local streets fed by underground supply; and 2) some handwells, namely those associated with poles that were not transferable from TH Energy, were not transferred to Toronto Hydro, as required by the OEB decision. The revenue requirement impact of these findings is estimated to be $0.2 million. Because the impact of the reassessment is significantly lower than the utility's materiality threshold of $1 million, Toronto Hydro has not updated the value of the assets that it proposes to transfer. For greater certainty, the utility confirms the reassessment does not adversely affect any of the utility's rate classes. For the Street Lighting class, the incremental costs would be offset by revenues from a Service Agreement with the City of Toronto. For the USL class, the effects are minimal, as only 5% of the costs are allocated to this class of customers.

PricewaterhouseCoopers LLP ("PWC") was retained to review and provide an independent assessment of the methodology used by Toronto Hydro to arrive at the revised transfer price of the street lighting assets. PWC issued a report on July 28, 2014, which was filed alongside the original version of this evidence on July 31, 2014. PWC has considered the changes to original evidence, and has issued an addendum to its report with respect to the noted revisions. The addendum is filed at Exhibit 2A, Tab 5, Schedule 2, Appendix A.

/C

3. ASSET TRANSFER VALUE

For purposes of the present application, Toronto Hydro requests OEB approval to transfer the former streetlighting assets into this utility's rate base at a value of $39.8 million, which represents the opening net book value of the assets in 2015. This amount reflects the actual cost incurred by Toronto Hydro to acquire the 2012 transferred assets from TH Energy, the additional assets that were put in service in the intervening period (i.e., 2012 to 2014), as well as depreciation on assets. A stepwise explanation of the derivation of this amount is set out below.

3.1. The Need For A Detailed Analysis Of The Transferred Assets

Several factors contributed to the need to perform a detailed analysis of the NBV of the transferred assets. First, accounting and financial reporting standards require Toronto Hydro to maintain its financial records in a manner that permits accurate recording of assets owned by the respective businesses and depreciation on those assets. In order to calculate depreciation, the companies must have accurate records of the vintage of their assets and of the remaining useful lives of those assets in cases where acquired assets are not new.

Given the structure and function of the fixed asset sub-ledgers of both companies, it was not possible from an accounting perspective to simply transfer an unassociated amount between the companies without linking that amount as closely as possible to the underlying assets. Doing so would have interfered with the process of recording depreciation on the remaining assets, as Toronto Hydro would have no way of calculating depreciation for different asset types and vintages based on a single unassociated value being transferred to it. Therefore, it was necessary to perform the detailed analysis outlined below in order to identify the types, quantities, and vintages of the assets being transferred from TH Energy to Toronto Hydro.

Second, as explained in further detail below, the definitions of asset classes differed between TH Energy's s fixed asset sub-ledger and the ValuQuest Study. The ValuQuest Study distinguished poles, pole foundations and handwells, whereas TH Energy's fixed asset sub-ledger considered those to be one asset class. Conversely, TH Energy's fixed asset sub-ledger distinguished underground from overhead conductors, while the ValuQuest Study did not. Since some poles were associated with either, or both of, foundations and handwells, while others were not, this meant that a detailed analysis was required to effectively disaggregate the pole asset class in TH Energy's fixed asset sub-ledger in order to properly reflect the assets that were transferred. Allocations were also required for other asset classes.

Third, while Toronto Hydro accepted the principles of asset classification set forth by the OEB in the Classification Decision, the fact remained that those principles did not correspond to the financial records associated with the assets. For the assets that were found to be eligible for transfer, no existing asset classes exclusively and exhaustively represented the assets that could be transferred. As mentioned above, TH Energy's financial records considered handwells, poles and pole foundation to be one asset class, whereas the OEB's Valuation Decision found that while all handwells could be transferred, only certain poles and poles foundation were eligible. Therefore, a detailed analysis was required to properly separate the assets that were eligible for transfer, according to the criteria set out by the OEB in the Classification and Valuation Decisions.

3.2. Initial Conditions for the Detailed Analysis

In late 2011 and early 2012, following the preparation of the evidence in EB-2011-0144, Toronto Hydro undertook the detailed analysis of plant records for the purpose of supporting the asset transfer. At that time, Toronto Hydro had available to it the following information:

- The initial 2006 purchase price for sale of the City of Toronto-owned streetlighting and expressway lighting assets to TH Energy of $60 million. This amount was subsequently recognized on TH Energy's books as the sum of amounts in five asset classes (poles; wires and fixtures; overhead distribution lines and feeders; underground conduit; underground distribution lines and feeders; and streetlight fixtures and luminaires).
- The continuity (additions and depreciation) for the assets originally acquired from the City of Toronto (the "originally acquired assets"), as well as the assets added from the date of the purchase (2006) to the end of 2011. However, TH Energy's fixed asset sub-ledger did not contain information on the location of any assets, and did not contain information on the vintage of the originally acquired assets.
- The Inventory Study database, containing information on all of the streetlighting (and expressway lighting) assets, including condition, and situation (i.e., location on distinguished street types in accordance with the Classification Decision). /C
- The GEAR (Geo-Spatially Enabled Asset Registry) database, which was used by the Inventory Study, and which associated a Feature Identification ("FID") Number and vintage information with each pole asset where available. /C
- The ValuQuest Study and related database.
- The Optimal Investment Portfolio ("OIP") Study that was conducted in 2004 to assess the vintages of all major assets in Toronto Hydro's system. /C
- The Sale Agreement, dated December 29, 2011.

3.3. Detailed Analysis of the Originally Acquired Pole Assets

In order to bring TH Energy's fixed asset sub-ledger vintage information on the originally acquired assets to a level comparable to that of the subsequently installed assets, Toronto Hydro used information in the Inventory Study to determine which pole assets were transferrable and to stratify the originally acquired pole assets into vintage bands. For example, TH Energy had a count of poles by 5-year vintage bands starting in /C

1971 and ending in 2005. (Vintage bands were designated by their mid-points, so that the 1971 – 1975 vintage band was designated 1973.) The useful life of pole assets was set at 40 years, so assets installed prior to 1972 were considered to be fully depreciated.

Location information for pole foundations and handwells was matched to location information for poles to associate those assets with the corresponding poles. As previously noted, not all poles were associated with foundations or handwells, while some poles were associated with either or both of foundations and handwells.

In 2006, the originally acquired assets were classified into five assets classes and were assigned estimated remaining useful lives. For financial statement purposes, poles, pole foundations and handwells were merged into one asset class, "poles".

In 2011, subsequent to the release of the Inventory Study, in which poles were stratified into eleven 5-year vintage bands TH Energy assessed the need to prospectively change the remaining useful lives of poles to reflect the new information. Hence in 2011, the originally acquired pole asset in the financial records was stratified according to the vintage bands as per the Inventory Study. To do this, TH Energy applied standard costs of poles from the ValuQuest Study, which was approximately $2,340.00.

For the purpose of applying standard costs to historical quantities, TH Energy deflated the pole standard costs by the CPI (2010=100) to the mid-points of each vintage to arrive at sets of deflated standard costs for each vintage band. The resulting figures are essentially estimates of, or proxies for, the unit gross acquisition costs for each vintage band, which TH Energy was required to use in the absence of information on actual historical acquisition costs.

/C

The last element to disaggregate the asset with vintage bands was to scale the results so that the sum of the initial disaggregated NBV by vintage to agree with the amounts carried in TH Energy's books at the end of 2010. To do so, the accumulated depreciated was allocated proportionally to the vintage bands.[7] In order to arrive at the NBV at the end of 2011, it was then necessary to roll forward and deduct from the proxy acquisition costs the corresponding derived accumulated depreciation.

As previously noted, Toronto Hydro had conducted an analysis of the Inventory Study database to determine which poles and related assets were transferable, and to stratify the acquired assets by vintage bands. The OEB Study was then used to determine the vintage of the pole assets eligible for transfer and to allocate pole assets between Toronto Hydro and TH Energy. A recalculation – based on the OEB Study – of the stratification of the originally acquired pole assets was completed and deemed immaterially different (less than $150,000). Therefore, although the OEB Study provided better information about the age of the assets than was available from the Inventory Study, Toronto Hydro determined that it was not necessary to restate the stratification of the acquired assets.

If a foundation or handwell was associated with the pole, they were assumed to be of the same vintage. With this information, Toronto Hydro was able to compile a list by vintage of the poles, foundations and handwells to be transferred.[8] The counts by vintage and type of each asset to be transferred were then divided by the corresponding total asset counts in each vintage, and multiplied by the corresponding adjusted NBVs to obtain the transferred NBV by vintage for all asset types. Using illustrative data, the

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[7] Due to the prospective treatment of the change in remaining useful life of the pole assets, it was not necessary to stratify the accumulated depreciation as the acquired assets at the close of December 31, 2010 were pooled and shared the same remaining useful life.

[8] As mentioned above in section 2, Toronto Hydro conducted an assessment and determined that a number of handwells were not transferred from TH Energy, as required by the OEB decision. Toronto Hydro has not updated the value of the transferred assets because the revenue requirement impact is immaterial.

process of determining the transferable proportion of each vintage's NBV by class is depicted in Table 4 below.

Table 1: Illustrative Determination of Asset Vintage NBV Proportion Transferred

		Transferred Assets			All Assets			Proportion of Asset Vintage NBV Transferred		
Vintage	Asset FID	Pole Count	Found. Count	Handw. Count	Pole Count	Found. Count	Handw. Count	Poles	Found's	Handw's
2003	1234567	1		1						
	2658976	1	1	1						
	1359678	1		1						
	3698647	1								
SubTota		4	1	3	7	5	3	0.5714	0.2000	1.0000
1998	2345678	1								
	4563985	1	1	1						
	3547851	1		1						
	2569864	1		1						
	4263587	1	1	1						
	3652698	1								
SubTota		6	2	4	11	5	4	0.5455	0.4000	1.0000
1993	3456789	1	1							
	4785692	1	1	1						
	2135689	1								
	1245785	1	1							
	3625634	1		1						
SubTota		5	3	2	9	7	2	0.5556	0.4286	1.0000
…										
1973	9876543	1	1							
	5698632	1		1						
SubTota		2	1	1	5	2	1	0.4000	0.5000	1.0000

/C

This example illustrates that the poles, which are the 'anchor' assets, may be associated with foundations, handwells, both, or neither. The pole FID enables that association to be made. In the result, there is no constant relationship or proportionality within or across vintages between poles and the other assets in order to properly execute the transfer of

only the authorized assets, it was necessary to perform the detailed analysis to establish what other assets were associated with the transferable poles, and properly value the entire transferred asset base. While it is possible after the fact of the analysis to calculate the proportion of the transferred assets by class, it is not possible to proceed in the opposite direction to infer from a simple proportion what assets from what class and vintage are properly transferable. /C

With respect to the balance of the assets in TH Energy's "Poles" asset class installed after the 2006 asset acquisition from the City, the process of determining the transferable proportion of NBV by vintage was the same. However, because of the detailed records then being kept, it was not necessary to go through the stratification process, and the "vintages" in the post-acquisition period were individual years.

3.4. Determination of the Transferred Proportions of Other Assets

Several other asset classes were also transferable according to the Classification Decision. These included overhead and underground conductors, and conduits, but did not include conductors within untransferred streetlight poles and brackets. In addition, since Toronto Hydro withdrew its request to transfer any expressway lighting assets, all conductors and conduits associated with expressway lighting were excluded.

In the case of conductors, conduits, and vaults, there were again differences in classification as between the ValuQuest Study and TH Energy's fixed asset sub-ledger. The ValuQuest Study identified only conductors for the streetlighting assets, and conductors and conduit for expressway lighting assets. In comparison, TH Energy's fixed asset sub-ledger classified these assets as underground conduit, underground distribution lines and feeders, and overhead distribution lines and feeders.

With the information available to it, Toronto Hydro was not able to specifically separate in the fixed asset sub-ledge these secondary assets based on location in the fixed asset sub-ledger. Therefore, Toronto Hydro relied on information presented to the OEB at the time of the Valuation Decision, specifically as shown in 'Table 4: Derivation of NBV by Asset Group and Classification,' on page 19 of that evidence.[9] In that evidence, the Group NBV figures represented the Group RCV values found by ValuQuest, scaled down by approximately 36% such that their total would be equal to the then current total NBV on TH Energy's books. Toronto Hydro summed the "Group NBV" figures for streetlighting conductors, and expressway lighting conductors and conduits and considered those groups to be equivalent to the TH Energy asset classes of underground conduit, underground distribution lines and feeders, and overhead distribution lines and feeders.

The total Group NBV for those three asset classes was $4.7 million, of which streetlighting conductors represented $3.6 million, or 76.65%. Expressway conductors and conduit, which were categorically excluded, represented the balance. Toronto Hydro then multiplied the streetlighting conductor percentage by the percentage of transferable streetlighting conductors, 64.62%, which latter percentage was based on Toronto Hydro's physical classification of assets into the transferable and non-transferable categories. The product of the percentages (76.65% * 64.62%) is 49.53%. On this basis, Toronto Hydro determined that 49.53% of the total NBV of TH Energy's asset classes of underground conduit, underground distribution lines and feeders, and overhead distribution lines and feeders would be transferred to Toronto Hydro. For the assets transferred to Toronto Hydro on January 1, 2012, this amount was $7.281 million.

[9] EB-2009-0180 et. al, Application and Evidence (January 31, 2011) at page 19 of 21.

3.5. Determination of the Transferred Proportion of CWIP

At any point in time, there is a balance in the Construction Work in Progress ("CWIP") account. In the case of TH Energy's street lighting assets, a CWIP balance of $6.265 million at December 31, 2011 existed, but it was not possible to specifically trace that balance to transferable versus non-transferable assets. As an interim proxy, the transferred proportion of in-service streetlighting assets (68%) was applied to the then existing CWIP balance to divide that balance between Toronto Hydro and TH Energy. Toronto Hydro's assumed share of the CWIP balance was therefore $4.264 million.

For that purpose, a "top-sided" entry was made to show the transfer of the portion of CWIP to Toronto Hydro. In the intervening years from 2012 to the current time, as projects were closed to net fixed assets, they were recorded in the books of TH Energy or Toronto Hydro as appropriate and any necessary adjustments were made to the top-sided entry to reflect any variance from the assumed proportion of 68%, and to draw down that balance as projects were closed. The closure of projects to Toronto Hydro's net fixed assets is reflected in the asset continuity tables set out below.

3.6. Summary of the Assets Transferred as of January 1, 2012

The assets were transferred to Toronto Hydro in the same asset classes as they existed in TH Energy's books, and were distinguished by asset class and vintage. For example, poles, foundations, and handwells of the 1988 vintage were transferred to Toronto Hydro as an asset designated "1988 Poles".

The incurred cost to Toronto Hydro upon transfer was treated as Toronto Hydro's gross acquisition cost of the assets, and accumulated depreciation at the time of transfer was zero in all cases. However, to recognize the fact that a variable portion of the useful lives of the assets had elapsed for the majority of the assets, the remaining useful life was determinative of the rate of depreciation subsequently applied to the assets.

The useful lives of all assets except Conduits were set at 40 years, with Conduits set at 50 years. The remaining useful life figures for each vintage of asset were calculated based on the useful lives and the vintages of the assets. As an example, a 1973 pole with a useful life of 40 years had at the end of 2011 a remaining useful life of two years. Although the 1973 vintage notionally included the year 1971, all assets (in this case, only poles) installed in 1971 or earlier were deemed to be fully depreciated and none were transferred at any value to Toronto Hydro.

Because of the deferral of the ratemaking treatment of the transferred assets, the utility determined that it was necessary, as a temporary measure, to record the transferred assets along with other non-rate regulated portions of Toronto Hydro's business (i.e., Conservation and Demand Management and microgeneration). Had the transferred assets been recorded in Toronto Hydro's rate-regulated financial records along with other fixed assets that are part of the utility's rate base, it would have been impossible, practically, to separately track the assets' cost and evolution over the period until the rate making treatment was established. In this Application, Toronto Hydro proposes to transfer the street lighting assets to the utility's Property, Plant and Equipment ("PP&E") fixed asset register.

3.7. Summary of the Continuity of Assets: 2012 to 2014

Over the period from the beginning of 2012 to the (forecast) end of 2014, Toronto Hydro has added assets and has similarly recorded depreciation on all the assets that it acquired effective January 1, 2012. For the assets added since January 1, 2012, Toronto Hydro has the normal and exact information on gross book value, accumulated depreciation, and net book value.

3.8. Explanation of Variance in Asset Valuation

The overall variance between the proposed 2014 year end NBV of the former street lighting assets ($39.8 million) and the original amount approved by the OEB in the Valuation Decision ($28.9 million) is composed of normal asset evolution amounts occurring over the period January 1, 2011 to December 31, 2014, and the difference in valuation amounts for the transferred assets. /C

The Valuation Decision amount was based on 2010 year-end figures, while the January 1, 2012 transfer amount was based on 2011 year-end figures. Therefore, some part of the difference between the two is due to asset evolution over 2011. Since a Valuation Decision amount based on 2011 year-end figures does not exist, it is not possible to precisely quantify what the difference would be between that (hypothetical) amount and the transfer amount. Nevertheless, the bulk of the variance is due to factors other than asset evolution over 2011.

These factors stem from a data and information gap at the time of the Valuation Application and Decision. Toronto Hydro fully acknowledges the valuable information provided through the Inventory Study and the LVQuest Study. However, it is still the case that the proxy value of $28.9 million provided at the time was the result of two simplifying assumptions that had to be made due to the lack of more precise information. The first was that the values of the transferred assets were proportional to their counts, which is effectively the same as assuming that individual assets within a class are of equal value regardless of their vintage and composition. The detailed analysis revealed new information indicating that assumption was not valid in the case of the streetlighting asset transfer. /C /C /C

The OIP Study, which was used to allocate pole assets between Toronto Hydro and TH Energy, provided more accurate and complete information about the age of the assets /C

than was available in Toronto Hydro's geospatial asset registry ("GEAR") system at the time of the Inventory Study and the Valuation Application. /C

The second assumption was that the proportions of the total asset represented by the various asset classes in both the TH Energy fixed asset sub-ledger and the ValuQuest Study were (approximately) equivalent. However, because of the differences in asset classifications, it was not evident prior to the detailed analysis whether this was valid, and upon that analysis, some significant differences became apparent.

In combination, these factors led to variances caused both by differences in the percentages of assets transferred on a class-by-class basis, and by differences in the initial NBVs by class, as between TH Energy's fixed asset sub-ledger and the ValuQuest Study amounts, which after being prorated downward underpinned the Valuation Decision amount of $28.9 million. In addition, the ValuQuest Study did not take into account CWIP, a portion of which was transferred as explained above. /C

It was necessary for Toronto Hydro to perform the detailed analysis resulting in the revised valuation in order to properly implement the OEB's Valuation Decision, and provide an accurate basis for Toronto Hydro's and TH Energy's ongoing accounting and financial reporting obligations. No existing asset classes exclusively and exhaustively represented the assets eligible for transfer; instead, the transferable assets were co-mingled with non-transferable assets. Therefore, it was necessary for example to disaggregate the existing TH-Energy class of poles' into its components of poles, foundations, and handwells, in order to extract the transferrable assets together with their corresponding values. Furthermore, since depreciation accounting depends on asset vintages and depreciation rates, it was not possible to simply transfer an amount unassociated with asset types and vintages; else, by doing so the information required for ongoing accounting would have been lost.

The detailed analysis created new information pertaining specifically to the transferred assets that was not available at the time the Valuation Application was submitted or the Valuation Decision was rendered. The new information, resulting from the detailed analysis, provides a better proxy for the Depreciated Historic Cost of the transferred assets than does the Depreciated Replacement Cost approach, with its results scaled down to match the then existing asset value carried on THEnergy's books. This is because the detailed analysis specifically traces the vintage and remaining useful life of the transferred assets, rather than simply assuming that all assets of a particular type were of equal value, regardless of vintage. However, the detailed analysis does not increase the value of the overall asset; rather, it changes the proportion of the unchanged total amount that is transferred to Toronto Hydro.

/C

4. SUMMARY OF CAPITAL AND OM&A PROGRAMS

In its decision authorizing the transfer of certain former street lighting assets into Toronto Hydro's Distribution system, the OEB determined that these transferred assets are effectively distribution assets. As such, these former transferred street lighting assets will be managed through Toronto Hydro's distribution capital and maintenance programs, as described in Exhibit 2B, Section E6 and Exhibit 4A, Tab 2, respectively.

4.1. Capital Programs

Three of Toronto Hydro's capital programs are relevant to the replacement of the transferred assets when those assets reach the end of their lives. These programs are:

- Overhead Circuit Renewal (Exhibit 2B, E6.4), which funds the replacement of overhead assets such as poles and conductor on a planned basis;
- Underground Circuit Renewal (Exhibit 2B, E6.1), which funds the replacement of underground cables and conduit on a planned basis; and

- Reactive Capital (Exhibit 2B, E6.20), which funds the replacement of both overhead and underground assets on an unplanned and non-discretionary basis to restore functionality or mitigate an unsafe condition due to asset degradation, damage, or failure.

The sub-set of capital expenditures under each of these programs associated with the transferred assets are summarized in Table 2 below.

Table 2: Capital Expenditures Associated with Transferred Assets ($ millions)

Capital Program	2015	2016	2017	2018	2019
Overhead Circuit Renewal	1.9	2.1	2.5	2.3	1.5
Underground Circuit Renewal	0.4	0.4	0.3	0.4	0.5
Reactive Capital	0.4	0.4	0.4	0.4	0.4
TOTAL	**2.7**	**2.9**	**3.2**	**3.1**	**2.4**

4.2. Operations and Maintenance Programs

Four of Toronto Hydro's maintenance programs are applicable to the transferred assets. These programs are:

- Preventative & Predictive Maintenance (Exhibit 4A, Tab 2, Schedule 1), specifically the Line Patrols and Pole Inspections Segment, assesses the structural integrity of transferred street lighting poles and identifies deficiencies with overhead plant that may raise unacceptable safety and system reliability risks;
- Corrective Maintenance (Exhibit 4A, Tab 2, Schedule 2), undertakes the permanent repair and remediation of overhead and underground assets such as conductors and cables that have deteriorated or are defective as identified during

the normal course of operations (e.g., Line Patrols and Pole Inspections);

- Emergency Maintenance (Exhibit 4A, Tab 2, Schedule 3), specifically the Grid Response or Significant System Disturbance Segment, responds to emergency conditions such as downed conductors, immediate asset failures, and situations that pose significant safety risks; and
- Customer-Driven Work (Exhibit 4A, Tab 2, Schedule 7), specifically the Damage Prevention Segment, conducts locates upon request from property owners and contractors.

The sub-set of operational expenditures under each of these programs associated with the transferred assets are summarized in Table 3 below. /C

Table 3: Operational Expenditures Associated with Transferred Assets ($ millions) /C

Operational Program	2015
Preventative & Predictive Maintenance	0.1
Corrective Maintenance	1.6
Emergency Maintenance	0.2
Customer-Driven Work	1.7
TOTAL	**3.7**

5. REVENUE REQUIREMENT AND COST ALLOCATION

The revenue requirement consequences of the utility's proposal to incorporate the street lighting assets into the utility's rate base effective January 1, 2015 are summarized in Table 4 below. /C

Table 4: Revenue Requirement from Streetlighting Assets ($ millions)

Revenue Requirement Component	2015 Test Year
NBV of Assets – opening	39.8
NBV of Assets – closing	39.1
Average NBV	39.5
Working Capital Allowance	0.2
Streetlighting Ratebase	**39.7**
OM&A	3.7
Cost of Capital	2.5
Depreciation	1.6
PILS	0.3
Service Revenue Requirement	**8.1**
Revenue Offset – Contract Revenue	8.1
Base Revenue Requirement	**0.0**

5.1. Revenue Offset

Under existing agreements between TH Energy and the City of Toronto, TH Energy receives service fees for the maintenance and operation of the street lighting assets. Given the transfer of a portion of these assets into Toronto Hydro's rate base as distribution assets, Toronto Hydro proposes to allocate a portion of the revenue that it expects to receive to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

5.2. Cost Allocation

For the purposes of Cost Allocation, Toronto Hydro has allocated all of the costs associated with the transfer of the streetlighting assets to a combination of the Street lighting rate class and the Unmetered Scattered Load ("USL") rate class. No other rate

class is affected by the transfer. This is the same treatment proposed by Toronto Hydro in the Streetlighting Transfer Application.

Between the two classes – Streetlighting and USL – the additional costs related to the transfer were allocated 95% / 5% to these classes, respectively. USL attracts some of the costs as the assets being transferred have in some cases served USL loads. Toronto Hydro's best estimate, based on informed judgment, is that 5% is a reasonable allocation to this class.

The revenue offset of $8.1 million is however allocated 100% to the Streetlighting class. /C Toronto Hydro submits that this is an appropriate allocation because the revenue offset is based on the contract with the City of Toronto to service the street lighting assets.

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Toronto Hydro Street Lighting Assets

Assessment of the valuation methodology used by Toronto Hydro in EB-2014-0116

July 28, 2014



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Assignment, Scope and Background

Assignment

1. Toronto Hydro Electric Systems Inc. ("THESL"), Toronto Hydro Energy Services Inc. ("THESI"), and 1798594 Ontario Inc. ("NewCo"), are all wholly owned subsidiaries of Toronto Hydro Corporation ("Toronto Hydro" or "the Company"). The City of Toronto ("the City") is Toronto Hydro's sole shareholder.

2. THESL owns and operates an electricity distribution system which delivers electricity to approximately 730,000 customers located in the City of Toronto. It is the largest municipal electricity distribution company in Canada and distributes approximately 19% of the electricity consumed in Ontario.

3. THESL is regulated by the Ontario Energy Board ("OEB") which regulates the province's electricity and natural gas sectors in the public interest.

4. THESL has filed a proposed rate application (EB-2014-0116) with the OEB which includes a revised purchase price for certain street lighting assets which THESL purchased from its unregulated affiliate, THESI on January 1, 2012 (the "Current Proposal"). Please refer to the background section of this report for further information on the original application and sequence of transactions.

5. Tory's LLP has engaged us, PricewaterhouseCoopers LLP ("PwC", "us" or "we"), to prepare a report to be used as evidence in the Current Proposal.

6. This report was prepared for the purpose of the rate application (EB-2014-0116) relating to the proposed 2015 distribution rates. Specifically, we have been asked to provide our opinion on the following two questions:

    1) Is the revised detailed analysis prepared by Toronto Hydro of the value of former street lighting assets to be included in rate base determined using a reasonable method of calculating the depreciated historical cost of such assets?

2) Does the revised method used to value the former street lighting assets provide a better proxy for the depreciated historic cost of the assets than was provided to the OEB at the time of the August 2011 decision?

7. This report has been prepared by Ken Goodwin to best of his knowledge, acting independently and objectively. A copy of Mr. Goodwin's credentials have been attached as Appendix A.

Scope

8. In preparing our report, we have reviewed relevant documents and relied upon their accuracy and completeness, including the following:

"Toronto Hydro Corporation – Street & Expressway Lighting Network – Estimate of Fair Market Value" prepared by Deloitte as at October 31, 2005;

OEB decision and orders dated February 11, 2010 (the "February Decision") and August 3, 2011 EB 2009-0180, EB 2009-0181, EB 2009-0182 and EB 2009-0183; (the "August Decision")

Additional evidence filed in EB 2009-0180, EB 2009-0181, EB 2009-0182 and EB 2009-0183 on January 31, 2011;

"Allocation of Street Lighting Assets for the Purpose of the Asset Transfer in 2011/2012" Provided by: Toronto Hydro to PWC on July 12, 2014;

Amended and Restated Asset Purchase Agreement between 1798594 Ontario Inc. and Toronto Hydro Energy Services Inc. (executed December 29, 2011);

Revised Purchase and Sale Agreement (with updated price) between THESI and THESL (dated October 10, 2012);

ValuQuest Street Lighting and Expressway Lighting Assets Valuation Report for Toronto Hydro-Electric System Ltd. and 1798594 Ontario Inc. as at November 1, 2010 (Issued December 1, 2010) (the ValuQuest Study);

Kinectrics Inc. Report No: K-418021-RA-0001-R002 – Toronto Hydro Electric System Useful Life of Assets (dated August 28, 2009); and

Interviews and discussions with Toronto Hydro management.

Background

9. We understand that all of the City's street lighting assets were sold to THESL's unregulated affiliate THESI, at a purchase price of $60 million in December 2006 (the "Acquired Assets"). We further understand that this purchase price was arrived at using a discounted cash flow analysis.

10. In 2009, three Toronto Hydro subsidiaries, THESL, THESI and NewCo filed applications with the OEB seeking approval for the Acquired Assets to be included in THESL's distribution system as defined by the Ontario Energy Board Act, 1998, S.O. 1998, c.15 (schedule B) (the "Act"). The applications collectively sought a declaration by the Board that streetlighting assets owned by THESI in the City of Toronto (the "SEL System Assets"), are deemed to be a distribution system and, ultimately, to make those assets part of a new amalgamated distribution company consisting of THESL and NewCo.

11. The OEB issued a decision in February 2010[1] (the "February Decision") which stated that THESL may only transfer street light assets which can be specifically identified as assets which are used to convey electricity at voltages of 50 kilovolts or less and meeting the specific criteria as set out in the February Decision (the "Distribution Assets"). The OEB also stated that that a valuation must be provided supporting the value of the Distribution Assets.

12. In January 2011, THESL submitted evidence[2] to respond to the OEB's request (the "Additional Evidence" or the "Original Application"). The evidence included an enumeration of all street lighting assets on public property including the characteristics required to classifiy the assets as Distribution Assets. This information was based on a detailed inventory count performed by a third party (the "Inventory Count"). The evidence also included a third party valuation of all street lighting assets purchased from the City using a depreciated replacement cost ("DRC") methdology (the "ValuQuest Study")[3].

13. In the period between the purchase of the Acquired Assets from the city in December 2006 and the submission of the Additional Evidence, THESI made additions to the street lighting assets (the "Additions") to meet the needs of the City. In addition, depreciation was recorded for both the Acquired Assets and the Additions (the

[1] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (February 11, 2010) Page 6 - 12
[2] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011)
[3] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 23 - 109

"Total Assets"). At the time of the submision of the Additional Evidence the net book value (the "NBV") of all street lighting assets in the books of THESI was $63.5 million[4].

14. The Inventory Count and the ValuQuest Study[3] were used by Toronto Hydro to determine what portion of the Total Assets' NBV of $63.5 million qualified as Distribution Assets. This resulted in $29.4 million of the Total Assets' NBV qualifying as Distribution Aseets which was included in the Additional Evidence. However, the OEB and the Intervenors challenged the amount of handwells and pole foundations to be included into the rate base, and Toronto Hydro agreed to reduce the transfer of Pole Foundations by 10%[5], hence the final approval from the OEB was $28.938 million of the Total Assets qualified as Distribution assets in the August Decision. This amount was then used as a basis of the transfer price on January 1, 2012 (the "Date of Transfer").

15. We understand that in 2012 THESL determined that the $28.938 million used as the transfer price for the Distribution Assets between THESI and THESL did not accurately reflect the actual NBV of the Distribution Assets and that further analysis was required.The Purchase and Sale Agreement between THESI and NewCo dated December 29, 2011 provided a provision to adjust the purchase price within 180 days of closing date. On October 10, 2012, the purchase price was adjusted to $42.473 million. As such, THESL submitted the Current Proposal detailing a revised methology to calcuate the transfer price of the Distribution Assets.

[4] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 20
[5] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (August 3, 2011) Page 11 - 15

Summary of Findings and Conclusions

16. Based on our knowledge, experience and analysis, and subject to the Scope of Review and Restrictions and Qualifications noted herein, our findings and conclusions in respect of the two questions posed in this report are outlined below:

Question 1:

17. Based on our understanding, depreciated historic cost ("DHC") should reflect the actual cost incurred in the acquisition and construction of the subject assets adjusted for depreciation. The Distribution Assets should be reported at DHC to ensure that THESL is appropriately compensated at the regulated rate of return for the investment made on its assets.

18. The following three-step approach was used to determine the value of the Distribution Assets as follows:

    Classification of the Total Assets into asset classes;

    Valuation of each individual asset class; and

    Allocation of the Total Assets into Distribution and Non-Distribution Assets.

19. The detailed classification of the Distribution assets was performed based on two asset groupings, further broken down into 6 asset classes. The assets were then categorized by age based on the Inventory Study.

20. The valuation methodology utilized in the Current Proposal relies on actual costs, where available, and depreciation details to estimate the DHC for the Additions. With respect to the Acquired Assets additional analysis was performed by allocating said assets into groups based on age, determining the standard replacement cost of the individual assets and deflating those costs based on the Consumer Price Index and depreciating the asset over its service life.

21. Based on our knowledge, experience and review of the detailed analysis, it is our view that Toronto Hydro utilized a reasonable method of estimating DHC in order to determine the value of the former street lighting assets and to identify the value of the assets eligible to be transferred from THESI to THESL and be included into the rate base.

Question 2:

22. We note from our review and analysis that there are differences in the approach used to value the Distribution Assets in the Original Application and the Current Proposal, however the underlying data is consistent as it relies upon the Inventory Study, the ValuQuest Study and the NBV in Toronto Hydro's books and records.

23. Based on our review, we noted that the Current Proposal incorporates a more detailed approach to estimating DHC.

24. Specifically the Current Proposal reflects actual costs borne by Toronto Hydro for the Additions and detailed analysis was undertaken to estimate the historic cost of the Acquired Assets as described above. Further, the Current Proposal considers the installation date of the Distribution Assets which was not contemplated in the Original Application.

25. Finally, the Original Application did not take construction work-in-progress (CWIP) into consideration, whereas the Current Proposal does.

26. Based on our knowledge, experience and review of Toronto Hydro's analysis, it is our view that revised methodology used to value the former street lighting assets provides a better proxy for the DHC of the assets than was provided to the OEB at the time of the August 2011 Decision.

Analysis and Findings

Question 1

"Is the revised detailed analysis prepared by Toronto Hydro of the value of former street lighting assets to be included in rate base determined using a reasonable method of calculating the depreciated historical cost of such assets?"

Depreciated Historic Cost

What is Depreciated Historic Cost?

27. In the context of the street lighting assets, DHC reflects the actual cost incurred in the acquisition and construction of the Total Assets less depreciation.

28. The ValuQuest Study submitted in the January 31, 2011 filing[3] utilized DRC to value the Total Assets. Per the ValuQuest Study, DRC considers the cost to reproduce or replace and install the assets being appraised. Per the Additional Evidence[6], DRC was used due to the fact that "a conventional historic- cost valuation of the assets in question was not and could not be made available" and "DRC yields a result which most closely approaches the Board's requirement for 'an asset valuation to be prepared for the physical assets' "

29. As stated in the Additional Evidence[7], "A significant conceptual difference between these two approaches is that the DRC method adopts (as it must) the current replacement cost as the basis for the calculation, whereas historical cost accounting naturally reflects a lower nominal historical acquisition cost since that is built up over time as equipment is acquired, and partially reflects lower nominal acquisition costs prevailing several decades ago without the effect of intervening inflation".

[6] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 16 - 17
[7] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 17

Why is DHC important?

30. As stated in the February Decision[8] and the August Decision[9], the amount to be included in rate base should be based on physical valuation of the assets and not a revenue-based fair market value approach. Further, in the Additional Evidence[10] THESL indicated that they seek to transfer an amount no greater than the actual net book value of the eligible distribution assets.

31. Regulated assets need to be reported at DHC to reflect the real cost borne by the organization in order to ensure that the organization is appropriately compensated at the regulated rate of return for the investment made on its assets.

Toronto Hydro's Revised Detailed Analysis

Overview

32. Toronto Hydro used the following three step approach to determine the value of the Distribution Assets:

    1) Classification of the Total Assets into asset classes;
    2) Valuation of each individual asset class; and
    3) Allocation of the Total Assets into Distribution and Non-Distribution Assets.

Classification of the Total Assets into asset classes

33. Using the Inventory Study, the Company organized the Total Assets into asset classes (and installation year, if applicable and where available) in order to consider the purpose, functionality or intended use of the assets.

34. To this end, Total Assets were organized into the two main asset classes qualifying as Distribution Assets per the February Decision[11] (i.e. Poles and Conductors). The assets within these two categories were then further disaggregated in order to allow Toronto Hydro to determine if a particular asset met the Distribution Asset criteria per the February Decision[11]. This process resulted in the identification of the following six asset classes:

[8] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (February 11, 2010) Pages 16, 19
[9] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (August 3, 2011) Page 12 - 13
[10] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 15
[11] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (February 11, 2010) Pages 7 - 12

1) "Poles", including:

   Poles;

   Handwells; and

   Pole Foundations.

2) "Conductors", including:

   Conduits;

   Overhead Lines and Feeders; and

   Underground Lines and Feeders.

35. There are two additional asset categories described in the February Decision, Streetlight Brackets and Conductors on Streetlight Brackets (including luminaires) and Expressway Lighting[11], which do not qualify as Distribution Assets and therefore were not considered by Toronto Hydro in the Current Proposal.

Valuation of each individual asset class

36. Asset valuation, in this context, refers to the process of estimating the DHC for each of the six asset classes noted above. We understand the asset valuation process was performed for both the Acquired Assets and the Additions.

Acquired assets

37. We understand based on discussions with Toronto Hydro management, and as stated in the August Decision, that the detailed historic cost information (by asset class and the year installed) of the Acquired Assets is not available. As such, an alternative approach was required to determine an estimate of the DHC of the Acquired Assets for the purpose of the Current Proposal.

38. We understand Toronto Hydro has utilized different approaches to estimate the DHC depending on the asset class and information available. A summary of the approaches by asset class follows below:

Poles, Handwells and Pole Foundations

39. In 2006, all poles, handwells, and pole foundations acquired as part of the transaction with the City were recorded as a single asset class named "poles, towers, fixtures" to which $24.5 million of the $60 million acquisition price was attributed.

40. The Inventory Study provided Toronto Hydro with physical information and installation year for each of the Acquired Assets in this class. The DHC of the Acquired Assets in this class was determined using the multi-step process described below.

Allocate Assets by Vintage Band

41. The first step was to allocate the Acquired Assets by age. Specifically, Toronto Hydro allocated the Acquired Assets into five year age bands ("Vintage Bands") ranging from 1971 to 2005, using the information in the Inventory Study. Each Vintage Band was designated and identified by the mid-point of the band (e.g. Assets installed between 1976 and 1980 would be designated as "1978 assets" for the purpose of this exercise).

Determine 2010 standard cost

42. The next step was to apply a standard cost per asset to the historic asset quantity in each Vintage Band. The standard cost was determined using the 2010 standard costs provided in the ValuQuest Study[3].

Calculate standard cost by installation year

43. In order to apply standard costs to historical quantities, Toronto Hydro deflated the current 2010 standard cost noted above, using 2010 Consumer Price Index rate, to the mid-points of each Vintage Band to arrive at sets of deflated standard costs for each Vintage Band.

Depreciate deflated standard cost

44. The final step in the process was to determine the accumulated depreciation for each Vintage Band based on the age and remaining useful life of each respective asset. The useful life of the assets was based on a 2009 useful life study conducted by Kinectrics Inc. entitled "Toronto Hydro Electric System Useful Life of Assets"[12] (the "Kinectrics Study"). The age of the assets (in years) was estimated using the mid-point of each Vintage Band.

[12] Report: K-418021-RA-0001-R0002, Toronto Hydro Electric System Useful Life of Assets (August 28, 2009) Page 80

Conductors

45. Unlike Poles, which can be separately identified, underground/overhead lines and feeders as well as conduit (together the "conductors") are difficult to count and validate as they are not separately identifiable. As such, in order to determine the quantity and value for the conductors which qualify as Distribution Assets, Toronto Hydro started with the total NBV of all conductors as at the Date of Transfer and eliminated the two asset categories considered ineligible for inclusion as Distribution Assets, being (i) Expressway Lighting conductors and (ii) conductors which are used exclusively for street-lighting.

46. The value of the Expressway Lighting conductors was excluded using information in Table 4[13] of Appendix B of the Additional Evidence "Derivation of NBV by Asset Group and Classification".

47. Additionally, Toronto Hydro used the proportion of assets deemed as distribution from the Table 4[13] of Appendix B of the Additional Evidence "Derivation of NBV by Asset Group and Classification". The proportion which qualifies as Distribution Assets was based on the detailed count from the Inventory Study.

Additions

48. Since the acquisition of the initial portfolio of street lighting assets from the City in 2006, Toronto Hydro has constructed and acquired additional street lighting assets.

49. We understand that as new street lighting assets were constructed and installed by THESI in the period between 2006 and 2011, the Company maintained detailed records of actual costs by installation year. We further understand that the Additions were depreciated based on the Kinectrics Study[12] as follows:

    Cabling is depreciated over a life span of 40 years; and

    Poles, Civil (Handwells, Tap Box), Conductors are depreciated over a life span of 50 years.

50. Based on the information above the Company has been able to calculate the DHC of the Additions based on the actual cost and depreciation details in its books and records.

[13] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 19

Allocation of the Total Assets into Distribution Assets and non-Distribution Assets

51. The allocation process refers to the bifurcation of the DHC for each of the six asset classes between Distribution Assets and non-Distribution Assets.

Poles, Handwells and Pole Foundations

52. Allocation rates for poles, handwells, and pole foundations were determined based on the ratio of estimated number of assets eligible for transfer to THESL and total poles, handwells and pole foundations. Eligibility of poles was determined based on the Inventory Study and the criteria set by the OEB in the February Decision.

53. These allocation rates were then multiplied by the DHC of each asset in each Vintage Band to determine the DHC value to transfer to THESL.

    The following is an illustrative example of the allocation process:

Vintage Band	DHC ($ millions) A	Total Number of Assets B	Distribution Assets C	Percentage to be Transferred D = C/B	Value to be Transferred ($ millions) E = A x D
Band 1	8	2,000	1,800	90%	7.2
Band 2	12	2,400	2,200	92%	11.0
Band 3	13	4,000	3,500	75%	9.8
Total	33	8,400	7,500	89.3%	28.0

(The numbers in the table are for illustrative purposes only and do not reflect the actual amounts filed by THESL)

Conductors

54. For conductors, an allocation rate was estimated based on the Inventory Study. Specifically, Toronto Hydro, using the Inventory Count details determined that a certain percentage of conductors were Expressway Lighting and therefore excluded from the Distribution Asset pool. Of the remaining conductor assets, a further deduction was made to remove the percentage of conductors used exclusively for street lighting. The remaining percentage was determined to represent conductors which qualify as Distribution Assets.

55. The conductor allocation percentage was then applied to the total conductor DHC to arrive at the conductor DHC eligible for distribution which was included in the Current Proposal.

56. We understand the conductor allocation percentages remain unchanged from the Additional Evidence which was accepted by the OEB in the August decision.

Construction work-in-progress

57. In addition to the acquired and constructed assets discussed above, Toronto Hydro also included CWIP balances that qualify as Distribution Assets in the Current Proposal. To the extent possible, Toronto Hydro used the construction and capitalization records, which include actual costs, to identify which CWIP assets qualify as Distribution Assets based on the criteria set out in the February Decision. For the remaining CWIP, Toronto Hydro has applied an assumed percentage of Total Assets which qualify as Distribution Assets based on the processes described above.

Conclusion

58. Based on our knowledge, experience and review of the detailed analysis noted above, and subject to the Scope of Review and Restrictions and Qualifications noted herein, it is our view that Toronto Hydro utilized a reasonable method of calculating DHC in order to determine the value of the former street lighting assets to identify the value of the assets eligible to transfer from THESI to THESL and therefore be included into the rate base.

Question 2

"Does the revised method used to value the former street lighting assets provide a better proxy for the depreciated historic cost of the assets than was provided to the OEB at the time of the August 2011 decision?"

59. The methodology used to determine the transfer price of the street lighting assets in the Current Proposal has been summarized in Question 1. The response to this question will focus on the methodology used in the Original Application and the key differences between the two methodologies.

Methodology used in the Original Application

60. We understand the estimate of the transfer price of the Distribution Assets which was included in the Original Application was based on the following three pieces of information:

    1) The ValuQuest Study[3];
    2) The Inventory Study; and
    3) The total net book value of all street lighting assets[13].

61. There were no changes in the ValuQuest Study and the Inventory Study between the two applications. The NBV was adjusted to the date of the Current Proposal based on additions and depreciation during the period between the applications.

62. The classification of the assets into asset classes in the Original Application was based primarily on the ValuQuest Study. Specifically, Toronto Hydro used the DRC of each asset class per the ValuQuest study[3] and divided it by the total DRC of all street lighting assets to determine the DRC percentage by asset class[13]. The DRC percentage by asset class was then applied to the NBV of the Total Assets to arrive at the estimated transfer value by asset class.

63. The estimated DHC by asset class was then allocated between Distribution Assets and non-Distribution Assets. We understand the allocation methodology for conductors was consistent between the Original Application and the Current Proposal. With respect to the Poles, the Original Application determined the Distribution

allocation percentage using the total number of poles which met the distribution criteria in the February Decision[11] using the Inventory Study, divided by the total number of poles. We further understand that the installation date of said poles was not considered in arriving at the allocation percentage.

Key differences between the Original Application and the Current Proposal

64. Both applications were derived from the same sources of information being the ValuQuest Study, the Inventory Count and the NBV of the street lighting assets in THESI's books and records.

65. A significant conceptual difference between the Original Application and the Current Proposal is the reliance on DRC versus DHC as the basis for the valuation of the Distribution Assets. Both methods consider and incorporate the concept of depreciation. However, as previously stated, the starting point for DHC is the cost of the asset at the time of acquisition whereas the starting point for the DRC is the current cost of replacement.

66. The table below summarises the differences in approach used in the Original Application as compared to the Current Proposal.

	Original Application	Current Proposal
Classification	Considers the asset classes as required in order to determine the purpose, functionality or intended use of the assets and meet the OEB criteria.	Considers the asset classes as required in order to determine the purpose, functionality or intended use of the assets and meet the OEB criteria; and Considers classification into Vintage Band or, where available, installation year.
Valuation	Uses DRC per the ValuQuest Study as the basis for the valuation; and DRC is decreased to NBV based on a	Uses actual NBV by asset class and installation date where available (the Additions);

	Original Application	Current Proposal
	percentage of the DRC by asset class applied to the NBV of the Total Assets.	Estimates the historic cost for Acquired poles using the standard cost per the ValuQuest Study adjusted for inflation; Calculates the depreciation for the Acquired poles based on the Kinectrics Study and Vintage Band; Uses the purchase price for the Acquired conductors at the Date of Transfer adjusted for depreciation; and Includes a value for CWIP based on the actual books and records.
Allocation	Uses the Inventory Count to identify the percentage of poles which meet Distribution criteria; and Uses the information in the ValuQuest Study to exclude the Expressway Lighting conductors and conductors used only for street lighting.	Uses the Inventory Count by Vintage Band or installation year to identify the poles which meet the Distribution criteria where available; Uses the information in the ValuQuest study to exclude the Expressway Lighting conductors and conductors used only for Street Lighting; and Allocates CWIP to Distribution Assets based on completed construction and cost information, where available, uses an allocation percentage for the remainder.

67. Using the date of installation either by year or Vintage Band allows Toronto Hydro to perform the second two steps in their process at a more detailed level.

68. There is different information available for the Additions and the Acquired Assets therefore separating these two groups allows THESL to refine the calculations to utilize the best information available for each category of asset.

69. The Original Application estimated a deflated value of the Total Assets through the process of allocation the DRC to the NBV at the Date of Transfer on a total basis. The cost of the Acquired assets used in the Current Proposal is a better proxy of the historic cost due to the fact that the replacement cost is deflated to the mid-point of the Vintage band. Further this process is performed only for the Acquired Assets as the actual cost of the Additions is known.

70. Cost and depreciation details are readily available for the Additions. The Current Proposal incorporates actual historical costs and depreciation which is the most reflective method of calculating DHC. The Original Application applied an estimate using the process described above.

71. The inclusion of the CWIP in the Current Proposal also provides a holistic view of all distribution assets that may be deemed transferrable to THESL.

72. In the Current Proposal, Toronto Hydro performed the Allocation to Distribution Assets of the pole assets (i.e. poles, handwells, foundations) by Vintage Band and installation year rather than the high level allocation rate used in the Original Application. As such the allocation in the Current Proposal provides a better proxy of assets eligible for transfer to THESL.

Conclusion

73. Based on our knowledge, experience and review of the detailed analysis noted above, and subject to the Scope of Review and Restrictions and Qualifications noted herein, it is our view that revised methodology used to value the former street lighting assets provides a better proxy for the DHC of the assets than was provided to the OEB at the time of the August Decision.

Respectfully submitted,

(Signed) "PricewaterhouseCoopers LLP"

Ken Goodwin
Partner

Appendix A



Ken Goodwin, MBA, CA•CBV
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Ken Goodwin is a Partner in PricewaterhouseCoopers LLP's Valuation Forensics & Disputes practice and the lead for PwC Canada's Power & Utilities Deal team. He has specialized in valuations on a full-time basis since 1998 and has performed valuations in a variety of contexts including analysing and commenting on client prepared valuation models, providing fairness opinions to Boards of Directors, assisting in pricing analyses related to potential transactions, preparing and reviewing purchase price allocations and other fair value related exercises, income tax reorganizations and strategic planning.

Ken has prepared and reviewed dozens of valuations of power generation, electric distribution and transmission companies in a variety of contexts including merger and acquisition activity, financial reporting, tax reorganizations and strategic planning. These assignments focused on obtaining an understanding the support for key financial inputs, testing the mathematical accuracy and integrity of the models, and preparing comments and research in support of discount rates used for the transactions.

Ken is a Chartered Business Valuator (CBV), Chartered Accountant (CA) and has a Masters of Business Administration (MBA) from the University of Toronto.

Appendix B

Restrictions and Qualifications

We understand that this Report and related appendices are intended to be tendered into evidence by THESL in EB-2014-0116 and solely for the purposes described in the Assignment section. The release of this Report, in whole or in part, to any party outside of this proceeding will require our prior written consent. We do not assume any responsibility or liability for losses incurred by any party as a result of the circulation, publication, reproduction or use of this Report contrary to the provisions of this paragraph.

We caution that the calculations, estimates and statements made in this Report are based solely on the information reviewed and communicated to us to date. We reserve the right to review all calculations, estimates and statements made or referred to in this Report and, if we consider it necessary, to revise our Report in light of any relevant information that becomes known to us after the date of this Report.

Our Report and related analysis must be considered as a whole. Selecting only portions of the analysis or the factors considered by us, without considering all factors and analysis together, could create a misleading view of our findings. The preparation of our analysis is a complex process and is not necessarily susceptible to partial analysis or summary description. Any attempt to do so could lead to undue emphasis on any particular factor or analysis.

Our review does not constitute an audit as defined by Canadian generally accepted auditing standards. The primary sources of information reviewed and relied upon are referred to in the Scope of Review section of this report. We have indicated the sources of factual information relied upon. Unless otherwise noted, we have not sought external verification of the information provided by Toronto Hydro or other sources as listed.

Our analysis is financial in nature. We make no representation regarding questions of legal interpretation.

The individuals that prepared this report did so to the best of their knowledge, acting independently and objectively in accordance with Rule 13A of the OEB's Rules of Practice and Procedure.

PwC's compensation is not contingent on an action or event resulting from the use of this Report.

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Toronto Hydro Street Lighting Assets

September 23, 2014

Assessment of the valuation methodology used by Toronto Hydro in EB-2014-0116 - Addendum



Introduction

A-1 PricewaterhouseCoopers LLP ("we", "us" or "PwC") was previously engaged by Tory's LLP on behalf of Toronto Hydro-Electric Systems Limited (Toronto Hydro) to author a report entitled "Toronto Hydro Street Lighting Assets; Assessment of the valuation methodology used by Toronto Hydro in EB-2014-0116" (the "Report") dated July 28, 2014. The Report provided an opinion on whether Toronto Hydro's analysis in support of its rate application EB-2014-0116 was a reasonable method of calculating depreciated historic cost ("DHC") of street lighting assets and whether the method provided a better proxy of the depreciated historic cost of the street lighting assets than that used by Toronto Hydro in support of the OEB decision related to filings EB-2009-0180, EB-2009-0181, EB-2009-0182 and EB-2009-0183 dated August 3, 2011 (the "August 2011 Decision").

A-2 Subsequent to issuing the Report, management of Toronto Hydro ("Management") informed us that better aging information for poles, handwells and pole foundations had come to their attention. Management has represented that this new aging information is better data than that used in support of the EB-2014-0116 application which was the basis of the Report.

A-3 The purpose of this addendum is to discuss the impact of this new information on the methodology employed and the resulting DHC estimate of the street lighting assets.

Original Aging Information

A-4 Management has represented to us that the original aging information related to poles, handwells and foundations used in the EB-2014-0116 application was from Toronto Hydro's Geo-Spatially Enabled Asset Registry ("GEARS") database.

A-5 This database contains a cataloge of the street lighting and expressway lighting assets by the asset's location, condition and other parameters necessary to properly classify the assets according to the terms of OEB decision related dto filings EB-2009-0180, EB-2009-0181, EB-2009-0182 and EB-2009-0183 dated February 11, 2010.

A-6 We understand that within the GEARS database a significant percentage of the poles had no installation date and were assumed by Management to have been installed prior to 1971, resulting in the majority of the poles having an assigned age greater than 40 years. Similarly the aging information for the handwells and foundations suggested that the majority of these asset categories were installed prior to 1971.

Revised Aging Information

A-7 The revised aging information is based on Toronto Hydro's Optimal Investment Portfolio ("OIP") study, which was conducted in 2004 to assess the vintages of all major assets in Toronto Hydro's system. We understand this information was also used to implement IFRS-consistent changes related to the manner in which Toronto Hydro accounts for it's assets. Specifically, the study assisted Toronto Hydro in attributing an installation date to poles, handwells and foundations for which no aging information was previously available.

A-8 The OIP data exists for poles, handwells and foundations for the relelvant vintage bands leading up to the original Toronto Hydro purchase of the street lighting assets from the City of Toronto (the "City") in 2006. The aging analysis is only necessary for pre-2006 assets as detalied records have been maintained for all assets installed subsequent to the initial purchase from the City.

Imapact of Revised Aging Information on Methodology

A-9 Toronto Hydro has informed us that no changes have been made to the methodology used to calculate DHC as described in EB-2014-0116 and that Management has recalculated the DHC estimates of the street lighting assets using the new aging information.

A-10 We have obtained the revised analysis and discussed the application of the methodology with Management and note that the methodology appears to have been applied in a manner consistent with that outlined in the Report.

Conclusion

A-11 As a result of the foregoing, and subject to the Restrictions and Qualifications noted in the Report, without commenting on the inputs and data used, we maintain our view that Toronto Hydro utilized a reasonable method of calculating DHC in order to determine the value of the former street lighting assets and that the methodology is a better proxy than that provided to the OEB at the time of the August 2011 Decision.

Respectfully submitted,

(signed) "PricewaterhouseCoopers LLP"

Ken Goodwin
Partner

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CAPITAL EXPENDITURES

In accordance with the OEB's Chapter 5 Filing Requirements, Toronto Hydro has filed a consolidated Distribution System Plan ("DSP") at Exhibit 2B. In this schedule, Toronto Hydro files OEB Appendix 2-AA (Capital Projects Table) and OEB Appendix 2-AB (Capital Expenditures Summary), as required by s. 2.5.5.2 of the OEB's Filing Requirements. In accordance with the Filing Requirements, this schedule also provides:

- a description of the proposed accounting treatment for projects that have a lifecycle greater than one year, including the treatment of the cost of funds; and
- the components of other capital expenditures, including a reconciliation of all capital components to the Total Capital Budget.

1. OEB-Required Appendices (2-AA and 2-AB)

Appendices 2-AA and 2-AB, which are filed at Exhibit 2A, Tab 6, Schedules 2 and 3, provide an overview of Toronto Hydro's capital expenditures from 2010 to 2019, by program and by investment category, respectively.

To maximize the usefulness of these appendices, Toronto Hydro mapped its historical and future capital expenditures to the investment categories, and programs presented in the DSP. Capital expenditures associated with historical programs that could not be mapped to an existing DSP program are only presented in the 2010 to 2014 timeframe, as applicable. Written variance explanations of Toronto Hydro's capital expenditures are provided at Exhibit 2B, Section E4.

Toronto Hydro's last rebasing application (EB-2010-0142) was settled, and the Settlement Agreement, which was approved by the OEB, reflected a reduction in capital expenditures of $119.2 million for the 2011 test year.[1] As a result, Toronto Hydro is

[1] EB-2010-0142, Partial Decision and Order (July 7, 2011) at pages 2 and 3 and at section 4.2 of the Settlement Agreement (Appendix C to the Partial Decision and Order).

unable to provide a granular variance analysis of actuals versus OEB-approved amounts. On a total basis, Toronto Hydro's 2011 OEB-approved capital expenditures were $378.8 million, and its actual capital expenditures were $445.5 million.

2. PROPOSED ACCOUNTING TREATMENT RE PROJECTS WITH A LIFE CYCLE GREATER THAN ONE YEAR

Some of Toronto Hydro's capital projects have a project life cycle greater than one year. Where large projects span multiple years, the construction costs are recorded in construction work in-progress ("CWIP") accounts until they are in-service. Under Canadian Generally Accepted Accounting Principles ("CGAAP") and United States Generally Accepted Accounting Principles ("USGAAP"), projects with a construction duration of greater than six months include a financing charge in the cost of assets capitalized. The financing charge is at the interest rate published quarterly by the OEB for CWIP. Under Modified International Financial Reporting Standards ("MIFRS"), projects expected to exceed a duration of greater than six months include a financing charge in the cost of assets capitalized. The interest rate used to calculate the financing charge for MIFRS is Toronto Hydro Corporation's weighted average cost of borrowing.

3. COMPONENTS OF CAPITAL EXPENDITURES

Toronto Hydro's capital expenditures under the Other Capital Expenditures investment category include engineering capital, roads, allowance for funds used during construction, inflation and miscellaneous, all of which are summarized below.

3.1. Engineering Capital

Engineering capital represents labour costs that are capitalized although they are not directly attributable to specific distribution system assets or projects. These costs consist of the labour costs of engineers, technologists, design technicians and power system controllers ("PSCs") for engineering, design and planning work that they perform on

distribution assets that are put in-service. Such planning and design work is non-discretionary and is critical to Toronto Hydro's ability to complete capital work as it continues its focus on the following key areas: the capital investment program to address aging equipment and legacy infrastructure, development and implementation of new approaches for engineering decision support for creation and optimization of capital programs, and modernization through new technologies and systems. Engineering capital expenditures are only included in Other Capital Expenditures from 2010 to 2011. From 2012 onwards, these costs were integrated with capital investment programs, and this is captured in the reduction of costs within this category from 2011 onwards to 2012.

3.2. Historical Road Cut Repairs

When Toronto Hydro installs equipment in the ground it generally must disturb the environment around the job site (such as sidewalks and roadways). Temporary repairs to the property are done when the utility completes construction. This is required to make the area safe for the public and provide continuity of the surface with the surrounding area. Permanent repairs are made later by contractors engaged by the City of Toronto, usually anywhere from one to four years after Toronto Hydro has completed construction. At that time, Toronto Hydro is invoiced at for the cost of the restoration work. The timing of these repairs is generally out of the utility's control. Most jobs tend to get tendered by the City anywhere from 18 to 30 months after job completion. As a result of the outstanding costs for road cut repairs related to historical jobs, Toronto Hydro continues to receive and be legally obligated to pay invoices for repairs for road cuts dating back as far as 30 months. Any variance between the historical estimated repair cost and actual City invoice represents an obligation to the City of Toronto, pursuant to its authority over highways (public roads) under sections 32 and 33 of the City of Toronto Act, 2006[2].

[2] S.O. 2006, C. 11, Sched. A, at sections 32-33 ["City of Toronto Act"]

3.3. Allowance for Funds Used During Construction (AFUDC)

The Accounting Procedures Handbook, Article 490, allows the utility to capitalize an allowance for funds used during construction ("AFUDC"). The AFUDC rate applied by Toronto Hydro for 2010 to 2013 actuals and 2014 forecast is based on the OEB-prescribed rate. The forecasted 2015 capital expenditures are based on MIFRS and thus include AFUDC calculated based on Toronto Hydro's weighted average cost of debt.

3.4. Inflation

From 2016 onwards to 2019, inflation costs at 2.07% per year, consistent with the Statistic Canada Consumer Price Index ("CPI") for Toronto,[3] are also included within this category.

3.5. Miscellaneous

Miscellaneous capital expenditures primarily include pre-capitalized inventory and major tools. Capital expenditures related to pre-capitalized inventory is dependent on the change in capital inventory levels year over year. Toronto Hydro invests in major tools and testing equipment to allow employees to continue to complete work effectively and efficiently. The utility invests in major tools on an ongoing basis to replace worn or broken tools, and as required to install, commission and maintain new technologies. These are regular utility expenses that are essential to being able to perform necessary capital and maintenance work.

[3] Statistics Canada, Consumer Price Index, by city (Index), (Ottawa: Statistics Canada, 2014), online: Statistics Canada <http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ45a-eng.htm>.

OEB Appendix 2-AA
Capital Projects Table

Projects	2010	2011	2012	2013	2014 BRIDGE	2015 TEST	2016 TEST	2017 TEST	2018 TEST	2019 TEST
Reporting Basis	**CGAAP**	**CGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Metering	28.4	22.1	12.1	12.2	14.0	24.7	16.6	14.7	11.7	13.7
Customer Connections	15.2	31.2	31.0	53.4	52.1	39.3	53.8	64.9	56.9	46.6
Externally-Initiated Plant Relocation & Expansion	0.7	5.0	9.8	18.6	8.8	4.0	4.0	4.0	4.0	4.0
Load Demand	-	-	0.3	2.4	1.1	12.0	13.9	14.0	15.7	19.2
Generation Projects Protection and Control	-	-	-	-	-	6.1	5.2	3.3	2.1	2.0
System Access Investments Sub-total	**44.4**	**58.3**	**53.2**	**86.6**	**76.0**	**86.1**	**93.5**	**100.9**	**90.4**	**85.5**
Underground Circuit Renewal	108.4	90.3	53.8	68.8	108.1	96.0	80.1	84.0	99.7	99.5
Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers	-	5.5	1.5	2.4	4.7	3.5	1.4	0.7	0.8	0.5
Underground Legacy Infrastructure	-	-	-	-	-	2.1	6.7	6.6	6.5	5.5
Overhead Circuit Renewal	25.8	28.3	23.2	49.0	53.3	44.0	23.0	24.9	25.3	30.3
Overhead Infrastructure Relocation	-	-	-	-	-	0.7	1.4	1.8	2.3	3.6
Rear Lot Conversion	6.9	16.6	17.5	23.8	22.7	17.0	8.1	10.3	10.3	13.6
Box Construction Conversion	5.7	7.1	0.8	13.8	23.3	16.8	20.7	21.1	21.6	22.7
SCADAMATE R1 Renewal	-	-	-	1.9	2.6	6.2	4.1	2.7	-	-
Network Vault Renewal	1.7	0.9	3.6	10.8	0.9	4.0	10.4	10.3	10.3	10.2
Network Unit Renewal	7.3	4.4	5.1	7.3	3.6	5.2	7.4	7.3	7.3	7.3
Legacy Network Equipment Renewal (ATS & RPB)	0.4	0.0	0.1	1.6	0.2	0.4	1.0	1.1	0.9	1.1
Network Circuit Reconfiguration	-	-	-	-	-	-	2.3	2.3	2.3	2.3
Stations Switchgear Renewal	14.9	12.9	11.6	7.9	24.6	11.9	18.9	25.5	27.6	22.4
Stations Power Transformer Renewal	1.8	4.0	2.7	1.7	1.3	1.7	2.6	2.6	2.7	2.7
Stations Circuit Breaker Renewal	0.0	0.9	0.2	1.0	2.1	1.7	1.8	1.8	2.1	1.8
Stations Control & Monitoring	-	-	0.1	0.5	0.2	0.1	0.9	1.1	1.5	1.4
Stations Ancillary Systems	0.1	0.1	0.2	0.6	0.2	0.7	0.6	0.4	0.3	0.4
Station Buildings	-	-	0.5	0.0	0.2	0.5	2.5	2.3	2.6	3.3
Stations DC Battery Renewal	0.2	0.2	0.4	0.3	0.6	0.3	0.7	0.7	0.7	0.7
Reactive Capital	25.1	28.6	29.2	37.4	32.1	31.9	32.7	33.1	33.6	34.2
Worst Performing Feeder	16.7	19.3	6.7	1.2	4.8	1.2	1.8	1.8	1.8	1.8
Telecom Program	-	-	-	1.0	0.9	6.1	6.0	4.0	-	-
System Renewal Investments Sub-total	**215.0**	**219.3**	**157.2**	**231.1**	**286.4**	**251.7**	**235.0**	**246.3**	**260.1**	**265.5**
Contingency Enhancement	-	-	-	-	-	10.0	5.9	9.7	9.7	13.5
Design Enhancements	-	-	-	-	-	0.4	1.7	1.7	1.7	1.7
Feeder Automation	3.3	0.9	6.2	8.8	0.8	11.1	15.1	9.4	10.0	8.5
Overhead Momentary Reduction	-	-	-	-	-	-	-	0.6	0.6	0.6
Handwell Upgrades	21.1	32.9	12.6	11.7	16.2	5.0	-	-	-	-
Polymer SMD-20 Renewal	-	-	-	0.8	2.8	4.8	-	-	-	-
Downtown Contingency	1.1	4.7	0.1	1.1	1.0	-	0.7	0.7	1.0	0.9
Customer Owned Station Protection	-	-	-	-	-	0.6	1.0	1.0	0.8	0.6
Stations Expansion	6.9	32.5	18.6	61.2	79.5	43.8	41.6	36.5	22.0	44.0
Energy Storage Systems	-	-	-	-	1.0	0.5	1.1	2.2	3.2	3.8
Local Demand Response	-	-	-	-	-	0.2	2.4	0.6	0.5	0.3
Grid Intelligence	3.0	4.8	0.8	0.1	-	-	-	-	-	-
EV	-	-	0.0	0.0	-	-	-	-	-	-
System Service Investments Sub-Total	**35.3**	**75.6**	**38.4**	**83.7**	**101.3**	**76.5**	**69.6**	**62.5**	**49.5**	**73.9**
Fleet and Equipment Services	10.6	11.8	0.8	2.2	2.6	3.9	3.2	3.7	3.5	3.6
Facilities	12.1	25.3	6.6	14.5	90.3	53.8	24.2	2.0	2.0	1.9
IT Hardware	10.6	9.4	7.4	6.0	5.2	5.9	8.0	7.4	9.8	5.6
IT Software	22.2	21.2	14.5	9.6	10.1	15.5	16.2	15.8	16.8	16.8
Radio Project	-	-	-	-	-	6.7	13.7	-	-	-
ERP*	-	-	-	1.5	0.9	17.7	33.6	-	-	-
Program Support	-	-	-	-	0.4	1.2	0.5	-	-	-
General Plant Investments Sub-Total	**55.5**	**67.7**	**29.3**	**33.8**	**109.5**	**104.6**	**99.4**	**28.9**	**32.1**	**27.9**
Miscellaneous	12.3	(4.2)	4.5	5.4	3.2	0.9	1.2	1.2	1.2	1.2
AFUDC	3.5	5.2	2.3	3.3	6.5	8.0	5.8	4.5	4.6	4.6
Roadcuts	-	-	3.1	1.8	3.0	3.3	4.1	4.1	4.1	4.1
EAR	34.5	23.6	-	-	-	-	-	-	-	-
Inflation	-	-	-	-	-	-	10.2	18.9	28.0	39.5
Other Sub-Total	**50.4**	**24.6**	**9.9**	**10.5**	**12.7**	**12.2**	**21.2**	**28.6**	**37.9**	**49.4**
Total	**400.6**	**445.5**	**288.0**	**445.7**	**585.9**	**531.1**	**518.8**	**467.4**	**470.0**	**502.2**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-	-	(6.3)	(5.9)	(5.1)	(5.0)	(5.4)
Total	**400.6**	**445.5**	**288.0**	**445.7**	**585.9**	**524.9**	**512.9**	**462.3**	**465.0**	**496.7**

OEB Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

CATEGORY					**Forecast Period** (planned)					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	Actual	**Actual**	**Actual**	**Actual**	**Bridge**	**Test**	**Test**	**Test**	**Test**	**Test**
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*
System Access	44.4	58.3	53.2	86.6	76.0	86.1	93.5	100.9	90.4	85.5
System Renewal	215.0	219.3	157.2	231.1	286.4	251.7	235.0	246.3	260.1	265.5
System Service	35.3	75.6	38.4	83.7	101.3	76.5	69.6	62.5	49.5	73.9
General Plant	55.5	67.7	29.3	33.8	109.5	104.6	99.4	28.9	32.1	27.9
Others	50.4	24.6	9.9	10.5	12.7	12.2	21.2	28.6	37.9	49.4
TOTAL EXPENDITURE	**400.6**	**445.5**	**288.0**	**445.7**	**585.9**	**531.1**	**518.8**	**467.4**	**470.0**	**502.2**
System O&M	$ 114.6	$ 111.9	$ 109.0	$ 119.8	$ 118.9	$ 128.8				

Note: Variances due to rounding may exist

CAPITALIZATION POLICY

This schedule addresses section 2.5.2.3 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements") which requires applicants to file a copy of their capitalization policies and to identify changes to their capitalization policy.

1. BACKGROUND

In 2007, Toronto Hydro commenced its International Financial Reporting Standards ("IFRS") conversion project with the intention of converting to IFRS on January 1, 2011. However, given uncertainty around the timing, scope and potential adoption of a rate-regulated accounting standard under IFRS, Toronto Hydro decided to defer the adoption of IFRS, and filed its 2011 rate application in accordance with its Canadian Generally Accepted Accounting Principles ("CGAAP") accounting practices in use at that time.

Prior to January 1, 2011, Toronto Hydro recorded depreciation and amortization on assets in accordance with the guidelines provided in the OEB's 2006 Electricity Distribution Rate Handbook ("EDRH"). The use of the guidelines was permitted under the CGAAP as the prescribed useful lives represented "estimated service lives" of assets under the regulatory framework.

Effective January 1, 2011, following a detailed review of the useful lives analyses conducted by Kinectrics and other third-parties for Toronto Hydro for the purposes of the IFRS conversion, the utility implemented certain changes in accounting estimates related to the manner in which it records and accounts for its property, plant and equipment ("PP&E").[1] Although Toronto Hydro decided to defer the adoption of IFRS, it determined that these changes were required to be applied under CGAAP as additional and more relevant information had been made available.

[1] EB-2010-0142, Application and Evidence (February 9, 2011) at Exhibit Q1, Tab 2, Schedule 7-2; and EB-2010-0142, Partial Decision & Order, (July 7, 2011) at page 41.

These changes in the estimates of useful lives of assets were reflected in the corresponding depreciation and amortization balances in Toronto Hydro's financial statements effective January 1, 2011, and in its last rebasing application (EB-2010-0142).[2] Toronto Hydro's external auditor acknowledged the appropriateness of the changes in accounting estimates effective January 1, 2011 under CGAAP,[3] and the Ontario Energy Board ("OEB") approved, for rate-making purposes, the depreciation and amortization expense that resulted from these changes effective May 1, 2011.

On July 21, 2011, the Ontario Securities Commission ("OSC") granted Toronto Hydro an exemption to prepare its financial statements in accordance with USGAAP for its fiscal years beginning on or after January 1, 2012, but before January 1, 2015. Toronto Hydro adopted USGAAP for financial reporting and rate-making purposes effective January 1, 2012.

On March 19, 2014, the Board of Directors approved the adoption of IFRS for the year beginning on January 1, 2015 due to the pending expiration of the above exemption.

On June 23, 2014, Toronto Hydro presented the IFRS policies to its Audit Committee. Once the IFRS policies are approved by the Audit Committee, Toronto Hydro intends to adopt a revised Capitalization Policy.

2. CAPITALIZATION POLICY

A copy of Toronto Hydro's current capitalization policy is filed as Appendix A to this schedule. As explained above, Toronto Hydro's Audit Committee is in the process of reviewing the revised IFRS policies. Therefore, the current capitalization policy filed at Appendix A to this schedule is based on USGAAP.

[2] EB-2010-0142 Exhibit Q1, Tab 1, Schedule 1,
[3] Toronto Hydro Corporation Consolidated Financial Statements December 31, 2011

Toronto Hydro confirms that for purposes of calculating rate base for the 2015 Test Year (Exhibit 2A, Tab 1, Schedule 1), its capitalization practices conform with IFRS guidance. Toronto Hydro does not expect the new IFRS Capitalization Policy to have any material impact on its 2015 test year rate base values.

3. CHANGES TO CAPITALIZATION POLICY

With the exception of the items noted below, there are no material differences between USGAAP and IFRS capitalization practices. The incremental net impact of the items listed below to the 2015 test year rate base is $0.1 million. The following table summarizes the differences between USGAAP and IFRS.

Topic	Aspect	USGAAP	IFRS
Borrowing Costs	Applicability	Assets requiring a "period of time" to complete	Assets requiring a "substantial period of time" to complete
	Commencement Date	After inception, not retroactive	At inception, on all project spend
	Interest Rate	OEB prescribed rate	Weighted average cost of borrowing
	Calculation	Simple Interest	Compounding Interest
Assets Retirement Obligation	Discount Rate	Credit adjusted risk free rate	Risk free rate
	Presentation	Accretion Expense shown as Operating Expense	Accretion Expense shown as Interest Expense
	Timing	Legal obligation	Legal or Constructive Obligation

POLICY

CAPITALIZATION	**Policy Owner:** Chief Financial Officer
	Policy Approver: Policy Administration Steering Committee
	Version Approval Date: 2013-09-24
	Last Review by PASC: 2013-09-24
The most recent version of this policy can be obtained from http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx	
The distribution of this policy is not restricted.	

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1 DOCUMENT REVIEW & REVISION HISTORY

This policy is reviewed annually.

Version Number	Date of Review	Reviewed By	Brief Description of Change
V1.0	2008-06-27	PASC	V1.0 approved by PASC
V2.0	2010-07-29	PASC	V2.0 approved by PASC
V3.0	2011-06-30	PASC	V3.0 approved by PASC
V4.0	2013-09-24	PASC	V4.0 approved by PASC

2 DISTRIBUTION HISTORY

Version Number	Date of Issue	Recipients
V1.0	2008-06-27	Toronto Hydro @ Home Employee Extranet
V2.0	2010-08-30	Toronto Hydro @ Home Employee Extranet
V3.0	2011-09-16	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V4.0	2013-09-30	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx

3 POLICY OVERVIEW

This document describes the accounting policy and specific criteria used to determine the appropriate classification of expenditures, in particular, whether expenditures should be capitalized on the balance sheet (capital assets) or expensed to operations in the period incurred (expense).

The purpose of recording expenditures as capital assets is to provide for an equitable allocation of costs among current and future periods. As capital assets are expected to provide future economic benefits for more than a year, expenditures incurred for the acquisition, construction or

development of capital assets should be capitalized and allocated over the estimated useful lives[1] of the associated capital assets in the form of amortization/depreciation. All other expenditures should be expensed in the accounting period incurred.

4 DEFINITIONS AND ABBREVIATIONS

TERM or ACRONYM	DESCRIPTION
AFUDC	Allowance for Funds Used During Construction
AP Handbook	Accounting Procedures Handbook for Electricity Distributors issued by the OEB
ASC	Accounting Standards Codification
CWIP	Construction Work In Progress
Corporation	Toronto Hydro Corporation and its affiliates
FASB	Financial Accounting Standard Board
OEB	Ontario Energy Board
On-cost	Materials handling costs
PASC	Policy Administration Steering Committee The committee members are: Chief Financial Officer VP, General Counsel & Corporate Secretary VP, Organizational Effectiveness and Environment Health & Safety VP, Information Technology and Strategic Management
PP&E	Property, Plant and Equipment
SLR	Standard Labour Rate
US GAAP	United States Generally Accepted Accounting Principles
VHR	Vehicle Hire Rate

5 SCOPE

5.1 This policy applies to Toronto Hydro Corporation and its affiliates.

6 OBJECTIVE

6.1 7R HQVXUH SURSHU FODVVLILFDWLRQ in accordance with US GAAP, and compliance with applicable regulations.

7 CRITERIA FOR CAPITALIZATION

7.1 **Asset Recognition ±Capitalization versus Expensing**

[1] Estimates of useful life are reviewed periodically and whenever events or changes in circumstances indicate that the current estimates or depreciation method are no longer appropriate. Changes in estimates are accounted for on a prospective basis.

In order to determine whether an expenditure should be capitalized or expensed, the expenditure must be evaluated based on the criteria discussed below. Subject to the threshold levels outlined in **Appendix A**, expenditures that meet the definition of an asset as well as a capital asset will be capitalized, while all remaining expenditures will be expensed. Below are the two definitions which must be met in order for an expenditure to be capitalized:

7.1.1 **Assets** are economic resources controlled by an entity from which future economic benefits may be obtained. Assets have three essential characteristics:

i) they embody a probable future benefit that involves a capacity, singly or in combination with other assets, to contribute directly or indirectly to future net cash inflows;
ii) the entity can obtain the benefit and control R W K H U V ¶ access to the benefit; and
iii) the W U D Q V D F W L R Q R U H Y H Q W J L Y L Q J U L V H W R W K H H Q W L benefit has already occurred.

7.1.2 **Capital assets** are expenditures for which the future benefits to the Corporation extend over a period greater than one year. Capital assets comprise property, plant and equipment and intangible assets. Property, plant and equipment consists typically of long-lived tangible assets used to create and distribute an H Q W L W \ ¶ V S U R G X F W V and include land and land improvements, buildings, machinery and equipment, and furniture and fixtures. Intangible assets are assets that lack physical substance.

For additional guidance, **Appendix B ±Decision Tree** illustrates the criteria that must be met in order for expenditures to be capitalized. Expenditures not meeting the criteria will be expensed in the period incurred. Additionally, **Appendix C** includes excerpts from the OEB AP Handbook outlining capital asset and expense account definitions. A review of these definitions provides practical references and examples to assist in the classification of various expenditures.

For complex transactions and when capital/operating decisions may be ambiguous, the Business Units will consult with the Finance group.

7.2 Betterments versus Repairs

When expenditures are incurred relating to existing capital assets, they should be evaluated against the criteria outlined below to determine whether the expenditure should be classified as a betterment or a repair. ***Expenditures that meet the definition of a betterment will be capitalized while expenditures that meet the definition of a repair will be expensed. If a cost has the attributes of both a repair and a betterment, the portion considered to be betterment will be included in the cost of the capital asset.***

7.2.1 **Betterments** are costs incurred to enhance the service potential of an existing capital asset. The service potential of an existing capital asset may be enhanced when:

i) there is an increase in the previously assessed physical output or service capacity;
ii) associated operating costs are lowered;
iii) the life or useful life is extended; or
iv) the quality of output is improved.

7.2.2 **Repairs** are costs incurred in the maintenance of the service potential of a capital asset. Frequently referred to as operating expenses or maintenance expenses, they are costs incurred more or less on a continuous basis to keep the capital asset in normal operating condition, but do not improve the value of the asset, nor prolong its life appreciably.

Operating expenses or maintenance expenses are the result of an activity that encompasses actions of a detective, preventive, and/or monitoring nature. They are normally planned or scheduled. They can also be reactionary, in response to an unscheduled breakdown in service function.

For those instances when professional judgement has to be exercised to determine the proper classification of the & R U S R U D W L R Q ¶ V H[SHQGLWXUH XQLW[will confirm W K H the classification as a betterment or repair with the Finance group.

8 ASSET COST COMPONENTS

8.1 Once it has been determined that an asset can be capitalized, below are the amounts that can be included in the cost of a capital asset:

i) A capital asset should be recognized at cost. Capital asset cost is the amount of consideration given to acquire, construct, develop, or better a capital asset and includes all costs directly attributable to the acquisition, construction, development or betterment of the capital assets including installing it at the location and in the condition necessary for the intended use. This would also include any borrowing costs and includes AFUDC captured in CWIP.

The AP Handbook provides for the inclusion of AFUDC when capitalizing CWIP, until such time the asset is substantially complete. The interest rate for capitalization is prescribed by the OEB and modified on a periodic basis and is applied to the eligible CWIP balance on a simple interest basis.

ii) For purchased capital assets, cost would include the purchase price and other acquisition costs, such as: broke U V ¶ F R P P L V V L R Q V L Q V W D O O D W L R Q F architectural, design and engineering fees; legal fees; survey costs; site preparation costs; freight charges; transportation insurance costs; duties; testing and preparation charges; and option costs when an option is exercised.

iii) For an electrical plant that is constructed, construction costs should include where applicable: the cost of labour; materials and supplies; transportation; work done by others for the utility; damages incurred in the construction work; privileges and permits; special machinery services; allowance for funds used during construction; and such portion of general engineering, administrative salaries and expenses, insurance, taxes and other similar items as may be properly included in construction.

8.2 Burdens

Four burden rates are specifically analyzed below with respect to the asset cost:

8.2.1 Time-sheeting of Indirect Labour

One of the methods of capitalizing labour costs is to allocate employee labour costs through the process of time-sheeting of indirect labour. Field crews are supported,

supervised and guided by those employees whose personnel costs are included in indirect labour.

The process of capitalizing costs of indirect labour includes labour costing (i.e. time-sheeting) which differentiates the time spent between capital, operating, and blend activities (i.e. a mix of capital and operating), in order to appropriately allocate costs across projects based on identified cost drivers.

Once time-sheeted hours are applied to specific activities, the calculated cost will be allocated to capital expenditures, operating expenses, or a blend of both based on the nature of the activity. Costs identified as capital or costs that are designated as capital in nature within a blend activity will be mapped to construction work-in-progress (CWIP) while costs identified as operating in nature within a blend activity will be mapped to operating expense.

8.2.2 Standard labour rate

Another method of capitalizing labour costs is to track direct labour costs for various employees and apply a SLR to time recorded to various jobs. There are three broad direct labour categories within the group of employees who currently submit time-sheets for direct labour and for whom SLRs have been calculated: inside workers, outside shift workers and outside hourly workers.

The SLRs are calculated by dividing the total employee compensation, including various types of benefits) by the total available hours (i.e. hours available for work during the course of the year on capital projects) for each SLR category. The total available hours consist of: a) the total working days in a year less b) leaves (such as vacation and statutory holidays) as well as c) various unproductive time (such as safety training, inclement weather, etc.).

All existing elements of employee burden are capitalized since these costs are all permissible as capital expense elements, however, adjustments are made to the pool of available hours related to various unproductive factors that should not be considered. Such unproductive factors to be removed from the SLR calculation include: meetings, training, modified duty time, supervisory relief time and overtime in lieu. Aside from training (which will always be an operating expense), time spent on these activities in relation to capital work will be capitalized through the time-sheeting mechanism.

8.2.3 On-cost

An on-cost charge is applied to all items issued from the Corporate Warehouses. Such items generally include transformers, poles, cables, etc. These items are then installed in their final locations throughout the City of Toronto and are then considered to be in use. If the items issued from the warehouse are associated with capital projects, the on-cost charge is capitalized, whereas if the items issued are associated with operating projects, the on-cost charge is expensed in the period in which it is incurred.

The on-cost charge associates the cost of warehousing and handling to the items themselves. The on-cost rate is calculated as the sum of budgeted expenses in four specific material handling responsibility centers divided by the budgeted dollar value of materials moving through the warehouse in a given year. This rate is then applied to the dollar value of all materials when issued to capital and operating projects.

Some of the budgeted expenses within the material handling responsibility centers are not capitalizable, thus should not be included in the on-cost calculation. The disallowed costs include:

- Payroll related to administrative staff supporting the procurement and warehousing functions;
- Inventory and direct purchases of materials used in the warehouse for internal purposes ±i.e. not used for capital projects;
- Utilities and communications related expenses;
- Office supplies used in procurement and warehousing;
- Employee expenses (i.e. reimbursed expenses for employee purchases); and
- Allocated IT charges related to telephone and computing equipment used by the procurement and warehousing departments.

8.2.4 Vehicle Hire Rate

Vehicles used in the construction of capital assets can be capitalized into the item of PP&E. This capitalization is applied to projects based on time-sheets for the use of each vehicle. A VHR is calculated for each vehicle class and applied to the hours time-sheeted to determine the amount capitalized to each project.

The VHRs are calculated by taking the sum of the total operating charges, fuel costs and depreciation, and dividing by the total available vehicle hours for each vehicle class. The total available vehicle hours are based on the number of working days in a year less a factor for vehicle repairs and maintenance. Some of the budgeted expenses are not capitalizable thus should not be included in the VHR calculation.

8.3 Asset retirement cost

The Corporation recognizes a liability, known as an asset retirement obligation, for future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties. The liability is measured at present value and an offsetting amount is added to the carrying amount of the related asset as asset retirement cost. This cost is depreciated over the useful life of the related asset. Changes to an existing asset retirement obligation are added to or deducted from the cost of the related asset and depreciated prospectively over the remaining useful life of the asset.

9 POLICY ADMINISTRATION OWNERSHIP, APPROVAL AND RESPONSIBILITIES

Policy Owner

9.1 This policy is owned by the *Chief Financial Officer,* who is responsible for:

- Ensuring that this policy is comprehensive, clear and current.
- Ensuring that this policy is implemented and communicated to the departments and staff that are impacted.
- Ensuring consistency between referenced policies and this document.
- Ensuring on-going compliance with this policy.
- Approving any exceptions to this policy, as required.
- Reviewing this policy annually.

Policy Approver

9.2 This policy is approved by the *Policy Administration Steering Committee,* which is responsible for:

- Considering the impact of the policy to the associated risk.
- Reviewing and approving this policy annually.

Directly Responsible Person

9.3 This policy is managed by the *Controller* of each affiliate through *Business Unit Managers and Senior Financial Analysts.*

9.4 The *Affiliate Controller* is responsible for:

- Ensuring that this policy is communicated to the departments and staff that are impacted and that it is implemented.
- Immediately communicating any exceptions or violations of this policy to the *Manager, Financial Reporting* for approval upon review.
- Reviewing this policy annually.

9.5 The *Business Unit Managers* are responsible for:

- Ensuring that this policy is communicated to the staff impacted and that it is implemented.
- Ensuring ongoing compliance with this policy.
- Ensuring that a review of expenditures recorded in CWIP accounts is performed on a regular basis. Expenditures are recorded in CWIP until such time as the project is essentially complete and may be capitalized as allowed by US GAAP. It is expected that Business Unit personnel and Finance staff periodically review this account for stranded costs and other entries that may be capitalized or expensed.
- Ensuring that a review of projects is performed on a regular basis, so that projects W K D W D U H H V V H Q W L D O O \ F R P S O H W H K D Y H W K D W D U H L Q F R U U H F W O \ V W D W X V X S J U SAP. Updating the status field is the trigger that initiates timely capitalization of costs.
- Immediately communicating any exceptions or violations of this policy to the *Senior Financial Analysts*.

9.6 The *Senior Financial Analysts* are responsible for:

- Providing support to the Business Units for proper application of this policy.
- Monitoring compliance with this policy.
- Immediately communicating any exceptions or violations of this policy to the *Finance Manager* and the *Affiliate Controller*.

9.7 The *Supervisor, Financial Reporting* is responsible for:

- Ensuring the policy is maintained and kept up to date.
- Immediately communicating any exceptions or violations of this policy to the *Manager, Financial Reporting*.
- Reviewing this policy annually.

10 POLICY COMMUNICATION

COMMUNICATION TRIGGER	TYPE OF COMMUNICATION	PARTY RESPONSIBLE FOR POLICY COMMUNICATION	AUDIENCE	ACKNOWLEDGEMENT
Policy Change/ Review	Presentation and/or e-mail	Manager, Financial Reporting	Affiliate Controller, Business Unit Managers and Senior Financial Analysts	Sign Off
Policy Change/ Review	Scheduled Meeting Presentation	Business Unit Managers	All affected employees	Sign Off
Policy Update	E-Mail	Manager, Financial Reporting	All affected employees	No
New Hire in Finance	Discussion, e-mail	Immediate Supervisor/Manager	New hire	No

11 POLICY COMPLIANCE AND VIOLATIONS

11.1 All Toronto Hydro employees, officers, directors and affiliates are required to comply with this policy.

11.2 Any employee who fails to comply with this policy could be subject to disciplinary action, up to and including dismissal.

11.3 Failure to comply with this policy could lead to a material misstatement of the &RUSRUDWLRQ¶V H[SHQGLWXUHV RQ WKH ILQDQFLDO VWDWHPH regulatory agencies. This can result in legal, regulatory and reputational ramifications.

12 RELATED LAWS, REGULATIONS AND DOCUMENTATION

12.1 Refer to ASC 360 ³3URSHUW\ 3ODQW ,QGXVWULDO (TXLSPHQW Accounting Concepts No.6 for more definitions and accounting guidelines. These Sections are available from the Finance group.

12.2 Refer to the ³&RPSXWHU 6RIWZDUH Guidelines´ for more detailed accounting treatment of expenditures related to the acquisition and/or development of computer software.

12.3 The following appendices were referenced in this policy:

- Appendix A - Minimum threshold dollar amounts for capitalization and Depreciation rates
- Appendix B - Decision Tree - Classification of an expenditure
- Appendix C - Capital asset and repair and maintenance expense definitions - Excerpts from the OEB AP Handbook

These appendices can be found on the Toronto Hydro Plugged In intranet site at http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx.

OVERHEAD EXPENSE

Appendix 2-DA of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements") requires the presentation of changes in the capitalization of overhead costs under modified International Financial Reporting Standards ("mIFRS") and the applicant's previous accounting standard. Toronto Hydro has not filed this Appendix because there are no differences between the capitalization of overhead expenditures upon adoption of mIFRS for the 2014 bridge and 2015 test years.

BACKGROUND

As noted in EB-2010-0142 Exhibit Q1, Tab 2, Schedule 1, Toronto Hydro commenced its IFRS conversion project in 2007 with the intention of converting to IFRS January 1, 2011. However, given uncertainty around the timing, scope and potential adoption of a rate-regulated accounting standard under IFRS, Toronto Hydro decided to file its rate application for 2011 in accordance with the Canadian Generally Accepted Accounting Principles ("CGAAP") in use at that time.

Toronto Hydro determined that certain changes in accounting estimates were required to be applied under CGAAP as additional and more relevant information had been made available through the IFRS project. Toronto Hydro's external auditor acknowledged the appropriateness of prospective application of the changes in accounting estimates effective January 1, 2011 under CGAAP.[1] The changes related to the manner in which Toronto Hydro records and accounts for its property, plant and equipment and were filed as an Accounting Update to the 2011 application.[2]

[1] Toronto Hydro Corporation Consolidated Financial Statements, December 31, 2011.
[2] EB-2010-0142, Application and Evidence (February 9, 2011), Exhibit Q1, Tab 2, Schedule 1.

As a result of the changes adopted under CGAAP, there are no differences between the capitalization of overhead expenditures upon adoption of MIFRS for the 2014 bridge and 2015 test years. Consequently, Toronto Hydro has not completed OEB Appendix 2-DA as part of this application. Refer to EB-2010-0142 Exhibit Q1, Tab 2, Schedule 1 for a description and quantification of the changes in the capitalization of overhead expenses applied prospectively under CGAAP commencing January 1, 2011.

COST OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING FACILITIES

Section 2.5.2.5 of the OEB's Filing Requirements for Electricity Distributor Rate Applications (July 17, 2013) (the "Filing Requirements"), contemplates that a distributor will file for provincial rate protection associated with any costs incurred to make eligible investments, as described in section 79.1 of the Ontario Energy Board Act, 1998 (the "Act") and Regulation 330/09 (O. Reg. 330/09)[1] made under the Act.

Costs incurred by a distributor, in accordance with the cost responsibility rules in the OEB's Distribution System Code, for the purpose of connecting or enabling the connection of a Renewable Energy Generation ("REG") facility to its distribution system are considered to be eligible investments for the purpose of provincial rate recovery under s. 79.1 of the Act.[2]

1. REG CONNECTIONS

There is significant renewable generation activity across Toronto Hydro's distribution system. As of May 31, 2014, Toronto Hydro has connected over 860 renewable generation projects representing over 20 MW of capacity, and has undertaken approximately 325 MW of pre-assessment capacity reviews. Toronto Hydro expects to connect approximately 972 renewable energy generation facilities during the 2015 to 2019 rate period, with a corresponding capacity of 148.9 MW. In summary, by the end of 2019, the utility anticipates to have almost 2000 renewable generation facilities, with a corresponding capacity of approximately 203 MW, connected to its distribution system.

[1] O. Reg. 330/09.
[2] O. Reg. 330/09, at s. 1(2).

Some renewable generation projects are currently unable to connect due to interconnection constraints either at transmission level or distribution level. These interconnection constraints are short circuit capacity, thermal capacity or reverse power flow issues associated with legacy system design or legacy equipment. The breaker upgrades presently underway by Hydro One Networks Inc. ("HONI") are expected to remove constraints at the transmission level and to be completed by end of 2014.

2. ELIGIBLE INVESTMENTS SUMMARY

To address interconnection constraints at the distribution level, Toronto Hydro proposes to undertake a number of Renewable Enabling Improvement ("REI") investments as part of its 2015 to 2019 Distribution System Plan ("DSP"), which is filed at Exhibit 2B.

2.1. Generation Protection, Monitoring & Control

- Advanced Protection System To enable more renewable generation projects to connect, a high speed protection scheme has been developed for implementation on station buses with short circuit constraints. This advanced protection, monitoring and control system uses a high speed communication network with the associated protective equipment to isolate the generator from the distribution system before the main circuit breakers operate, thus maintaining system integrity for upstream customers. For additional details refer to the Generation Protection Control and Monitoring Program (Exhibit 2B, E5.5) in the DSP.
- Installation of Bus-Tie Reactors Bus-tie reactors lower the short circuit current on the station bus and distribution system by insertion of an impedance at the bus-tie point. This method of fault mitigation has been successfully applied by Powerstream and HONI. Toronto Hydro proposes to work with HONI to install a bus tie reactor at Richview TS to eliminate the existing fault current constraint, which will enable renewable generation connections which at present cannot

proceed. For additional details refer to the Generation Protection Control and Monitoring Program (Exhibit 2B, E5.5) in the DSP.

- Remote Monitoring and Control of Generation (SCADA): Toronto Hydro requires real-time monitoring and control of renewable generation resources via communication networks with the utility's supervisory control and data acquisition ("SCADA") system to enable safe operation of the distribution system and feeder management of bi-directional distribution grid flows. The system has the ability to forecast resources and coordinate with Toronto Hydro's distribution outage management system, thereby enabling greater penetration of renewable generation by providing real-time visibility. Toronto Hydro's requirement for monitoring and control is modelled after requirements developed by the Independent Electricity System Operator ("IESO"). Consistent with the Distribution System Code ("DSC"), the costs associated with this investment program pertains only to renewable generation resources, as conventional generation projects bear the cost of monitoring and control requirements. For additional details refer to the Generation Protection, Control and Monitoring Program (Exhibit 2B, E5.5) in the DSP.

2.2. Energy Storage

- Toronto Hydro plans to deploy 24 energy storage systems at various strategic locations across the distribution system. These energy storage systems represent a total aggregated peak capacity of 4 MW and aggregated energy capacity of 10MWh. Toronto Hydro's infrastructure was not designed to accommodate two-way, variable renewable generation resources and these energy storage systems will balance energy flows in specific areas, allowing renewable generation connections to proceed and helping defer the need for conventional infrastructure upgrades. For additional details refer to the Energy Storage Program in the DSP (Exhibit 2B, E7.11).

The Ontario Power Authority ("OPA") reviewed Toronto Hydro's plans for REG investments and found that: 1) the utility's plans are reasonably consistent with the OPA's information regarding REG, and 2) that the investments support and enable the connection of additional REG, which enhances the ability of local customers and proponents to participate in ongoing renewable programs, while contributing to the supply diversity within the Integrated Regional Resource Plan ("IRRP") study for the Central Toronto region. For more information, please refer to the OPA Comment Letter filed at Exhibit 2B, Section B.

3. ELIGIBLE INVESTMENTS COSTS

Table 1 below summarizes the costs associated with REI investments over the 2015 to 2019 rate period. Toronto Hydro is not proposing any specific Renewable Expansion ("RE") investments during the period 2015 – 2019. However, Toronto Hydro notes that certain investments in its Station Expansion program (Exhibit 2B, E7.9) are expected to improve the utility's ability to connect REG facilities.

Table 1: Renewable Enabling Improvements (REI) from 2015 to 2019 ($ Millions)

Capital Program	2015	2016	2017	2018	2019
Generation Protection Control and Monitoring	6.12	5.19	3.26	2.10	2.02
Energy Storage	0.54	1.09	2.16	3.24	3.78
Totals	**6.66**	**6.27**	**5.43**	**5.34**	**5.79**

/C

4. PROVINCIAL RATE PROTECTION

In accordance with s. 2.5.2.5 of Filing Requirements, Toronto Hydro applied the six percent direct benefit assumption provided by the OEB with respect to REI investments to calculate the provincial rate protection amounts summarized below in Table 2. A more detailed breakdown of these figures is provided in the OEB Appendices 2-FA and 2-FB at Exhibit 2A, Tab 8, Schedules 2 and 3, respectively. (Note that Appendix 2-FC provided in Schedule 4 is not applicable).

Table 2: Provincial Rate Protection Amounts from 2015 to 2019 ($Millions)

Year	2015	2016	2017	2018	2019
Provincial Rate Protection	0.31	1.00	1.69	2.31	2.93

/C

OEB Appendix 2-FA
Renewable Generation Connection Investment Summary (over the rate setting period)

Enter the details of the Renewable Generation Connection projects as described in Section 2.5.2.5 of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.

For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB

For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments.

Part A

REI Investments (Direct Benefit at 6%)	2015	2016	2017	2018	2019	
Project 1						
Leslie BY Bus Adv. P/M/C						
Capital Costs	$212,609	$134,771	$133,137	$133,467	$26,532	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 2						
Richview BY Bus Tie Reactors						
Capital Costs	$31,891	$269,541	$234,322	$0	$0	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 3						
Wiltshire TS Adv. P/M/C						
Capital Costs	$382,696	$129,380	$127,812	$128,129	$127,352	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 4						
Basin TS Adv. P/M/C						
Capital Costs	$159,457	$134,771	$133,137	$106,774	$0	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 5						
Existing DG Connections M/C						
Capital Costs	$1,071,548	$1,086,790	$1,044,989	$0	$0	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 6						
New DG Connections M/C						
Capital Costs	$2,371,012	$1,407,652	$1,483,299	$1,626,380	$1,755,085	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 7						
DG SCADA Management						
Capital Costs	$1,887,974	$2,022,646	$106,510	$106,774	$106,127	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	

Project 8						
Energy Storage						
Capital Costs	$541,684	$1,087,616	$2,164,315	$3,239,819	$3,777,405	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Total Capital Costs	**$ 6,658,870**	**$ 6,273,166**	**$ 5,427,521**	**$ 5,341,343**	**$ 5,792,500**	/C
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	

Part B

Expansion Investments (Direct Benefit at 17%)	**2015**	**2016**	**2017**	**2018**	**2019**
Project 1					
Project Description					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

OEB Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2015 Test Year			2016			2017			2018			2019		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ 3,262,846	$ 195,771	$ 3,067,075	$ 9,466,367	$ 567,982	$ 8,898,385	$ 14,807,885	$ 888,473	$ 13,919,412	$ 19,458,797	$ 1,167,528	$ 18,291,269	$ 24,073,171	$ 1,444,390	$ 22,628,781
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	7.99%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ 195,771	$ 3,067,075		$ 567,982	$ 8,898,385		$ 888,473	$ 13,919,412		$ 1,167,528	$ 18,291,269		$ 1,444,390	$ 22,628,781
Deemed ST Debt	4%		$ 7,831	$ 122,683		$ 22,719	$ 355,935		$ 35,539	$ 556,776		$ 46,701	$ 731,651		$ 57,776	$ 905,151
Deemed LT Debt	56%		$ 109,632	$ 1,717,562		$ 318,070	$ 4,983,095		$ 497,545	$ 7,794,871		$ 653,816	$ 10,243,111		$ 808,859	$ 12,672,117
Deemed Equity	40%		$ 78,308	$ 1,226,830		$ 227,193	$ 3,559,354		$ 355,389	$ 5,567,765		$ 467,011	$ 7,316,508		$ 577,756	$ 9,051,512
ST Interest	1.38%		$ 108	$ 1,693		$ 314	$ 4,912		$ 490	$ 7,684		$ 644	$ 10,097		$ 797	$ 12,491
LT Interest	4.34%		$ 4,758	$ 74,542		$ 13,804	$ 216,266		$ 21,593	$ 338,297		$ 28,376	$ 444,551		$ 35,104	$ 549,970
ROE	9.30%		$ 7,283	$ 114,095		$ 21,129	$ 331,020		$ 33,051	$ 517,802		$ 43,432	$ 680,435		$ 53,731	$ 841,791
Cost of Capital Total			$ 12,149	$ 190,330		$ 35,247	$ 552,198		$ 55,135	$ 863,783		$ 72,452	$ 1,135,083		$ 89,633	$ 1,404,252
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ 133,177	$ 7,991	$ 125,187	$ 391,818	$ 23,509	$ 368,309	$ 625,832	$ 37,550	$ 588,282	$ 841,209	$ 50,473	$ 790,737	$ 1,063,886	$ 63,833	$ 1,000,053
Grossed-up PILs			-$ 255	-$ 3,999		$ 5,031	$ 78,819		$ 15,277	$ 239,338		$ 24,493	$ 383,725		$ 33,773	$ 529,104
Revenue Requirement			$ 19,884	$ 311,518		$ 63,787	$ 999,326		$ 107,962	$ 1,691,403		$ 147,418	$ 2,309,544		$ 187,239	$ 2,933,408
Provincial Rate Protection				$ 311,518			$ 999,326			$ 1,691,403			$ 2,309,544			$ 2,933,408
Monthly Amount Paid by IESO				$ 25,960			$ 83,277			$ 140,950			$ 192,462			$ 244,451

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis

Note 2: For the Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2015 Direct Benefit	2015 Provincial	2016 Direct Benefit	2016 Provincial	2017 Direct Benefit	2017 Provincial	Total	2018 Direct Benefit	2018 Provincial	Total	2019 Direct Benefit	2019 Provincial
Net Income - ROE on Rate Base	$ 7,283	$ 114,095	$ 21,129	$ 331,020	$ 33,051	$ 517,802		$ 43,432	$ 680,435		$ 53,731	$ 841,791
Amortization (6% DB and 94% P)	$ 7,991	$ 125,187	$ 23,509	$ 368,309	$ 37,550	$ 588,282		$ 50,473	$ 790,737		$ 63,833	$ 1,000,053
CCA (6% DB and 94% P)	-$ 15,981	-$ 250,374	-$ 30,684	-$ 480,717	-$ 28,229	-$ 442,260		-$ 25,971	-$ 406,879		-$ 23,893	-$ 374,329
Taxable income	-$ 708	-$ 11,092	$ 13,954	$ 218,612	$ 42,372	$ 663,824		$ 67,934	$ 1,064,293		$ 93,671	$ 1,467,515
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%		26.50%	26.50%		26.50%	26.50%
Income Taxes Payable	-$ 187.61	-$ 2,939.26	$ 3,697.80	$ 57,932.13	$ 11,228.52	$ 175,913.45		$ 18,002.40	$ 282,037.60		$ 24,822.86	$ 388,891.43
Gross Up												
Income Taxes Payable	-$ 255.25	-$ 3,998.99	$ 5,031.01	$ 78,819.22	$ 15,276.89	$ 239,338.02		$ 24,493.06	$ 383,724.62		$ 33,772.59	$ 529,103.99
Grossed Up PILs												

/C

Net Fixed Assets

		2015	2016	2017	2018	2019
Enter applicable amortization in years:	25					
Opening Gross Fixed Assets			$ 6,658,870	$ 12,932,036	$ 18,359,557	$ 23,700,900
Gross Capital Additions		$ 6,658,870	$ 6,273,166	$ 5,427,521	$ 5,341,343	$ 5,792,500
Closing Gross Fixed Assets		$ 6,658,870	$ 12,932,036	$ 18,359,557	$ 23,700,900	$ 29,493,401
Opening Accumulated Amortization			$ 133,177	$ 524,996	$ 1,150,827	$ 1,992,037
Current Year Amortization (before additions)			$ 266,355	$ 517,281	$ 734,382	$ 948,036
Additions (half year)		$ 133,177	$ 125,463	$ 108,550	$ 106,827	$ 115,850
Closing Accumulated Amortization		$ 133,177	$ 524,996	$ 1,150,827	$ 1,992,037	$ 3,055,923
Opening Net Fixed Assets		$ -	$ 6,525,692	$ 12,407,041	$ 17,208,730	$ 21,708,864
Closing Net Fixed Assets		$ 6,525,692	$ 12,407,041	$ 17,208,730	$ 21,708,864	$ 26,437,478
Average Net Fixed Assets		$ 3,262,846	$ 9,466,367	$ 14,807,885	$ 19,458,797	$ 24,073,171

UC

UCC for PILs Calculation

		2015	2016	2017	2018	2019
Opening UCC			$ 6,392,515	$ 5,881,114	$ 5,410,625	$ 4,977,775
Capital Additions (from Appendix 2-FA)		$ 6,658,870	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ 6,658,870	$ 6,392,515	$ 5,881,114	$ 5,410,625	$ 4,977,775
Half Year Rule (1/2 Additions - Disposals)		$ 3,329,435	$ -	$ -	$ -	$ -
Reduced UCC		$ 3,329,435	$ 6,392,515	$ 5,881,114	$ 5,410,625	$ 4,977,775
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ 266,355	$ 511,401	$ 470,489	$ 432,850	$ 398,222
Closing UCC		$ 6,392,515	$ 5,881,114	$ 5,410,625	$ 4,977,775	$ 4,579,553

OEB Appendix 2-FC
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.

Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.

Rate Riders are not calculated for Test Year as these assets and costs are already in the distributors rate base.

	2015 Test Year			2016			2017			2018			2019		
	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -			$ -			$ -

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis
Note 2: For the Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2015			2016			2017			2018			2019		
		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial	Total	Direct Benefit	Provincial	Total	Direct Benefit	Provincial
Net Income - ROE on Rate Base		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization (17% DB and 83% P)		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
CCA (17% DB and 83% P)		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Taxable income		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Tax Rate (to be entered)															
Income Taxes Payable		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Gross Up															
Income Taxes Payable		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Grossed Up PILs															

Net Fixed Assets	2015	2016	2017	2018	2019
Enter applicable amortization in years: 25					
Opening Gross Fixed Assets		$ -	$ -	$ -	$ -
Gross Capital Additions	$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization		$ -	$ -	$ -	$ -
Current Year Amortization (before additions)		$ -	$ -	$ -	$ -
Additions (half year)	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation

		2015	2016	2017	2018	2019
Opening UCC			$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -

ICM TRUE-UP – DEFERRAL PROPOSAL

1. INTRODUCTION

This schedule outlines Toronto Hydro's proposal for the treatment of its 2012-2014 Incremental Capital Module ("ICM") true-up.

In its Accounting Order in Toronto Hydro's 2012-2014 ICM application, the Ontario Energy Board ("OEB") ordered the utility to true-up the revenue requirement which was used to derive the ICM rate rider revenues for the ICM funding at a future date, on the basis of total annual revenue requirements based on the actual in-service assets of OEB-approved ICM segments.[1] Toronto Hydro's accounting process is not expected to have a final report of actual in-service additions ("ISAs") for 2014 until the second quarter of 2015. Therefore, Toronto Hydro proposes to defer the ICM true-up and bring forward a separate application in 2015, once actual ICM amounts are known.

2. PROPOSED APPROACH TO TRUE-UP

Toronto Hydro's 2012-2014 ICM application provided a detailed view into the utility's planned capital work based on the following hierarchy:

- Projects (10): the highest-level of work that can consist of one or more segments;
- Segments (24): a medium-level of work that consists of multiple jobs, and
- Jobs (hundreds): the most granular and detailed description of Toronto Hydro's capital activities.

In its Partial Decision and Order, the OEB approved Toronto Hydro's capital program at the level of the ICM segments[3] filed by the utility, with rate riders determined for each year calculated using a forecast of ISAs for the funded ICM segments. For example, "B1

[1] EB-2012-0064, Rate Order, 9 May 2013, pages 2-3.
[3] As discussed in Exhibit 2B, ICM capital segments are comparable to DSP programs in this application.

Underground Infrastructure" and "B2 Paper Insulated Lead Covered Cable – Piece Outs and Leakers" were both approved ICM segments. Toronto Hydro's rate riders were determined based on the cumulative forecast ISAs of the segments that were approved for rate rider funding.

The OEB contemplated the need to true-up to accommodate differences between forecast and actual expenditures at the segment level. Individual jobs within each segment may vary for a number of reasons, including (i) difference between cost forecast and actuals; (ii) prudent addition and removal of jobs from segments; (iii) the fact that jobs may come into service in a different calendar year than originally forecast.[4]

Upon determining final expenditures and ISAs by segment, Toronto Hydro proposes to complete the ICM workforms using these actual in-service amounts, as stipulated in the OEB's Accounting Order. On an annual basis, the recalculated actual revenue requirement will be compared to revenues collected through the respective rate rider to determine variances due to under-spend or prudent over-spend. The OEB determined that these variances would be returned to, or collected from, customers through a separate rate rider.

The steps described above are necessary precursors to truing-up ICM revenue requirement and actual ISAs. Toronto Hydro does not expect to be able to determine the required 2014 actual expenditures or ISAs in accordance with the likely timeframe of this proceeding. Toronto Hydro therefore submits that the true-up of the 2012-2014 ICM activities is most appropriately undertaken in a separate proceeding from this application, following the determination of actual expenditures and ISAs for the full 2012-2014 ICM period.

[4] For a discussion of operational factors that may lead to variances between planned and actual work, please see the "Execution Challenges" section in Exhibit 1B, Tab 1, Schedule 4, Appendix A (Execution Challenges)

SERVICE QUALITY PERFORMANCE

Toronto Hydro's service quality performance has been steady in most metrics over the five previous years, meeting or exceeding OEB standards in all areas, with the exception of the Appointment Rescheduling and Emergency Response metrics. A summary table of Toronto Hydro's performance, OEB Appendix 2G, is provided in Tab 10, Schedule 3. Detailed explanations of notable variances and results below OEB standards are described below.

1. APPOINTMENT RESCHEDULING

This metric requires utilities to contact a customer in advance of missing an appointment and reschedule a replacement appointment within two business days. As discussed below, Toronto Hydro did not meet the OEB's 100% standard for this metric in 2009, 2012, or 2013. When these three years are combined, Toronto Hydro had 50,251 customer appointments, 235 of which were missed, and of these only three were not rescheduled within two business days. /C

Toronto Hydro's results under this metric are more a function of the mathematical data than an underlying performance issue. Toronto Hydro focuses its efforts primarily to meet as many appointments as possible, such that very few are actually missed on an annual basis. When one of these very few missed appointments is subsequently not rescheduled in accordance with the OEB's performance metrics, it results in a fairly dramatic impact in percentage terms. For example, in 2009 of 23,027 total appointments with customers, only 82 were missed, of which only 1 was not rescheduled within the parameters of this metrics. Similarly, in 2012 and 2013, of 12,547 and 14,677 total appointments with customers, only 91 and 61 were missed, of which only 1 each were not properly rescheduled. As shown in Table 1 below, the number of appointments not rescheduled within the parameters of the Appointment Rescheduling metric are /C

immaterial as a percentage of the total.

Table 1: Appointments Rescheduling Summary

Year	Total Appointments	Appointments Missed	Appointments Not Rescheduled within 2 business days	Appointment Rescheduling ESQR	Appointments Not Rescheduled as a percentage of Total Appointments
2009	23,027	82	1	98.8%	99.9999%
2012	12,547	91	1	98.9%	99.9999%
2013	14,677	61	1	98.4%	99.9999%

/C

2. TELEPHONE ACCESSIBILITY

This metric requires utilities to respond to a customer's call within 30 seconds at least 65% of the time. Toronto Hydro has consistently exceeded this standard. The utility did experience a slight decline in performance in 2010 and 2011. This was primarily a result of pre- and post-business activities and training associated with converting to a new Customer Information System. In 2012, Toronto Hydro introduced a new customer care business model to better serve customer needs and improve efficiency by directing residential calls and simple clerical tasks to an external call centre, while internally retaining the complex work associated with business customers. During the three-month transition to this new model, the service level response time was temporarily affected but continued to exceed the OEB standard. This period is reflected in the annual results.

3. WRITTEN INQUIRY RESPONSE

The written response metric requires utilities to respond to customers' written inquiries within ten days at least 80% of the time. Toronto Hydro has consistently exceeded this standard, but did experience a slight decline in performance in 2012. The transition to a new customer care business model, combined with a large increase in inquiries in the month of November regarding an issue related to ePost (an external electronic bill

presentment service) slightly affected the annual results, which still exceed the OEB standard.

4. EMERGENCY RESPONSE

The Emergency Response metric requires utilities to respond to emergency calls within one hour in urban settings at least 80% of the time. Toronto Hydro exceeded this metric in 2010 and 2011, but had difficulties meeting it in 2009, 2012 and 2013. In these years, Toronto Hydro underperformed by between 0.5% and 7.5%. In all three years, but in 2012 and 2013 in particular, the major contributing factor to underperformance were the timing and severity of Major Event Days ("MEDs") – typically storms – which may not allow for a timely response to all (often simultaneous) emergency calls.

In 2012, the weather originating from Tropical Storm Sandy alone was responsible for 8% of all emergency incidents in 2012. Given the severity of the storm, THESL was only able to achieve a response target of 20% during this event. In addition, five of the eight MEDs in 2012 occurred after-hours, during which fewer resources were available for immediate dispatch, and once these were fully-engaged there was an unavoidable time delay before additional crews could be mobilized. With even a portion of these MEDs excluded or normalized, THESL's performance would have exceeded the 80% standard in 2012.

Similarly, in 2013 Toronto Hydro's underperformance was also the result of MEDs (8 of 10 of which occurred after hours) particularly the ice storm in December. This five-day period alone accounted for 16% of the yearly volume of emergency events, meaning that Toronto Hydro achieved an hourly response rate of 15% during the month of December. As a result of the ice storm, Toronto Hydro's annual year-to-date performance dropped from 86% as of December 21 to 74% by December 31, only ten days later.

In addition to emergencies originating from Police, Fire, or Ambulance (as per the definition of this metric), Toronto Hydro responds with the same priority to any emergency situation reported by any other member of the public. Therefore, the number of true emergency incidents (i.e., any for which THESL dispatches a crew on an emergency basis) is substantially higher than reported.

Nonetheless, Toronto Hydro is committed to continuing to improve its Emergency Response during the 2015-2019 period, and has planned investments to allow for a more timely response by its emergency response crews. Please refer to Exhibit 4A, Tab 2, Schedule 3 for additional details.

RELIABILITY PERFORMANCE

1. INTRODUCTION

Toronto Hydro tracks reliability performance indicators System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), and Customer Average Interruption Duration Index ("CAIDI") in several ways:

1) including all events;
2) excluding Loss of Supply;
3) excluding Major Event Days ("MEDs") and Loss of Supply; and
4) excluding MEDs, Loss of Supply, and Scheduled Outages

Scenarios 1 and 2 provide SAIFI and SAIDI in the filing manner required by OEB Appendix 2-G (Exhibit 2A, Tab 10, Schedule 3). Scenarios 3 and 4 provide SAIFI and SAIDI values by excluding additional externalities and controllable outages, to give a more normalized reflection of total system reliability. Each of these values provides valuable information as to the causes, duration, and frequency of outages within Toronto Hydro's distribution system.

2. SYSTEM OVERVIEW

Figures 1 and 2 below show the system total SAIFI and SAIDI between 2009 and 2013, respectively under each of the four scenarios. The notable increase in SAIFI and SAIDI in 2013 under scenarios 1 and 2 can be attributed to the flooding of Manby TS in July and the Ice Storm in December, both of which were MEDs. Under scenarios 3 and 4, (which exclude MEDs and other externalities, as well as planned outages), there is actually a slight overall downward trend in both SAIFI and SAIDI, suggesting improving system performance. Toronto Hydro places greater value in these latter scenarios (which exclude MEDs) since they provide a better indication of the performance trend of the

system and the impact of recent investments, and are more commonly used across the industry for benchmarking against past performances.

Figure 1: System Level SAIFI

Figure 2: System Level SAIDI

3. LOSS OF SUPPLY

Loss of Supply events have a significant impact on the overall reliability of Toronto Hydro's distribution system, and being external to Toronto Hydro's operations and control, are generally excluded from a system reliability analysis. In 2013, a total of 54 Loss of Supply events affected the system, with 17 such events occurring in 2012. On a system level, Loss of Supply typically affects up to 13% of the SAIFI and 10% of the SAIDI. Figures 3 and 4 below show the SAIFI and SAIDI system impact due to Loss of Supply.

Figure 3: Loss of Supply Impact on Total SAIFI

Figure 4: Loss of Supply Impact on Total SAIDI

3.1. Major Event Days

Major Event Days ("MEDs") are defined by the Institute of Electrical and Electronics Engineers ("IEEE") as "events that are beyond the design and/or operational limits of a utility." Similarly to Loss of Supply events, MEDs are generally external to routine utility operation, and in addition, are highly volatile from year to year. The exclusion of MEDs allows a utility to normalize its reliability data to make trending and goal setting possible. MEDs experienced by Toronto Hydro since 2003 are shown in Table 1 below:

Table 1: Major Event Days

Date	Description	SAIDI
Aug 14 - 15, 2003	Blackout	2 days
Sep 19, 2003	Hurricane Isabel	8.01 minutes
Jul 26, 2005	Loss of Supply to Esplanade TS	6.93 minutes
Aug 19, 2005	Major storm (thunderstorm)	19.16 minutes
Aug 20, 2005	Major storm (thunderstorm)	6.44 minutes
Jul 17, 2006	Major storm (thunderstorm)	12.46 minutes
Aug 21, 2006	Loss of Supply to Scarborough TS	7.30 minutes

Date	Description	SAIDI
Mar 2, 2007	Major ice storm	24.21 minutes
Jun 8, 2007	Major storm (thunderstorm)	11.63 minutes
Jan 15, 2009	Dufferin TS flooding	54.98 minutes
Apr 25, 2009	Major storm (thunderstorm)	12.69 minutes
Aug 20, 2009	Major storm (thunderstorm)	13.69 minutes
Aug 22, 2009	Major storm (thunderstorm)	10.42 minutes
Jul 5, 2010	Loss of Supply to Manby TS	21.61 minutes
Oct 29, 2012	Hurricane Sandy	9.37 minutes
Oct 30, 2012	Hurricane Sandy	18.83 minutes
Jul 8, 2013	Major storm (thunderstorm)	197.26 minutes
Jul 9, 2013	Major storm (thunderstorm)	7.60 minutes
Dec 21, 2013	Freezing Rain Ice Storm	263.90 minutes
Dec 22, 2013	Freezing Rain Ice Storm	683.13 minutes
Dec 23, 2013	Freezing Rain Ice Storm	16.19 minutes
Dec 24, 2013	Freezing Rain Ice Storm	12.30 minutes
Dec 25, 2013	Freezing Rain Ice Storm	7.65 minutes
Dec 26, 2013	Freezing Rain Ice Storm	7.53 minutes

3.2. Scheduled Outages

Scheduled Outages are associated with construction and preventative maintenance activities. Assets that are at risk of failing in the near future may be taken out of service to be repaired or replaced. While this can lead to lengthy outages, the duration of the outage would generally be much shorter than those caused by the asset failing during regular operation. Such planned replacements are also often required to mitigate safety risks to Toronto Hydro's employees. Toronto Hydro provides customers advanced notification of any impending work prior to engaging the project, which gives them the opportunity to plan their activities around the repair work. As planned outages do not reflect the inherent performance of the distribution system, they are typically excluded from reliability analysis.

Figure 5: Scheduled Outages Impact on Total SAIFI

Figure 6: Scheduled Outages Impact on Total SAIDI

4. SYSTEM RELIABILITY EXCLUDING LOSS OF SUPPLY, MAJOR EVENT DAYS AND SCHEDULED OUTAGES

As noted above, Toronto Hydro has minimal control over Major Event Days and Loss of Supply events. As a result, these factors are typically excluded from analysis of the overall system performance. In addition, Scheduled Outages are required in order to replace assets that are at their end of life and are not a reflection of distribution system performance. As such, they are also typically excluded from the analysis of the overall system performance. Figures 7, 8, and 9 below show the adjusted SAIFI, SAIDI, and CAIDI (excluding Loss of Supply, MEDs, and Scheduled Outages).

The year over year adjusted values show steady improvement over the years, with a dramatic improvement in 2012 for both SAIFI and SAIDI. While a part of this is a result of Toronto Hydro's investment strategy, which has focused on replacing old and aging infrastructure and reducing outages caused by defective equipment, the majority of the 2012 improvement can be attributed to favourable weather conditions and a decrease in overall wind speeds. This is further shown in the cause code breakouts in Figures 10 and 11, and highlighted in the weather related breakouts in Figures 12 and 13.

Figure 7: System SAIFI Excluding MEDs, Loss of Supply and Scheduled Outages

Figure 8: System SAIDI Excluding MEDs, Loss of Supply and Scheduled Outages

Figure 9: System CAIDI Excluding MEDs, Loss of Supply and Scheduled Outages

5. CAUSE CODE ANALYSIS

Toronto Hydro tracks causes of service interruptions using the ten primary cause codes as specified in OEB's Reporting and Record Keeping Requirements. Figures 10 and 11 show the reliability performance for SAIFI and SAIDI by cause code from 2009 through 2013. Table 2 shows the percentage contribution of each cause code to overall system SAIFI and SAIDI.

Figure 10: SAIFI Cause Code Breakdown (Excluding MEDs)

Figure 11: SAIDI Cause Code Breakdown (Excluding MEDs)

Table 2: Five-Year Average SAIFI and SAIDI Contribution by Cause Code

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
Defective Equipment	41.1%	44.3%
Unknown	12.0%	2.6%
Loss of Supply*	9.6%	5.9%
Foreign Interference	9.3%	9.4%
Tree Contacts	9.0%	12.8%
Adverse Weather	8.7%	11.3%
Lightning	3.5%	5.2%
Scheduled Outage*	3.2%	6.2%
Human Element	2.7%	1.0%
Adverse Environment	0.8%	1.3%

* Excluded from typical system analysis when demonstrating the true condition of THESL's system

Between 2009 and 2013, defective equipment was the main contributor to SAIFI and SAIDI, at 41.1% and 44.3% respectively. As shown in Figures 10 and 11, the majority of improvement in SAIFI and SAIDI in 2013 over the previous years is in Defective Equipment and, to a lesser extent, Adverse Environment and Lightning. Outages due to Adverse Environment and Lightning are typically not reflective of the condition of the assets in the system, but rather the environmental stresses that the assets experience. Toronto Hydro views the Defective Equipment cause code as a primary indicator of the condition of its distribution system, and tracks this cause code as a measure of continuous improvement over the course of its capital expenditure and maintenance plans. Additional analysis of various relevant cause codes is provided below.

5.1. Weather Impacts

Three cause codes can generally be combined to reflect weather impacts on the system:

(a) Adverse Weather,

(b) Lightning, and

(c) Tree Contacts

Figures 12 and 13 show the cumulative weather reliability impacts on the system.

Figure 12: Weather Impacts to SAIFI

Figure 13: Weather Impacts to SAIDI

Weather impacts on the distribution system account for a significant portion of total system SAIFI and SAIDI. In 2013 weather related causes attributed 11% to the annual SAIFI and nearly 40% to the annual SAIDI. While volatile from year to year, the three cause codes combined provide a more accurate reflection of the impact of weather events on the system. Figures 12 and 13 above demonstrate that a large portion of the SAIFI and SAIDI improvements in 2012 can be attributed to favorable weather conditions, while part of the decline in 2013 relative to 2012 can be attributed to a return to more typically normal weather patterns.

5.2. Foreign Interference Impacts

Foreign interference consists of outages caused by animal contact, dig-ins, vehicles, and other foreign objects. Though there are different ways to mitigate foreign interference, such as installing animal guards or moving assets to more secure locations, the yearly performance is generally more volatile to single events. Figures 14 and 15 below show the foreign interference impacts on Toronto Hydro's distribution system.

Figure 14: Foreign Interference – Root Cause SAIFI

Figure 15: Foreign Interference – Root Cause SAIDI

Of the four sub-categories, animal contact is one of the most "controllable", in that Toronto Hydro is able to reasonably install measures to effectively militate against the risk. Toronto Hydro's capital programs include animal guard replacement activities for this purpose (see the Overhead Circuit Renewal program, Exhibit 2B, Section E6.4, and the Worst Performing Feeder program, Exhibit 2B, Section E6.21), with new standard animal guards that eliminate a physical point of contact with live equipment and insulate all critical components. Since the start of animal guard replacement activities in 2010, animal contact has had a slight downward trend for both SAIFI and SAIDI. The remaining sub-categories are far more variable and generally beyond Toronto Hydro's direct control. For example, 13% of the foreign interference SAIDI for the year 2012 was attributed to a single incident, occurring on August 20th 2012, where a construction crane fell onto Toronto Hydro overhead lines. Similarly, on January 31st, 2012, contractors dug into Toronto Hydro's underground cable causing repeated disruptions that added up to 12% of the foreign interference SAIFI for the year.

5.3. Defective Equipment Impacts

As shown in Figures 16 and 17, the contribution of defective equipment to Toronto Hydro's SAIFI and SAIDI has remained relatively stable, with the exception of the overhead system sub-cause code, which has seen a considerable reduction in outages.

Figure 16: Defective Equipment SAIFI

Figure 17: Defective Equipment SAIDI

5.4. Overhead Defective Equipment

In the overhead sub-cause codes (Figures 18 and 19 below) the majority of the customer interruptions are caused by pole and pole hardware failures, as well as overhead switches. This is mainly due to the magnitude of these types of failures, which often disable large sections of feeders. Toronto Hydro has experienced an improvement in the SAIFI and SAIDI trend across all sub-categories, but particularly poles and pole hardware. This can be attributed to the extensive investment program that Toronto Hydro has been undertaking over the past years, with many overhead rebuilds and an aggressive porcelain insulator replacement program. Programs such as Rear Lot Conversion (see Exhibit 2B, E6.6) and Box Construction Conversion (see Exhibit 2B, E6.7) have also contributed to the improvement of the Overhead System. To maintain this result, Toronto Hydro plans to continue this effective replacement program throughout 2015-2019.

Figure 18: Defective Equipment SAIFI - Overhead

Figure 19: Defective Equipment SAIDI - Overhead

5.5. Underground Defective Equipment

In the underground sub cause code (Figures 20 and 21 below), underground cable faults dominate both the SAIFI and SAIDI indices and are the biggest equipment related cause of interruptions in Toronto Hydro's system. The majority of these failures are due to direct buried cables. Despite a heavy emphasis on the replacement of these cables over the past few years, the number of these cables reaching end of life or showing accelerated deterioration continues to increase. This trend supports the need to continue investment in replacing Direct Buried Cables, as detailed in Exhibit 2B, E6.1.

Figure 20: Defective Equipment SAIFI - Underground

Figure 21: Defective Equipment SAIDI - Underground

OEB Appendix 2-G
Service Reliability Indicators
2009 - 2013

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2009	2010	2011	2012	2013	2009	2010	2011	2012	2013
SAIDI	2.900	1.660	1.430	1.500	21.190	2.760	1.190	1.380	1.450	17.810
SAIFI	1.860	1.950	1.620	1.600	2.910	1.710	1.540	1.480	1.470	2.390

5YearHistorical Average

SAIDI		5.736		4.918
SAIFI		1.988		1.718

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2009	2010	2011	2012	2013	
LowVoltage Connections	90.0%	96.6%	96.2%	94.0%	92.5%	94.2%	
HighVoltage Connections	90.0%	99.0%	99.2%	98.6%	99.3%	100.0%	
TelephoneAccessibility	65.0%	83.7%	69.9%	72.7%	76.9%	82.0%	
AppointmentsMet	90.0%	99.7%	99.9%	99.6%	99.3%	99.6%	
WrittenResponse to Enquires	80.0%	99.3%	97.5%	91.4%	86.5%	98.9%	
EmergencyUrban Response	80.0%	79.5%	83.0%	83.4%	72.5%	74.4%	
EmergencyRural Response	80.0%	n/a	n/a	n/a	n/a	n/a	
TelephoneCall Abandon Rate	10.0%	0.9%	2.5%	2.4%	1.7%	1.2%	
AppointmentScheduling	90.0%	96.5%	95.6%	97.6%	97.3%	96.6%	
ReschedulingaMissed Appointment	100.0%	98.8%	100.0%	100.0%	98.9%	98.4%	/C
ReconnectionPerformance Standard	85.0%	N/A	N/A	N/A	99.8%	100.0%	
MicrorEmbeddedGeneration Facilities	90.0%	N/A	N/A	N/A	N/A	100.0%	

DISTRIBUTION SYSTEM PLAN
2015 - 2019



TORONTO HYDRO®

Distribution System Plan (DSP)

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Distribution System Plan (DSP)

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1 Introduction

Toronto Hydro produced this Distribution System Plan (DSP) in close accordance with Chapter 5 of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission & Distribution Applications (Chapter 5). As prescribed in Chapter 5, this DSP describes Toronto Hydro's asset management process and capital expenditure plan, while also providing information pertaining to Toronto Hydro's coordination with third parties, identification of customer preferences, and proposed performance measures to be applied over the course of the plan.

Toronto Hydro has produced a DSP designed to provide the OEB and customers with an accessible, plain-language view of the distributor's investment plans for the five year planning horizon (also referred to as the forecast period) of 2015-2019, while illustrating how the utility plans to meet the expectations set out in the Renewed Regulatory Framework for Electricity (RRFE). Toronto Hydro believes that its plan is designed to address the needs and preferences of the utility's customers by presenting optimized investments that support (1) the achievement of public policy objectives, (2) the need for a significant level of investment in Toronto's distribution system and (3) the overriding objective of delivering value for money.

(i) DSP Organization

The DSP provides the OEB and customers with detailed information and justification on the material investments that Toronto Hydro plans to make during the period from 2015 to 2019. Toronto Hydro has adopted the requirements set out in Chapter 5, dividing the DSP into the following five chapters:

- Chapter A – Distribution System Plan Overview: Provides an introductory overview of the DSP, including (1) the purpose, background and objectives, (2) declaration of capital investment drivers and expected cost savings and (3) an overview of Toronto Hydro's asset management (AM) process with discussion on what has changed within that process from previous filings.

- Chapter B – Coordinated Planning with Third Parties: Provides information on how Toronto Hydro's DSP aligns to broader regional planning efforts, and shares information with respect to the various consultation processes that were executed.

- Chapter C – Performance Measures for Continuous Improvement: Provides information with respect to the selected measures that Toronto Hydro plans to use in order to track

continuous improvement of planning, execution and outcomes of investments over the course of the planning horizon.

- Chapter D – Asset Management Process: Provides information with respect to Toronto Hydro's long-term, short-term and maintenance planning processes, which are used to produce the capital investment plan described in Chapter E.

- Chapter E – Capital Expenditure Plan: Provides information on how Toronto Hydro has applied its Asset Management Process to the utility's distribution system in order to produce the capital investments contemplated by the DSP. This section also contains the detailed description and justification of material investments planned for the five-year forecast period.

(ii) Capital Programs and Drivers

Chapter 5 includes incremental filing requirements for projects/activities that meet the distributor's materiality threshold. Toronto Hydro has applied these filing requirements to a series of 46 unique capital programs, all of which contain over $1 million in spending over five years, and which are grouped according to the OEB's defined investment categories (i.e. System Access, System Renewal, System Service and General Plant). These programs are groups of projects or activities that are similar in nature and that share the same basic justification and business case elements. In accordance with the organization framework established in Chapter 5, Toronto Hydro has assigned a single "trigger" driver to each capital program along with any applicable secondary drivers. With the exception of two programs in the General Plant category, Toronto Hydro has generally adhered to the example drivers provided for specific investment categories by the OEB in Table 1 of the Chapter 5. The following table illustrates how Toronto Hydro's chosen trigger drivers map to the drivers listed in Chapter 5. A summary of forecast expenditures by trigger driver is provided in section E1.2.2 of the DSP.

TABLE 1: OEB EXAMPLE DRIVERS AND TORONTO HYDRO EQUIVALENTS

	Example Drivers	Example Projects / Activities	Toronto Hydro Trigger Drivers
System Access	Customer service requests	• New customer connections • Modifications to existing customer connections • Expansions for customer connections	Customer Service Requests

	Example Drivers	Example Projects / Activities	Toronto Hydro Trigger Drivers
		or property development	
	Other third party infrastructure development requirements	ƒ System modifications for property or infrastructure development (e.g. relocating pole lines for road widening)	Third Party Requests
	Mandated service obligations (DSC; Conditions of Service.; etc.)	ƒ Metering ƒ Long-term load transfer	Mandated Service Obligations
System Renewal	Assets/asset systems at end of service life due to: ƒ Failure ƒ Failure risk ƒ Substandard performance ƒ High performance risk ƒ Functional obsolescence	Programs to refurbish/replace assets or asset systems (e.g.: batteries; cable (by type); cable splices; civil works; conductor; elbows and inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)	ƒ Failure ƒ Failure Risk ƒ Functional Obsolescence
System Service	Expected changes in load that will constrain the ability of the system to provide consistent service delivery	ƒ Property acquisition ƒ Capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation ƒ Line extensions	Capacity Constraints
	System operational objectives: ƒ Safety ƒ Reliability ƒ Power quality ƒ System efficiency ƒ Other performance/	ƒ Protection & control upgrades; e.g. reclosers; tap changer controls/relays; transfer trip ƒ Automation (new/upgrades) by device type/function ƒ SCADA ƒ Distribution loss reduction	ƒ Safety ƒ Reliability ƒ System Efficiency

	Example Drivers	Example Projects / Activities	Toronto Hydro Trigger Drivers
	functionality		
General Plant[1]	ƒ System capital investment support ƒ System maintenance support ƒ Business operations efficiency ƒ Non-system physical plant	ƒ Land acquisition ƒ Structures & depreciable improvements ƒ Equipment and tools ƒ Supplies ƒ Finance/administrative/billing software and systems ƒ Rolling stock ƒ Intangibles (e.g. land rights; capital contributions to other utilities)	System Maintenance and Capital Investment Support

For a complete summary of capital programs, including brief descriptions and total program expenditures, please refer to Section 7 of this executive summary. Full details and justification for all capital programs is provided in sections E5 through E8 of the DSP.

2 Distribution System Plan Objectives

Toronto Hydro's 2015-2019 Capital Expenditure Plan (see Chapter E) reflects the utility's need for a sustained period of capital investment to replace and expand the City's aging distribution infrastructure. The suite of capital programs and projects within the DSP are based on system needs and opportunities as identified through Toronto Hydro's asset management process and informed by the utility's asset management policy objectives (discussed in detail in Chapter D).

Figure 1 illustrates the overall level of spending, grouped by the OEB's specified investment categories (for a detailed discussion of expenditures on a category basis, see Section E4). This level of investment is required primarily to address a large and growing backlog of end-of-life and obsolete assets, while also addressing critical system challenges and operational needs at a pace and in a manner that moderates rate increases and is consistent with customer preferences.

[1] Toronto Hydro elected to use Functional Obsolescence and Safety as trigger drivers for two General Plant programs.



FIGURE 1: CAPITAL INVESTMENT REQUIREMENTS BY CATEGORY[2] (2015-2019)

2.1 Capital Investment Needs and Opportunities

This section provides an overview of the system and operational investment needs facing Toronto Hydro during the 2015-2019 forecast period and a discussion of the utility's long-term asset management objectives. For a comprehensive discussion of Toronto's existing distribution system assets, configurations, climate and utilization please refer to Section D2.

(iii) System Pressures: Aging and Obsolete Assets

Toronto Hydro's distribution system faces a number of significant and evolving challenges that necessitate the proposed level of investment. The foremost of these challenges is the large and growing backlog of in-service assets that are operating beyond their expected useful lives, which is reflected in the large percentage of System Renewal investments in all five years of the expenditure plan. To illustrate the rate of system aging, Figure 2 breaks the existing in-service asset base into three portions:

[2] The "Other" investment category includes forecast expenditures related to inflation, road cut repairs, and other capital expenditures that are unrelated to specific capital programs. For a complete explanation of this expenditures, refer to Section E4.2.5.

1. the forecast percentage of assets that Toronto Hydro anticipates will be operating beyond end-of-life as of 2015;

2. the forecast percentage of assets that are expected to reach or surpass end-of-life by 2020 should Toronto Hydro adopt a "run-to-failure" approach (i.e. executing a capital expenditure plan with minimal proactive asset replacement); and

3. the percentage of assets that are forecast not to have reached end-of-life in 2020.

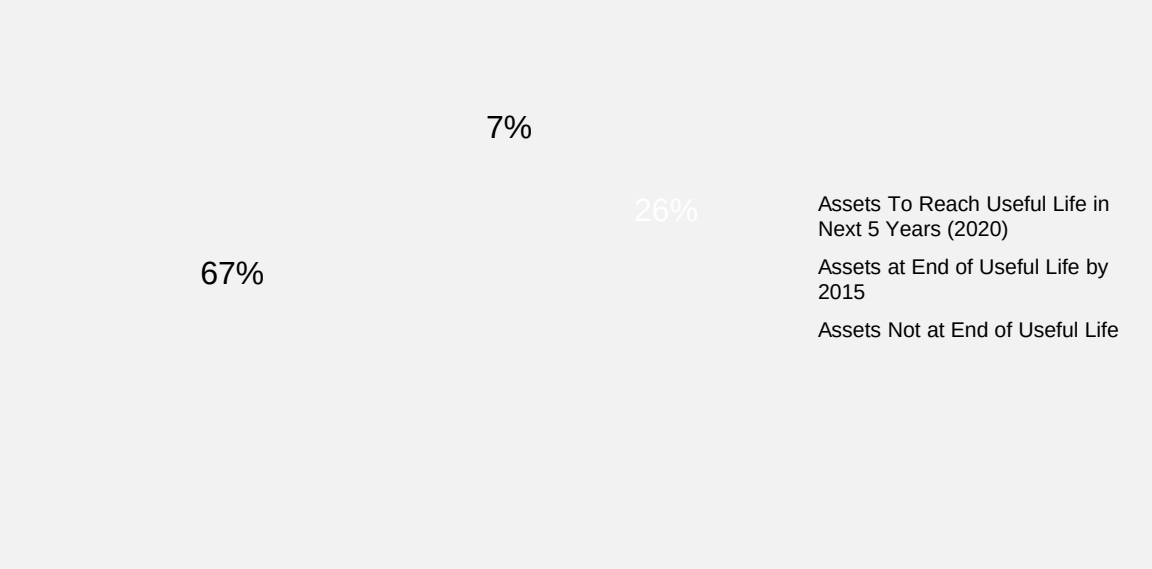


FIGURE 2: USEFUL LIFE DEMOGRAPHICS – 2015 TO 2020 ('RUN TO FAILURE' APPROACH)

The figure above shows that, without a proactive intervention strategy, approximately 32% of existing assets are forecast to be operating beyond end-of-life by the end of the five-year planning horizon contemplated by the DSP. As described later in this section, Toronto Hydro's long-term asset management objective is to reduce the percentage of assets operating beyond end-of-life at any given time until a theoretically optimal "steady-state" is achieved, at which point the capital needs of the system are generally balanced with the overall asset risk costs so that the cost of operating the system over time is minimized, in effect maximizing the value that customers and the utility derive from the existing asset base.

Setting aside this longer-term objective, the consequences of allowing the backlog of aging assets to continue to grow can be illustrated by comparing the forecast reliability outcomes of Toronto Hydro's proposed five-year capital plan to a run-to-failure approach over the same time period. Figures 3 and 4 illustrate these projections for the System Average Interruption Duration

Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). (A detailed discussion of these reliability forecasts is provided in Section E2).

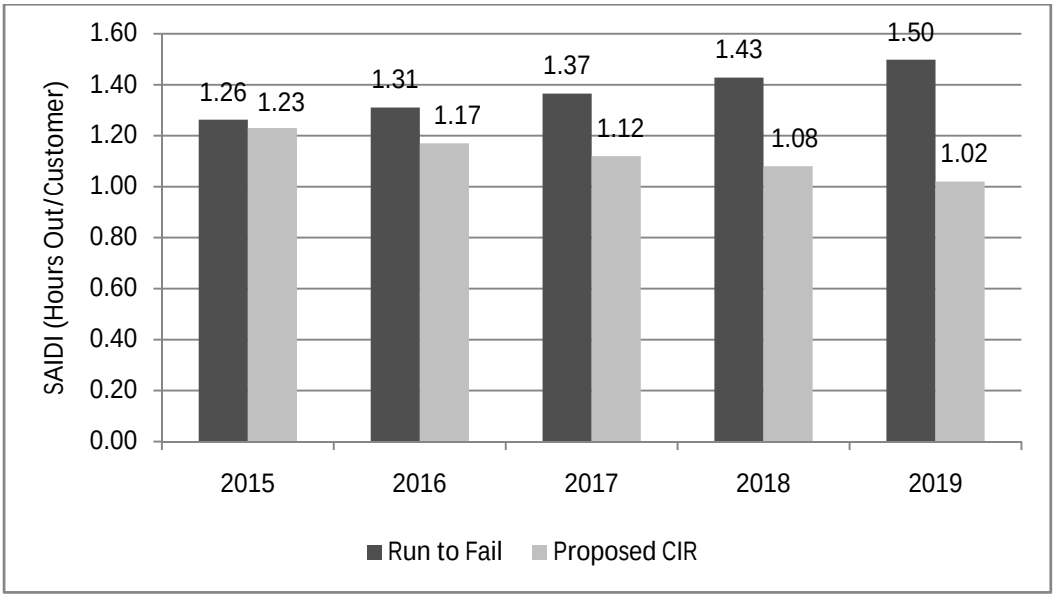


FIGURE 3: FIVE-YEAR SAIDI PROJECTION

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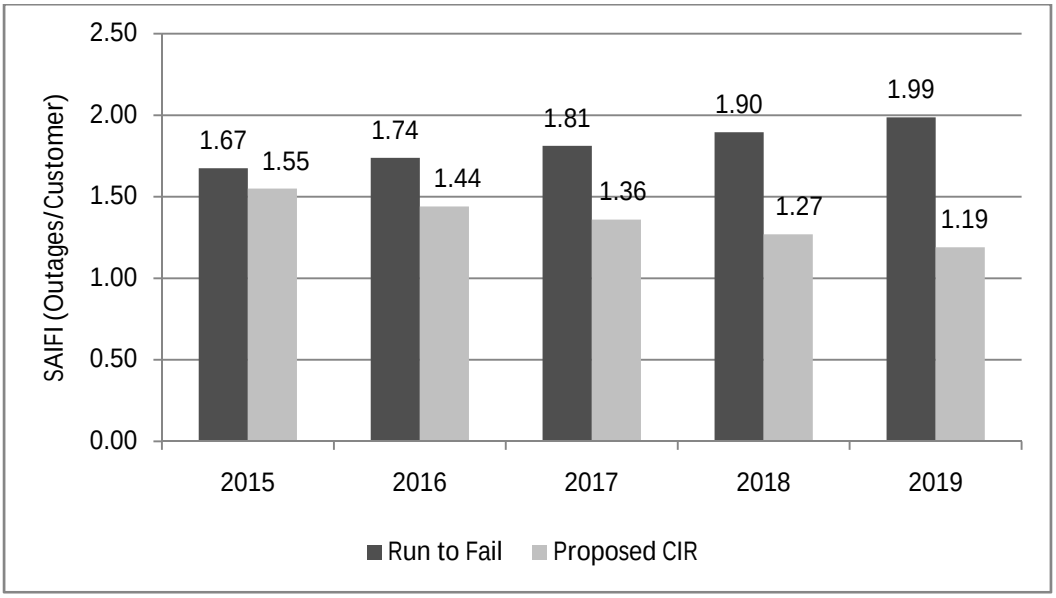


FIGURE 4: FIVE-YEAR SAIFI PROJECTION

The forecast improvement in reliability associated with Toronto Hydro's proposed capital plan is due in part to the ongoing renewal of aging and defective assets, but is also an expected outcome of a small number of targeted, high-value System Service programs such as Feeder Automation (E7.3) and Design Enhancement (E7.2), which are forecast to deliver significant improvements in system performance and operational efficiency for a level of annual investment that is relatively small compared to the typical renewal program. These cost-effective interventions should allow Toronto Hydro to enhance customer value through system reliability and efficiency improvements while executing core renewal programs at a moderate pace.

(iv) System Pressures: Economic Growth and Capacity Constraints

Toronto's distribution system continues to face utilization pressures related to economic growth and evolving system use. Examples of this include the following.

- Capacity constraints (System Access and System Service): A number of Toronto Hydro's station busses are currently overloaded; forecast load growth is expected to exacerbate these issues during the 2015-2019 planning horizon and beyond. The DSP proposes to address these concerns through targeted, near-term interventions (Load Demand, E5.4); medium to long-term capacity expansions (Stations Expansion, E7.9); and other, targeted means (e.g. Local Demand Response, E7.10).

- Externally initiated projects (System Access): The number of large third party infrastructure renewal and expansion projects across the City of Toronto is expected to significantly increase the amount of externally initiated plant relocations projects that Toronto Hydro will be required to carry-out during the 2015-2019 forecast period. Major projects that could drive investment during this period include the Metrolinx light rail transit projects and the electrification of the GO rail service between Pearson airport and Union Station.

- Accommodating distributed generation (DG) (System Access): DG connections, consisting mostly of renewable energy generation (REG) facilities, are expected to more than triple in total capacity by 2019, reaching over 625 MW. Toronto's distribution system is not presently equipped to accommodate this level of DG penetration, and a series of renewable enabling improvements will be required within the forecast period in order for Toronto Hydro to continue fulfilling its obligation to safely and reliably connect generators.

For a comprehensive discussion of forecast system development, including load and customer growth, smart grid development and capacity to accommodate forecast renewable energy

generation growth, see Section E1.3.

(v) System Pressures: Critical Issues

Toronto Hydro also plans to address a number of critical distribution system issues that go beyond core renewal and capacity/utilization concerns. These System Service investments include potential safety issues (e.g., Polymer SMD-20 Switch Renewal, E7.6), system design deficiencies (e.g., Contingency Enhancement, E7.1), and reliability issues (e.g., Customer-Owned Substation Protection, E7.8).

(vi) System Pressures: Climate Change

On July 8, 2013, and December 22, 2013, the City of Toronto was hit with two different types of extreme weather (a flood and an ice storm, respectively) that had widespread adverse affects on the distribution system. An AECOM-Toronto Hydro report entitled Future Impacts of Climate Change on Toronto Hydro's Distribution System (E8.8, Appendix A) concludes that weather and climate change can be expected to impact the reliability of the distribution system going forward, and that Toronto Hydro will be required to manage assets that may not have been designed for future climate conditions. Climate change forecasts anticipate growing pressures such as increases in extreme maximum temperatures and increases in intensity of rainfall events.

FIGURE 5: HEAVY RAINS WASH-OUT THE BASE OF A POLE IN THE DON VALLEY (JULY 2014)

A number of Toronto Hydro's planned investments in the DSP are expected to improve system performance during major storm events. For example, the Overhead Infrastructure Relocation program (E6.5), as part of end-of-life asset renewal, relocates vulnerable and difficult to access pole lines from areas such as heavily treed ravines and highway crossings. Other renewal programs that replace obsolete and difficult to access feeders (e.g., Rear Lot Conversion, E6.6; Box Construction Conversion, E6.7) are expected to have similar performance benefits during storm events.

Non-renewal programs are also expected to improve system and operational performance during storm events. For example, Feeder Automation (E7.3) is expected to significantly improve fault isolation, location and restoration on feeder trunks, simplifying restoration efforts during certain types of major storm events and freeing up resources for reactive repairs on lateral sections of feeders. Targeted, high-value programs such as Contingency Enhancement (E7.1), Downtown Contingency (E7.7) and Design Enhancement (E7.2) are expected to improve system performance during storms by ensuring that operators and crews have full flexibility to transfer and restore load and by hardening vulnerable parts of the system with more optimal fusing arrangements and the installation of assets such as tree-proof overhead conductors.

During the 2015-2019 planning horizon, Toronto Hydro intends to conduct climate adaptation studies to assist with engineering analysis, informed decision-making and standards development for overhead and underground capital programs. These studies are expected to focus specifically on identifying areas of the distribution system that are vulnerable to extreme weather and climate change, and include pilot projects for assessing study recommendations. These pilot projects are intended to help Toronto Hydro finalize climate adaptation solutions before programs are carried out at a system level.

(vii) Business Operations Needs (i.e. General Plant investments)

Toronto Hydro must also continue to maintain and enhance its non-distribution system assets to allow the utility to efficiently and effectively execute the proposed capital program, maintenance activities and other business functions. In addition to routine fleet, facilities and IT asset renewal investments, Toronto Hydro has identified several additional, one-time capital projects that are required during the forecast period.

- Toronto Hydro's current enterprise resource planning (ERP) system, installed in 2002 and last upgraded in 2006, has reached obsolescence due to lack of vendor support and other functional deficiencies. Toronto Hydro plans to replace the existing system with a

new, fully-supported ERP, which would incorporate new functional requirements that can deliver incremental benefits such as cost savings and process improvements.

- Toronto Hydro's voice radio system is not supportable beyond 2016 and must be upgraded in order to maintain safe and effective work practices.

- Toronto Hydro is executing an Operating Centers Consolidation Program (E8.3) to achieve permanently and significantly lower operating center costs.

Complete details and justification for all of the aforementioned system and non-system investments (as well as additional investment programs not highlighted in this section) are available in sections E5 through E8 of the DSP. A detailed discussion of the pacing of investment and its alignment to longer-term objectives is provided below.

2.2 Long-term Objective: Achieving "Steady-State"

The pace of investment during the 2015-2019 period is driven by system needs. The detailed rationale and decision-making frameworks that ultimately yielded this proposed pacing are described in Toronto Hydro's asset management policy and processes in Section D. At a high level, the long-term objective of Toronto Hydro's asset management policy is to achieve an optimal "steady-state", in which the number of assets that are past their economic end-of-life (explained below) is minimized. When the system is in that theoretical steady state, the total operating (or lifecycle) costs associated with the broader in-service asset population is minimized, meaning that customer value is effectively maximized.

The concept of a steady state can be better understood by examining Toronto Hydro's risk-based optimization approach to investment planning. Using the Feeder Investment Model (FIM), Toronto Hydro determines the optimal asset renewal timing based on the economic end-of-life criteria for each asset. The economic end-of-life of an asset is derived from two offsetting cost curves:

1. Annualized risk cost (red line below): increases as the asset ages; represents the quantifiable costs of asset failure (including customer interruption costs) multiplied by the probability of failure.

2. Annualized capital cost (green line below): decreases as the asset ages; represents the capital cost of replacement, annualized over the asset's projected life.

(For a detailed explanation of the FIM and how it is used within Toronto Hydro's asset management process, refer to Section D3.)

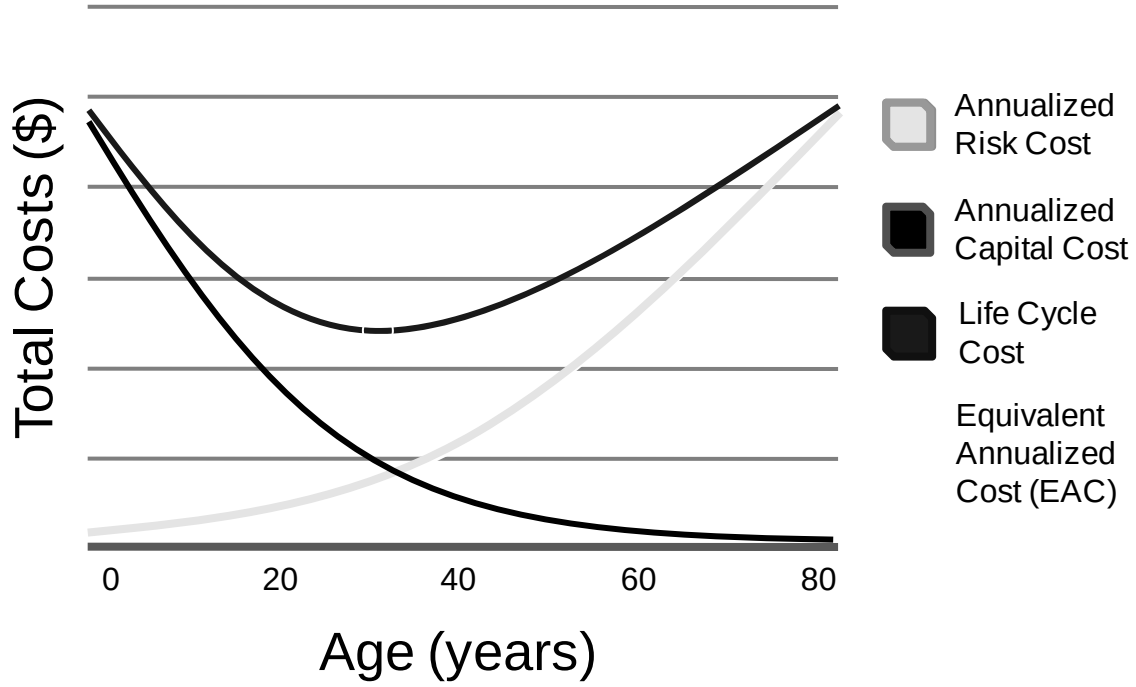


FIGURE 6: LIFECYCLE COST OF A DISTRIBUTION ASSET

An asset reaches its economic end-of-life when the annualized capital cost of replacing the asset becomes less than the annualized risk cost of continuing to operate the asset. Put another way, the asset has reached its economic end-of-life when the total life cycle cost – i.e. the sum of the annualized risk cost and the annualize capital cost (depicted as the blue line in the above figure) – is at its lowest point. This is referred to as the optimal intervention time. Replacing the asset any sooner than the optimal intervention time risks wasting the remaining useful life of the asset, while replacing the asset after the optimal intervention time risks incurring unnecessary and avoidable costs associated with asset failure.

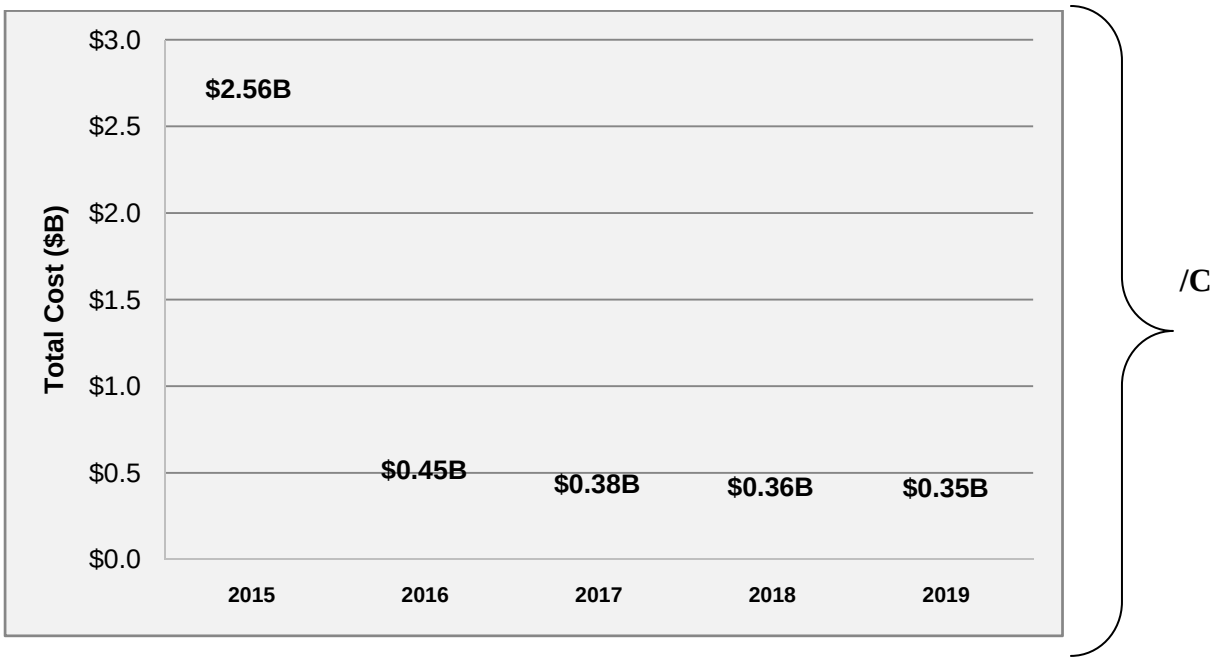
The objective of this risk-based approach is to minimize the total lifecycle or operational cost of the equipment in order to maximize the value derived from the assets. Of course, any given asset is likely to fail earlier or later than the optimal intervention time prescribed by the probabilistic FIM approach. The aggregate benefits of this risk-based approach are realized by applying the asset-level approach to a broader population of assets. Doing so means that, on average, Toronto Hydro is replacing assets in a manner that minimizes total lifecycle costs, and therefore the cost of service over time.

Theoretically, Toronto Hydro's risk based model defines the ideal steady state as the scenario where, on a system level, no assets are allowed to operate beyond their optimal intervention time, and all assets are replaced at exactly the optimal intervention time and no earlier (except those that inevitably fail prematurely). In reality, this approach would not be feasible as it would limit Toronto Hydro's ability to group assets into geographic, feeder, or station based renewal projects. Project-based asset renewal allows Toronto Hydro to undertake capital replacement cost-effectively by realizing design, scheduling, procurement and construction efficiencies. Toronto Hydro will therefore, in appropriate circumstances, elect to replace some assets prior to or following the optimal intervention time if doing so will allow the utility to realize project-based efficiencies. (Toronto Hydro's FIM tool includes functionality that helps planning engineers determine asset groupings that result in economically optimized renewal projects.) The OEB commended Toronto Hydro for developing this approach to asset management in the utility's previous distribution rates application (EB-2012-0064).

Taking these practical considerations into account, Toronto Hydro estimates that the optimal steady state for the distribution system will include a small percentage of assets operating beyond their economic end-of-life criteria in any given year, and that this percentage will change from year to year depending on the mix of projects. The following section includes a forecast of the percentage of assets that Toronto Hydro estimates will be operating beyond their economic useful lives if the proposed capital investment program is extended until steady state is reached.

Achieving Steady State

As explained above, the steady state approach represents the system state in which the total aggregate lifecycle cost of the existing asset base is minimized. Once the steady state is achieved, it must be maintained by continuing to renew assets as they reach economic end-of-life. This purely risk-based approach is indifferent to year-over-year changes in the level of investment required. In theory (i.e., without considering other practical constraints like bill impacts and resource constraints), the risk-based model recommends the following capital spending profile for the 2015-2019 planning horizon:

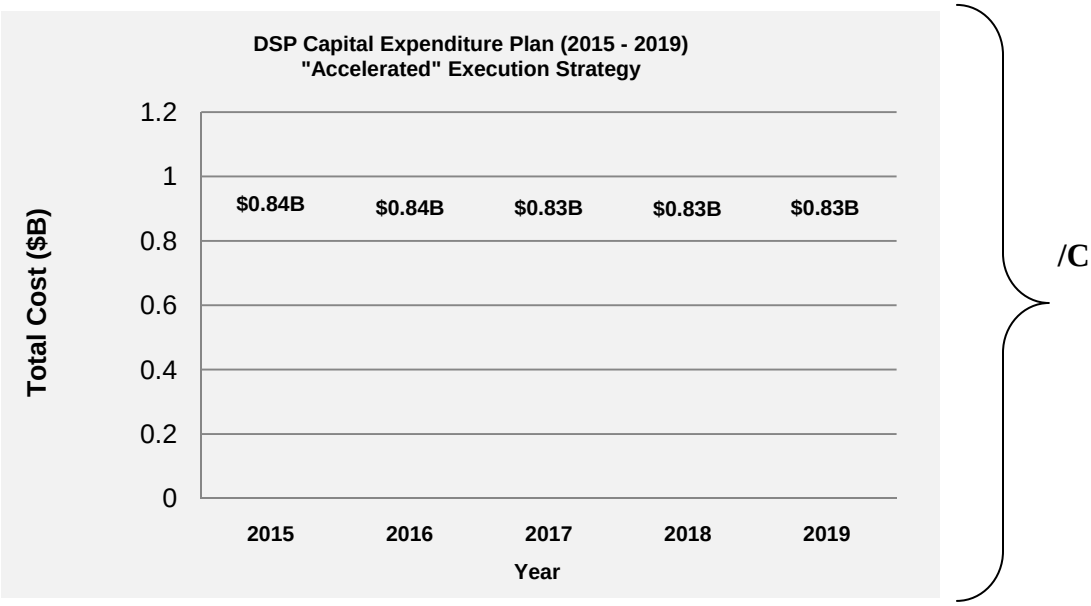


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FIGURE 7: ECONOMICALLY OPTIMAL CAPITAL INVESTMENT APPROACH (2015-2019)

This economically optimal capital investment approach would theoretically achieve steady state by 2016. However, this approach would constitute an unprecedented single-year capital investment that Toronto Hydro recognizes would result in large step-increases in rates, and, in any event, could not be completed as a practical matter. In short, this backlog of investments cannot be reasonably addressed in one year when considering bill impacts, system constraints and available resources.

For a more reasonable investment program, Toronto Hydro considered two alternatives: an "accelerated" strategy and a "paced" strategy. The accelerated strategy would allow for the backlog of investments to be managed over the five-year DSP period, such that "steady state" is achieved by 2019 with a level of investment of approximately $830 million on average per year, for a total of $4.17 billion over five years.



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FIGURE 8: ACCELERATED CAPITAL INVESTMENT STRATEGY (2015-2019)

One of the benefits of the accelerated strategy is that the system would be forecast to reach steady state in time for Toronto Hydro's next five-year rate filing, delivering more predictable rate impacts and system performance beginning in 2020.

However, the accelerated strategy would still feature levels of investment that do not immediately align to Toronto Hydro's current resources and system constraints, and, most importantly, would result in steeper rate increases over the DSP forecast period that would likely be unacceptable to customers. For this reason, Toronto Hydro's DSP is based on a paced strategy, which is illustrated in the figure below and represents the level of capital investment in the proposed 2015-2019 DSP. (Note that the annual investment amounts vary in this scenario. This is because these amounts are based on detailed DSP program level forecasts of assets to be replaced and projects to be executed within the DSP forecast period. For the reasons described above, the utility has not developed the accelerated strategy to this level of detail.)

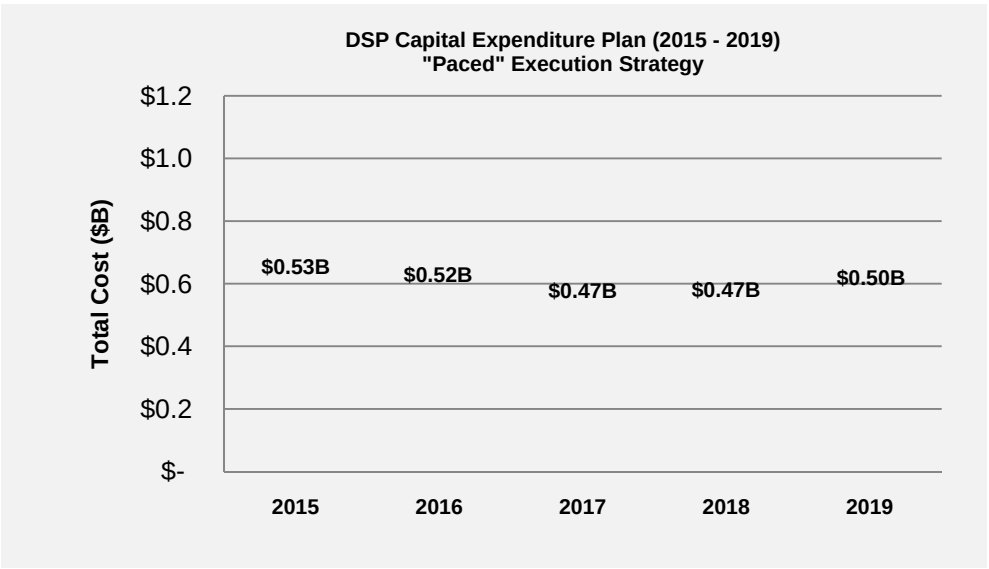


FIGURE 9: PACED CAPITAL INVESTMENT STRATEGY (2015-2019)

The paced execution strategy features an average annual investment of just under $500 million, which, as the DSP evidence in Chapters D and E demonstrates, is the minimum level of investment that is appropriate given the magnitude of the asset backlog and other critical system issues and operational needs. If Toronto Hydro were to continue at this annual pace beyond 2019, the system is forecast to reach steady state by approximately 2037.

The disadvantage of this strategy is that customers are exposed to greater total asset lifecycle costs during the entire period of 2015 to 2037. However, this approach has the advantage of more predictable and tolerable bill increases during the 2015-2019 period and alignment with Toronto Hydro's immediate execution capacity.

The paced strategy has another significant advantage over the accelerated strategy: bill impacts and system performance are forecast to be more predictable beyond the achievement of steady-state. This is because the paced strategy takes a more gradual or dispersed approach to clearing the backlog of end-of-life assets. While achieving steady-state faster would maximize customer value sooner, the rapid renewal of aging assets would likely result in another large "lump" of end-of-life assets in the future, which would require another period of significantly large, multi-year investment needs.

To illustrate the overall impact on the system of reaching steady state, Figure 10 shows the forecast useful life demographics of the system as of 2037. The projected steady state in 2037

features a 15 percentage point reduction in the percentage of assets operating beyond end-of-life versus the current state of the system illustrated in Figure 2.

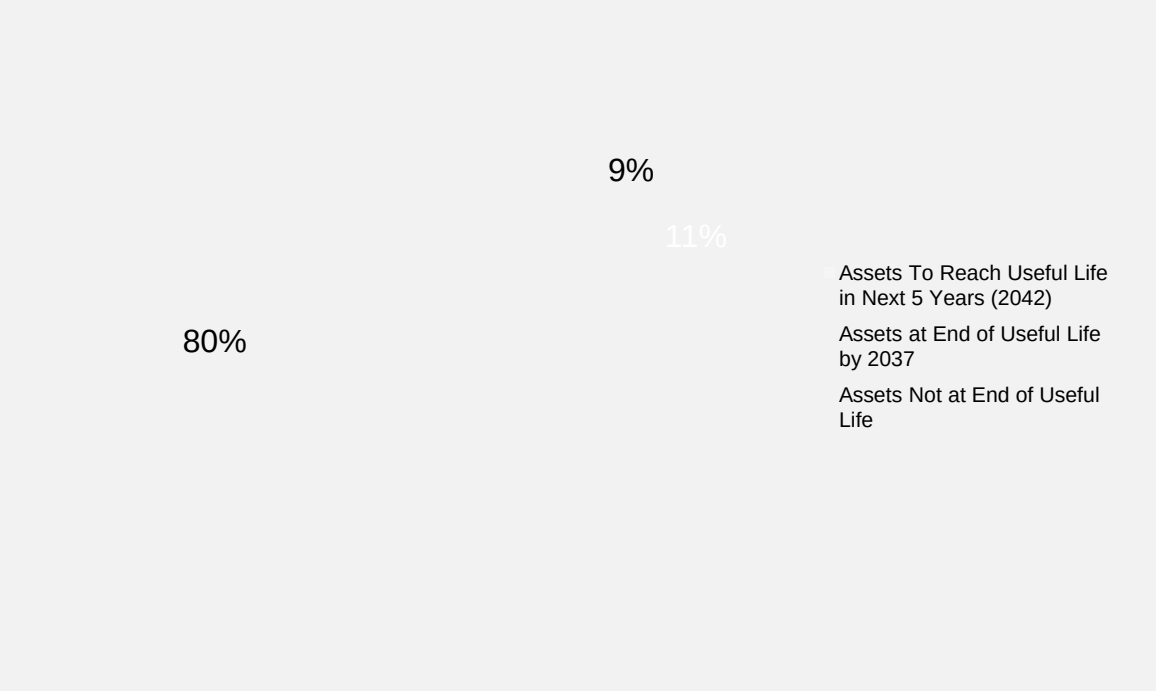


FIGURE 10: PROJECTED ASSET AGE DEMOGRAPHICS AS OF 2037

3 Coordinated Planning with Third Parties

Toronto Hydro recognizes the importance of coordinated regional planning between licensed distributors and transmitters and agrees with the view articulated in the RRFE that regional planning is an essential input to the cost-effective development of electricity infrastructure. The OEB's RRFE report and associated filing requirements place an emphasis on the integration of regional issues and requirements into utility planning processes.

Toronto Hydro, through its participation in the Central Toronto Integrated Regional Resource Plan led by the OPA, and in its participation in the Needs Screenings for Metro Toronto Northern sub-region and GTA North Western sub-region led by Hydro One Networks Inc. (HONI), has coordinated its planning efforts and subsequent DSP with the outcomes of the completed plans. The utility continues to coordinate with regional plans that are under development.

Transmitter Consultations

HONI consulted with Toronto Hydro and neighbouring distributors through a Needs Screening of two electrical areas:

- Metro Toronto Northern Sub-region, and
- GTA North Western Sub-region.

The Needs Screening Report for the Metro Toronto Northern Sub-region was completed on June 12, 2014 and is provided as Appendix A of Chapter B. The Needs Screening Report for the GTA North Western Sub-region was completed on June 27, 2014 and is provided in Appendix B to Chapter B. Neither of these Needs Screening Reports identified any transmission infrastructure needs during the planning horizon. There is no impact on the DSP due to either report.

Regional Planning Process

The Metro Toronto Region has been divided into two sub-regions for ease of planning: Central Toronto and the Northern sub-regions. The two sub-regions are shown in Figure 11.

FIGURE 11: INTEGRATED REGIONAL RESOURCE PLAN REGIONS

The Central Toronto sub-region study in December of 2011 was started before the introduction of the Regional Planning Process. Previously known as the Toronto Regional Plan, it is now the Central Toronto Integrated Regional Resource Plan (IRRP).

The Ontario Power Authority is the lead in this process and the following organizations are the study participants:

- Toronto Hydro
- Hydro One Networks Inc. (HONI)
- Independent Electricity System Operator (IESO)

The purpose of the IRRP is to help ensure that the electricity service requirements of the central Toronto community are served by an appropriate combination of demand and supply options that reflect the priorities of the community. The Central Toronto IRRP is still in progress but the Ontario Power Authority (OPA) has confirmed a long identified issue of capacity shortfalls in the

Runnymede TS, Manby TS and Copeland TS areas. Toronto Hydro has been planning remedies for these shortfalls and has discussed and shared alternatives with the OPA and HONI as part of the planning effort. The projects contained within the Stations Expansion capital investment program, further detailed in Section E7.9, reflect the regional planning consultations to date for Central Toronto.

The Central Toronto IRRP is currently expected to be completed by December 2014.

4 Performance Measurement for Continuous Improvement

In section 5.2.3 of the filing requirements, the OEB requests that distributors identify and define the methods and measures that will be used to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning objectives are met. Following the OEB's guidance, Toronto Hydro has developed a set of 12 measures to monitor quality and drive continuous improvement in its distribution system planning and implementation work over the 2015-2019 planning horizon. The measures cover several distinct dimensions of the utility's capital planning and implementation processes and/or speak directly to the outcomes of such processes, motivated by customer needs, regulatory compliance obligations, or the utility's efficiency objectives.

Table 2 outlines Toronto Hydro's proposed DSP performance measures, grouped by primary category.

TABLE 2: PROPOSED PERFORMANCE MEASURES FRAMEWORK

Customer-Oriented Performance	Cost Efficiency/ Effectiveness of Planning and Implementation	Asset/System Operation Performance
1. System Average Interruption Duration Index (SAIDI). 2. System Average Interruption Frequency Index (SAIFI). 3. Customer Average Interruption Duration Index (CAIDI). 4. Feeders Experiencing Sustained Interruptions (FESI). 5. Momentary Average Interruption Frequency Index (MAIFI).	1. Distribution System Plan Implementation Progress. 2. Planning Efficiency: Engineering, Design and Support Costs. 3. Supply Chain Efficiency: Materials Handling On-Cost. 4. Construction Efficiency: Internal vs. Contractor Cost Benchmarking. 5. Construction Efficiency: Standard Asset Assembly Labour Input.	1. Outages caused by defective equipment. 2. Stations capacity availability.

For a detailed discussion of these measures, their technical definitions, and the expected outcomes over the DSP forecast period, please refer to Section C of the DSP.

For each proposed measure, (with the exception of new measures) Toronto Hydro provides performance results along with the associated trend over the recent years, describes the methodology used to calculate the measure and its implementation, and outlines the ways in which the measure informs and/or otherwise interacts with the utility's DSP and the related processes. Where relevant, Toronto Hydro also describes the unique planning and implementation considerations that shape the measure's design and the utility's expectations as to its future performance levels.

5 Asset Management Process

Toronto Hydro's AM Process, which is explained in detail in Section D, can be broken down into five major components: (i) the planning process, (ii) the associated decision-support systems, (iii) the enterprise databases that support both the planning process and systems, the (iv) distribution

system plan itself that is supplied by outputs from the planning process, and finally (v) a measurement and enhancement process that supports continuous improvement. Figure 12 depicts the AM process and its various elements and support systems.

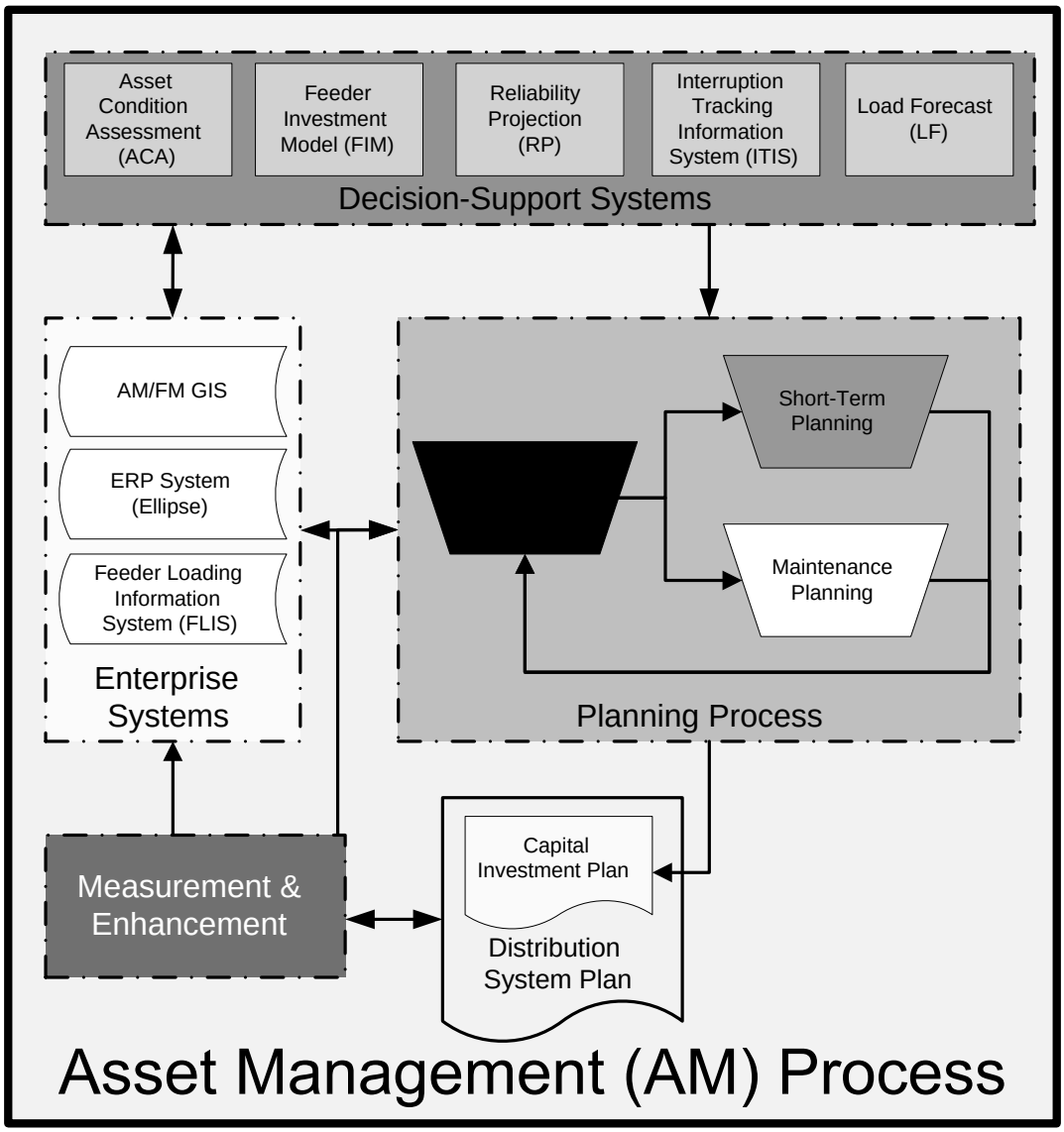


FIGURE 12: ASSET MANAGEMENT PLANNING PROCESS OVERVIEW

The planning process element of the AM process can be further subdivided into three stages:

(i) Long-term planning, discussed in detail in Section D1.2.1, results in the development of a capital investment approach and execution strategy along with corresponding investment programs that align to AM objectives.

(ii) Short-term planning, discussed in detail in Section D1.2.2, results in the production of discrete projects within each investment program.

(iii) Maintenance planning, discussed in detail in Section D1.2.3, focuses on extracting the maximum value out of Toronto Hydro's distribution system assets, through inspections, upkeep and repair activities. The outputs from the AM Planning Process as a whole are integrated into the DSP.

Toronto Hydro is continually monitoring and improving decision-support systems, enterprise systems and various inputs that support the AM planning process. Recent improvements include the following:

- Kinectrics, in their independent audit of Toronto Hydro's Asset Condition Assessment program (Chapter D, Appendix A), notes that Toronto Hydro has worked to improve its maintenance practices in a number of ways, including improved asset inspection forms and an expanded scope for transformer oil testing.
- Toronto Hydro introduced additional quantifiable benefits as an enhancement to the business case evaluation process. This allows for a broader set of benefits to be considered in the quantified analysis, thereby allowing for a more accurate and robust analysis of the proposed program. This enhancement is further discussed in detail in Section D3.
- Toronto Hydro has made efforts to improve data quality within its enterprise geographical information system (GIS) and enterprise resource planning (ERP) system respectively such that improved decision making can be performed at both the long-term and short-term planning levels. This includes development of data quality reporting processes, consolidation of data from the two systems, improvement of connectivity of information within systems, etc.
- Toronto Hydro has improved on various elements of the Asset Condition Assessment process. Key improvements include increased sample size of each asset category and improvements to the Business Intelligence Calculator

6 Customer Needs and Preferences

In accordance with the OEB's requirement to obtain information on customer preferences, Toronto Hydro has engaged with its customers specifically around the utility's DSP for 2015-

2019. As explained in detail in Exhibit 1B, Tab 2, Schedule 7, Toronto Hydro engaged Innovative Research Group Inc. ("Innovative"), a national consultancy with expertise in public opinion research, to design and carry-out a consultation process intended to provide the utility with meaningful information to assist in preparing the DSP.

Innovative's final report (Appendix B to Exhibit 1B, Tab 2, Schedule 7) documents the process and findings of this consultation in detail. Overall, Toronto Hydro has found that customers' preferences and values align with central pillars of the utility's DSP. Toronto Hydro learned that, while its customers expect the utility to make prudent investment decisions, the majority accept the need for timely renewal of the distribution system, while acknowledging that this will mean an increase in their monthly bills. A detailed discussion of how the results of this consultation are reflected in Toronto Hydro's 2015-2019 Distribution System Plan is provided in section E2.4.

7 Capital Expenditure Plan

Table 3 shows the level of spending for the System Access, System Renewal, System Service and General Plant investment categories, as well as the System O&M expenditures over the historical period from 2010 to 2014 and over the forecast period from 2015 to 2019. This table aligns to "Table 2 – Capital Expenditure Summary" in Chapter 5 of the Filing Requirements.

Expenditures within the 2010-2013 historical period are actual expenditures, whereas expenditures for 2014 are forecast (i.e. bridge year) expenditures, as the 2014 year has not yet concluded as of this writing.

For a complete analysis of year-over-year historical and forecast variances within each category, refer to Section E4 of the DSP.

TABLE 3: CAPITAL EXPENDITURE SUMMARY

CATEGORY	Historical Spend ($M)					Forecasted Spend ($M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System Access	$44.37	$58.31	$53.15	$86.62	$76.01	$86.13	$93.54	$100.93	$90.41	$85.47
System Renewal	$215.00	$219.25	$157.25	$231.08	$286.37	$251.74	$234.99	$246.35	$260.08	$265.49
System Service	$35.32	$75.63	$38.35	$83.67	$101.34	$76.45	$69.60	$62.51	$49.54	$73.95
General Plant	$55.53	$67.71	$29.28	$33.77	$109.47	$104.63	$99.44	$28.93	$32.13	$27.88
Other CAPEX	$50.36	$24.63	$9.92	$10.52	$12.73	$12.18	$21.22	$28.65	$37.89	$49.37
Total	**$400.58**	**$445.53**	**$287.95**	**$445.66**	**$585.92**	**$531.13**	**$518.79**	**$467.36**	**$470.05**	**$502.16**
System O&M	$114.64	$111.89	$109.03	$119.84	$118.94	$128.76	-	-	-	-

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The following sections provide a summary of System Access, System Service, System Renewal and General Plant programs as well as System O&M expenditures. For full details and justification of the programs listed throughout these sections, see Sections E5 through E8 of the DSP. For a detailed explanation of System O&M expenditures, see Section E4.2.6.

7.1 System Access

Toronto Hydro's capital expenditures under the System Access investment category are driven by statutory, regulatory or other obligations that require Toronto Hydro to provide customers with access to the distribution system or to otherwise respond to service requests.

TABLE 4: SUMMARY OF SYSTEM ACCESS PROGRAMS

Program Index and Name		Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E5.1	**Metering**	Enable Toronto Hydro to meet its mandatory service obligations with respect to revenue metering and wholesale metering. This will be accomplished by testing meters, replacing damaged and obsolete meters, and upgrading the under-capacity and obsolete collector stations. Upgrading Toronto Hydro's Interval Metering MDM software will help customers manage their energy use and costs by providing them with timely access to their data.	**$81.5 M**	Mandated Service Obligations	Failure Risk

Program Index and Name		Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E5.2	**Customer Connections**	Toronto Hydro is obligated to connect new customers or upgrade existing customers to a larger service if requested, as required under the terms of Toronto Hydro's distribution license, the Distribution System Code and the *Electricity Act, 1998*. On average, 10,000 requests for new services, upgrades, and removals are made each year and the amount is expected to increase with current and proposed development.	**$261 M**	Customer Service Request	Mandated Service Obligations
E5.3	**Externally-Initiated Plant Relocation & Expansion**	Toronto Hydro is required to modify/relocate its system to accommodate property or infrastructure development (e.g., requests from a road authority to move a pole line). Toronto Hydro works with the external agency in question to accommodate the project, and investigates opportunities for cost-efficient expansion work. Note that the cost listed in the DSP is significantly below forecast costs. Due to the externally-driven natures of this work, Toronto Hydro proposes to seek rates funding only for this sub-forecast base amount, with a variance account to record differences from this forecast.	**$20.1 M**	Third Party Request	
E5.4	**Load Demand**	With increased load in concentrated areas due to the city's growth, equipment (such as undersized cables) in the system must be upgraded in the short-term to address contingency issues to accommodate this increased demand. The problem is expected to be addressed by transferring loads to stations with available capacity, upgrading undersized equipment and cables, and ensuring civil infrastructure can support increased demand, allowing Toronto Hydro to continue connecting customers in these areas without harming system reliability, customer value, and operational flexibility.	**$74.9 M**	Customer Service Requests	Mandated Service Obligations - Reliability - System Efficiency
E5.5	**Generation Monitoring, Protection and Control**	Toronto Hydro is mandated to make every reasonable effort to connect distributed generation users. This program involves installation of bus-tie reactors at station buses, advanced protection systems, and monitoring and control systems to handle the increasing DG penetration in the City of Toronto, including renewable energy generation (REG) projects.	**$18.7 M**	Mandated Service Obligations	Safety - Reliability

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7.2 System Renewal

Capital expenditures in the System Renewal investment category are driven by the need to maintain distribution system asset performance at an acceptable standard. These investments will serve to renew those assets that are nearing, at, or exceeding their end-of-life criteria, along with assets that are functionally obsolete due to accessibility or serviceability deficiencies.

TABLE 5: SUMMARY OF SYSTEM RENEWAL PROGRAMS

Program Index and Name		Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E6.1	Underground Circuit Renewal	Replace end-of-life and obsolete underground assets with new ones on a "like-for-like" basis. The assets include switches, transformers, and cables. Replacing the assets is forecast to help improve system reliability and efficiency.	$459 M	Failure Risk	Safety - Functional Obsolescence
E6.2	Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers	Program will address two issues related to underground PILC cable. PILC cables are aging and a number have developed cracks and pinholes and must either be replaced or repaired. The program will also increase cable length to address unsafe congested areas and allow the cables to be safely and properly routed.	$6.88 M	Failure Risk	Safety - Reliability
E6.3	Underground Legacy Infrastructure	Targets non-standardized equipment that is at or near end-of-life and poses a failure risk. Many of these assets are now obsolete and will be replaced with standardized equipment, helping to improve safety and system reliability.	$27.4 M	Functional Obsolescence	Safety - Reliability - Failure Risk
E6.4	Overhead Circuit Renewal	Focuses on replacing poles, switches, transformers, overhead accessories and street lighting assets that are either aged, in poor condition, or functionally obsolete on a “like-for-life” basis. Toronto Hydro expects the program to mitigate significant sources of outages that negatively impact service reliability to customers and may pose potential safety risks for employees and the general public.	$147 M	Failure Risk	Safety - Functional Obsolescence

Program Index and Name		Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E6.5	Overhead Infrastructure Relocation	Provide a modern and efficient configuration to replace feeders that are past end-of-life and functionally obsolete from a design perspective to mitigate the number of system outages. Feeders will be relocated to eliminate difficult-to-access overhead plant, overhead egress plant and overhead plant crossing highways.	$9.87 M	Functional Obsolescence	Safety - Reliability
E6.6	Rear Lot Conversion	This program replaces the existing, end-of-life rear lot distribution service configuration with an underground front lot access system to eliminate challenges in performing maintenance activities and to mitigate the increased risk of long duration outages inherent in the existing plant design. The conversion eliminates operational constraints and reduces the safety and reliability risks associated with this obsolete connection configuration.	$59.3 M	Functional Obsolescence	Safety - Reliability - Failure Risk
E6.7	Box Construction Conversion	This program transitions customers from functionally obsolete 4.16 kV box construction feeders to the current standard 13.8 kV or 27.6 kV overhead infrastructure. By eliminating box construction feeders, Toronto Hydro anticipates that the program will reduce safety concerns for crew members dealing with restricted working spaces, improve restoration times and mitigate costs related to load capacity constraint when connecting new customers in the downtown area.	$103 M	Functional Obsolescence	Safety - Efficiency - Reliability

Program Index and Name		Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E6.8	SCADA-MATE R1 Replacement	This program replaces malfunctioning switches. Moisture has caused internal switch components to corrode. The corrosion poses significant safety hazards to the public and Toronto Hydro employees due to misrepresentation of the switch state; therefore, core functions of the switch can no longer be used. The new R2 design improves remote functionality and reliability of the switch, thereby reducing prolonged outages and failure risk for customers.	$12.9 M	Functional Obsolescence	Safety - Failure Risk
E6.9	Network Vault Rebuild Program	Rehabilitation of vaults that were identified to be high-risk (through asset condition assessment studies) to protect the assets that are housed within and to mitigate potential safety hazards for crews, pedestrians and emergency response crews in busy downtown areas. Rehabilitation options include decommissioning the vaults, rebuilding the vault roofs, or rebuilding the entire vault.	$45.1 M	Failure Risk	Safety
E6.10	Network Unit Renewal Program	Replacement of obsolete and poor condition Network Units that are at risk of failure with new submersible Network Units. Toronto Hydro anticipates that this program will increase service reliability, improve employee safety and reduce environmental concerns by mitigated oil leaks.	$34.4 M	Failure Risk	Safety
E6.11	Legacy Network Equipment Replacement (ATS & RPB)	Replacement of automatic transfer switches (ATSs) and reverse power breakers (RPBs) with manual secondary switches, stand alone network protectors (SANPs), or network units. The ATSs and RPBs are no longer supported by their original manufacturer, making it difficult to comply with prudent maintenance practices and policies. These assets are also not submersible by design and are subject to a high risk of equipment failure.	$4.62 M	Functional Obsolescence	Failure Risk - Safety

Program Index and Name		Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E6.12	Network Circuit Reconfiguration	Reconfiguration of the functionally obsolete network system by splitting a large secondary grid into enhanced mini grids. Increasing grid flexibility is expected to enhance the utility's ability to supply new classes of customers, to operate under different contingency events and decrease the necessity to drop the entire network during failure.	$9.14 M	Functional Obsolescence	Reliability - System Efficiency - Safety
E6.13	Stations Switchgear Renewal	Replacement of existing switchgears that have become functionally obsolete and that have passed the end of their useful lives. The existing non-arc resistant switchgear at municipal stations and transformer stations will be replaced with type C, arc resistant switchgear with vacuum circuit breakers.	$106 M	Functional Obsolescence	Reliability - Safety
E6.14	Stations Power Transformer Renewal	Replacement of power transformers located at municipal stations across the city to mitigate the failure risk of prolonged outages due to assets at the end of their useful lives. This program is expected to directly benefit customers connected to the transformers identified for replacement by reducing outage risk and increasing system reliability in their respective areas.	$12.3 M	Failure Risk	
E6.15	Stations Circuit Breaker Renewal	Replacement of obsolete oil circuit breakers, which are no longer supported by manufacturers, with stand-alone vacuum circuit breakers. Vacuum circuit breakers are cheaper to maintain and are less likely to fail catastrophically.	$9.13 M	Functional Obsolescence	Failure Risk - Safety
E6.16	Stations Control & Monitoring	This program aims to replace aging and obsolete remote terminal units (RTUs) and install SCADA systems at substations with no SCADA capabilities. Existing RTUs and radio communications networks at Etobicoke MS and downtown Toronto TS will be replaced while modern SCADA systems at Scarborough MS will be installed.	$5.05 M	Functional Obsolescence	Reliability - Cyber Security

Program Index and Name		Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E6.17	Stations Ancillary Systems	Replacement of end-of-life and outdated ancillary systems (air compressors, station service power supply systems, fire alarm systems, and fire barriers) that are at risk of failure and functionally obsolete with more reliable modern technologies.	$2.29 M	Failure Risk	Functional Obsolescence - Safety
E6.18	Stations Buildings	This program focuses primarily on the structural integrity of 11 TS and MS buildings in which electrical stations assets are housed. The program takes a proactive approach to improve existing station buildings to extend their serviceable lives. Toronto Hydro anticipates that this will help it deliver uninterrupted service, improve the safety of crews and the public, and help protect nearby customer property.	$11.1 M	Failure Risk	Safety
E6.19	Stations DC Battery Replacement	Replacement of end-of-life DC batteries and chargers systems with new ones at various stations locations to mitigate battery failure risk and ensure faults are isolated to the local feeder. These batteries are used to provide the necessary power supply to operate the associated circuit breaker assets if the main power supply to the entire station is lost.	$3.14 M	Failure Risk	Safety
E6.20	Reactive Capital	Accounts for unplanned, non-discretionary capital expenditures required to repair or replace assets. With proper budgeting and resource allocation, timely reactive work improves safety, reduces the backlog of assets to be maintained, avoids depriving other capital programs of planned resources and reduces strain on the distribution system.	$166 M	Failure	Safety - Reliability

Program Index and Name		Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E6.21	Worst Performing Feeder	This program analyses the performance of feeders that are at risk of seven or more outages in a year and determines the root cause of the outage trend. Condition of the equipment will be assessed during feeder patrols and appropriate mitigation work will be performed to alleviate outages caused by design or environmental disturbances. The program is expected to improve the reliability of feeders, minimizes power outages for customers experiencing especially poor service, and mitigates the risk of additional asset failures.	$8.49 M	Failure Risk	
E6.22	Distribution System Communication Infrastructure	This program renews and improves the telecommunications system by identifying gaps in the communication service platform, updating the obsolete SONET technology and SCADA infrastructure. An updated telecommunication system reduces failure risk an provides safe, efficient and reliable supply of electricity to customers.	$16 M	Functional Obsolescence	System Capital Investment Support - System Maintenance Support - Safety

7.3 System Service

Capital expenditures under the System Service investment category are driven primarily by the need to resolve critical system-wide issues, including capacity and operational constraints, security-of-supply risks, potential safety risks, system reliability deficiencies and other inefficiencies within the existing grid. Beyond the safety and capacity-driven investments in this category, a number of the programs were selected as cost-effective means of enhancing customer value (in the form of improved service and service efficiency) during the 2015-2019 period while maintaining a relatively modest pace of System Renewal work.

TABLE 6: SUMMARY OF SYSTEM SERVICE PROGRAMS

Program Index and Name	Description	Total (5 years)	Trigger Driver	Secondary Drivers

Program Index and Name		Description	Total (5 years)	Trigger Driver	Secondary Drivers
E7.1	**Contingency Enhancement**	Make improvements to feeders in the existing distribution systems that are currently unable to quickly restore power to affected customers under a contingency situation.	**$48.9 M**	Reliability	System Efficiency - Safety
E7.2	**Design Enhancement**	Implementing fusing enhancements to resolve the issues of undersized fuses, mis-coordinated fuses and redundant trunk sections that lack fusing. Replacement and strategic location of fuses and the implementation of tree proof conductors to mitigate sustained interruptions caused by tree contact outages.	**$7.27 M**	Reliability	System Efficiency
E7.3	**Feeder Automation**	Facilitating faster and less labour intensive system restoration procedures by replacing existing switches with autonomously operating Supervisory Control and Data Acquisition switches, reducing the impact of trunk outages to customers and isolating the faulted section of the feeder in less than a minute.	**$54.1 M**	System Efficiency	Reliability
E7.4	**Overhead Momentary Reduction**	Installation of reclosers to provide flexibility to the system, fault protection and improve the distribution feeder reliability performance by limiting outage times and containing the outage to a minimum area.	**$1.91 M**	Reliability	System Efficiency - Safety
E7.5	**Handwell Upgrades**	Replacing the remaining legacy handwells with new standard handwells made from non-conducting composite materials to remove the risk of contact voltage to the public.	**$4.98 M**	Safety	Functional Obsolescence
E7.6	**Polymer SMD-20 Switch Renewal**	Targets SMD-20 switches that were installed between 2006 and 2011, as breakages inhibit these switches from functioning safely as designed. New switches utilize a fiberglass core that has five times the strength of the previous design. Replacement of the switches eliminates the known safety risk to the public and Toronto Hydro employees.	**$4.84 M**	Safety	Substandard Performance - Reliability

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Program Index and Name		Description	Total (5 years)	Trigger Driver	Secondary Drivers
E7.7	**Downtown Contingency**	Providing distribution load transfer capability between stations in the downtown Toronto area by tying feeders from one station with feeders from an adjacent station. This program addresses a risk in the downtown area where no back-up is provided for certain low probability, high impact events.	**$3.36 M**	Reliability	Operational Constraints - Safety
E7.8	**Customer Owned Station Protection**	Installation of utility-owned protection devices upstream of customer-owned substations to isolate any faults occurring at customer owned substations.	**$4.04 M**	Reliability	Safety
E7.9	**Stations Expansion (including HONI contributions)**	Upgrades to either Toronto Hydro or Hydro One Networks Inc. owned transformer stations. These upgrades address recent trends in customer connection requirements and loading, by mitigating system limitations imposed by existing station equipment.	**$188 M**	Capacity Constraints	Reliability
E7.10	**Local Demand Response**	Providing medium-term capacity relief to Cecil TS by implementing a targeted and localized demand response strategy which primarily leverages new and existing demand response resources.	**$4.06 M**	Capacity Constraints	Reliability
E7.11	**Energy Storage Systems**	To provide a conventional support for local capacity constraints and service reliability issues throughout Toronto Hydro's distribution system. These systems are also categorized as a renewable enabling improvement to accommodate the increasing numbers of renewable energy generation (REG) connections.	**$10.8 M**	System Efficiency	Reliability - Power Quality

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7.4 General Plant

Capital expenditures under the General Plant investment category represent necessary routine and one-time investments into the backbone assets that support Toronto Hydro's operational activities. These investments are essential to the execution of the capital and O&M related activities and expenditures discussed in the DSP and elsewhere.

TABLE 7: SUMMARY OF GENERAL PLANT PROGRAMS

Program Index and Name		Description	Total (5 years)	Trigger Driver	Secondary Drivers
E8.1	**Fleet and Equipment Services**	As Toronto Hydro's fleet ages, regular vehicle replacement and repair is necessary. This program replaces 24-95 vehicles a year as well as installing new equipment on existing vehicles requiring refresh or replacement, all to ensure the fleet is safe, reliable, and cost-efficient.	**$17.9 M**	System Maintenance and Capital Investment Support	Safety - Reliability - Business Operations Efficiency
E8.2	**Facilities Management & Security**	Security enhancements are necessary to ensure assets, employees and the general public are protected by up-to-date security equipment and technologies. Additionally, facilities program is needed to improve the safe, reliable and efficient operation of the work centers and stations as well as increase the overall asset value for all of Toronto Hydro	**$31.8 M**	System Maintenance and Capital Investment Support	Safety - Failure Risk - Reliability
E8.3	**Operating Centers Consolidation**	Consolidation of Toronto Hydro's operating centers is required to secure tenure for Toronto Hydro in the northwest and northeast areas of the City while delivering benefits to ratepayers. Toronto Hydro plans to vacate four facilities, two of which it currently owns, and relocate staff, equipment and operations to three facilities already owned by Toronto Hydro to achieve efficiencies and improve space utilization. The utility plans to sell the two surplus Toronto Hydro-owned facilities, crediting the net after-tax gains on sale and related tax savings to ratepayers through rate riders.	**$52.2 M**	System Maintenance and Capital Investment Support	Business Operations Efficiency
E8.4	**IT Hardware Refresh**	The program addresses the renewal and maintenance of core backend infrastructure (e.g. servers, storage disks) and endpoint assets (i.e. laptops, desktops) that enable Toronto Hydro to plan and execute capital and operational programs and to fulfill its obligations to customers and applicable regulatory bodies.	**$36.7 M**	System Maintenance and Capital Investment Support	Cyber Security Risks - Business Operations Efficiency
E8.5	**IT Software**	The Software program covers planned IT upgrades to more than 70 software applications that support Toronto Hydro's core functions and processes. Toronto Hydro must upgrade these applications to ensure their availability to meet operational needs, and to protect itself against cyber threats that	**$81.0 M**	System Maintenance and Capital Investment Support	Cyber Security - IT Systems Compatibility -

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Program Index and Name		Description	Total (5 years)	Trigger Driver	Secondary Drivers
		could jeopardize the security of the distribution system and the privacy of sensitive operational, customer and employee information. The program also includes initiatives to enhance, modify or implement new software applications that are necessary to optimize business operations, or to comply with external requirements imposed by entities such as Measurement Canada, the OEB and the IESO.			Regulatory Compliance
E8.6	ERP Implementation	The current end-of-life ERP, Ellipse, will soon no longer be supported by its vendor, introducing a number of technical risks. The program will replace Ellipse and 30 other legacy applications with a new ERP that meets functional requirements.	$51 M	Functional Obsolescence	Business Operations Efficiency
E8.7	Voice Radio System	The voice radio system is critical to Toronto Hydro's ability to safely and effectively deliver its planned capital and maintenance programs and to respond to trouble calls in a safe, timely and efficient manner. The current voice radio system cannot be supported by the vendor beyond 2016 and must be upgraded to mitigate safety and operational risks.	$20 M	Safety	System Capital and Maintenance Program Support - Functional Obsolescence
E8.8	Program Support	This program will perform two studies to enhance the asset management process and improve the long-term and short-term strategy. The first will be a climate adaption study, focusing on at risk areas to extreme weather and climate change. The second will be a customer interruption study to estimate outage costs.	$1.7 M	System Maintenance and Capital Investment Support	

7.5 System Operating & Maintenance (O&M)

System Operational and Maintenance (O&M) expenditures represent the following five functional areas:

- Supply Chain Services;
- Control Centre;
- Operations Support;

- Distribution Maintenance Programs; and
- Fleet and Equipment Services.

Specific O&M programs within these areas are explained in detail in Exhibit 4A, Tab 2.

Capital and System O&M programs are interrelated. Ageing and deteriorated assets that are not replaced through capital work typically result in deteriorating conditions over time that are managed through System O&M work. These activities place upwards pressure on expenditures within certain segments of System O&M programs. The opposite also typically holds true as increases in capital work can result in reductions in certain System O&M work. Examples of this include capital replacements and enhancements for legacy distribution assets such as fibertop network units, reverse power breakers, and porcelain insulators. Examples also include corrective maintenance expenditures, which during the 2010 to 2013 period, experienced a reduction in part due to increases in planned capital expenditures on ageing and deteriorated assets. Corrective maintenance is expected to rise in 2015, however it is forecast to remain below the peak levels experienced in 2011.

Although System O&M and capital investments are interrelated, a significant portion of System O&M expenditures are directed to activities that are independent of particular capital expenditure levels, including routine maintenance to preserve asset performance over its expected life; vegetation management to maintain minimum clearance requirements for overhead conductor and equipment; cyclical patrols and inspections undertaken to comply with minimum Distribution System Code requirements; corrective maintenance activities to address deficiencies caused by animal, pest, or tree contacts; and emergency maintenance following severe weather and storm damage. In addition, System O&M programs are necessary to provide the information that is used to plan Toronto Hydro's capital programs, such as asset health and condition information. This is particularly important given Toronto Hydro's ageing asset base, which cannot be feasibly replaced through capital work in a short time frame due to a variety of factors such as resource and logistic constraints, as well as potentially intolerable bill increases. The information captured through Toronto Hydro's System O&M programs is necessary to enable the prioritization of assets for capital work and to maximize the likelihood that assets that remain in-service have not surpassed end-of-life.

The projected budgets from 2016 to 2019 for System O&M are expected to increase in line with inflation.

Distribution System Plan (DSP)

A DISTRIBUTION SYSTEM PLAN OVERVIEW

ID	Section
A1	Introduction
A2	Capital Investment Drivers and Expected Cost Savings
A3	Asset Management Process Summary & Enhancements

A1 INTRODUCTION

Toronto Hydro produced this Distribution System Plan ("DSP") in close accordance with Chapter 5 of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission & Distribution Applications.[1] As prescribed in Chapter 5, this DSP describes Toronto Hydro's asset management process and capital expenditure plan, while also providing information pertaining to Toronto Hydro's coordination with third parties, identification of customer preferences, and proposed performance measures to be applied over the course of the plan.

Toronto Hydro has produced a DSP designed to provide the OEB and customers with an accessible, plain-language view of the distributor's investment plans for the five year planning horizon (also referred to as the forecast period) of 2015-2019, while illustrating how the utility plans to meet the expectations set out in the Renewed Regulatory Framework for Electricity (RRFE). Toronto Hydro believes that its plan is designed to address the needs and preferences of the utility's customers by presenting optimized investments that support (1) the achievement of public policy objectives, (2) the need for a significant level of investment in Toronto's distribution system and (3) the overriding objective of delivering value for money.

The DSP has been subdivided into five chapters. Section A serves to provide an introductory overview of the DSP, including the purpose, background and objectives, declaration of capital investment drivers and expected cost savings and an overview of Toronto Hydro's asset management (AM) process. Section A includes discussion on what has changed within that process from previous filings. Section A1.1 provides further detail into the remaining four chapters in the DSP.

A1.1 Purpose

The main purpose of the DSP is to provide the OEB and customers with detailed information and justification on the material investments that Toronto Hydro plans to make during the period from 2015 to 2019. Toronto Hydro has adopted the requirements set out in Chapter 5, dividing the DSP into the following five sections:

[1] Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications, (Toronto: Ontario Energy Board, 2013). ["OEB Filing Requirements"]

- Section A – Distribution System Plan Overview: Provides an introductory overview of the DSP, including (1) the purpose, background and objectives, (2) declaration of capital investment drivers and expected cost savings and (3) an overview of Toronto Hydro's asset management (AM) process with discussion on what has changed within that process from previous filings.

- Section B – Coordinated Planning with Third Parties: Provides information on how Toronto Hydro's DSP aligns to broader regional planning efforts, and shares information with respect to the various consultation processes that were executed.

- Section C – Performance Measures for Continuous Improvement: Provides information with respect to the selected measures that will be adopted by Toronto Hydro to track continuous improvement of planning, execution and outcomes of investments over the course of the planning horizon.

- Section D – Asset Management Process: Provides information with respect to Toronto Hydro's long-term, short-term and maintenance planning processes, which are used to produce the capital investment plan described in Chapter E.

- Section E – Capital Expenditure Plan: Provides information on how Toronto Hydro has applied its Asset Management Process to the utility's distribution system in order to produce the capital investments contemplated by the DSP. This section also contains the detailed description and justification of material investments planned for the five-year forecast period.

A1.2 Background & Objectives

Toronto Hydro has developed a capital investment plan designed to (i) renew grid systems (overhead, underground, secondary network, stations) infrastructure at or beyond their useful life or economic end-of-life criteria, (ii) mitigate critical system-wide issues such as capacity constraints, downtown contingency, security of supply and safety issues while also making (iii) necessary and mandatory investments supporting Toronto Hydro's 24/7 operations, including customer connections, metering, fleet, facilities, information technology (IT), externally-initiated plant relocations and expansion, and system capital and maintenance investment support to ensure that these investment plans are executed and mandated obligations to customers are satisfied.

It is important that Toronto Hydro's DSP address the significant renewal, critical issues and other investment pressures on Toronto's distribution system, as well as deliver value to customers and reflect prudent utility investments. Among other things, Toronto Hydro plans to achieve these goals through the long-term planning processes described in Section D. These planning processes enable the utility to (i) assess the current state of the distribution system; (ii) derive a capital investment approach from this current state foundational data and select an execution strategy that allows for alignment to AM objectives; and (iii) develop capital investment programs that target prioritized assets and issues for intervention.

The derived capital investment approach and execution strategy aligns to asset management objectives. Those objectives, which are described in detail in Section D1.1 aim to: (i) maximize value to the customer; (ii) minimize or eliminate potential safety risks; and (iii) enable the eventual achievement of an optimal balance between required annual capital investment and aggregate risk costs associated with asset failure, also referred to as a "steady state".

As discussed in Section E2.1.2, the produced capital investment approach has revealed a substantial backlog of investments that must be performed in 2015, comprised of assets at or beyond their useful life or economic end-of-life coupled with critical issues. From a purely system-focused perspective, an optimal execution strategy would be to address this backlog of investments in 2015.

However, Toronto Hydro also considers the pacing of those investments and its effect on customers. The utility has therefore proposed a "paced" execution strategy, designed to achieve a steady state in a gradual manner. This "paced" strategy allows for steady capital investments and predictable rate impacts for customers during the 2015-2019 period and beyond. While it would be possible, and optimal from a system perspective, to invest more aggressively today to eliminate the backlog of investments sooner, Toronto Hydro believes that its proposed plan, which is more moderate and predictable, fairly balances the needs of current and future customers and will help mitigate future surges in capital commitments for the long-term.

As explained in Section E2.1.3, the proposed capital expenditure plan and "paced" execution strategy results in a forecasted SAIFI reduction from 1.53 outages in 2014 (target) to 1.13 outages in 2019, and a projected SAIDI reduction from 1.21 hours in 2014 (target) to 0.97 hours in 2019 respectively. Were Toronto Hydro not to execute this investment approach and instead adopt a run to failure approach, SAIFI and SAIDI are forecasted to worsen by another 30%, and 24% respectively over the period from 2015 to 2019.

Toronto Hydro has also engaged with its customers specifically on the needs addressed and the investments proposed in the DSP, as well as the anticipated bill impacts of those investments. Further information on the various customer engagement activities that Toronto Hydro has carried out in relation to the DSP is available in Section E2.4.

In order to monitor the benefits produced by this DSP within the filing period from 2015 to 2019, Toronto Hydro is proposing a series of customer-oriented, cost efficiency and effectiveness-oriented and asset/system operations performance-based metrics. Further details are available in Section C.

Finally, Toronto Hydro has undertaken a variety of coordination and communication efforts with third parties, including the Ontario Power Authority (OPA) and Hydro One Networks Inc. (HONI) as part of the Chapter 5 requirements.

A2 CAPITAL INVESTMENT DRIVERS & EXPECTED COST SAVINGS

A2.1 Capital Investment Drivers

In this DSP, Toronto Hydro proposes capital investment programs with specific drivers. Toronto Hydro developed a list of capital investment drivers based on the OEB's example drivers. Each program includes its own trigger and secondary drivers. Each program is classified under its respective investment category, as shown in Table 1, according to its trigger driver. In the case where one program has multiple drivers from different investment categories, its trigger driver is what determines which investment category it is placed in. Table 1 also provides clarification on the application of these categories to Toronto Hydro's capital investments.

TABLE 1: CAPITAL INVESTMENT CATEGORIES

System Access	ƒ Modifications that the utility is obligated to perform or that are otherwise necessary to provide customers with access to electricity services, driven by statutory, regulatory or other obligations.
System Renewal	ƒ The replacement and/or refurbishing of assets at, or approaching, end of life to extend the service life of the assets, and/or replacement of those assets that no longer align to current operating practices such that accessibility and serviceability conflicts are produced.
System Service	ƒ Modifications to the system to ensure that operational objectives are met while addressing system-wide critical issues and future electricity service requirements.
General Plant	ƒ Modification, replacements or additions to assets that are not part of the distribution system, but represent the backbone of Toronto Hydro's 24/7 operations, including capital and maintenance supporting activities.

Capital investment drivers were developed based on the needs of maintaining reliable services of Toronto Hydro's distribution system. The utility's descriptions for each driver are shown below in Table 2. The core issues addressed by work under each driver can be found in Sections E5 though to E8. Program-specific descriptions are provided in the evidence relating to each program. While the issues identified in the description (both in the table below and in DSP programs themselves) are reasonably illustrative of the issues addressed under each driver, they are not exhaustive lists. The basis and justification for each program is ultimately found in the substantive information provided in the program.

TABLE 2: TORONTO HYDRO DRIVER DESCRIPTIONS

	Driver	Description
System Access	Customer Service Requests	ƒ The fulfilment of Toronto Hydro's obligation to connect a customer to its service. This includes both traditional demand customers and distributed generation (DG) customers. The obligation to connect holds as long as there are no safety concerns for the public or employees and there is no adverse affect on the reliability of the distribution system. ƒ Expansion or enhancements to the system when a connection cannot be made with existing infrastructure.
	Mandated Service Obligation	ƒ Compliance with all legal and regulatory requirements and government directives. ƒ Compliance with Measurement Canada (Gas and Electricity Inspection Act[2]), the Ontario Energy Board (Standard Supply Service Code for Electricity Distributors[3]) and the Independent Electricity System Operator (Wholesale Revenue Metering Standard[4]) and other regulations
	Third Party Request	ƒ Mandated system modifications for property or infrastructure development by government agencies and other entities.
System Renewal	Functional Obsolescence	ƒ Assets/asset installations that no longer align to Toronto Hydro's current operating processes and practices including those assets with accessibility (ravines, rear lots, highway crossings) or serviceability (e.g. Lack of spare parts, lack of ability perform maintenance, operational constraints) conflicts, which can result in increased reliability and/or safety related risks.
	Failure	ƒ Failures have already taken place that Toronto Hydro must reactively respond to as part of capital investment activities.
	Failure Risk	ƒ There is the imminent risk of failure due to age or condition deterioration ƒ The potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public.

[2] R.S.C. 1985, c. E-4.[" Gas and Electricity Inspection Act"]
[3] Ontario Energy Board, Standard Supply Service Code for Electricity Distributors (Toronto: Ontario Energy Board, 2011). ["Standard Supply Service Code"]
[4] Independent Electricity System Operator, Whole Revenue Metering Standard – Hardware (Issue 10.0) (Toronto: Independent Electricity System Operator, 2012). ["Wholesale Revenue Metering Standard"]

	Driver	Description
System Service	Safety	ƒ Assets are exposing known safety-related hazards/risks to crew workers or the general public, or assets are an integral part of maintaining safe work practices, and the failure of those assets would result in safety-related hazard/risk exposure.
	Reliability	ƒ Maintain or improve reliability at a local, feeder-wide or system-wide level.
	System Efficiency	ƒ The need to improve restoration capability, ultimately resulting in substantial reliability and customer experience improvements. ƒ The need to reduce losses in distribution lines.
	Capacity Constraints	ƒ Expected changes in load that will constrain the ability of the system to provide consistent service delivery. ƒ Current or potential incapability of the system to handle demand requirements.
General Plant	System Maintenance and Capital Investment Support	ƒ Renewal and enhancement of critical backbone assets (vehicles, buildings), systems (IT) and systems supporting Toronto Hydro's 24/7 operations, including capital and maintenance investment activities (e.g. Feeder Investment Model)

In Toronto Hydro's planning process, and consequently in this DSP, the trigger driver indicates the primary reason that a particular program must be carried out. However, secondary drivers may be as or more consequential than the trigger driver. For example, a program's trigger driver may be functional obsolescence, meaning that a type of asset can no longer be maintained due to age, availability of parts, and other issues. However, that functional obsolescence may also result in serious safety or reliability issues. The safety or reliability issues would be listed as secondary drivers for the program because they are a consequence of the functional obsolescence of those assets. However, addressing the resulting safety or reliability issues may ultimately be the most pressing reason for Toronto Hydro to proceed with that program, even though those drivers are listed as "secondary".

Table 3 illustrates the association of Toronto Hydro's trigger drivers to each of the four capital investment categories as defined in Table 1 of OEB's Chapter 5 documentation.

TABLE 3: OEB EXAMPLE DRIVERS AND TORONTO HYDRO EQUIVALENTS

	Example Drivers	Example Projects / Activities	Toronto Hydro Trigger Drivers
System Access	Customer service requests	ƒ New customer connections ƒ Modifications to existing customer connections ƒ Expansions for customer connections or property development	Customer Service Requests
	Other third party infrastructure development requirements	ƒ System modifications for property or infrastructure development (e.g. relocating pole lines for road widening)	Third Party Requests
	Mandated service obligations (DSC; Conditions of Service.; etc.)	ƒ Metering ƒ Long-term load transfer	Mandated Service Obligations
System Renewal	Assets/asset systems at end of service life due to: ƒ Failure ƒ Failure risk ƒ Substandard performance ƒ High performance risk ƒ Functional obsolescence	Programs to refurbish/replace assets or asset systems (e.g.: batteries; cable (by type); cable splices; civil works; conductor; elbows and inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)	ƒ Failure ƒ Failure Risk ƒ Functional Obsolescence
System Service	Expected changes in load that will constrain the ability of the system to provide consistent service delivery	ƒ Property acquisition ƒ Capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation ƒ Line extensions	Capacity Constraints
	System operational objectives:	ƒ Protection & control upgrades (e.g. reclosers; tap changer controls/relays;	ƒ Safety ƒ Reliability

	Example Drivers	Example Projects / Activities	Toronto Hydro Trigger Drivers
	ƒ Safety ƒ Reliability ƒ Power quality ƒ System efficiency ƒ Other performance / functionality	transfer trip ƒ Automation (new/upgrades) by device type/function ƒ SCADA ƒ Distribution loss reduction	ƒ System Efficiency
General Plant	ƒ System capital investment support ƒ System maintenance support ƒ Business operations efficiency ƒ Non-system physical plant	ƒ Land acquisition ƒ Structures & depreciable improvements ƒ Equipment and tools ƒ Supplies ƒ Finance/administrative/billing software and systems ƒ Rolling stock ƒ Intangibles (e.g. land rights; capital contributions to other utilities)	System Maintenance and Capital Investment Support

A2.2 Expected Sources of Cost Savings

Cost savings that are realized through the execution of the DSP have been captured within each capital investment program through the development of a business case evaluation (BCE) per Toronto Hydro's Investment Planning process. Key inputs into the BCE process, including asset risk and non-asset risk variables are derived from the Feeder Investment Model (FIM). The FIM, discussed in detail in Section D3.1.2, is a risk-based analytical model that is used to establish the economic end-of-life for the major asset classes within Toronto Hydro's distribution system. It also establishes an optimal time for intervening on a particular asset by balancing the risk associated with asset failure against the capital cost of intervention.

Two different BCE approaches are applied for the capital investment programs within the DSP. For in-kind renewal programs, where existing assets are replaced with their standardized equivalents without any changes to asset configuration, an Avoided Risk Cost (ARC) BCE is

applied. For non-in-kind renewal programs - where existing assets are removed and new assets are installed as per a completely new configuration or where new technologies are introduced such that some form of benefit is introduced to the existing assets in the form of reduced outage durations or reduced overall risks - a Cost of Ownership (COO) BCE is applied. These BCE results are calculated for the first year of activities in each program (for which necessary asset-level details are generally available) and demonstrate cost savings that are achieved through the execution of this work in the form of reduced asset risk or non-asset risk costs, reduced maintenance costs or other efficiencies that can be quantified as Additional Quantifiable Benefits (AQB's). These BCE approaches are discussed in detail in Section D3.3.

As seen in Sections E6.6 and E6.7, execution of the Box Construction and Rear Lot Conversion programs in 2015 result in reductions of maintenance costs of approximately over $3.1 million. BCE's have been applied to the majority of capital investment programs where practicable, and a total NPV of approximately over $380 million is produced through the execution of these programs in 2015.

In addition to the cost savings captured through the BCE process, the majority of Toronto Hydro's proposed DSP programs also include elements that are expected to deliver some form of system efficiency benefit. Some of the specific programs that are expected deliver efficiency to both the customer and Toronto Hydro are:

- Within the Station Expansion program, as outlined in Section E7.9, the completion of the Strachan TS transformer upgrade is expected to prevent Toronto Hydro from having to pay the full cost to replace the transformer again when additional capacity is required. New customers being connected are more likely to be serviced from the station that is geographically closest, thus reducing the connection costs.

- The Box Construction Conversion program, as outlined in Section E6.7, presents reduction in line losses by upgrading from 4.16kV to 13.8kV. The upgrade in overhead feeders is expected to present a three-fold capacity increase, which can accommodate more connections with reduced costs.

- Within the Stations Circuit Breaker Renewal program, as outlined in Section E6.15, the vacuum circuit breakers that Toronto Hydro plans to install through this program entail fifty percent less maintenance cost compared to the oil circuit breakers, since the oil handling expenses associated with oil circuit breakers is eliminated and vacuum circuit breakers have less moving parts to maintain.

In addition, the following table lists the major cost-saving factors with brief explanations into how programs are achieving a more efficient process within Toronto Hydro and reducing costs:

TABLE 4: COST SAVING FACTORS

Cost Saving Factors	Description
Tree trimming	• Use of tree proof conductor in areas where it is expected to reduce the pace of tree trimming cycles by mitigating tree contact outages
Maintenance	• Increased capacity is expected to allow for more flexibility in scheduling planned outages for maintenance at the effected stations • Limiting the number of different types of assets in the system is expected to result in savings in maintenance since there are fewer equipment types with different maintenance needs • Improved availability of spare parts for equipment repair • Automatic switching capability is expected to help achieve maintenance efficiency by reducing maintenance crew hours to complete the same work through a more effective streamlining of functions • Analysis of SCADA monitoring data may help Toronto Hydro make adjustments and corrections, which may result in corrective maintenance cost savings
Control and Monitoring	• Improved restoration time by replacing older and unreliable assets with modern equipment capable of remote troubleshooting and switching capabilities at with no SCADA connection • Installation of sensors providing Toronto Hydro's Control Room the ability to remotely view real time statuses such as flooding, temperature and loading. This is expected to reduce the number of visits to vaults and stations
Operation Efficiencies	• Improved productivity for power system controllers and system response crews – Crews will not have to patrol the entire feeder, only the faulted section, reducing time for restoration • Deploying SCADA enabled tie point and sectionalizing switches reduces the need to send crews to perform the extensive switching work that would otherwise be needed to restore power during outages; is expected to result in labor cost savings by eliminating manual switching

Cost Saving Factors	Description
	ƒ Automated switches allow system controllers to make more efficient use of their time. Since switching actions on automated feeders would be able to occur autonomously, they would be able to focus on other areas requiring restoration
Elimination of Functionally Obsolete Assets	ƒ Provide better access to distribution equipment and allowing for use of standard equipment in the future (i.e. bucket trucks); this is expected to reduce operational costs ƒ Expenditure of engineering resources to deal with asset failure on a reactive basis is avoided, improving organizational efficiency ƒ Installing a current standard asset, opposed to like for like legacy asset – if it is even available, is better for the system and is more efficient from a cost/procurement/standards perspective ƒ Reduce cost associated with repairing obsolete assets and supporting assets (e.g. communications systems)
Reduction of Failure Risk	ƒ Saving cost by planned replacements compared to reactive replacements of failed assets
Project coordination with external parties	ƒ Reduction in capital costs during the installation of infrastructure through cost sharing agreements, as well as shared construction efforts between Toronto Hydro and other organizations
Grouping assets together in projects	ƒ Coordinate work with other asset replacement projects where optimization of work program can be achieved through time and material saving efforts. This includes pole/transformer coordinated replacements to reduce truck rolls, executing work on adjacent feeders to minimize manual switching efforts, etc.
Future Planning	ƒ Enhanced condition monitoring on automated feeders is expected to allow day to day operating decisions and long term asset investment decisions to be made more efficiently and effectively ƒ Implementing the best the technology and material used in construction to extend asset and civil life

As the DSP is executed, Toronto Hydro expects to continue to refine its AM planning processes, which should result in further improvements to capital investment programs. This refinement is performed through a measurement and enhancement process that is further discussed in Section D3.1.2.3. Section C, in particular, highlights a series of performance measures that Toronto Hydro has proposed in order to demonstrate savings and successes that will be realized over the course of the five-year period from 2015 onwards to 2019.

A3 ASSET MANAGEMENT PROCESS SUMMARY & ENHANCEMENTS

This section provides a brief overview of Toronto Hydro's AM Process, along with a summary of recent changes and enhancements to the elements contained within this process from previous EDR filing applications submitted by Toronto Hydro.

A3.1 Asset Management Process Summary

The AM Process, which is presented in Section D, can be broken down into five major components: (i) the planning process; (ii) the associated decision-support systems; (iii) the enterprise databases that support both the planning process and systems' the (iv) distribution system plan itself that is supplied by outputs from the planning process; and (v) a measurement and enhancement process that supports continuous improvement.

The planning process itself can be further subdivided into three stages:

(i) Long-term planning, discussed in detail in Section D1.2.1, results in the development of a capital investment approach and execution strategy along with corresponding investment programs that align to AM objectives.

(ii) Short-term planning, discussed in detail in Section D1.2.2, results in the production of discrete projects within each investment program.

(iii) Maintenance planning, discussed in detail in Section D1.2.3, focuses on extracting the maximum value out of Toronto Hydro's distribution system assets, through inspections, upkeep and repair activities.

The outputs from the AM Planning Process as a whole are integrated into the DSP.

A3.2 Asset Management Process Enhancements

Enhancements to the Asset Management Process can be broken down into two categories: (i) enhancements that have taken place since previous filing periods, and (ii) future enhancements and the processes associated with fulfilling those enhancements. The following sections provide further details on these two forms of enhancements.

A3.2.1 Recent Enhancements from Past Filing Periods

Toronto Hydro has continually monitored and improved decision-support systems, enterprise systems and their respective inputs that support the asset management planning process. This section further provides a breakdown of (i) process-related improvements and (ii) data quality & system improvements.

A3.2.1.1 Process-Related Improvements

Asset Condition Assessment (ACA) represents a core decision-support system used to monitor the condition of core asset classes within Toronto Hydro's distribution system and produce a Health Index (HI) score to support the development of capital investment programs and projects. ACA, which is further explained in Section D3.1.2.1(ii) is driven by inspection information coming out of Toronto Hydro's maintenance program.

As identified by Kinectrics within their independent audit of Toronto Hydro's Asset Condition Assessment program (Appendix A to Section D3), Toronto Hydro has worked to improve its maintenance practices in the following ways:

- Expanded the scope of transformer oil testing (e.g. oil quality tests, furan analyses, dissolved gas analysis (DGA) to include transformers outside of Toronto Hydro's transformer stations. Toronto Hydro-owned transformers at customer locations are now subject to such oil tests).

- Use of enhanced inspection forms for all station assets, network vaults, cable chambers, and overhead switches. In the new forms, there is increased use of dropdown comments as opposed to free-form text. These changes will improve data quality and accuracy.

- Improved record keeping for assets, namely line disconnects, bus disconnects, fuse compartments, and relays. Inspections and maintenance records for these assets are now in the Ellipse database.

- Improvement of inspection forms for wood poles and migration of data into Ellipse. Inspectors will also provide remaining pole strength in PSI.
- Improvements have been made to maintenance inspection training program in order to improve inspection data quality and consistency.

More broadly, Toronto Hydro has enhanced its short-term and long-term planning processes such that specific requirements detailed in OEB's Chapter 5 documentation are satisfied. This includes:

- The use of capital investment drivers for each investment program
- Organizing each capital investment program to one of the four capital investment categories as defined in Chapter 5
- Explaining of timing and pacing of the capital investment program, based upon historical and forward spending
- Alignment of each capital investment program to the program/activity evaluators as defined in Chapter 5, including customer value, reliability, efficiency and safety.

Finally, Toronto Hydro introduced additional quantifiable benefits as an enhancement to the business case process. This allows for a broader set of benefits to be considered in the quantified analysis, thereby allowing for a more accurate and robust analysis of the proposed program. This enhancement is further discussed in detail in Section D3.

A3.2.1.2 Data Quality & System Improvements

Toronto Hydro has worked to improve data quality within its enterprise geographical information system (GIS) and enterprise resource planning (ERP) system respectively such that improved decision making can be performed at both the long-term and short-term planning levels. This includes the following initiatives:

- Development of a data quality reporting process that allows for the discovery, monitoring and repair of data quality issues within various systems.
- Consolidation of data from enterprise systems (GEAR, Ellipse) such that data integrity can be improved.

- Improvement of connectivity of information within various enterprise systems and decision-support systems. For instance, a process was developed to introduce linkages between the GEAR enterprise system and associated asset photos.

A3.2.1.3 Asset Condition Assessment Improvements

Toronto Hydro has improved on various elements documented in the Asset Condition Assessment report. Key improvements include increased sample size of each asset category and improvements to the Business Intelligence Calculator. Other improvements but not limited to include the following:

- Improved maintenance practices – Improvement to inspection data quality and consistency has been made with the enhanced maintenance practices.
- Maintenance tools – New maintenance tools are being used as prototypes and may potentially be incorporated as part of the main maintenance program such as SF_6 sniffer tool for SF_6 equipment and Ultrasonic inspection tools for station switchgears.
- Training of inspectors – The training program has been improved in order to enhance the data quality, such as restructuring the maintenance manuals with updated photos and technical information.

A3.2.2 Future Enhancements

Toronto Hydro is also examining and exploring future enhancements to further improve upon its AM planning process. These include:

- Potential enhancements to the Feeder Investment Model (FIM) in order to respond to feedback provided as part of the 2012-2014 IRM Filing submission. These include:
  - Geospatial tracking of non-asset-related outage events to further improve the calculation of non-asset-related risks
  - Improvements to link customer data to assets in order to improve asset-level load impact data used as part of the outage cost calculation procedure
  - Improvements to customer interruption costs used as part of the outage cost calculation procedure. These have been further defined as part of the Program Support capital investment program in Section E8.8.
- Introduction of performance measures as described in Section C to measure progress and effectiveness of Toronto Hydro's Distribution System Plan. These measures will be used to further enhance Toronto Hydro's AM process.

Distribution System Plan (DSP)

B

COORDINATED PLANNING WITH THIRD PARTIES

ID	Section
B1	Overview of Coordi nated Planning Approach
B2	Regional Planning Process
B3	OPA Comments on Renewable Energy Generation

B1 OVERVIEW OF COORDINATED PLANNING APPROACH

On October 18, 2012, the Ontario Energy Board (OEB) issued its Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.[1] The RRFE Board Report concluded a consultation process aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters.

In the RRFE Board Report, the OEB concluded that infrastructure planning on a regional basis is required to ensure that regional issues and requirements are effectively integrated into utility planning processes. The OEB also noted that the effective use of Regional Infrastructure Planning and the inclusion of regional considerations in distributors' and transmitters' plans will be key in ensuring that the development and implementation of the smart grid in Ontario is carried out on a coordinated basis and that smart grid investments are made at the system level (distribution or transmission) that will best serve the interests of the region.

Toronto Hydro, through its participation in the Central Toronto Integrated Regional Resource Plan led by the OPA, and in its participation in the Needs Screenings for Metro Toronto Northern sub-region and GTA North Western sub-region led by Hydro One Networks Inc. (HONI), has coordinated its efforts and DSP with the outcomes of the completed plans and continues to coordinate with the plans that are under development.

B1.1 Coordinated Planning Approach

Planning for the electricity system in Ontario is done at essentially three levels:

- Bulk system planning
- Regional system planning
- Distribution system planning

[1] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (RRFE) (Report of the Board) (Toronto: Ontario Energy Board, 2012), online: Ontario Energy Board < http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf>. [the "RRFE Board Report"]

These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Bulk system planning typically looks at the broader power system. The bulk power system transfers large quantities both within Ontario (as between major generation sources and load centres) as well as between the provincial grid and neighbouring power systems external to the province via the interconnections. The Ontario Power Authority (OPA) has the accountability for the integrated planning of the bulk power system.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the portions of the power system that supply various parts of the province. There are portions of the power system which can be electrically grouped together due to their bulk supply points and their electrical interrelationships whereby common facilities may impact many connected customers.

Regional planning focuses on the facilities that provide electricity to transmission connected customers such as distributors and large directly-connected customers. This typically includes the transformer load stations and the transmission supply circuits to these stations. It also includes the 115/230 kV auto-transformers and their associated switchyards. From a resource perspective, regional planning considers the local generation and/or Conservation and Demand Management (CDM) that could be developed to address supply and reliability issues in a region or local area.

Local Distribution Companies (LDCs) conduct wires (and resource) planning at the distribution level and coordinate with the Transmitter and the OPA mainly on transmission supply facilities. Toronto Hydro has coordinated new/enhanced transmission supply facilities for some of its stations. These are discussed in more detail in Section B2.

Regional planning can overlap with bulk system planning and distribution system planning. Overlaps with distribution system planning occur largely at the transformer load stations which deliver power to distributors and at large directly-connected customers. In the case of building transformer load stations, this planning can sometimes take place at the distribution level. Another example where regional planning may require coordination with distribution planning occurs when a distribution solution may address the needs of the broader local area or region, for example, by providing load transfer capability between transformer stations.

B1.2 Transmitter Consultations

HONI consulted with Toronto Hydro and neighbouring distributors through a Needs Screening of two electrical areas:

- Metro Toronto Northern Sub-region, and
- GTA North Western Sub-region.

The scope of these Needs Screening processes was to consider whether transmission infrastructure potential transmission needs within these The Needs Screening process produces a Needs Screening Report. The Needs Screening Report for the Metro Toronto Northern Sub-region was completed on June 12, 2014 and is provided as Appendix A. The Needs Screening Report for the GTA North Western Sub-region was completed on June 27, 2014 and is provided in Appendix B.

B1.3 Other Distribution Consultations

Toronto Hydro is the largest LDC in Ontario, is not an embedded distributor and does not supply any embedded distributors. Therefore, the utility does not typically carry out formal planning consultations with other LDCs. Regional system planning processes that are coordinated by HONI and the OPA are generally sufficient in addressing the needs of Toronto Hydro's service area and adjacent regions.

B1.4 OPA Consultations

Toronto Hydro is in active consultation with the OPA, the Independent Electricity System Operator (IESO) and HONI to develop a Central Toronto Integrated Regional Resource Plan (IRRP). The purpose of the IRRP is to ensure that the electricity service requirements of the central Toronto community are served by an appropriate combination of demand and supply options, which reflect the priorities of the community. The plan forecasts the expected growth in electricity demand and investigates the costs and benefits of conservation, distributed generation, and transmission and distribution options in meeting the future electricity needs of customers in the central Toronto area for the next 25 years. The outcome is expected to be an integrated plan with a long-term perspective - one which recommends a balance of options that account for costs, the contribution to reliable electricity service, and mitigation of environmental impacts.

B2 REGIONAL PLANNING PROCESS

The province of Ontario is divided into 23 regional areas for planning purposes. Toronto Hydro's service territory is within the Metro Toronto Region. Toronto Hydro also receives supply from outside of its service territory and this is from the GTA North Region.

The regional planning process is an important input to distribution system planning (stations planning in particular) and the regional planning process is informed by Toronto Hydro's plans. The regional planning process for Toronto is characterized by:

- A large load that is dynamic in the city area
- A significant number of transmission lines and stations
- The presence of a large generator
- A customer base that has experienced and is sensitive to major events that disrupt continuity of service

B2.1 Central Toronto Integrated Regional Resource Plan

The Metro Toronto Region has been divided into two sub-regions for ease of planning: Central Toronto and the Northern sub-regions. The two sub-regions are shown in Figure 1.

The Central Toronto sub-region study in December of 2011 was started before the introduction of the Regional Planning Process. Previously known as the Toronto Regional Plan, it is now the Central Toronto Integrated Regional Resource Plan.

The Ontario Power Authority is the lead and the following organizations are the study participants:

- Toronto Hydro
- Hydro One Networks Inc. (HONI)
- Independent Electricity System Operator (IESO)

FIGURE 1: INTEGRATED REGIONAL RESOURCE PLAN (IRRP) REGIONS

The purpose of the Integrated Regional Resource Plan (IRRP) is to ensure that the electricity service requirements of the central Toronto community are served by an appropriate combination of demand and supply options that reflect the priorities of the community. Planning activities include forecasting the expected growth in electricity demand for the next 25 years, investigating the costs and benefits of conservation, distributed generation, and transmission and distribution options in meeting the future electricity needs of customers in the central Toronto area. The outcome of the planning process will be an integrated plan, with a long-term perspective, which recommends a balance of options that account for costs, reliable electricity service, and mitigation of environmental impacts. The plan has not been completed yet, and is currently

expected to complete by April 2015 (see Exhibit 2B, Appendix D). The impact of the regional plan on the Distribution System Plan is discussed in Section E1.4 - Regional Planning Considerations. ***IC***

B2.2 Metro Toronto – Northern Sub-Region Needs Screening

The purpose of the Needs Screening report was to undertake an assessment of the Metro Toronto Northern Sub-Region and determine if there were regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required. No need for coordinated regional planning was identified. Impacts to the Distribution System Plan are described in Section E1.4 (Regional Planning Considerations).

B2.3 GTA North – Western Sub-Region Needs Screening

The purpose of the Needs Screening report was to undertake an assessment of the Greater Toronto Area (GTA) North, Western Sub-region and determine if there were regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary, such needs will be addressed between the relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required. No need for coordinated regional planning was identified. Impacts to the Distribution System Plan are described in Section E1.4 (Regional Planning Considerations).

B3 OPA COMMENTS ON RENEWABLE ENERGY GENERATION

B3.1 OPA Comment Letter

In compliance with section 5.1.4.2 of the OEB's Filing Requirements for Electricity Transmission and Distribution Applications, Toronto Hydro formally requested a letter of comment from the Ontario Power Authority with respect to the utility's planned renewable energy generation (REG) investments. Toronto Hydro received the OPA Letter of Comment on July 24, 2014. This letter can be found in Appendix C.

B3.2 Toronto Hydro's Response to OPA Letter

The OPA found that Toronto Hydro's REG investment plan is consistent with the OPA's information regarding REG applications to date and that the investments in Toronto Hydro's plan support and enable the connection of additional REG.

The OPA also confirmed that the Integrated Regional Resource Plan (IRRP) is currently under development that Toronto Hydro has participated in all required technical meetings, and that, in early 2013, Toronto Hydro provided the IRRP Working Group (which includes the OPA, Hydro One Networks Inc. and the Independent Electricity System Operator) with a detailed long-term load forecast for the utility's service area in support of the assessment of needs.

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NEEDS SCREENING REPORT

Region: Metro Toronto
Sub-Region: Northern

Revision: Final
Date: June 11, 2014

Prepared by: Metro Toronto Northern Sub-Region Study Team

Study Team Members

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Independent Electricity System Operator	Philip Woo
Toronto Hydro-Electric System Limited	Angelo Boschetti
Veridian Connections Inc.	Craig Smith
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Hydro One Networks Inc. (Distribution)	Charlie Lee

Disclaimer

This Needs Screening Report was prepared for the purpose of identifying potential needs in the Metro Toronto Northern Sub-Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Screening Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Screening Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Screening Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Screening Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Screening Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Screening Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS SCREEN EXECUTIVE SUMMARY

NAME	Metro Toronto Northern Sub-Region Study Team		
LEAD	Hydro One Networks Inc.		
REGION	Metro Toronto Northern Sub-Region		
START DATE	April 14, 2014	END DATE	June 11, 2014

1. INTRODUCTION

The purpose of this Needs Screening report is to undertake an assessment of the Metro Toronto Northern Sub-Region and determine if there are regional needs that require coordinated regional planning.

Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether a OPA-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/TRIGGER

The Needs Screening for the Metro Toronto Northern Sub-Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process that was approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, with Group 1 Regions being reviewed first. The Metro Toronto Northern Sub-Region belongs to Group 1 and the Needs Screening for this Sub-Region was triggered on April 14, 2014 and was completed on June 11, 2014.

3. SCOPE OF NEEDS SCREENING

The scope of this Needs Screening assessment was limited to the next 10 years because relevant data and information was collected up to the year 2023. Needs arising over the near-term (1-5 years) and mid-term (6-10 years) should be further assessed as part of the Needs Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20 year IRRP with strategic direction for the Sub-Region.

The assessment included a review of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis, system reliability, and operational issues such as load restoration, and any relevant asset replacement plans.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the OPA, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Metro Toronto Northern Sub-Region. The information included historical load, forecast, conservation and demand management (CDM), distributed generation (DG), load restoration and performance information along with identification of major equipment approaching end-of-useful life. See Section 4 for further details.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective over the study period (2014 to 2023) is to identify the electrical infrastructure needs in the Sub-Region over the study period (2014 to 2023). The assessment reviewed available information, including load forecasts, and included contingency analysis to confirm the need(s), if and when required. See Section 5 for further details.

6. RESULTS

Transmission Capacity Needs

A. 230 kV Transmission Lines

- Circuit C10A is a 230 kV radial circuit from Cherrywood TS that supplies both Agincourt TS and Cavanagh TS. Following certain contingencies, flow on this circuit may exceed its long-term emergency (LTE) rating. Further assessment is required.

B. 230kV Connection Facilities

- The following DESN stations approach their normal supply capacity in the study period based on the gross demand forecast, but the net demand forecast shows that there is sufficient capacity at these stations throughout the study period. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.
  - Sheppard TS (T3/T4)
  - Leslie TS (T1/T2, 27.6kV windings)
  - Cavanagh MTS

System Reliability, Operation and Restoration Needs

Generally speaking, there are no significant system reliability and operating issues identified for one or two elements out of service in this sub-region. There are contingencies where the loss of load exceeds 150 MW by configuration which must be restored within 4 hours as per the Ontario Resource and Transmission Assessment Criteria (ORTAC). Further assessment is required.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace major equipment do not affect the needs identified. Planned replacement of the T3/T4 DESN at Sheppard TS may provide opportunities for additional capacity at that station.

7. RECOMMENDATIONS

The study team recommends that "local" wires only solutions be developed in the near-term to adequately and efficiently address the needs associated with 230 kV circuit C10A and replacement/upgrading of Sheppard TS through planning between Hydro One Networks Inc. and the impacted distributors.

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1 INTRODUCTION

This Needs Screening report provides a summary of needs that are emerging in the Metro Toronto Northern Sub-Region (“Sub-Region”) over the next ten years. The development of the Needs Screening report is in accordance with the regional planning process as set out in the Ontario Energy Board’s (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the “Planning Process Working Group (PPWG) Report to the Board”.

The purpose of this Needs Screening report is to undertake an assessment of the Metro Toronto Northern Sub-Region to identify near-term and/or emerging needs in the area and determine if these needs require a “local” wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with local distribution companies (LDC) or other connecting customer(s) will further undertake planning to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by the Metro Toronto Northern Sub-Region Needs Screening study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, the OPA and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Metro Toronto Northern Sub-Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Ontario Power Authority
4.	Hydro One Networks Inc. (Distribution)
5.	PowerStream Inc.
6.	Toronto Hydro-Electric System Limited
7.	Veridian Connections Inc.

2 REGIONAL ISSUE/TRIGGER

The Needs Screening for the Metro Toronto Northern Sub-Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Metro Toronto Northern Sub-Region belongs to Group 1. The Needs Screening for this Sub-Region was triggered on April 14, 2014 and was completed on June 11, 2014.

The Metro Toronto Region can be divided into two sub-regions: Metro Toronto Northern Sub-Region and Metro Toronto Central Downtown Sub-Region. The Metro Toronto Central Downtown Sub-Region currently has an IRRP under development, which was initiated prior to the new Regional Infrastructure Planning process.

3 SCOPE OF NEEDS SCREENING

This Needs Screening covers the Metro Toronto Northern Sub-Region over an assessment period of 2014 to 2023. The scope of the Needs Screening includes a review of transmission system connection facility capability which includes transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Screening.

3.1 Metro Toronto Northern Sub-Region Description and Connection Configuration

The Metro Toronto Northern Sub-Region comprises the northern portion of the municipality of Toronto. It includes the area roughly bordered geographically by Highway 401 on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east in addition to the area east of the Don Valley Parkway and north of O'Connor Dr. The boundaries of the Metro Toronto Northern Sub-Region are shown below in Figure 1.

Figure 1: Metro Toronto Region

Electrical supply to the Metro Toronto Northern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities. Supply to this sub-region is provided from a 230 kV transmission system consisting of the Richview TS to Parkway TS, the Richview TS to Cherrywood TS, the Richview TS to Claireville TS, as well as the Cherrywood TS to Leaside TS system. The distribution system in this sub-region is predominantly at 27.6 kV and small pockets at 13.8 kV.

The 230-115kV autotransformers at Leaside TS and Manby TS, the 115 kV transmission lines in Toronto, the Richview TS to Manby TS 230 kV transmission lines, and the stations supplied from all of these lines are not included in the Metro Toronto Northern Sub-Region, but are included in the Metro Toronto Central Downtown Sub-Region. In the Cherrywood TS to Leaside TS system only the station capacity needs are reviewed in this report; the transmission line and all other needs for this system are part of the Metro Toronto Central Downtown Sub-Region.

A single line diagram of the 230 kV system in the Metro Toronto Northern Sub-Region is shown in Figure 2 below.

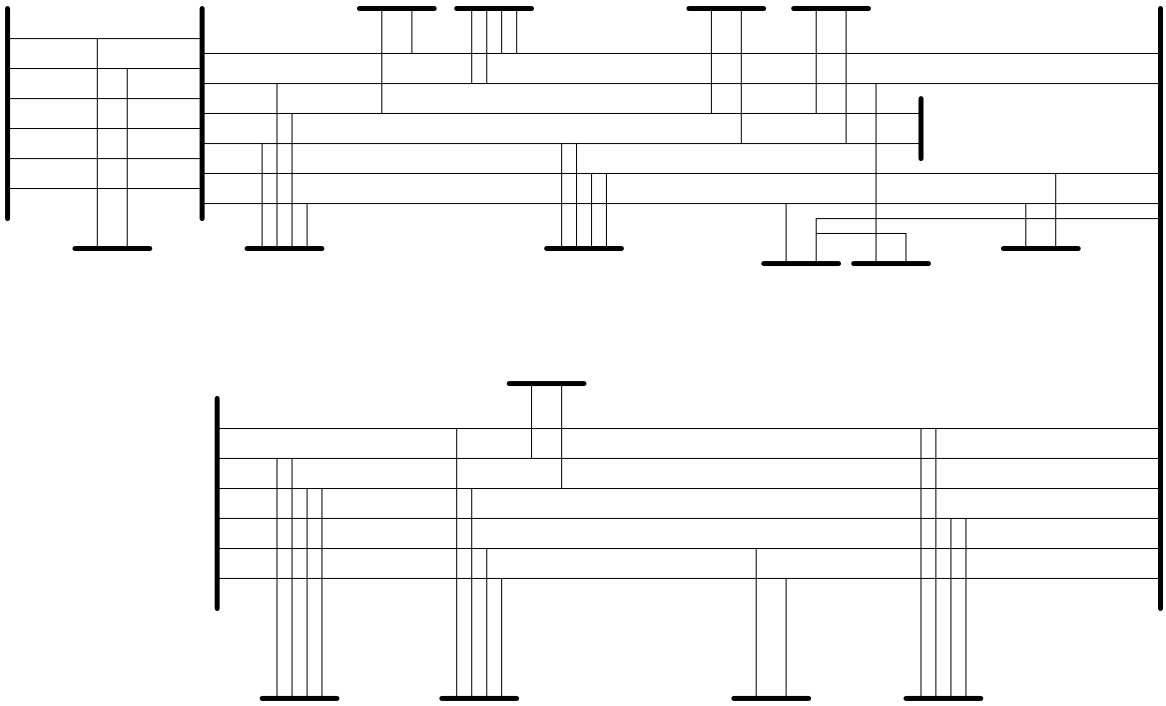


Figure 2: Single Line Diagram – Metro Toronto Northern Sub-Region

4 INPUTS AND DATA

In order to conduct this Needs Screening, study team participants provided the following information and data to Hydro One:

- IESO:
  - i. Historical 2013 regional coincident peak load and station non-coincident peak load
  - ii. List of existing reliability and operational issues
- LDCs and Transmission Connected Customers: Historical (2011-2013) net load, gross load forecast (2014-2023) and any relevant planned distribution investments;
- Hydro One (Transmission): Circuit and transformer ratings
- OPA: Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- Hydro One: Any relevant planned transmission investments.

4.1 Load Forecast

As per the data provided by the LDCs the load in the Metro Toronto Northern Sub-Region is expected to grow at an average of approximately 1.6% annually from 2013-2018, and 0.6% from 2018-2023.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Screening assessment:

1. The Sub-Region is summer peaking, so this assessment is based on summer peak loads.

2. Forecast loads are provided by the LDCs.

3. The LDC's load forecast is translated into load growth rates, and is applied onto the 2013 summer peak load as a reference point.

4. The 2013 summer peak loads are adjusted for extreme weather conditions according to Hydro One's methodology.

5. The needs were first identified based on the gross demand forecast which is deemed to be the worst case scenario. Both the gross demand forecast and the net demand forecast (which includes forecasted CDM and DG contributions) were used to determine the timing of the needs.

6. Review and assess impact of any on-going and/or planned development projects in the Sub-Region during the study period.

7. Review and assess impact of any critical elements planned/identified to be replaced at the end of their useful life such as lines and stations.

8. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).

9. To identify the emerging needs in each Sub-Region, the study was performed observing all elements in service and one or two elements out of service, in accordance with ORTAC.

10. Transmission adequacy assessment is primarily based on but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per ORTAC criteria.
    - With two elements out of service, the system is capable of meeting the load loss limits and restoration guidelines of ORTAC.

6 RESULTS

This section summarizes the results of the Needs Screening in the Metro Toronto Northern Sub-Region.

6.1 Transmission Capacity Needs

6.1.1 230 kV Transmission Lines

C10A is a 20 km long radial circuit from Cherrywood TS. This circuit's capacity is thermally limited by a section approximately 4 km long between Duffin Jct. and Agincourt Jct. This need was also identified in the IESO's System Impact Assessment for Clarington TS (CAA ID 2012-462) which states that flow on this circuit may exceed its LTE rating under peak load conditions.

The conductor on this section is comprised of 795 kcmil, 26/7 ACSR and the Long-Term Emergency (LTE) rating for this type of conductor is typically based on 127ºC. However, the thermal limit for this section is based on a lower temperature of 63ºC and a technical assessment is required to to determine if and how this limit can be removed.

6.1.2 230kV Connection Facilities

The 230kV connection capacity needs identified during the study period include, but may not be limited to the following:

- Sheppard TS consists of two DESN stations and the T3/T4 DESN may reach its normal supply capacity in the near term based on the gross demand forecast.

However, the normal supply capacity is not exceeded in the study period based on the net demand forecast.

It is worth noting that the Sheppard TS T3/T4 DESN is currently scheduled for replacement and upgrade options should be considered. Additionally, the T1/T2 DESN can also be expanded, if needed, by connecting the second pair of transformer secondary windings and adding feeder breakers.

- In the near term (1-5 years), Leslie TS T1/T2 DESN (27.6kV windings) is forecast to reach its normal supply capacity based on the gross demand forecast. However, the normal supply capacity is not exceeded in the study period based on the net demand forecast. No action is required at this time and the capacity need will be reviewed in the next planning cycle.
- In the medium term (6-10 years), Cavanagh MTS is forecast to reach its normal supply capacity based on the gross demand forecast. However, the normal supply capacity is not exceeded in the study period based on the net demand forecast. No action is required at this time and the capacity need will be reviewed in the next planning cycle.

The station capacity needs outlined above are not expected to require further coordinated regional planning.

6.2 System Reliability, Operation and Load Restoration

Generally speaking, there were no significant system reliability and operating issues identified for this sub-region. Load loss exceeding 250 MW and 150 MW for design criteria contingencies must be restored within 30 minutes and 4 hours respectively, according to ORTAC. Based on the net coincident demand forecast, there were no contingencies identified in this sub-region where more than 250 MW would be lost by configuration. Some contingencies may result in load loss at this approaching 250 MW in the study period, and this should be reviewed in the next planning cycle. However, there are contingencies in the sub-region where load lost by configuration may exceed 150 MW. Further assessment is required by the transmitter.

Based on the net demand forecast there are contingencies in the Cherrywood x Leaside transmission system that may result in loads in excess of 250 MW. Load restoration issues for this system are being further assessed as part of the Metro Toronto Central Downtown study.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any auto-transformers, power transformer and high-voltage cables. There are no major refurbishment or replacement plans that will affect capacity needs in the

Sub- Region with the exception of transformers (T3 and T4) and associated switchyard at Sheppard TS.

7 RECOMMENDATIONS

The study team's recommendations are as follows:

a) At this time, the potential needs identified above do not require further regional coordination. Rather, these potential needs can be adequately and more efficiently addressed by Hydro One Networks Inc. and the relevant LDCs.

The Metro Toronto Central Downtown Sub-Region currently has an OPA-led IRRP study underway. OPA will later append the results of this sub-region's Needs Screening to the Regional IRRP.

The needs that have been identified through this Needs Screening may be re-evaluated based on the findings of subsequent analysis.

8 NEXT STEPS

Following the Needs Screening process the next regional planning step, based on the results of this report, is for Hydro One Transmission and impacted LDCs to develop and implement local solutions for the aforementioned near-term needs.

9 REFERENCES

- Planning Process Working Group (PPWG) Report to the Board
- IESO 18-Month Outlook
- IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)
- IESO System Impact Assessment Report for Clarington TS (CAA ID#: 2012-462)

10 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
FETT	Flow East Towards Toronto
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NS	Needs Screening
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
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NEEDS SCREENING REPORT

Region: GTA North
Subregion: Western

Date: June 27, 2014

Prepared by: GTA North, Western Subregion Study Team

Study Team Participants	
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Hydro One Brampton Networks Inc.	Tom Wasik
Hydro One Networks Inc.(Distribution)	Charlie Lee
PowerStream Inc.	Richard Wang
Toronto Hydro-Electric System Limited	Angelo Boschetti

Disclaimer

This Needs Screening Report was prepared for the purpose of identifying potential needs in the GTA North, Western Subregion and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Screening Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Screening Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Screening Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Screening Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Screening Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Screening Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS SCREEN EXECUTIVE SUMMARY

REGION	GTA North, Western Subregion (the "Subregion")		
LEAD TRANSMITTER	Hydro One Networks Inc. ("Hydro One")		
START DATE	April 28, 2014	**END DATE**	June 27, 2014

1. INTRODUCTION

The purpose of this Needs Screening report is to undertake an assessment of the GTA North, Western Subregion and determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary, such needs will be addressed between the relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution) is required, or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Screening for the Subregion was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups - Group 1 Regions are being reviewed first. The GTA North, Western Subregion belongs to Group 1 and the Needs Screening for this Region was triggered on April 28, 2014 and was completed on June 27, 2014.

3. SCOPE OF NEEDS SCREENING

The scope of this Needs Screening assessment was limited to the next 10 years because relevant data and information was collected up to the year 2023, as per the recommendations of the Planning Process Working Group Report to the Board. Needs emerging over the near-term (0-5 years) and mid-term (6-10 years) should be further assessed as part of the OPA-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year plan and strategic direction for the Region.

The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from relevant LDCs, the OPA, the IESO, and Hydro One transmission provided information for the GTA North, Western Subregion. The information included historical load, load forecasts, Conservation and Demand Management (CDM) information, Distributed Generation (DG) information, and load restoration and performance information along with end-of-useful-life of any major equipment. See Section 4 for further details.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective over the study period (2014 to 2023) was to identify the electrical infrastructure needs in the region. The study reviewed available information and load forecasts and conducted single contingency analysis to confirm needs, if any, and when they may be required. See Section 5 for further details.

6. RESULTS

Transformer stations and transmission facilities in the Subregion have sufficient capacity to accommodate the expected load over the study period.

Inherent to radial configuration, loss of two radial 230 kV circuits V43 and V44 will result in loss of load. Load restoration for the loss of these two circuits as per the ORTAC guidelines is being further assessed as part of the OPA led Integrated Regional Resource Plan (IRRP) for the GTA West, Northern Subregion.

See section 6 for details.

7. RECOMMENDATIONS

Based on the findings of the Needs Screening process, the study team recommends that further coordinated regional planning is required to assess load restoration for the loss of two radial elements (230 kV circuits V43 and V44). OPA will coordinate the assessment of this need currently underway as part of GTA West Northern Subregion IRRP process with the study team.

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1 INTRODUCTION

This Needs Screening report provides a summary of needs that are emerging in the GTA North, Western Subregion (the "Subregion") over the next ten years. The development of the Needs Screening report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC), Distribution System Code (DSC) and the Planning Process Working Group (PPWG) Report to the Board.

The purpose of this Needs Screening report is to undertake an assessment of the Subregion, and determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a wires-only solution is necessary such needs will be addressed between the relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required. For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution) is required, or whether both are required.

The preparation of this report was carried by the GTA North, Western Subregion Needs Screening study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by the LDCs, the Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for GTA North, Western Subregion

No.	Organization
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	The Ontario Power Authority
3.	The Independent Electricity System Operator
4.	Enersource Hydro Mississauga Inc.
5.	Hydro One Brampton Networks Inc.
6.	Hydro One Networks Inc.(Distribution)
7.	PowerStream Inc.
8.	Toronto Hydro-Electric System Limited

Figure 1: GTA North, and Western Subregion (shown in yellow highlight).

2 REGIONAL ISSUE/TRIGGER

The Needs Screening for the GTA North, Western Subregion was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The GTA North region belongs to Group 1. The Needs Screening for this Subregion was triggered on April 28, 2014 and was completed on June 27, 2014.

3 SCOPE OF NEEDS SCREENING

This Needs Screening covers the Subregion over an assessment period of 2014 to 2023. The scope of the Needs Screening includes a review of system capability which covers transformer station loading and transmission line thermal and voltage analysis. System reliability, operation, load restoration and asset sustainment issues were also reviewed as part of this screening.

3.1 Subregion Description and Connection Configuration

The GTA North, Western Subregion includes the area roughly bordered geographically by Steeles Avenue on the south, King-Vaughan Rd on the north, Highway 50 on the west and Weston Road on the east. The GTA North Western Subregion comprises the Western portion of the City of Vaughan.

Electrical supply to the GTA North Western Subregion is provided through 230 kV transmission lines and step-down transformation facilities as shown in Figure 1 above and Figure 2 below. Supply to this Subregion is provided through the 230 kV Claireville TS to Kleinburg TS transmission lines (V43 and V44). The distribution systems supplied by this Subregion operate at 27.6 kV and 44 kV.

The 230 kV Claireville TS to Brown Hill TS and the Claireville TS to Parkway TS transmission lines and the stations supplied from these lines are not included in the GTA North Western Subregion but are included in a the York Subregion of GTA North.

Table 2 below lists the substations in the GTA North, Western Subregion, the LDCs supplied by each station and the stations' actual 2013 non-coincident summer peak demand as per IESO data.

Table 2: 2013 Summer Peak Station Demand

Station	2013 Peak Station Demand (MW)	LDCs
Woodbridge TS	151	Enersource Hydro Mississauga Inc.
		Hydro One Brampton Networks Inc.
		PowerStream Inc.
		Toronto Hydro-Electric System Limited
Vaughan MTS #3	152	Powerstream Inc.
Kleinburg TS	136	Hydro One Networks Inc. (Distribution)
		PowerStream Inc.

A single line diagram of the Subregion's transmission supply and transformer stations is shown in Figure 2 below. Goreway TS is not part of this Subregion, but its loading is considered due to the impact on the V43 circuit which supplies the Subregion. The 2013 coincident summer peak demand supplied by the 230 kV V43/V44 circuits is approximately 500 MW, which includes the portion of Goreway TS coincident summer peak demand supplied by the V43 circuit.



* Goreway TS is not part of the GTA North, Western Sub-Region study but its loading is considered due to impact on loading of circuit V43.

Figure 2: Single Line Diagram – GTA North, Western Subregion

4 INPUTS AND DATA

In order to conduct this Needs Screening, study team participants provided the following information and data to Hydro One:

- IESO provided:
  i. Historical regional coincident peak load and station non-coincident peak load.
  ii. List of existing reliability and operational issues.
- LDCs and Transmission Connected Customers provided historical (2011-2013) net load and gross load forecast (2014-2023).
- Hydro One provided transformer, station, and line ratings.
- OPA provided Conservation and Demand Management (CDM) and Distributed Generation (DG) data.
- Any relevant planned transmission and distribution investments were provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per data provided by the study team, gross load in the GTA North, Western Subregion is expected to grow at an approximate rate of 1.1% annually between 2014 and 2023. The near term growth rate, between 2014 and 2018, is expected to be approximately 1.17% per year and the medium term growth rate, between 2018 and 2023, is expected to be 1.03% per year.

The Needs Screening assessment considered gross loads at individual stations based on the 2013 summer peak non-coincident demand and the summer peak non-coincident demand forecasts for stations within the Subregion. The station load forecast was developed by applying load growth rates derived from the LDCs' load forecasts.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions were made in this Needs Screening assessment:

1. The Subregion is summer peaking so this assessment is based on summer peak loads.
2. The coincident load forecast is based on the forecast growth rates provided by the Subregion's LDCs and historical 2013 summer peak loads as the reference point. The 2013 historical peak loads are adjusted for extreme weather conditions according to Hydro One methodology.
3. The Subregion's non-coincident peak load forecast for station capacity assessment was developed from load forecasts provided by LDCs.

4. Gross coincident peak load forecast is used to develop a worst-case scenario to identify needs. Where applicable, net coincident peak load forecast, which includes forecasted CDM and DG contributions, is used to determine the timing of needs.
5. Review and assess the impact of any on-going or planned development project in the Subregion during the study period.
6. Review and assess the impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as auto transformers, cables and stations.
7. To identify the emerging needs in each area, the study was performed observing all elements in service and one element out of service.
8. Station capacity adequacy is assessed by comparing non-coincident peak load with the station's normal supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
9. Normal supply capacity for transformer stations is the summer 10-Day Limited Time Rating (LTR).
10. Transmission adequacy assessment is primarily based on but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per ORTAC criteria.

6 RESULTS

This section summarizes the results of the Needs Screening in the GTA North, Western Subregion.

6.1 230kV Supply in the Subregion

The 230kV transmission system in the Subregion consists of two radial transmission circuits, V43 and V44 which originate from Claireville TS and supply the three stations in the region: Woodbridge TS, Vaughan #3 MTS and Kleinburg TS. In addition to supplying the three stations in the Subregion, V43 supplies Goreway TS which is not within the GTA North, Western Subregion. Loading of Goreway TS has been considered in performing the Needs Screening for the 230 kV transmission supply.

With the expected load growth in the Subregion, the V43 and V44 circuits are expected to remain within their normal supply capacity over the period covered by the Needs Screening. Line voltages under regional peak loading conditions are within the limits specified in ORTAC.

6.2 Transformer Stations in the Subregion

Transformer Stations in the Subregion include the following:

i) Woodbridge TS: Capacity at Woodbridge TS is sufficient to accommodate the expected load growth over the study period.

ii) Vaughan MTS #3: This station is loaded to its normal rated supply capacity as of 2013. Vaughan MTS #4, which is expected to be in service in 2017, will relieve Vaughan TS #3. The 230 kV transmission lines between Claireville TS and Minden TS, which are expected to supply Vaughan MTS #4, are not part of this Subregion.

iii) Kleinburg TS: Capacity at Kleinburg TS is sufficient to accommodate the expected load growth over the study period.

6.3 System Reliability, Operation and Load Restoration

Generally speaking, there are no significant system reliability and operating issues for one element out of service.

Inherent to radial configuration, loss of two radial 230 kV circuits V43 and V44 will result in loss of load. Load restoration for the loss of these two circuits as per the ORTAC guidelines is being assessed as part of the OPA led Integrated Regional Resource Plan (IRRP) for the GTA West, Northern Subregion.

6.4 Aging Infrastructure and Replacement Plans for Major Equipment

During the study period:

- None of the sub-station step-down transformers are expected to reach the end of their useful life.
- No high voltage cables in the area are expected to reach the end of their useful life.

7 RECOMMENDATIONS

Based on the findings of the Needs Screening, the study team recommends that further coordinated regional planning is required to assess load restoration for the loss of two radial elements (230 kV circuits V43 and V44). OPA is assessing this need as part of its GTA West, Northern Subregion IRRP and will coordinate the assessment with the study team.

8 NEXT STEPS

Based on the findings of the Needs Screening process, the next steps for this Subregion include:

a) OPA to include relevant LDCs in the GTA West, Northern Subregion IRRP process to participate in the assessment of load restoration needs identified for this Subregion.

b) Revisit the Subregion's needs during the next regional planning cycle, which is expected to be within the next five years.

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015.

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

iv) OPA Terms of Reference for the GTA West, Northern Subregion IRRP.

OPA Letter of Comment

Toronto Hydro-Electric System Limited

Renewable Energy Generation Investments Plan

July 24, 2014

region in the PPWG report, and the Central Toronto IRRP was initiated prior to the formalization of regional planning in Ontario by the OEB. THESL has been working with the OPA, Hydro One Networks Inc., and the Independent Electricity System Operator as part of an IRRP Working Group. The OPA confirms that THESL has participated in all required technical meetings, and in early 2013, THESL provided the IRRP Working Group with a detailed long-term load forecast for the area to support the assessment of needs.

THESL has also been a lead partner in developing an engagement plan and supporting materials in preparation for the stakeholder engagement phases of the Central Toronto IRRP. THESL has been a key contributor to the planning and logistics and will jointly conduct the engagement in partnership with the OPA.

The first phase of the engagement is currently set to be undertaken in 2014, and the information can be found at: http://powerauthority.on.ca/power-planning/regional-planning/toronto/central-downtown. An engagement workbook, providing information on key plan objectives, needs and a review of potential options, has been developed to provide interested stakeholders with context in advance of more detailed in-person discussions with key stakeholders. THESL played a central role developing the list of invitees for the engagement. Stakeholders invited to the engagement sessions will include a diverse group of customer representatives from commercial, public sector, City of Toronto, ratepayer groups, environmental groups, and others.

Options for the IRRP include conservation and demand management, distributed generation development (including REG), and transmission and distribution system expansion to both enable the incorporation of distributed generation and to accommodate growth in the city. Many opportunities exist in the context of an integrated resource plan for Central Toronto. The investments identified in THESL's Plan support and enable the connection of additional REG, which enhances the ability of local customers and proponents to participate in these ongoing renewable programs, while contributing to the supply diversity within the IRRP study area. The outstanding IRRP process steps include the identification and consideration of local community preferences and the economic comparison of technically viable options.

The final deliverable, an IRRP report, is scheduled to be issued by the end of 2014.

A Needs Screening for the remainder of Metro Toronto area, including the areas outside of Central Toronto, has been completed by Hydro One, and has been posted to their website at: http://www.hydroone.com/RegionalPlanning/Toronto/Pages/default.aspx. The Needs Screening concluded that, at this time, there is no further need for regional coordination to address the potential needs identified in the Needs Screening report, and that the needs can be addressed by Hydro One and the relevant local distribution companies.

The OPA looks forward to working further with THESL in the Regional Planning process, and appreciates the opportunity to comment on the information provided.

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February 3, 2015

Mr. Jack Simpson
Toronto Hydro-Electric System Limited
500 Commissioners Street
Toronto, Ontario M4M 3N7

Dear Jack:

Re: Update to July 24, 2014 Letter of Comment regarding THESL's Renewable Energy Generation Investments Plan

In response to your request for an update to the OPA's[1] July 24, 2014 Letter of Comment, I am pleased to provide THESL with updated information as follows.

The FIT and microFIT applications referenced in the Letter of Comment remain consistent with the renewable energy generation information that was received from THESL, as of May 31, 2014.

With respect to the Central Toronto Integrated Regional Resource Plan ("IRRP"), since July 2014, the IESO and THESL, with Hydro One Networks, have completed a stakeholder engagement process that included:

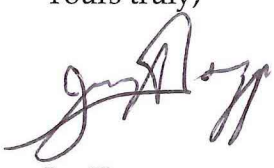
- the release of an online discussion workbook,
- two public webinars,
- three stakeholder workshops with representatives from the City of Toronto, Board of Trade, environmental non-governmental organizations and major consumers,
- focus group sessions with residential and small business customers,
- public open houses, and
- customer telephone surveys.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

THESL was a full partner in developing and delivering the engagement plan. This included developing supporting materials in preparation for the stakeholder engagement, and the planning and logistics. The IESO has archived the engagement materials which can be found at the following link: http://powerauthority.on.ca/power-planning/regional-planning/toronto/central-downtown.

The completion date of the IRRP has been revised to April 2015 to allow time for incorporating the impact of new customer connection inquiries and meaningful consideration of input from the stakeholder engagement.

Yours truly,



Joe Toneguzzo
Director, Transmission Integration
IESO

Copied to:
Nancy Marconi, IESO
Amanda Klein, THESL Regulatory Affairs

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Metro Toronto Region – Northern Subregion

The Need Assessment report for this Subregion was completed in June 2014 and is available on Hydro One's Regional Planning website. From a regional planning perspective, THESL has little impact from this Subregion. In addition, the study team determined that the needs identified for this Subregion can be addressed directly by Hydro One and LDCs and further regional coordination is not required.

GTA North Region – Western Subregion

The Need Assessment report for this Subregion was completed in June 2014 and is available on Hydro One's Regional Planning website. Based on the findings of the Need Assessment, the study team determined that further coordinated regional planning is required to assess load restoration issues for the loss of two radial elements (230 kV circuits V43 and V44). The IESO (formerly OPA) will coordinate the assessment of this need as part of GTA West Northern Subregion IRRP process currently underway. Other needs identified for the rest of the Subregion will be addressed directly by Hydro One and the relevant LDCs, and further regional coordination is not required.

Hydro One looks forward to working with THESL in executing the new regional planning process. If you have any further questions, please feel free to contact me.

Sincerely,

Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Ma S R I 2 Q W D U L R ¶ V 3 O D Q Q L Q J 5 H J L R Q V

Northern Ontario



Southern Ontario



Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo-Cambridge-Guelph ³.:&*´		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	**x** Brant County Power Inc. **x** Brantford Power Inc. **x** Burlington Hydro Inc. **x** Haldimand County Hydro Inc. **x** Horizon Utilities Corporation **x** Hydro One Networks Inc. **x** Norfolk Power Distribution Inc. **x** Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	**x** Hydro 2000 Inc. **x** Hydro Hawkesbury Inc. **x** Hydro One Networks Inc. **x** Hydro Ottawa Limited **x** Ottawa River Power Corporation **x** Renfrew Hydro Inc.
3. GTA North	**x** Enersource Hydro Mississauga Inc. **x** Hydro One Brampton Networks Inc. **x** Hydro One Networks Inc. **x** Newmarket-Tay Power Distribution Ltd. **x** PowerStream Inc. **x** PowerStream Inc. [Barrie] **x** Toronto Hydro Electric System Limited **x** Veridian Connections Inc.
4. GTA West	**x** Burlington Hydro Inc. **x** Enersource Hydro Mississauga Inc. **x** Halton Hills Hydro Inc. **x** Hydro One Brampton Networks Inc. **x** Hydro One Networks Inc. **x** Milton Hydro Distribution Inc. **x** Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph	Cambridge and North Dumfries Hydro Inc. Centre Wellington Hydro Ltd. Guelph Hydro Electric System - Rockwood Division Guelph Hydro Electric Systems Inc. Halton Hills Hydro Inc. Hydro One Networks Inc. Kitchener-Wilmot Hydro Inc. Milton Hydro Distribution Inc. Waterloo North Hydro Inc. Wellington North Power Inc.
6. Metro Toronto	Enersource Hydro Mississauga Inc. Hydro One Networks Inc. PowerStream Inc. Toronto Hydro Electric System Limited Veridian Connections Inc.
7. Northwest Ontario	Atikokan Hydro Inc. Chapleau Public Utilities Corporation Fort Frances Power Corporation Hydro One Networks Inc. Kenora Hydro Electric Corporation Ltd. Sioux Lookout Hydro Inc. Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	E.L.K. Energy Inc. Entegrus Power Lines Inc. [Chatham-Kent] EnWin Utilities Ltd. Essex Powerlines Corporation Hydro One Networks Inc.
9. East Lake Superior	N/A This region is not within Hydro One territory

10. GTA East	Hydro One Networks Inc. Oshawa PUC Networks Inc. Veridian Connections Inc. Whitby Hydro Electric Corporation
11. London area	Entegrus Power Lines lnc. [Middlesex] Erie Thames Power Lines Corporation Hydro One Networks Inc. London Hydro Inc. Norfolk Power Distribution Inc. St. Thomas Energy Inc. Tillsonburg Hydro Inc. Woodstock Hydro Services Inc.
12. Peterborough to Kingston	Eastern Ontario Power Inc. Hydro One Networks Inc. Kingston Hydro Corporation Lakefront Utilities Inc. Peterborough Distribution Inc. Veridian Connections Inc.
13. South Georgian Bay/Muskoka	Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) Hydro One Networks Inc. Innisfil Hydro Distribution Systems Limited Lakeland Power Distribution Ltd. Midland Power Utility Corporation Orangeville Hydro Limited Orillia Power Distribution Corporation Parry Sound Power Corp. Powerstream Inc. [Barrie] Tay Power Veridian Connections Inc. Veridian-Gravenhurst Hydro Electric Inc. Wasaga Distribution Inc.

14. Sudbury/Algoma	Espanola Regional Hydro Distribution Corp. Greater Sudbury Hydro Inc. Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	Bluewater Power Distribution Corporation Entegrus Power Lines Inc. [Chatham-Kent] Hydro One Networks Inc.
16. Greater Bruce/Huron	Entegrus Power Lines Inc. [Middlesex] Erie Thames Power Lines Corporation Festival Hydro Inc. Hydro One Networks Inc. Wellington North Power Inc. West Coast Huron Energy Inc. Westario Power Inc.
17. Niagara	Canadian Niagara Power Inc. [Port Colborne] Grimsby Power Inc. Haldimand County Hydro Inc.* Horizon Utilities Corporation Hydro One Networks Inc. Niagara Peninsula Energy Inc. Niagara-On-The-Lake Hydro Inc. Welland Hydro-Electric System Corp. Niagara West Transformation Corporation* *Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A This region is not within Hydro One territory

19. North/East of Sudbury	Greater Sudbury Hydro Inc. Hearst Power Distribution Company Limited Hydro One Networks Inc. North Bay Hydro Distribution Ltd. Northern Ontario Wires Inc.
20. Renfrew	Hydro One Networks Inc. Ottawa River Power Corporation Renfrew Hydro Inc.
21. St. Lawrence	Cooperative Hydro Embrun Inc. Hydro One Networks Inc. Rideau St. Lawrence Distribution Inc.

Distribution System Plan (DSP)

C PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

ID	Section
C1	Overview of Continuous Improvement Principles and Approach
C2	Customer Oriented Performance
C3	Cost Efficiency and Effectiveness
C4	Asset and System Operations Performance

C1 OVERVIEW OF CONTINUOUS IMPROVEMENT PRINCIPLES AND APPROACH

C1.1 Introduction

The purpose of this exhibit is to describe Toronto Hydro's proposed Distribution System Plan (DSP) measures that the utility plans to track and periodically report on over the 2015-2019 ratemaking period.

Toronto Hydro has developed a set of 12 measures to monitor quality and drive continuous improvement in its distribution system planning and implementation work over the 2015-2019 planning horizon. The measures cover several distinct dimensions of the utility's capital planning and implementation processes and/or speak directly to the outcomes of such processes, motivated by customer needs, regulatory compliance obligations, or corporate efficiency objectives.

Table 1 outlines Toronto Hydro's proposed DSP performance measures, grouped by primary category.

TABLE 1: PROPOSED PERFORMANCE MEASURES FRAMEWORK

Customer-Oriented Performance	Cost Efficiency/ Effectiveness of Planning and Implementation	Asset/System Operation Performance
1. System Average Interruption Duration Index (SAIDI).	1. Distribution System Plan Implementation Progress.	1. Outages caused by defective equipment.
2. System Average Interruption Frequency Index (SAIFI).	2. Planning Efficiency: Engineering, Design and Support Costs.	2. Stations capacity availability.
3. Customer Average Interruption Duration Index (CAIDI).	3. Supply Chain Efficiency: Materials Handling On-Cost.	
4. Feeders Experiencing Sustained Interruptions (FESI).	4. Construction Efficiency: Internal vs. Contractor Cost Benchmarking.	
5. Momentary Average Interruption Frequency Index (MAIFI).	5. Construction Efficiency: Standard Asset Assembly Labour Input.	

In developing the proposed measures, Toronto Hydro referred to the Section 5.2.3, Chapter 5 of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission and Distribution Applications[1], which sets out the key parameters for measures or metrics supporting the applicants' Distribution System Plan filings. Toronto Hydro's proposed framework of measures is consistent with the OEB's expectations set out in the Chapter 5 Filing Requirements, and should provide the OEB with useful insights into the quality and sophistication of the utility's distribution planning and implementation activities, as well as Toronto Hydro's improvement in recent years.

For each proposed measure, (with the exception of new measures) Toronto Hydro provides performance results along with the associated trend over the recent years, describes the methodology used to calculate the measure and its implementation, and outlines the ways in which the measure informs and/or otherwise interacts with the utility's Distribution System Plan and the related processes. Where relevant, Toronto Hydro also describes the unique planning

[1] Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications, (Toronto: Ontario Energy Board, 2013). ["OEB Filing Requirements"]

The table would be accompanied by a discussion document which provides: additional context for Toronto Hydro's performance on each of the measures, including year-over-year variance explanations; a discussion of planned and completed activities that may have a bearing on the utility's performance on one or more of the measures; and such other information as may be relevant to the explanation of the utility's annual results. /C

Consistent with the OEB's decision to treat information relating to the cost difference between internal and external construction of projects in a confidential manner as part of this application,[3] Toronto Hydro proposes to file the annual results of the Construction Efficiency: Internal vs. Contractor Cost, in a confidential manner as well.

[3] EB-2014-0116, Decision on Confidentiality And Procedural Order No. 4 (January 7, 2014). /C

C2 CUSTOMER ORIENTED PERFORMANCE

C2.1 Reliability Measures – SAIDI, SAIFI, CAIDI

C2.1.1 Measure Description

Toronto Hydro tracks its results on the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) in accordance with the OEB-mandated measurement and reporting practices specified in Section 2.1.4.2 of the Reporting and Record Keeping Requirements (RRR) as established by the OEB. The methodology used to calculate and report on these metrics is consistent with the requirements in the OEB's RRR document and IEEE 1366-2012. Calculation of SAIDI, SAIFI, and CAIDI is as follows:

`

Each outage is captured in Toronto Hydro's Interruption Tracking Information System (ITIS), further described in Section D3.1.2.1 (iii) of the DSP. Outage statistics such as Customers Interrupted (CI), Customer Minutes Out (CMO) and Duration are kept as individual entries in each individual report. The ITIS tool was developed in-house to facilitate Toronto Hydro's operational and reporting requirements with respect to outage information tracking and analysis. The CI values, used for SAIFI, and the CMO values, which are an input for SAIDI are tracked in ITIS and aggregated on a monthly basis to derive the Total Number of Customer Interruptions and Minutes Out. To calculate monthly SAIDI and SAIFI values, Toronto Hydro uses the most recent customer count data from its Customer Care and Billing (CC&B) system. At the end of the year, Toronto Hydro aggregates the monthly SAIDI and SAIFI values to calculate the annual reliability measure

values. All SAIFI, SAIDI, and CAIDI values showcased further in this document are based on year-end calculations. Toronto Hydro excludes the major event days (MEDs), as defined by IEEE 1366-2012 2.5 beta method, from all representations of reliability metrics.

C2.1.2 Historical Performance Trends

Figures 1, 2, 3, and 4 respectively illustrate Toronto Hydro's SAIDI, SAIFI and CAIDI over the past five years both including and excluding loss of supply. For SAIDI and SAIFI, the trend over the five year historical period can be attributed to the capital investments made over that time. CAIDI, on the other hand, has remained stable over the five-year historical period, as it is proportional to SAIDI and inversely proportional to SAIFI. As such, when it comes to CAIDI, the improvement of SAIDI is negated by a similar improvement to SAIFI. Toronto Hydro notes that improvements made towards SAIDI and SAIFI can lag the investments by a year or more.

Activities such as rear lot conversion and direct-buried cable replacement that reduce the number and duration of outages are among the investments that have contributed to the historical improvements shown.

FIGURE 1: HISTORICAL SAIDI EXCLUDING MEDS – 2009-2013

FIGURE 2: HISTORICAL SAIFI EXCLUDING MEDS – 2009-2013

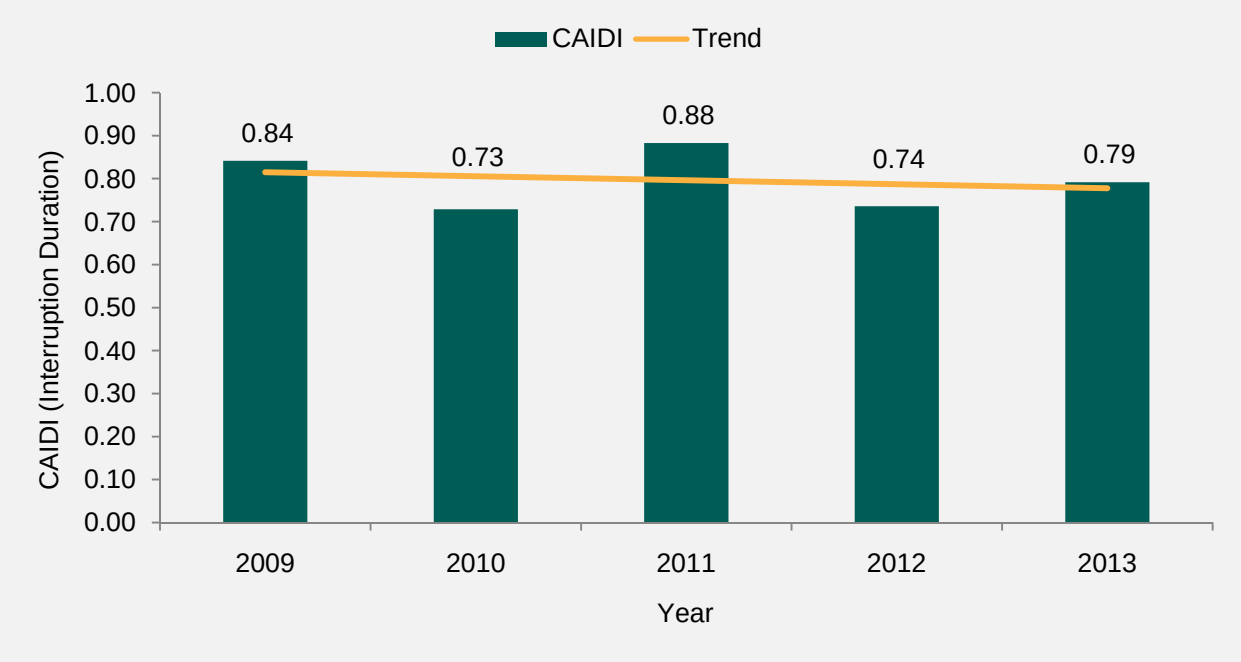


FIGURE 3: HISTORICAL CAIDI EXCLUDING MEDS – 2009-2013

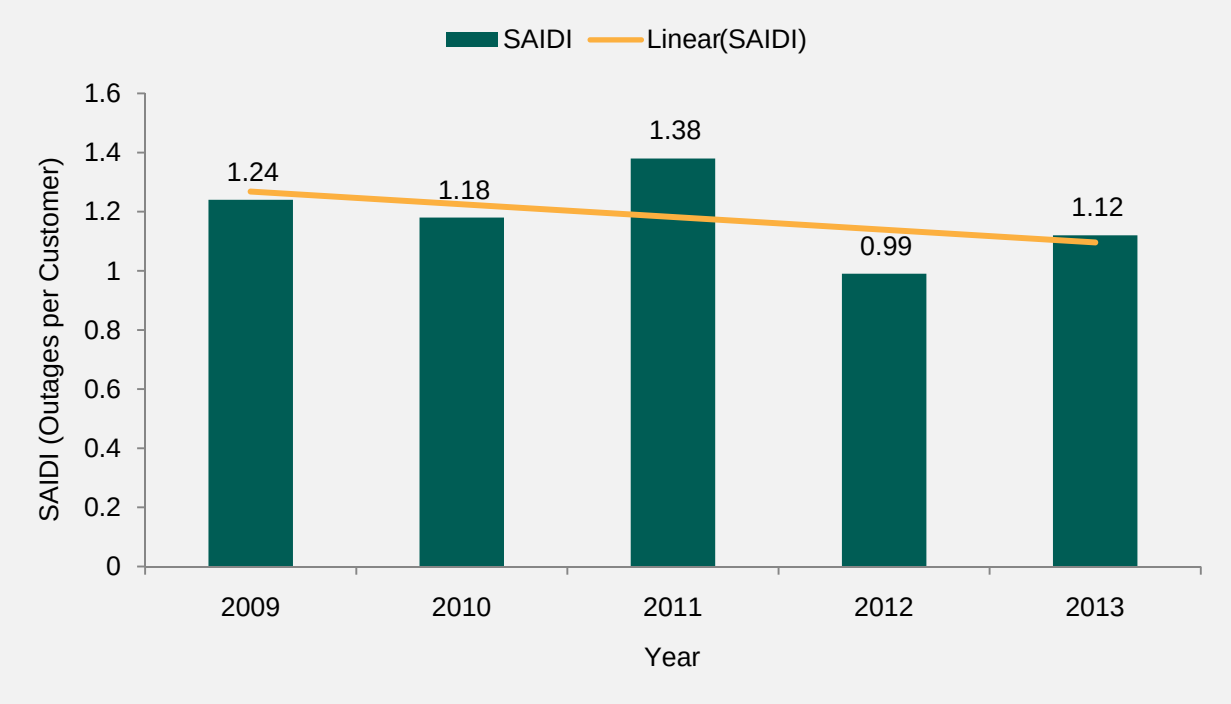


FIGURE 4: HISTORICAL SAIDI EXCLUDING MEDS AND LOSS OF SUPPLY – 2009-2013

FIGURE 5: HISTORICAL SAIFI EXCLUDING MEDS AND LOSS OF SUPPLY – 2009-2013

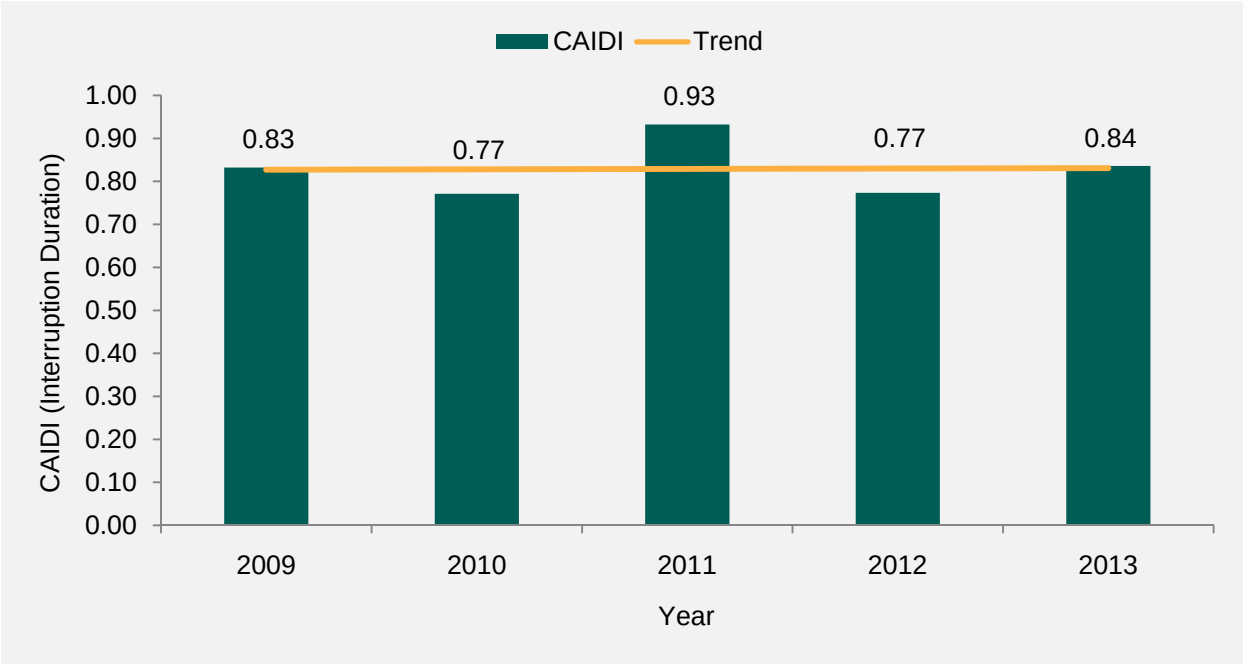


FIGURE 6: HISTORICAL CAIDI EXCLUDING MEDS AND LOSS OF SUPPLY – 2009-2013

C2.1.3 Interaction with the Distribution System Plan

Toronto Hydro uses historical reliability data as a key input into its Asset Management Process, discussed in further detail in Section D of the DSP. Within the long-term asset management policies, described in Section D3.1.1, reliability data serves as a key input to develop investment programs that will target key assets and manage critical issues. As part of short-term asset management policies, further defined in Section D3.1.2, reliability data is used at a local level to identify opportunities for capital projects.

On a system-wide level, the measures inform the asset management process to identify assets and programs required to address the root issues across the system, including activities such as direct-buried cable replacement, air insulated PMH switchgear and others. At the local or project level, historical SAIDI and SAIFI performance and anticipated improvements are considered when selecting individual assets to be replaced, enhanced or modified. On a system level, SAIDI and SAIFI are projected to improve by about 20% and 26% respectively by the end of the CIR period due to the investment programs proposed. Once again, Toronto Hydro expects CAIDI to remain relatively stable as SAIDI and SAIFI are improving in a similar trend.

C2.2 Feeders Experiencing Sustained Interruptions

C2.2.1 Measure Description

The Feeders Experiencing Sustained Interruptions (FESI) measure tracks the number of times Toronto Hydro's feeders (and by extension, some of the customers served by these feeders) are interrupted in a given rolling 12-month period. FESI aims to identify and develop mitigating strategies for the areas with the largest number of annual interruptions. Similar to other reliability metrics, FESI's source of outage data is ITIS. For some tracking measures, such as FESI, the number of feeder interruptions are aggregated by feeder. The measure focuses on interruptions that can be addressed at the feeder level and excludes value such as MEDs, loss of supply, planned interruptions and bus-level interruptions so as to focus on the performance of the feeder itself.

FESI is valuable because it measures pure distribution equipment performance by excluding external non-distribution related events that also impact the feeder level performance. Unlike SAIFI, SAIDI and CAIDI, which are effective for measuring the overall system performance, FESI focuses on specific areas of the distribution system that are underperforming relative to the system averages. Accordingly, the tracking of FESI allows Toronto Hydro to gain insights into the performance of smaller neighbourhoods and individual streets so that the overall customer experience can be improved.

As described in the Worst Performing Feeder Program (E6.21), Toronto Hydro's current management approach related to issues measured by FESI focuses on feeders that have experienced seven or more interruptions in a given 12-month period. Toronto Hydro established the threshold of seven outages based on a review of its historical feeder-level performance statistics, which determined that 3.5% of all feeders (those with seven or more annual outages) in the system were responsible for about half of the total system SAIDI and SAIFI. For the purposes of annual tracking, Toronto Hydro proposes to normalize the annual results by excluding Major Event Days and Loss of Supply events.

C2.2.2 Historical Performance Trends

Figure 7 shows Toronto Hydro's historical FESI-7 performance over the last five years, along with the associated trend. The number of feeders sustaining seven or more interruptions has

decreased from 38 in 2009 to 33 in 2013, and declining to as low as 29 in 2012. The average number of feeders with seven or more interruptions in 2009-2013 was 35.

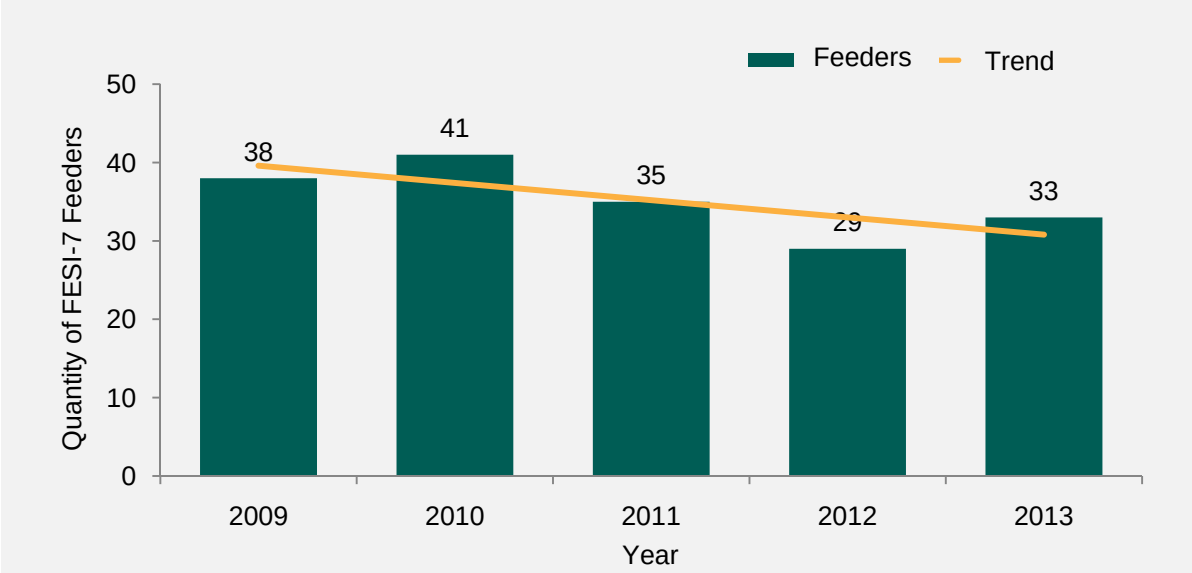


FIGURE 7: QUANTITY OF FESI-7 FEEDERS –2009-2013

C2.2.3 Interaction with the Distribution System Plan

The declining trend illustrated above speaks to the effectiveness of Toronto Hydro's Worst Performing Feeder program over the recent years, including specific reliability-driven capital and maintenance programs, such as tree trimming, targeted asset replacement, insulator washing and animal guard replacement. Toronto Hydro plans to continue monitoring the outcomes of its investments targeted towards service improvements on the utility's worst performing feeders. The Worst Performing Feeder Program (E6.21) contains a detailed list of maintenance and capital work planned to target FESI feeders. However, beyond the specific work planned as part of the Worst Performing Feeder program, which deals with primarily short term mitigation, every aspect of the Toronto Hydro's Capital Expenditure plan that is driven to some degree by reliability (e.g. circuit renewal work), and will ultimately contribute to the improvement of the FESI performance.

Based on the scope and volume of investments proposed within the utility's 2015-2019 Distribution System Plan, Toronto Hydro anticipates that its average number of feeders experiencing seven or more interruptions will continue to decline, or at least remain in line with the 2009-2013 average. At the same time, and as seen from the historical data, some year-over-

year volatility in single year results can be expected. This volatility stems mainly from large events such as thunder storms or a single failure mode that can cause a single feeder to fail in rapid succession.

C2.3 Momentary Average Interruption Frequency Index

C2.3.1 Measure Description

Momentary Average Interruption Frequency Index (MAIFI) measures the average frequency of momentary interruptions that affect Toronto Hydro's customers. Similar to SAIFI, MAIFI is an aggregation of the number of CI month–over-month, normalized to the number of customers served. Unlike SAIFI, MAIFI tracks only those interruptions lasting less than one minute. MAIFI is calculated as follows:

Avoidable momentary outages arising from defective equipment or other controllable factors can be a concern for certain customers. Industrial customers can experience interruptions to their normal production schedules, retail customers may experience interruptions to their ability to serve customers, and residential customers can be affected in a number of ways associated with downtime of household appliances or other technology. In extreme cases, a momentary interruption can result in significant damage to customer equipment or machinery.

C2.3.2 Historical Performance Trends

Figure 8 shows Toronto Hydro's historical MAIFI performance over the 2009-2013 period, and the associated trend. As the figure shows, the average frequency of momentary interruptions has decreased from 3.3 per year in 2009 to 2.37 interruptions in 2013 (a 28% improvement), with the five-year average frequency value of 2.74. Toronto Hydro attributes its improved MAIFI performance to the same factors that have led to a decreasing trend in SAIFI. While the two metrics measure different types of events, the activities aimed at reduction of SAIFI can also lead to improvements in MAIFI. Maintenance and capital work such as insulator washing and tree proofing can improve both SAIFI and MAIFI.

Toronto Hydro currently performs MAIFI tracking using a manual data entry process and resource-intensive background analysis, but plans to address this limitation over the 2015-2019 timeframe. In light of these potential process enhancements, Toronto Hydro notes that its MAIFI performance calculated through fully automatic processes may be materially different from the data collected using the manual approach currently employed. At this point, Toronto Hydro is not in a position to assess the direction or magnitude of potential performance changes following automation of the tracking process.

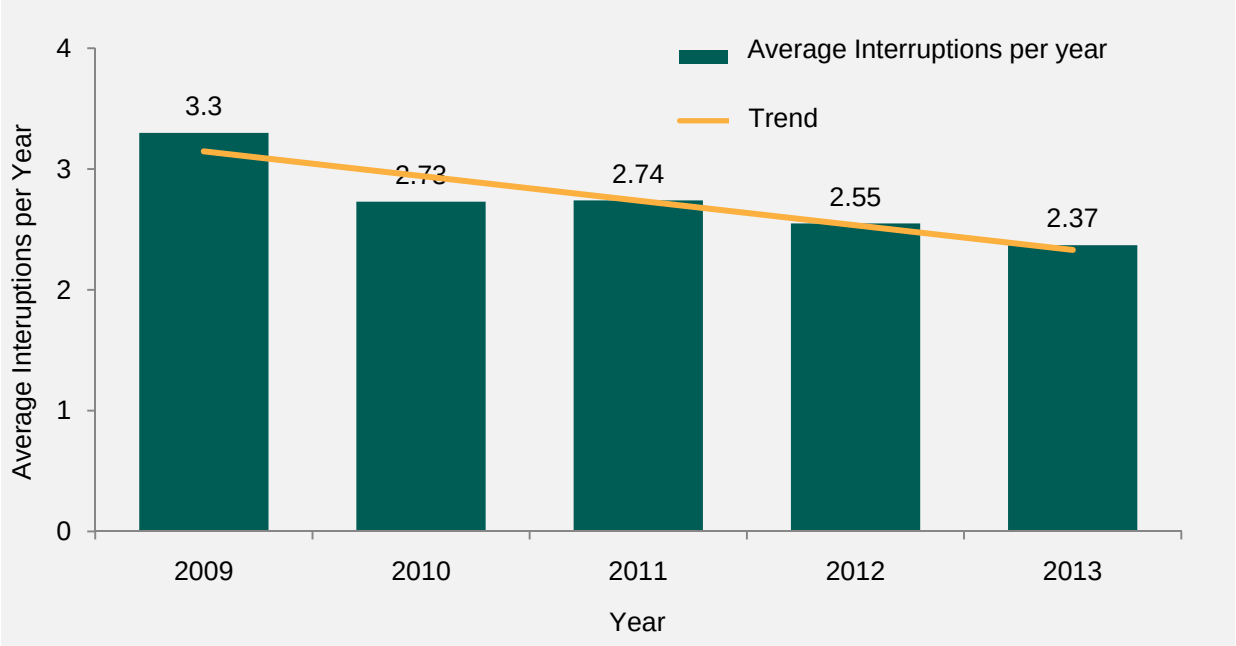


FIGURE 8: MAIFI PERFORMANCE – 2009-2013

C2.3.3 Interaction with the Distribution System Plan

Toronto Hydro's Distribution System Plan and planned maintenance expenditures include a number of programs and projects that are expected to directly and indirectly impact the number of momentary interruptions across the utility's service territory. Programs and activities such as the Overhead Momentary Reduction program, insulator washing, tree trimming and tree proofing are expected to assist in the reduction of avoidable momentary outages. For the purposes of the 2015-2019 planning timeframe, however, Toronto Hydro anticipates its MAIFI levels to improve in line with SAIFI improvements. Both measures reflect the frequency of interruptions, with the key

difference that SAIFI measures outages over one minute and MAIFI outages less than one minute. Given the similar measurement criteria, Toronto Hydro expects that its MAIFI results will follow a similar trend to SAIFI projections, subject to the above-noted measurement considerations. As the utility continues to track its momentary events over the 2015-2019 period, it expects to work with its customers affected by momentary outages and with industry colleagues to devise more precise MAIFI reduction objectives.

C3 COST EFFICIENCY & EFFECTIVENESS

C3.1 Distribution System Plan Implementation Progress

C3.1.1 Measure Description

Toronto Hydro plans to measure the overall progress of its Distribution System Plan implementation as a rolling ratio of total capital expenditures made over the plan years completed to date, divided by the five-year total amount of OEB-approved capital expenditures approved as a part of the utility's 2015-2019 Distribution System Plan, Including the System Access, System Renewal, System Service, and General Plant investment categories. The proposed measure will be calculated using the following formula:

$$\frac{\text{Actual Capital Expenditures for Completed Plan Years}}{\text{OEB-Approved Capital Expenditures for Completed Plan Years}} \geq \text{Actual Capital Expenditures for Plan Year}$$

According to this formula, if Toronto Hydro's total five-year approved capital envelope was approved to be $2.47 billion and the utility's Year 1 (2015) and Year 2 (2016) capital expenditures amounted to $524 million, and $502 million respectively, then the utility's plan implementation progress metric at the end of the 2016 rate year would be:

$$\frac{\text{\$524 million + \$502 million}}{\text{\$2.47 billion}} = 42.1\%$$

Toronto Hydro's preference for using the rolling measure of plan implementation progress stems from the fact that the utility operates in a dynamic business environment, where a number of issues can emerge over the course of any given year that require the utility to advance,

postpone, or otherwise amend the schedule, sequencing or pacing of projects slated for completion in that year. These considerations are often outside of the utility's control, and include the following factors:

- Major weather events (floods, ice storms);
- Atypical seasonal conditions (shorter construction seasons or limited switching capability);
- Urgent third-party work requests (e.g. plant relocations for transit);
- City and/or third-party (e.g. Hydro One Networks Inc. (HONI)) dependencies (resulting in longer project timelines);
- Changes in labour force availability (job action, higher than anticipated retirement rates, changes in the contractor community);
- Actions of HONI or the IESO (e.g. outage coordination challenges);
- Other related circumstances.

While these activities can have a significant affect on Toronto Hydro's ability to implement certain programs or projects in any specific year, that potential impact is significantly reduced over a longer (five-year) timeframe, providing the utility sufficient flexibility to adjust the pace on the affected projects, while redeploying its resources towards the work that can be completed in the immediate term. The aggregate five-year target ensures that the utility will work towards delivering the entirety of the capital program approved for the 2015-2019 planning period.

C3.1.2 Historical Performance Trends

The proposed 2015-2019 Distribution System Plan is the first time that Toronto Hydro expects to implement an approved medium-length multi-year capital plan. Accordingly, the utility is not in a position to provide the comparable historical results in a similar format, in light of the variety of circumstances under which Toronto Hydro's capital plans for 2009 through 2014 were prepared, amended and subsequently reviewed and approved by the OEB.

C3.1.3 Interaction with the Distribution System Plan

The proposed plan implementation progress measure is expected to allow Toronto Hydro and the OEB to gauge the utility's progress towards the completion of its entire 2015-2019 capital plan at

regular intervals. Reviewing the progress at one-year intervals will assist in providing the OEB regular updates regarding the plan progress.

C3.2 Planning, Engineering & Support Efficiency

C3.2.1 Measure Description

Planning, engineering, and other eligible administrative costs associated with capital program or project development are a component of Toronto Hydro's total capital costs. For the purposes of its 2015-2019 Distribution System Plan, Toronto Hydro proposes to track the proportion of its total capital expenditures on distribution plant and associated civil infrastructure that is comprised of indirect planning, engineering and support labour costs related to this portion of the utility's capital expenditures. By measuring the resulting ratio and taking steps to ensure that it remains within or below the historical levels, Toronto Hydro plans to drive the efficiency and productivity of these processes, ultimately resulting in more cost-effective assets being put into service.

The eligible costs to be tracked for the proposed measure include capitalized labour costs associated with long-term, short-term planning functions, including development of the long-term system studies, capital investment programs and specific projects. Section D1 provides a high level summary of each of the planning processes, while Section D3 provides details with respect to the elements and outputs produced by each planning process. The work to develop and refine the utility's decision support systems is also included in Section D3.1.2.1. The formula for the proposed performance measure is as follows:

$$\text{Ž ƒ • • ‹ • ‰ á • ‰ ‹ • ‡ ‡ " ‹ • ‰ ¬ — ' ' : " ÷ ' • – ^ Ð ‹ … ‹ ‡ • … ›}$$
$$L = \frac{\text{D ƒ ' ‹ – ƒ Ž Ž ƒ • • ‹ • ‰ á • ‰ ← • ‡ ‡ " ‹ • ' ‡ • † : š Ž ƒ • – ;}}{\text{D ' – ƒ Ž ƒ ' ‹ – ƒ Ž ' ‡ • † : š Ž ƒ • – ;}}$$

Using a hypothetical example to illustrate the mechanics of this formula, if Toronto Hydro's total capitalized indirect labour costs related to electric distribution plant amounted to $5 million in a year, while the utility's total capital expenditures attributable to the distribution plant and associated civil infrastructure were $50 million, the resulting metric for the year in question would be:

$$\frac{\text{D w}}{\text{D w r}} \text{ L s r ¨}$$

Toronto Hydro tracks the eligible costs through a thorough time-sheeting process. This process assigns indirect labour costs to capital, operating, or blended activities, in accordance with a detailed set of pre-established criteria. These criteria are approved by Toronto Hydro's senior management and reviewed for compliance with the applicable accounting frameworks. Given that the utility has had no experience in explicitly tracking its performance on this measure in the past, Toronto Hydro proposes to track the yearly results on a rolling five-year average starting in 2015, in order to reduce the effects of any one-time events that may affect the results. While a portion of eligible indirect labour costs such as regular salary and burden of full-time employees is typically "fixed" year-over-year, subject to headcount changes, a significant portion of these costs can vary year-over-year. The variability is caused by circumstances such as overtime use, implementation of new tools or process streamlining, or additional hiring to support the changes in the utility's capital program. Accordingly, by commencing the measurement of its indirect labour costs supporting its electrical distribution plant and the associated infrastructure, Toronto Hydro plans to be in a better position to assess and improve the efficiency of its indirect labour costing and resourcing through a variety of potential management decisions.

C3.2.2 Historical Performance Trends

While Toronto Hydro has not explicitly tracked the proposed metric in the past, the application of the proposed formula to the eligible portion of the utility's historical capital expenditures produces the results presented in Figure 9.

Over the past five years, the portion of Toronto Hydro's indirect labour costs relative to the total distribution plant-related capital expenditures has decreased from 13.1% in 2009 to 7.1% in 2013, for the average five-year value of 9.9%. Toronto Hydro attributes the improvement in this measure's results to the increasing size of the utility's capital work program and subsequent optimization of the available labour resources. Although part of this improvement is attributed to the staffing reductions and certain accounting changes (2011), Toronto Hydro has generally been able to manage an increasing capital work program with the smaller work force. In addition, the performance improvements are attributable to the increased efficiency of asset management processes through automation of many manual procedures and the use of decision support systems, detailed in Section D3.

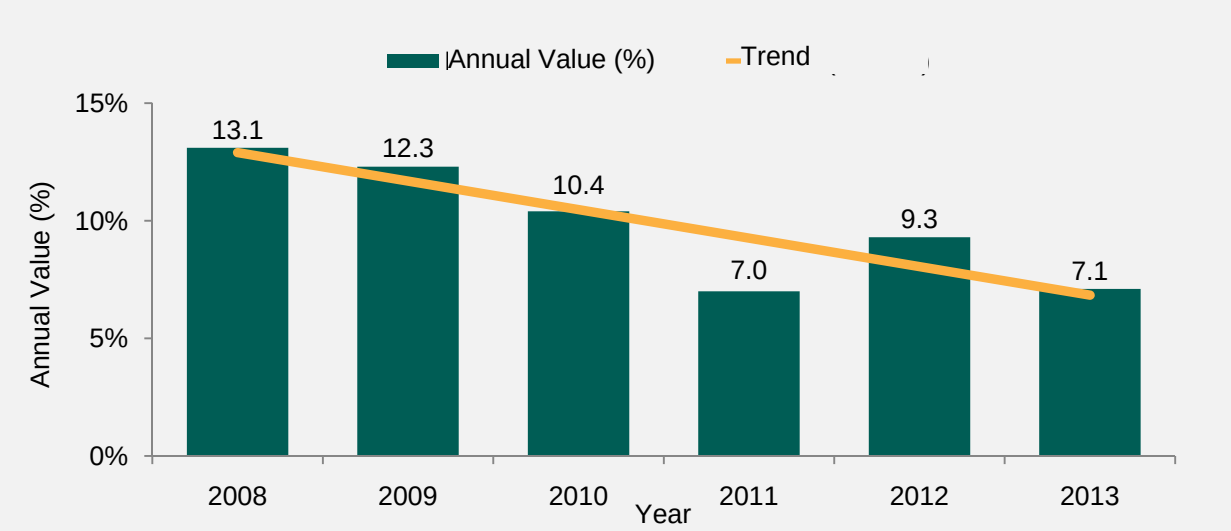


FIGURE 9: INDIRECT LABOUR % OF DX PLANT EXPENDITURES – 2009-2013

To gauge the appropriateness of its historic performance levels, Toronto Hydro consulted the 2014 edition of the RSMeans Electrical Cost Data Book[2] that provides the electric contractor industry with estimate ranges for a variety of electrical construction activities, including the proportion of total project costs made up of specific activities. A copy of the relevant information from this document can be found in Appendix A to this section of the DSP. According to the RSMeans data, the suggested total range of engineering costs as a portion of total project costs is within the 4.1% - 10.1% range. While Toronto Hydro's historical average result of 9.9% falls within the acceptable range, the utility notes that its indirect labour costs include other activities, such as management and support costs beyond the scope of activities captured by the RSMeans range.

For the purposes of its 2015-2019 capital plan, Toronto Hydro proposes to track the proportion of its indirect labour costs associated with electrical distribution plant relative to the total electrical distribution plant expenditures on a rolling five-year basis, with the 2009-2013 average value serving as a reference point. As the utility and the OEB gain more experience in this performance measurement area, Toronto Hydro may set more concrete targets in its future applications.

[2] RSMeans Electrical Cost Data Book, 2014 Edition, p 8. (See Appendix)

C3.2.3 Interaction with the Distribution System Plan

Toronto Hydro has no previous experience in tracking the proposed metric. Accordingly, the utility's current Distribution System Plan was not explicitly informed by any assumptions as to the capital planning, engineering, and support efficiency. By measuring these activities over the 2015-2019 timeframe, Toronto Hydro expects to gain valuable insights into this dimension of its capital work, while ensuring that the amount of supporting labour costs included in its distribution plant capital project costs remains appropriate.

C3.3 Supply Chain Efficiency: Materials On-Cost

C3.3.1 Measure Description

In accordance with the applicable accounting frameworks, Toronto Hydro adds the eligible portion of its supply chain and warehousing activities costs directly to the capital projects and programs that these activities support. The supply chain and warehousing costs are added to the total costs of capital projects through the service charge referred to as "On-Cost," which is applied as a percentage of the project's total costs. Since capitalized warehousing activities make up a material portion of each project's final costs, Toronto Hydro proposes to track the annual On-Cost value as a measure of efficiency of the utility's supply chain and warehousing activities.

Toronto Hydro calculates the On-Cost rate as the sum of budgeted eligible expenditures (e.g. warehouse employee labour costs), divided by the budgeted dollar value of materials moving through the utility's warehouses (including the recently outsourced warehousing operation) in a given year. The utility then applies the resulting rate to the dollar value of all materials when issued to capital and operating projects. At the end of each year, Toronto Hydro calculates the final on-cost rate on the basis of actual warehouse expenditures and the value of materials processed through the warehouse, and makes the appropriate adjustments to the capital costs of all projects.

Not all warehousing expenditures are included in the on-cost rate. For example, the inventory of materials used for internal warehousing purposes, utilities and communications-related expenses, and administrative staff costs are excluded. As with the indirect labour costs measure discussed above, Toronto Hydro's On-Cost calculation methodology is based on pre-determined parameters that are periodically evaluated.

C3.3.2 Historical Performance Trends

Figure 10 illustrates Toronto Hydro's historical On-Cost rates and the associated performance trend. Toronto Hydro's On-Cost charges remained relatively flat between 2009 and 2013, with a 2009-2013 historical average of 11.8%. The utility attributes its generally steady On-Cost levels to better utilization of available resources, the increase of the overall volume of capital program and a number of efficiencies detailed in the Supply Chain Program OM&A evidence (Exhibit 4A, Tab 2, Schedule 12). Over the 2015-2019 planning horizon, the utility expects its On-Cost rate to decline because of anticipated attrition and other productivity and efficiency improvements, including the deployment of a third-party warehousing outsourcing model that began in 2013.

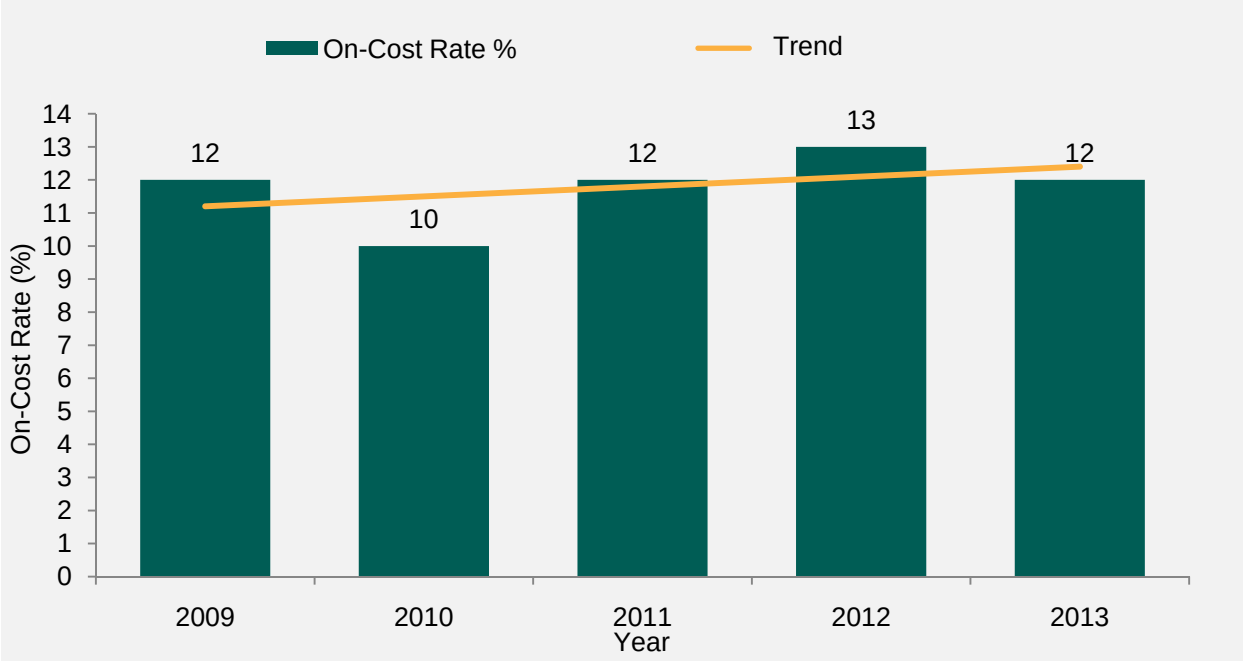


FIGURE 10: ON-COST PERFORMANCE (%) – 2009 – 2013

C3.3.3 Interaction with the Distribution System Plan

Subject to any developments outside of Toronto Hydro's control, Toronto Hydro's supply chain and warehousing efficiencies tracked through the On-Cost measure is expected to facilitate more cost-effective completion of the utility's capital program, enabling higher volumes of capital work to be completed for the same cost, thus directly benefiting Toronto Hydro ratepayers.

C3.4 Construction Efficiency: Internal vs. Contractor Cost

C3.4.1 Measure Description

To assess the reasonableness of the costs of capital construction projects completed by the utility's internal construction crews, Toronto Hydro compares the cost of select projects constructed "in-house" to the unit prices charged for similar work performed by external contractor crews. Toronto Hydro currently employs six full-service design and construction contractors that provide the utility with turnkey electrical project design and construction services. This service enables the utility to complete the requisite volume of capital work in a safe and efficient manner, while providing the resourcing scalability and flexibility to account for the changing capital program funding levels.

When presented with individual project designs, contractors break down each project into the number and type of applicable activity-based units, which are based on Toronto Hydro's certified Distribution Construction Standards. The aggregation of unit prices determines the total price that the contractors are paid for delivering the project. As such, contractors are ultimately responsible for managing the variances between the unit cost estimate and their actual costs.

Once properly adjusted for the differences in cost structures between Toronto Hydro's operations and those of external contractors, the comparative results show Toronto Hydro the cost gap between internally and externally executed projects. Given that Toronto Hydro's external contractors operate in the same environment as the utility's internal crews, and use materials paid for and procured by the utility, comparisons between the costs of externally and internally constructed projects constitute an appropriate form of construction cost benchmarking. Operating in the Canadian and Toronto construction markets, the cost structures of Toronto Hydro's external contractor partners must reflect the optimal efficiency levels across both its operating and support activities in a competitive market. Accordingly, the unitized cost estimates provided to Toronto Hydro by its construction partners at the time of contract negotiation reflect the competitive market costs to complete the projects of the scope, scale and complexity characteristic of Toronto Hydro's aging and dense urban distribution system.

C3.4.1.1 Comparison Methodology

Beginning in 2011, each year Toronto Hydro selects up to ten reference capital projects constructed by its internal crews over the previous year. To date, the projects have been selected from three of the utility's larger capital portfolios, namely Direct Buried Cable Replacement, Overhead and Underground Rehabilitation. To establish a consistent baseline for cost comparison, the selected internally delivered projects have minimal cost and scope variations from the original design.

The reference project design packages are divided among several of Toronto Hydro's participating contractors, who disaggregate them into individual units. To better reflect the range of contractor costs available to Toronto Hydro, the utility applies the unit costs of all six contractors to the number and type of units identified for each project. This provides Toronto Hydro with six unique contractor cost estimates for each of the ten reference projects.

Prior to undertaking comparisons, Toronto Hydro's actual project costs and the contractor estimates require adjustments to account for a number of differences inherent in the respective entities' business models. The most significant of these adjustments is necessitated by the fact that Toronto Hydro's capital costs do not capture the full extent of the utility's expenses, as a significant portion of the utility's costs is recovered through the OM&A expenditures and other means of cost recovery available to regulated distributors in Ontario. At the same time, Toronto Hydro assumes that the contractors must recover and earn profit on the entirety of their operating activities through the prices charged for project delivery. To correct for this important distinction, Toronto Hydro's capital costs require adjustments to include the relevant overhead, burden and regulated return components.

In performing the above adjustment Toronto Hydro accounts for the fact that it performs a number of functions which the contractors do not perform at all (e.g. feeder switching), or which they perform on a smaller scale than the LDCs (customer care, finance, HR, etc). Because of these distinctions, certain components of Toronto Hydro's overhead and burden costs are either explicitly excluded from the capital cost adjustment, or are proportionally allocated to reflect the costs associated with Toronto Hydro's internally executed capital construction costs. The end product of the adjustment process is an all-in cost estimate of Toronto Hydro's construction costs for internally executed projects, inclusive of all the relevant support functions that may not be intuitively associated with construction. In other words, the resulting adjusted estimate represents a approximation of a hypothetical price that Toronto Hydro would charge its customers if it were a design and construction-only utility, as opposed to a regulated distributor.

In a similar manner, contractor project estimates require adjustments to account for the project-related cost drivers that are incremental to their project costs, including costs of audit and verification mandated by Toronto Hydro, and administration charges from the utility's Program Support Office that manages the design and construction contractors. After the completion of the adjustment process, Toronto Hydro's reference project costs are reasonably comparable to the contractor estimates..

C3.4.2 Historical Performance Trends

Based on the above comparison methodology, the costs of Toronto Hydro's internal project construction were on average [redacted] higher[3] than the costs of the same projects had they been constructed by the six design and construction contractors. The cost gap value was calculated using the weighted average of individual estimate variances commensurate to the proportion of external contract work performed by each of the six contractors in a reference year.

Toronto Hydro's analysis indicates that a significant portion of fully burdened construction cost variance stems from the higher overhead and burden expenditures associated with the scale and scope of the utility's operations as compared to the analogous cost drivers for the external contractors. Some of these costs are driven by the terms of Toronto Hydro's collective agreements and by the need for Toronto Hydro to have specialized trades to work on unique aspects of its distribution system (downtown network, lead cable, box construction etc.). Contractors, on the other hand, generally employ high voltage workers with generic qualifications and experience needed for more standard overhead and underground systems most prevalent across their customer base. However, with respect to other cost drivers, such as facilities expenditures and the On-Cost rate, Toronto Hydro anticipates overall improvement due to the planned or ongoing productivity and efficiency initiatives. For the purposes of the 2015-2019 CIR period, Toronto Hydro will use the results of its historical analysis as a general point of reference. The utility notes, however, that it has recently issued a Request for Proposals (RFP) with the goal of awarding and re-negotiating its contracts with all external design and construction service providers for the 2015 – 2018 timeframe. The outcomes of the RFP may materially affect the results of future comparative efforts relative to the past year assessments. This is especially relevant in light of the high demand for qualified services currently characterizing Toronto Hydro's electrical construction market, and expected to remain a significant factor in the medium term. This is primarily due to a large number of construction projects planned or underway in the city

[3] The redacted information has been filed confidentially pursuant to the OEB's Practice Direction on Confidential Filings

including the residential high rise real estate developments, the PanAm/ParaPan Games construction, waterfront redevelopment, major transportation projects, and outsourcing work undertaken by other utilities.

C3.4.3 Interaction with the Distribution System Plan

Toronto Hydro uses the results of its external project construction cost benchmarking as a general reference for the reasonableness of the cost of projects completed by the utility's internal construction crews. As the utility continues conducting these comparative exercises over the 2015-2019 planning horizon, it may undertake more detailed assessments of individual cost drivers that make up the cost gap between contractor-delivered and internally constructed projects. At present, Toronto Hydro does not plan to expand the scale of this annual comparative activity, in part because of the complexity of conducting these assessments.

C3.5 Construction Efficiency: Standard Asset Assembly Labour Inputs

C3.5.1 Measure Description

Toronto Hydro is in the early stages of investigating the possibility of developing a comprehensive framework for tracking the total number of labour hours required to stage, install and energize a fully assembled unit corresponding to each major asset class of the utility's electricity distribution plant (e.g. transformers, switchgear etc). The project's envisioned scope entails developing a framework of about 25 major "Asset Assemblies," which in aggregate account for over 80% of the utility's planned capital program executed by internal resources.

At present, Toronto Hydro's engineers and designers use a fragmented framework of over 180 discrete labour activity cost estimates to prepare project scopes and develop associated designs, by taking into account the varying job-specific field conditions and circumstances that impact installation timeframes. While this framework enables Toronto Hydro to prepare extremely detailed cost estimates, it is not optimally suited for easy and effective tracking in the field by the utility's crews conducting the work. Accordingly, Toronto Hydro's objective is to augment the existing system with a more uniform, yet sufficiently flexible, labour hours input framework that would meet all of Toronto Hydro's planning, design and project tracking needs.

While the project is currently in an early testing stage, the envisioned end-state scope includes about 25 discrete estimates of total labour and "non-wrench" hours (e.g. driving, set-up/take-down, breaks) required to fully complete a single installation of a major asset class unit. The estimates of total hours will be developed based on system averages derived through analysis of past results, pilot time studies, and other activities determined as necessary during the subsequent project stages. To provide the requisite flexibility and scalability in light of the diversity of conditions and configurations inherent in Toronto Hydro's distribution system, the core Asset Assemblies framework will be augmentable through a standardized and centrally managed set of Project Adjustment Factors. These additional estimate adjustment capabilities are expected to allow the engineers and designers to customize the expected project completion estimates to account for specific engineering, topographic or other related circumstances applicable to each individual project.

To faciliate the core labour and non-wrench hours estimates continuing to reflect the reality of field conditions, the underlying numbers will undergo periodic updates on the basis of actual results obtained from the field. This periodic update process is expected to effectively create a positive feedback loop, allowing Toronto Hydro to reflect the emerging improvements in crew productivity levels in its future estimates. This process will enable Toronto Hydro to maintain realistic capital construction targets and foster a culture of continuous improvement. To enable effective day-to-day tracking of project progress by individual construction crews, the project scope includes the development of a user-friendly IT application for use on handheld devices issued to crew leaders.

Toronto Hydro chose to focus on labour input hours rather than any other units (e.g. dollars), because labour hours are a commodity that is not affected by inflation, is generally comparable across the utility's field resources, and has inherent potential for improvement through adoption of more efficient work execution practices and the introduction of new tools or other process improvements.

C3.5.2 Historical Performance Trends

Toronto Hydro is in the early stages of the Asset Assemblies project implementation and testing, so the utility does not have any historical results associated with this measure.

C3.5.3 Interaction with the Distribution System Plan

Given the early stages of what Toronto Hydro estimates to be a three-year project implementation timeline, Toronto Hydro's tracking of this measure will amount to annual updates on the project status, based on the following anticipated timeline:

- 2015-2016: develop and test the conceptual framework and implement the tracking system;
- 2017-2018: collect actual data and establish initial labour and non-wrench time benchmarks;
- 2019: begin reporting on performance related to a subset of specific Asset Assemblies.

While Toronto Hydro acknowledges that the above project tracking schedule is general in its nature, the utility is not in a position to provide a more detailed schedule at this time. Accordingly, Toronto Hydro plans to provide more detailed project development schedule forecasts with each annual update. Once Toronto Hydro is in a position to track the adherence to specific labour targets for Asset Assemblies completion, it plans to track approximately three to five individual asset categories for the purposes of any single Distribution System Plan performance measurement.

More generally, Toronto Hydro anticipates that the successful implementation of the Asset Assemblies framework will allow the utility to effectively benchmark its internal construction inputs (and by extension costs), thus driving continuous improvement. Among other things, the Asset Assemblies labour hours tracking framework may prove to be a useful way to inquire further into the utility's internal labour costs as compared to the results of benchmarking of its internal construction costs to the prices charged by the external construction contractors (See Section C3.4).

C4 ASSET & SYSTEM OPERATIONS PERFORMANCE

C4.1 Outages Caused By Defective Equipment

C4.1.1 Measure Description

For the purposes of measuring the performance of its equipment over the 2015-2019 planning horizon, Toronto Hydro plans to track the number of outages occurring over a rolling 12-month period due to defective or otherwise malfunctioning equipment. These outages are distinct from other outage causes such as vegetation/animal contacts, upstream supply interruptions or weather-related events. On average over the past five years, defective equipment-related outages were responsible for approximately 44% of total SAIDI and 41% of SAIFI results. Toronto Hydro tracks its equipment-related outages using ITIS, where each event is assigned a specific cause code. The count or number of outages caused by failed equipment speaks to the general condition of the utility's assets. Toronto Hydro proposes to track the number of equipment related-outages on a rolling 12-month basis.

C4.1.2 Historical Performance Trends

Figure 11 provides a summary of Toronto Hydro's historic performance on the equipment-related outages measure over the 2009-2013 timeframe. As seen in the chart, Toronto Hydro's performance on this measure has steadily improved over the past five years from 728 events in 2009 to 636 in 2013 – an improvement of over 11%. The utility attributes this performance improvement to the high level of System Renewal investments made in recent years, but notes that as with SAIDI and SAIFI, improvements in the defective equipment-caused outages often lag behind the investments to rectify them by several years. Accordingly, to maintain and/or improve on the current trend, Toronto Hydro plans to continue investing in System Renewal and other programs facilitating equipment performance improvements.

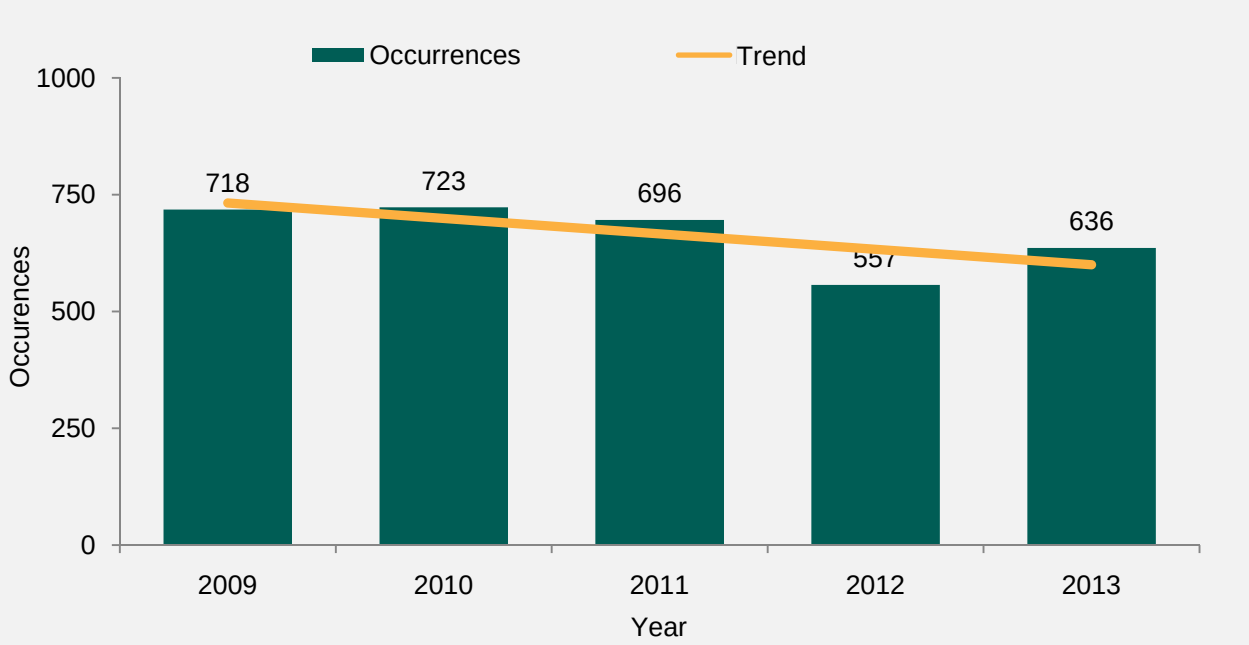


FIGURE 11: OUTAGES CAUSED BY DEFECTIVE EQUIPMENT – 2009-2013

C4.1.3 Interaction with the Distribution System Plan

As stated above, Toronto Hydro attributes performance improvement as illustrated in Figure 11 to the level of System Renewal investments made in recent years, but notes that given the current system demographics, continued focus on the system renewal investments is required to avoid a reversal of this trend.

Toronto Hydro plans to continue improving the general health of the system assets and ensure the historical trend continues so as to improve the system reliability. Given the proposed levels of System Renewal investments in its 2015-2019 Distribution System Plan, Toronto Hydro anticipates that the number of defective equipment-related outages will improve in line with the expected improvement in asset demographics. As a pure failure metric that does not consider imact and duration, the trajectory of this metric is expected to be affected by system renewal but not significantly changed by modernization. Overall, Toronto Hydro expects the historic trend to continue during the 2015-2019 period.

The results of this measure will inform Toronto Hydro as to the effectiveness of its asset replacement strategies and preventive maintenance activities. Should the results over the future years display trends significantly different from the historical levels, Toronto Hydro plans to investigate the underlying reasons and make the appropriate adjustments as necessary and feasible. Customers that are interrupted due to failed equipment can typically expect extended outages as Toronto Hydro crews replace the failed asset. By reducing the volumes of equipment at risk of failure across its system, Toronto Hydro will be assisted delivering more reliable system performance to its customers.

C4.2 Stations Capacity Availability

C4.2.1 Measure Description

As its final performance measure for the purposes of its 2015-2019 Distribution System Plan, Toronto Hydro proposes to track the availability of capacity at its Transformer Stations (TS). The utility regularly monitors its available station capacity across the service territory to ensure that sufficient capacity exists to satisfy system peak demand, accommodate new customer connections, and provide a reasonable amount of operating flexibility to the Control Centre for the purposes of load transfers. These monitoring activities enable the planned and reactive capital and maintenance work, and facilitate outage restoration efforts.

Toronto Hydro forecasts station-specific demand on an annual basis and compares the forecasts against the available equipment capacity. Where forecasts indicate potential capacity shortages, Toronto Hydro develops and executes the plans to transfer the incremental load to adjacent stations or increase the existing equipment's capacity. Given the pace of the recent and projected economic growth across the utility's service territory, stations capacity monitoring represents a crucial dimension of Toronto Hydro's asset management activities.

For the purposes of the 2015-2019 Distribution System Plan performance monitoring, Toronto Hydro proposes to track the number of stations where peak demand exceeds 90% of station capacity over the next five years. Given that a number of station expansion activities are currently underway (including construction activities at Copeland TS), Toronto Hydro proposes to track this measure based on a five-year rolling outlook starting in 2015. Since Toronto Hydro is not always in a position to unilaterally affect the station capacity limitations (e.g. due to upstream

transmission system constraints), the utility proposes to narrow the scope of this measure to include the stations where capacity limitations are at the station bus and/or switchgear level.

C4.2.2 Historical Performance Trends

Figure 12 shows the historical data for the proposed Stations Capacity measure for the 2009-2013 period. As evidenced by the chart, the number of stations with capacity limitations has increased from three to five over 2009-2013, with a historical high of six stations in 2011-2012. This trend reflects ongoing load growth and new connections throughout the city. Over the time period shown, no new stations or additional station busses have been put into service. The metric drops from 2012 to 2013 primarily as a result of load transfer projects that have been planned since the 2013 load forecast was issued.

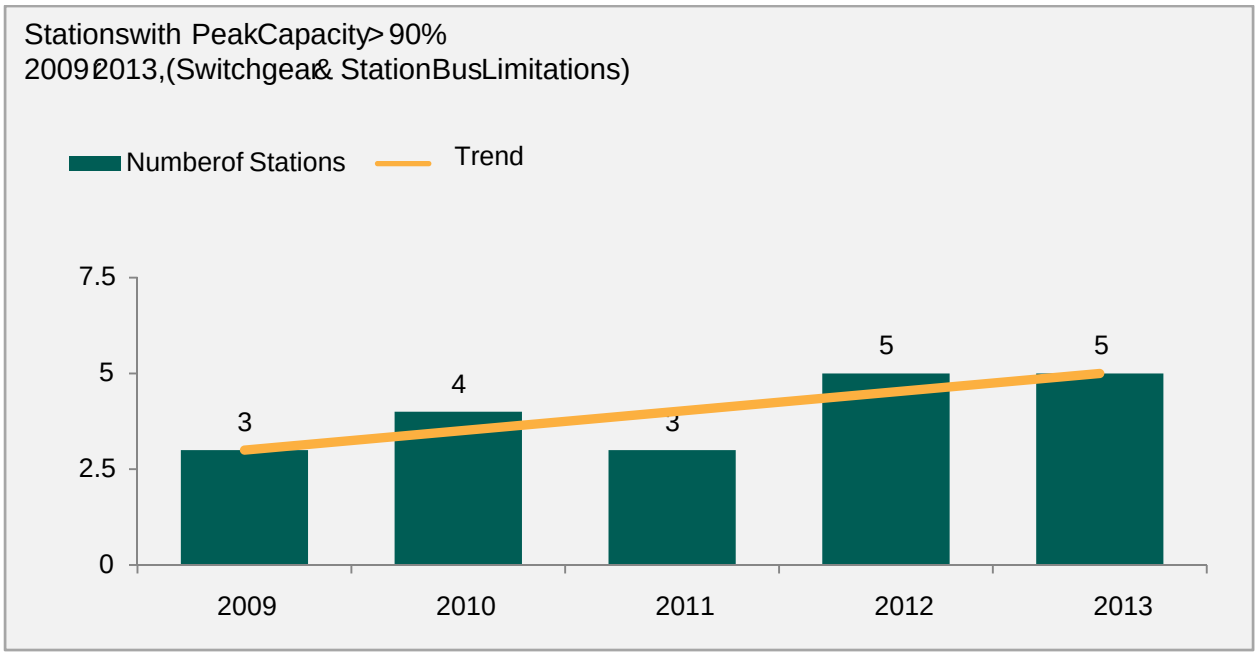


FIGURE 12: STATIONS WITH PEAK CAPACITY > 90% – 2009-2013, (SWITCHGEAR & STATION BUS LIMITATIONS)

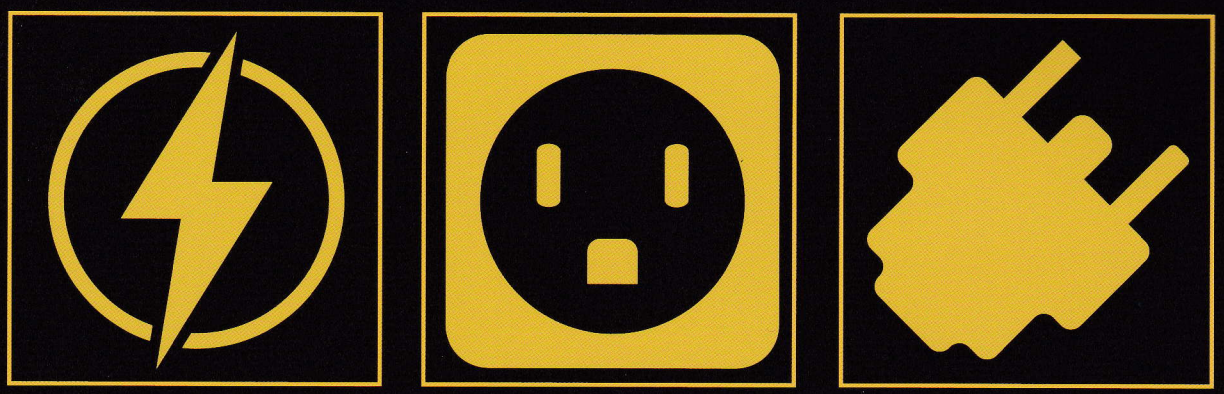
C4.2.3 Interaction with the Distribution System Plan

Tracking the number of stations with peak capacity exceeding 90% will allow Toronto Hydro to gauge the effectiveness of its capacity planning processes and the timeliness of the associated

constraint mitigation measures, including permanent load transfers, capacity increases, targeted CDM programs and other related activities. The Station Expansion Program specifically targets stations at which peak demand is approaching available capacity through upgrades and expansion of station infrastructure. The Load Demand program also aims to mitigate capacity shortfalls by balancing station bus loading through permanent load transfers.

Over the course of the 2015-2019 period, Toronto Hydro expects the measure and associated trend to remain generally constant, or potentially trend further upward, as more station busses approach their peak demand. Toronto Hydro's ability to maintain this trend is closely linked with the Station Expansion (E7.9) and Load Demand (load transfers) (E5.4) programs, which are expected to alleviate the most pressing concerns and add flexibility to the system to enable us to balance load between stations. Absent the investment levels proposed in either of these two programs, the measure would trend upward at a significantly higher pace.

RSMeans® Electrical Cost Data



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2014

37th annual edition

Cost data from the most quoted name in construction

01 11 Summary of Work

01 11 31 – Professional Consultants

01 11 31.20 Construction Management Fees	Crew	Daily Output	Labor-Hours	Unit	2014 Bare Costs Material	Labor	Equipment	Total	Total Incl O&P
0010 **CONSTRUCTION MANAGEMENT FEES**									
0020 $1,000,000 job, minimum				Project				4.50%	4.50%
0050 Maximum								7.50%	7.50%
0060 For work to $100,000								10%	10%
0300 $50,000,000 job, minimum								2.50%	2.50%
0350 Maximum								4%	4%

01 11 31.30 Engineering Fees

0010 **ENGINEERING FEES** R011110-30									
0020 Educational planning consultant, minimum				Project				.50%	.50%
0100 Maximum				"				2.50%	2.50%
0200 Electrical, minimum				Contrct				4.10%	4.10%
0300 Maximum								10.10%	10.10%
0400 Elevator & conveying systems, minimum								2.50%	2.50%
0500 Maximum								5%	5%
0600 Food service & kitchen equipment, minimum								8%	8%
0700 Maximum								12%	12%
1000 Mechanical (plumbing & HVAC), minimum								4.10%	4.10%
1100 Maximum								10.10%	10.10%

01 21 Allowances

01 21 16 – Contingency Allowances

01 21 16.50 Contingencies

0010 **CONTINGENCIES**, Add to estimate									
0020 Conceptual stage				Project				20%	20%
0050 Schematic stage								15%	15%
0100 Preliminary working drawing stage (Design Dev.)								10%	10%
0150 Final working drawing stage								3%	3%

01 21 53 – Factors Allowance

01 21 53.50 Factors

0010 **FACTORS** Cost adjustments									
0100 Add to construction costs for particular job requirements									
0500 Cut & patch to match existing construction, add, minimum				Costs	2%	3%			
0550 Maximum					5%	9%			
0800 Dust protection, add, minimum					1%	2%			
0850 Maximum					4%	11%			
1100 Equipment usage curtailment, add, minimum					1%	1%			
1150 Maximum					3%	10%			
1400 Material handling & storage limitation, add, minimum					1%	1%			
1450 Maximum					6%	7%			
1700 Protection of existing work, add, minimum					2%	2%			
1750 Maximum					5%	7%			
2000 Shift work requirements, add, minimum						5%			
2050 Maximum						30%			
2300 Temporary shoring and bracing, add, minimum					2%	5%			
2350 Maximum					5%	12%			
2400 Work inside prisons and high security areas, add, minimum						30%			
2450 Maximum						50%			

Distribution System Plan (DSP)

D ASSET MANAGEMENT PROCESS

ID	Section
D1	Asset Management Process Overview
D2	Overview of Assets Managed
D3	Asset Lifecycle Optimization Policies & Practices
D4	Information Technology (IT) Asset Management Process

D1 ASSET MANAGEMENT PROCESS OVERVIEW

Section D of the Distribution System Plan provides both a summary as well as full details of the Asset Management (AM) Process that is applied at Toronto Hydro in order to produce the Capital Expenditure Plan, which is discussed in Section E.

Toronto Hydro's AM Process forms the foundational architecture for long-term, short-term and maintenance planning functions, bringing together input data and decision support systems to produce load, system performance and capital investment forecasting, investment programs and investment projects as part of the capital expenditure plan.

Section D1 provides an overview of the elements that form the AM process, including process maps that conceptualize the interactions between long-term, short-term and maintenance planning. Section D2 provides current information and challenges associated with Toronto Hydro's distribution system. Section D3 provides further details of the policies and practices associated with the AM process elements, including long-term, short-term and maintenance planning components contained within the planning process. Section D4 provides an overview of Toronto Hydro's distinct Information Technology (IT) Asset Management Process, which consists of a set of business principles and practices that support prudent IT asset life cycle management and IT investment planning.

D1.1 Overview of Asset Management Objectives

Toronto Hydro's asset management process proactively identifies, manages and mitigates deficiencies and risks to the electrical distribution system in order to (i) maximize value to the utility's customers, (ii) minimize or eliminate safety risks, and (iii) strike an optimal balance between required capital investment and risk costs associated with asset failure (on a system level, Toronto Hydro refers to this balance as "steady state").

The AM process described in this section allows Toronto Hydro to meet these AM objectives while also aligning to its corporate pillars as described below:

- People: Strive to foster a fully engaged, safe and healthy workforce that meets the changing requirements of the utility's business. This includes developing a skilled and knowledgeable workforce and keeping that workforce engaged and productive.

- Customer: Provide value for money. This includes providing long-term value for rate payers, helping customers conserve energy, providing customers with tools and technology, and making it easier to work with Toronto Hydro.

- Operations: Work to improve reliability through optimal and sustainable system management. This includes keeping the lights on, keeping the system safe, building a grid that supports a modern city in an environmentally responsible manner, and maintaining above-average productivity.

- Financial: Aim to meet the financial objectives of Toronto Hydro's shareholder, the City of Toronto.

Toronto Hydro's AM process provides a foundation for the execution of long-term, short-term and maintenance planning functions. This process takes into account requirements established in both the Electricity Act, 1998,[1] and the Distribution System Code (DSC). Among the purposes of the Electricity Act, are:

- "[Ensuring] the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand"[2] and

- "[Protecting] the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service"[3]

Among other things, the DSC requires a distributor to follow good utility practices for system planning to ensure reliability and quality of electricity service on both a short-term and long-term basis.[4]

Toronto Hydro used its AM process to develop the 2015-2019 Capital Expenditure Plan, which is discussed in detail in Section E of this 2015-2019 Distribution System Plan. To promote continued alignment with changing legislative and regulatory requirements (including the Ontario Energy Board Act, 1998,[5] Toronto Hydro's Distribution License, the Standard Supply Service Code, and relevant City of Toronto By-laws), Toronto Hydro is continually refining and enhancing its AM process and improving its practices.

[1] S.O. 1998, c. 15, Sched A. ["Electricity Act"]
[2] Electricity Act, at section 1.
[3] Electricity Act, at section 1.
[4] DSC, at section 4.4.1.
[5] S.O. 1998, c. 15, Sched. B. ["Ontario Energy Board Act"]

D1.2 Asset Management Process Overview

This section outlines the major elements of Toronto Hydro's AM process, the inter-relationships between these elements, and the key inputs and outputs between these elements.

As illustrated in Figure 1 below, the AM process consists of five elements: (i) the planning process itself; (ii) the enterprise systems that support both the planning process and decision-support systems; (iii) the decision-support systems; (iv) the produced Distribution System Plan; and (v) measurement and enhancement activities that are conducted during the term of the CIR filing period (2015-2019).

The first element – the planning process – can be further subdivided into three stages:

- Long-term planning
- Short-term planning
- Maintenance planning

Long-term planning involves the development of a capital investment approach, execution strategy and associated investment spending levels, derived from long-term system studies and current-state assessments of the distribution system, which ultimately allow for the production of capital investment programs targeting prioritized assets and issues. This long-term planning process is further discussed in Section D1.2.1, with specific details on the process elements provided in Section D3.2.1.

Short-term planning involves the development of discrete projects that intervene upon prioritized assets and issues identified within the long-term investment programs. These projects are scheduled based upon system, resource and external constraints, and are executed accordingly. Project development, scheduling and execution result in further refinement and finalization of the investment spending levels for each capital investment program. The short-term planning process is further discussed in Section D1.2.2, with specific details on the process elements provided in Section D3.2.2.

Maintenance planning focuses on extracting the maximum value out of Toronto Hydro's distribution system assets through regular inspections, upkeep and repair activities. Maintenance planning also produces condition-related data which feeds back into enterprise databases and

planning tools. This process is further discussed in Section D1.2.3, with specific details on the process elements in Section D3.2.3.

The second element of the AM process is the collection of enterprise systems that contain nameplate asset information (age, asset type, etc), locations, historical reliability and loading data. This information is used either directly within the planning process or as inputs to the decision-support systems. Enterprise systems are as follows:

- Automated Mapping/Facilities Management Geographic Information System (AM/FM GIS): Provides locations and nameplate information associated with assets.
- Enterprise Resource Planning (ERP) System (Ellipse): Provides asset nameplate information, inspection data and project estimates.
- Feeder Loading Information System (FLIS): Used to capture raw load readings from supervisory control and data acquisition (SCADA) devices.

The third element of the AM process is the collection of decision-support systems, which are used in long and short-term planning processes to make informed decisions when producing capital investment programs and corresponding projects respectively. Decision-Support Systems are discussed in more detail in Section D3.1.2.1.

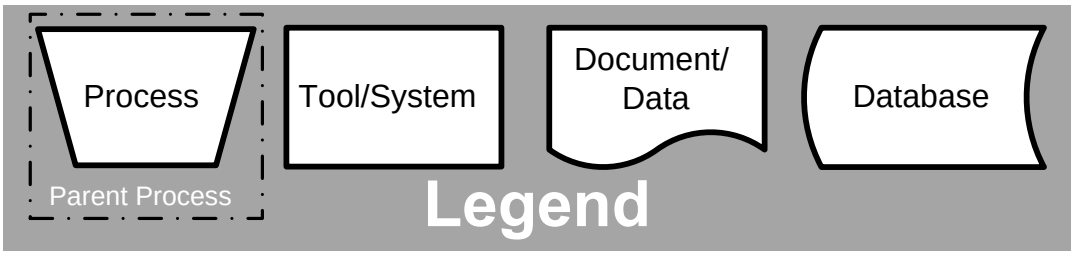


FIGURE 1: PROCESS LEGEND

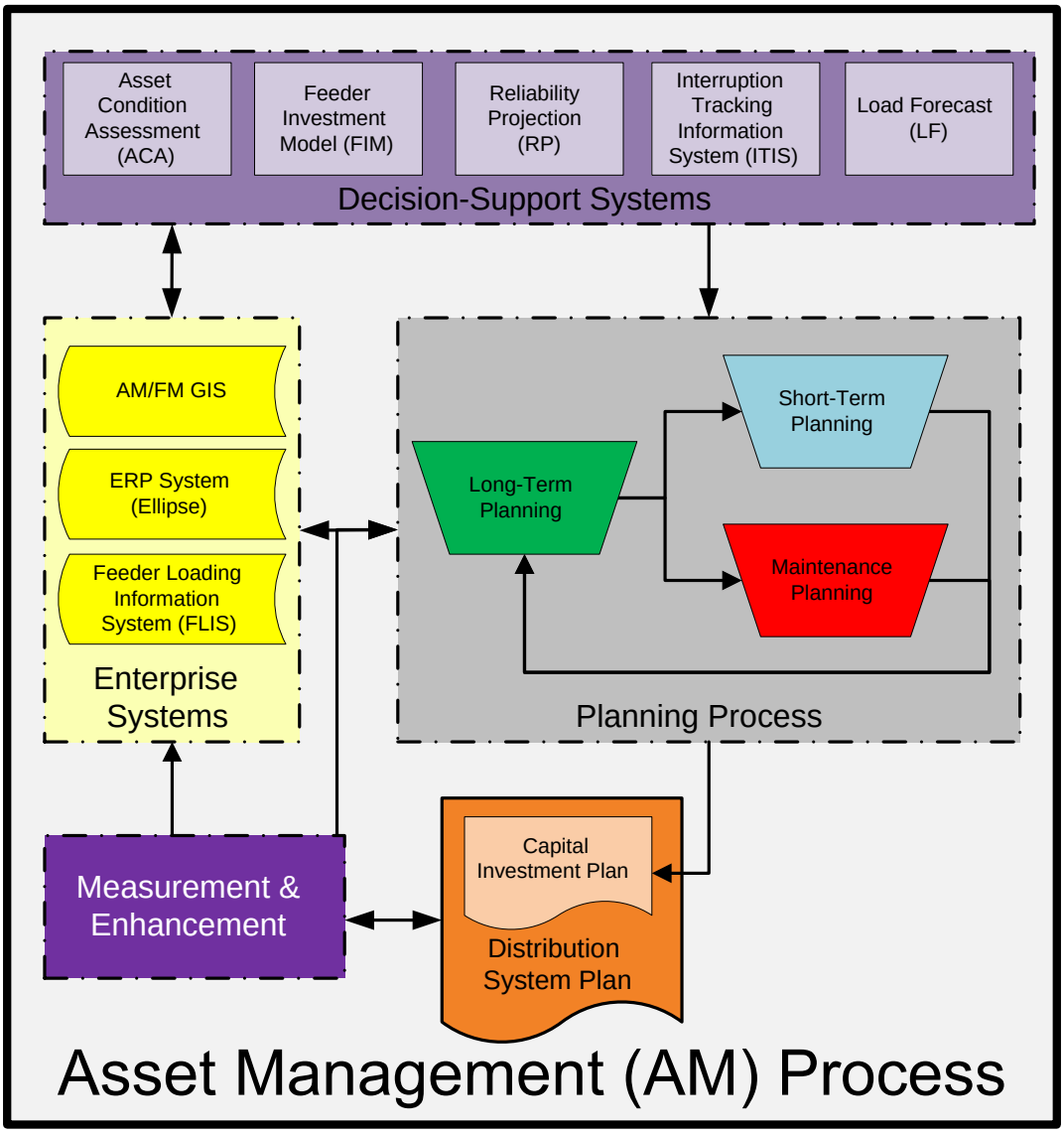


FIGURE 2: ASSET MANAGEMENT PLANNING PROCESS OVERVIEW

The fourth element in the AM process is the Capital Expenditure Plan, published within the DSP (Section E), which is produced based on the outputs derived from the planning process.

The fifth and final element of the AM process is the collection of measurement and enhancement activities whereby the Distribution System Plan itself is monitored and measured in order to produce continuous improvements and enhancements to the planning process and to input data within the enterprise systems. This is further discussed in Section D1.2.4, with specific details

discussed in Section D3.1.2.3. Legends for all figures provided in the proceeding content are in Figure 3.

D1.2.1 Long-Term Planning Process

The long-term planning process is a systematic process involving a current-state system analysis and long-term system review process, which ultimately results in the production of a long-term investment approach and execution strategy, followed by the development of investment programs with associated investment levels.

The current-state system analysis (CSA) is a foundational analysis performed to understand the current state of the distribution system in terms of asset performance (age, condition), asset properties and quantities, historical reliability and remaining useful life. This analysis is further detailed in Section D3.1.1.1. Outputs of the CSA produced for the 2015-2019 Distribution System Plan are provided in Section D2.

Data from the CSA is used as part of the long-term system review process, in which the following deliverables are produced:

(a) a proactive capital investment approach that addresses all known challenges and enables progress toward achievement of a system “steady state”;

(b) evaluation and selection of an execution strategy that is responsive to customers’ price sensitivity while being practical to execute; and

(c) comparison of reliability outcomes for the proactive capital investment approach and selected execution strategy against a “do nothing”/”run to failure” approach.

A proactive capital investment approach is designed based upon the necessary forms of investment that are required over the DSP planning period. These necessary forms of investment will be informed by the results of the CSA, coupled with known system challenges that must be addressed. The forms of investment defined as per the 2015-2019 Capital Expenditure Plan include: (i) asset renewal; (ii) system-wide critical issues; and (iii) mandatory operational investments. These are further defined and discussed in Section E2.1. This proactive capital investment approach must enable progress toward a “steady state”, which represents an optimal balance between required capital investment and aggregate risk costs associated with asset failure, such that the distribution system exists in an economically optimal composition. Section E2.1 further details the results of the capital investment approach produced for the 2015-2019

Capital Expenditure Plan, which shows a backlog of investments, mostly comprised of assets that are past their economic end-of-life criteria. Mitigating this backlog will permit the achievement of steady state, such that the total aggregate lifecycle costs of the system are minimized.

The final deliverable within the long-term system review process involves a comparison of the reliability outcomes of the proactive capital investment approach and selected execution strategy against a run-to-failure/"do nothing" approach. Section D3.1.1.2 provides further details on the Long-Term System Review Process, while Section E2.1 provides the results of the long-term system review process that were applied as part of the 2015-2019 Capital Expenditure Plan.

Outputs from the long-term system review process are used to develop capital investment programs as part of the Investment Planning process. Capital investment programs are produced by prioritizing system assets and issues based upon their alignment to associated program trigger drivers. Prioritization factors will vary depending on the program driver. For instance, programs driven via Failure Risk adopt factors such as asset age, condition, economic end-of-life criteria and historical reliability in order to prioritize assets. On the other hand, programs driven by Safety address specific asset types and sub-types that introduce known safety risks into the system. Enterprise and decision-support systems are used to aid in the identification and prioritization of assets and issues at the system level, depending on the program drivers. Outputs produced by the Investment Planning process include:

- the individual capital investment programs, which are aligned to the forms of investment identified within the long-term system review process;
- the prioritized assets and/or issues that are to be addressed within each capital investment program across the DSP planning period; and
- the associated investment spending levels for each capital investment program.

Each investment program takes into consideration the maintenance activities that are occurring in parallel. Ultimately, each capital program represents required investments above and beyond what current maintenance practices are able to accomplish. The Investment Planning process is further detailed in Section D3.1.1.3.

Once investment programs have been established at the long-term planning level, and discrete projects are established at the short-term planning level, a business case evaluation (BCE) is produced at the investment program level, where practicable. The BCE identifies the most cost-

effective solution for mitigating the associated challenges and issues to help ensure that the program is providing value to customers over its life-cycle.

This BCE relies upon knowledge of discrete assets to be intervened upon and specific locations where issues are to be mitigated. A BCE cannot be produced practicably for those investment programs that are dynamic in nature. For dynamic investments, the exact discrete assets are yet to be determined as of the DSP publication (e.g., customer connections and reactive capital).

The BCE approach is further defined in Section D3.3. Capital investment programs along with their respective BCE results are provided in Sections E5 through to E8.

As illustrated in Figure 3, outputs of the long-term planning process, including the considered capital investment approaches, execution strategies and the produced capital investment programs are integrated into the produced Distribution System Plan. The produced capital investment programs are also used as a key input to the short-term planning process in order to develop projects as further explained in Section D1.2.2.

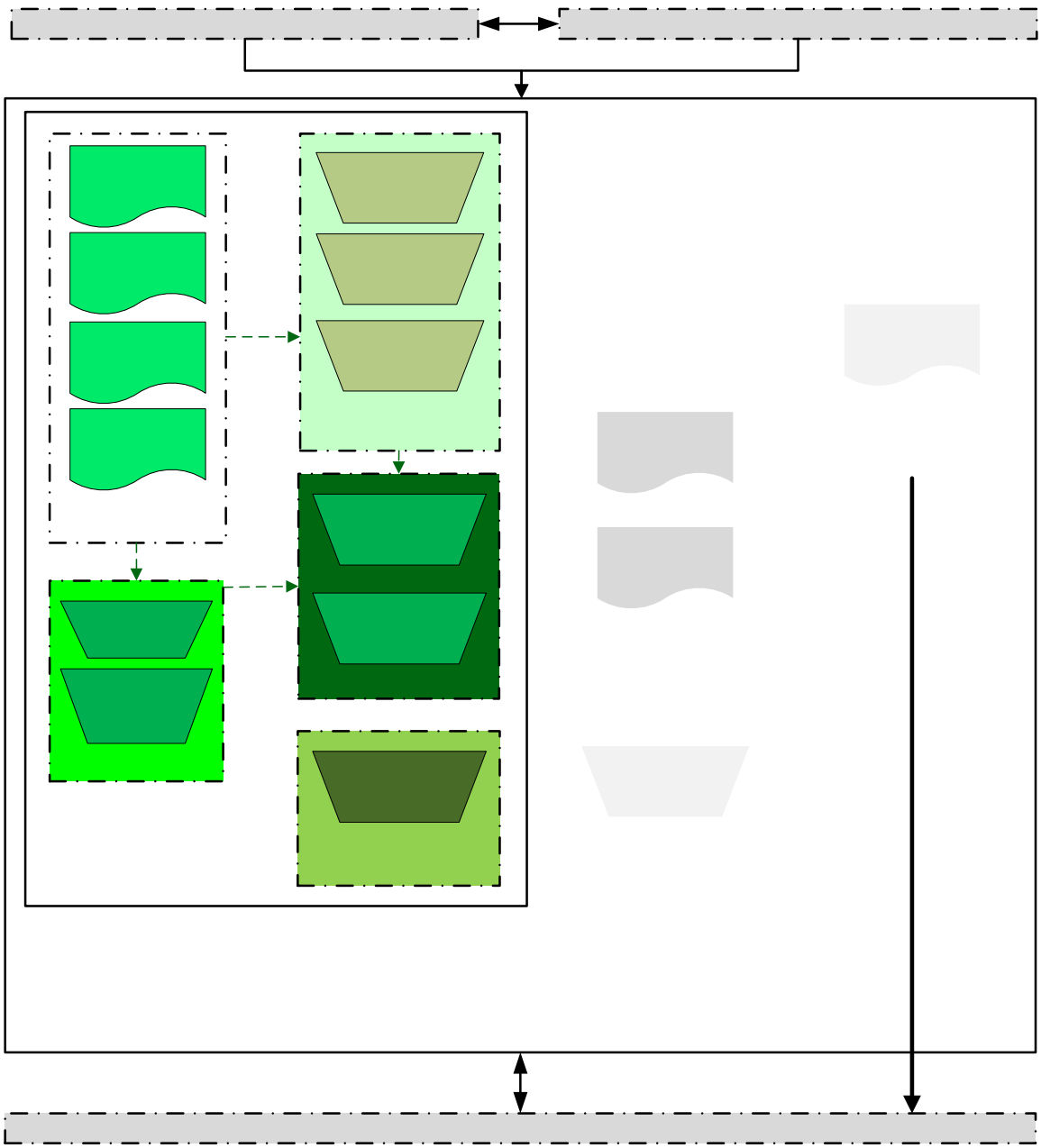


FIGURE 3: LONG-TERM PLANNING PROCESS

D1.2.2 Short-Term Planning Process

The short-term planning process involves the development of discrete projects within each capital investment program. This process involves three components: a study, a draft and an approved project.

The long-term planning process, as explained in Section D1.2.1, identifies and prioritizes the assets and/or issues to be mitigated within each capital investment program, across the DSP planning period. The short-term planning process converts this information into discrete capital projects.

The project development process begins with a study, where these prioritized assets and issues are identified within discrete locations through the use of corresponding enterprise data, decision support tools and load forecasts. Input data used as part of the study to identify these discrete assets will vary depending on the investment program's trigger and secondary drivers.

For example, should an investment program be driven by Failure Risk, decision-support systems such as the Feeder Investment Model (FIM), Asset Condition Assessment (ACA) and enterprise systems such as Ellipse (ERP) would be utilized to identify the prioritized assets that are exceeding their economic end-of-life criteria, are in poor/very poor condition and/or are past their useful lives, respectively. For an investment program that is driven by capacity constraints, decision-support systems such as load forecasting processes would be applied to identify specific investment opportunities. These decision-support systems are each discussed in further detail in Section D3.1.2.1.

Once an investment opportunity is identified, a project draft is produced, in which existing assets are confirmed and new assets to be installed are identified as per a high-level design. These projects then go through a project finalization process where they are validated for content (estimate, description, and justification). Ultimately, this project development process is applied to produce a series of projects within a given capital investment program up to the capital investment spending levels established for that program through the long-term planning process. The project finalization process will also result in further refinement to the capital investment spending levels, as project-level estimates are produced.

As illustrated in Figure 4, some of these projects involve assets to be replaced or issues to be resolved that are of the most urgent nature. These urgent projects will be assigned to the first year of the Capital Expenditure Plan, and therefore, all projects within the same year have equal

priority relative to each other. Projects contained in the later years of the Capital Expenditure Plan will involve assets of lesser priority relative to those projects in the first year of the plan.

Finalized projects will be scheduled for execution within the given year, and the associated capital investment spending levels will be finalized for that given year through the development of detailed designs, estimates and schedules as per this process. Discrete details of the finalized projects (e.g. assets to be replaced, assets to be installed) are used to as inputs to the BCE process as part of long-term planning.

This two-stage process for cost estimation – i.e. high-level estimates used for planning purposes, followed by detailed estimates used for execution purposes – is essential for the efficient planning and execution of Toronto Hydro's large work program.

A planning engineer prepares a high-level estimate to reflect the costs associated with the technical requirements of a specific project, as opposed to the operational realities of executing the work. These requirements can include, for example, the amount of load to be converted, the number of customers to be transferred, the size of cables to be replaced, the capacity requirements, etc. This estimation approach is used for the initial screening of projects and avoids the significant cost involved to produce a detailed estimate for a project that may not go forward.

/C

A designer then prepares a detailed estimate based on the particular features and field conditions for a specific project. A number of factors may cause the cost of a specific project to deviate from the average cost assumptions used for the initial estimate, and these factors are accounted for in the detailed estimate. (Additional factors, such as season, use of overtime labour, system loading, and real-time switching options may also affect actual costs versus detailed estimate costs.)

Over a large number of projects, and through the rigorous application of structured project management techniques, the positive and negative cost variances of individual projects may cancel out such that in aggregate the initial estimates form a reliable indication of the total cost of the projects in the specific program.

The scheduling and execution of projects exists outside of the AM Process as part of the Capital Expenditure Plan. For the 2015-2019 Distribution System Plan, this approach is further detailed in Section E2.3. Capital projects have been produced and scheduled for 2015, and can be found within their respective capital investment programs that are detailed in Sections E5 through to E8 of the 2015-2019 Distribution Systems Plan.

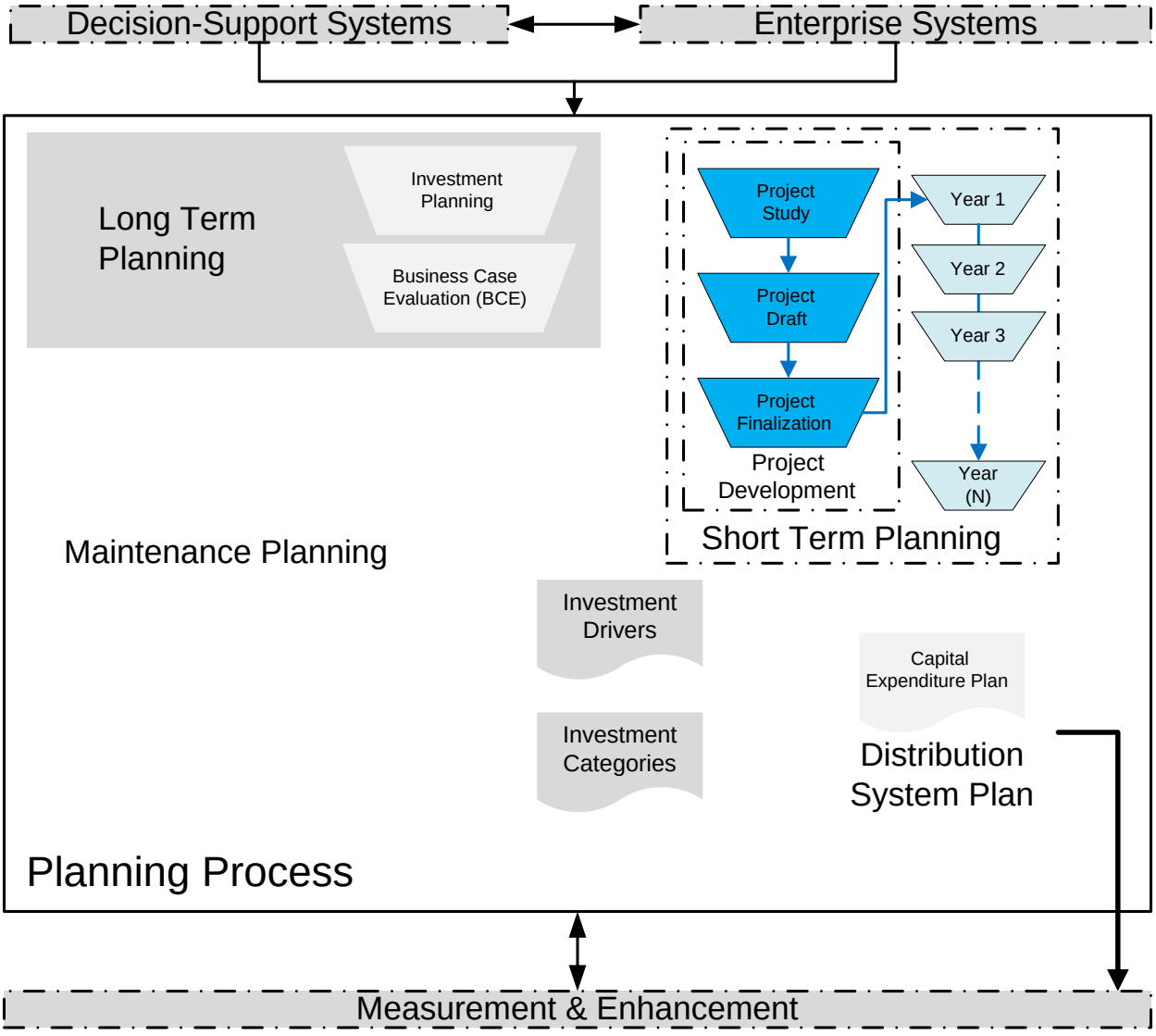


FIGURE 4: SHORT-TERM PLANNING PROCESS

D1.2.3 Maintenance Planning Process

Toronto Hydro's maintenance planning process is designed to assess the condition and extend the life of distribution assets, and maintain their reliability through the development of maintenance programs. Maintenance programs are designed to extract the maximum value from the assets. Maintenance programs complement the produced capital investment programs by allowing Toronto Hydro to sustain the intended operating condition of its asset and preserve operability. Equipment condition is also critical to the safe operation of distribution assets and

directly affects Toronto Hydro employees and the public. Finally, equipment maintenance is essential to help minimize the environmental impact of assets.

As seen in Figure 5, the maintenance programs fall into four categories. High level summaries of these categories are discussed below with more details provided in Section D3.2:

- Preventive Maintenance: Typically involves cyclical inspection and maintenance tasks, which emphasize assessing asset condition and preserving asset performance over the expected life of the asset, and maintaining public and employee safety.

- Predictive Maintenance: Involves testing or auditing equipment for a predetermined condition (or conditions) to anticipate failures, then undertaking the maintenance tasks necessary to prevent those failures.

- Corrective Maintenance: Involves repairing or replacing equipment after a deficiency has been reported, such as actions taken after Emergency Maintenance has restored power. Corrective Maintenance actions may also result from deficiencies discovered during the execution of Preventive or Predictive Maintenance tasks or other planned work.

- Emergency Maintenance: Is the urgent repair or replacement of equipment when the equipment fails, causing a power disruption to Toronto Hydro customers.

Also illustrated in Figure 5, the Maintenance Planning and Long-Term Planning processes intersect at the following points:

- Capital investment programs are developed with knowledge of cross-referencing maintenance programs, to help ensure that program spending is necessary above and beyond the life extension benefits that the maintenance programs offer

- Maintenance programs account for changes associated with capital investment programs, such as new asset classes being introduced or existing asset classes being eliminated.

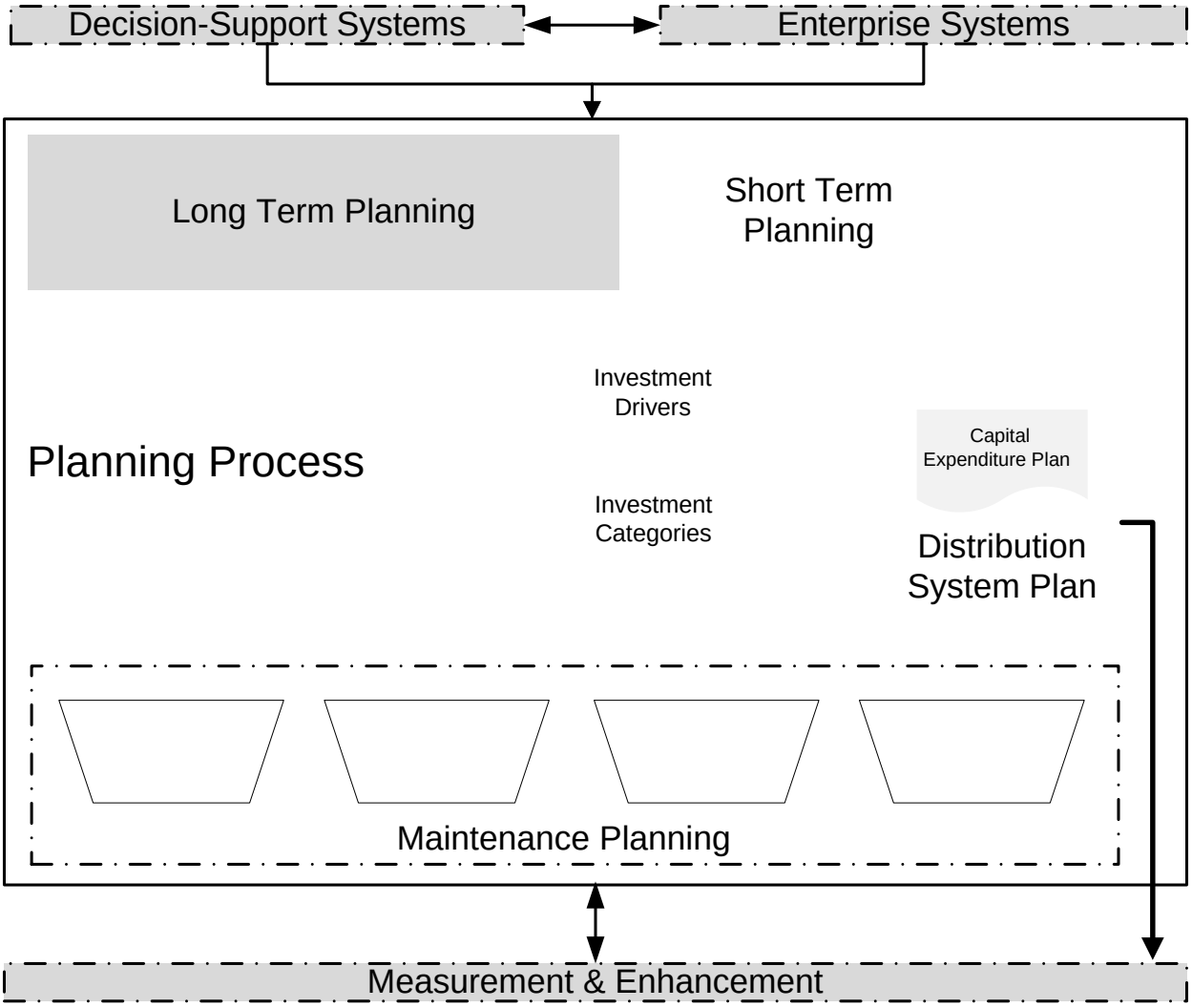


FIGURE 5: MAINTENANCE PLANNING PROCESS

D1.2.4 Measurement & Enhancement

Toronto Hydro's long-term, short-term and maintenance planning processes, discussed in Sections D1.2.1, D1.2.2 and D1.2.3 respectively are executed to produce the Capital Expenditure Plan as part of the Distribution System Plan. As illustrated in Figure 6, this Capital Expenditure Plan is monitored and measured over its execution period, such that continuous improvements can be made. Metrics that Toronto Hydro has adopted in order to measure and monitor continuous improvement during execution of the 2015-2019 Capital Expenditure Plan are further described in Section C.

In addition, Toronto Hydro also expects to execute data quality and decision support system enhancement processes over the course of the Capital Expenditure Plan execution period. These enhancements would ultimately flow back into the long-term planning functions, and influence the outputs of short-term and maintenance planning functions. Improvements and enhancements would also be integrated into future Distribution System Plans.

Section A3 highlights recent improvements and enhancements that have been implemented with respect to data quality, decision support systems and capital expenditure monitoring and measurement as part of the development of this 2015-2019 Distribution System Plan.

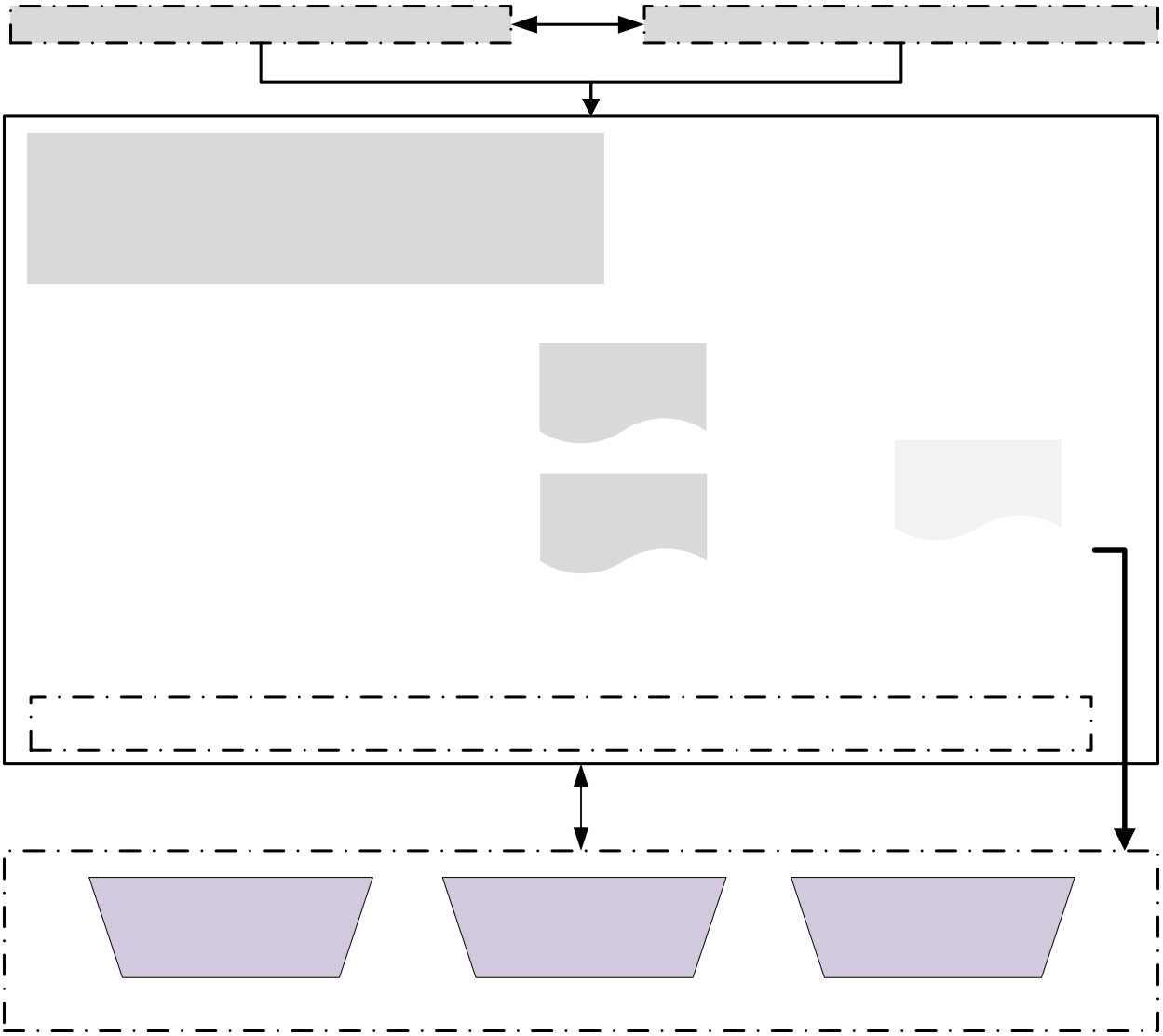


FIGURE 6: MEASUREMENT AND ENHANCEMENT PROCESS

D2 OVERVIEW OF ASSETS MANAGED

D2.1 Distribution Service Area

Toronto Hydro is the second largest municipal electrical distribution utility in North America, serving the City of Toronto – Canada's largest city. The city is bounded by Lake Ontario to the South, Steeles Ave to the North, Mississauga (mainly Highway 427) to the West, and Scarborough/Pickering Townline to the East. Toronto is made up of two distinct customer demographic areas: an urban center in downtown Toronto, and a suburban area around downtown Toronto, which is colloquially referred to as the Horseshoe area. The following sections provide details and insight into the characteristics of the City of Toronto, including the city's customer and load growth attributes, its climate and weather, and its economic profile.

A description of the asset demographics, configuration and the asset condition assessment (ACA) of Toronto Hydro's distribution system follows in section D2.2. For details on Toronto Hydro's ACA program, refer to section D3.1.2.1.

D2.1.1 Customer and Load Growth

Toronto Hydro's distribution system supplies over 730,000 customers with a peak load of 5,362 MVA record in the summer of 2013. Toronto has been experiencing slow and steady population and customer growth, with some minor acceleration in the past few years.

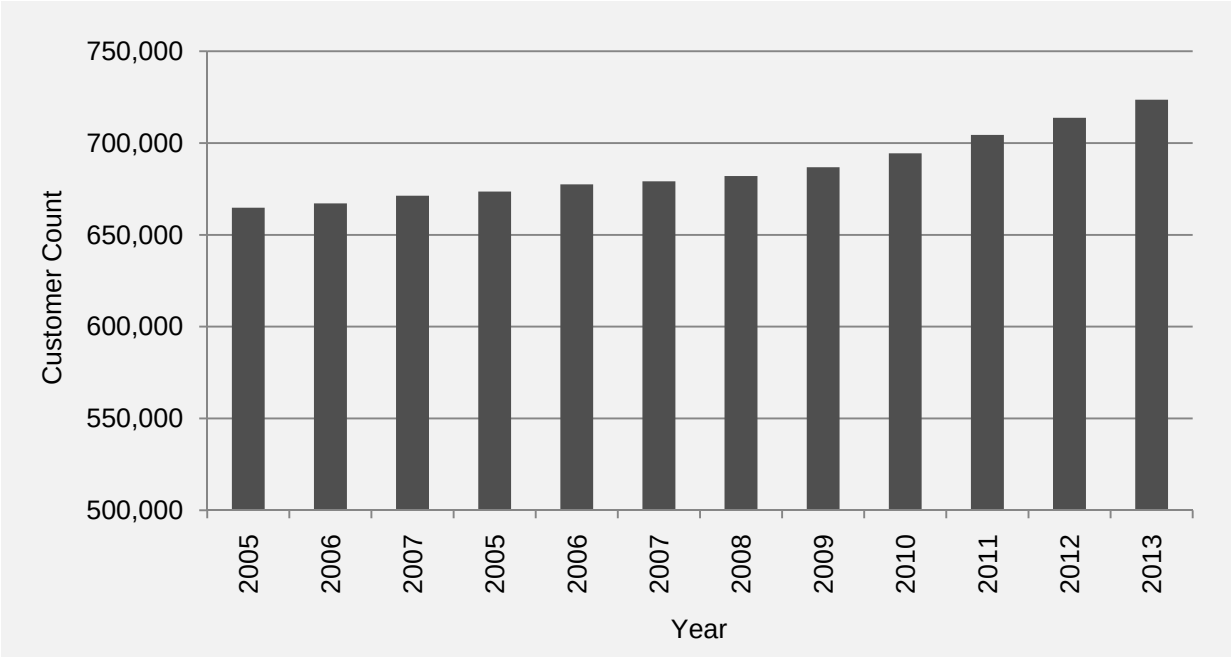


FIGURE 1: HISTORICAL TORONTO HYDRO CUSTOMER COUNTS

Overall system load growth has also been slow and steady. However. growth is highly concentrated due to the high number of large condominium developments. As such, some parts of Toronto are experiencing large increases in demand.

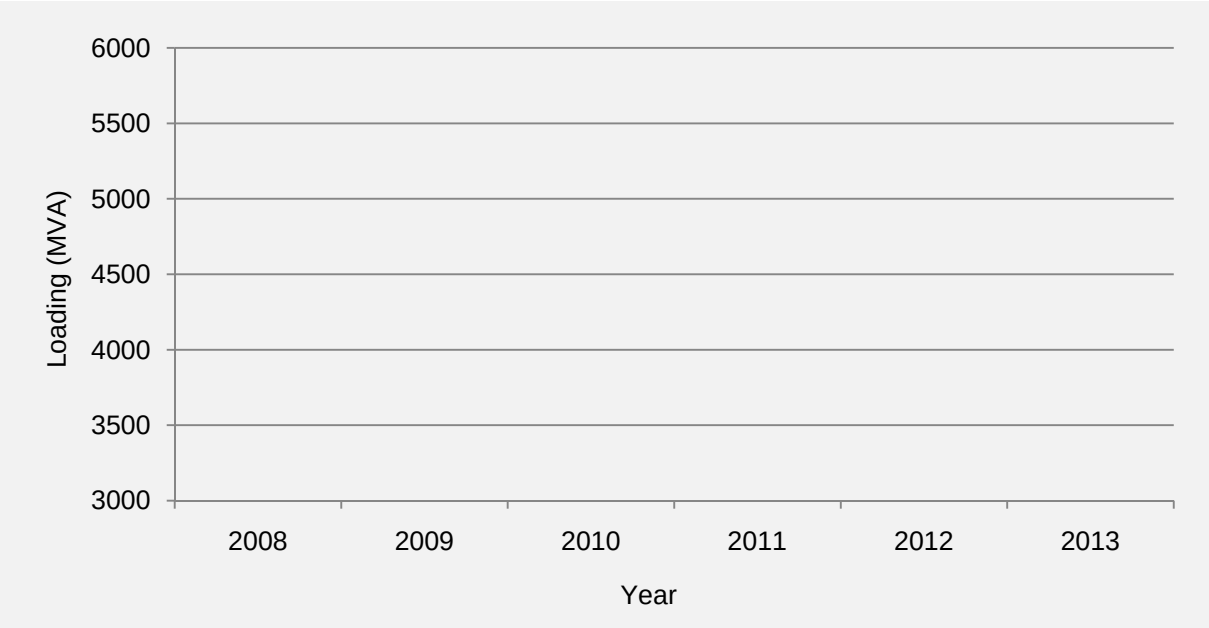


FIGURE 2: HISTORICAL TORONTO HYDRO SYSTEM PEAK LOADING

Per Figures 3 and 4, Toronto had more high rise buildings under construction than any other North American city for four years in a row. This concentrated growth occurs mainly in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue. The growth is pushing connected distribution and stations equipment to capacity. Infrastructure renewal and upgrades are required to allow Toronto Hydro to continue to supply power to these customers. These investments are also necessary to maintain performance in these areas at the same level as in the rest of the system.

FIGURE 3: TORONTO ECONOMIC UPDATE JANUARY 2014 - NUMBER OF HIGH RISE BUILDINGS UNDER CONSTRUCTION

FIGURE 4: TORONTO ECONOMIC UPDATE JANUARY 2012 - NUMBER OF HIGH RISE BUILDINGS UNDER CONSTRUCTION

D2.1.2 Climate and Weather

Toronto experiences extreme weather at both ends of the spectrum. During hot summers, temperatures can reach up to the mid-30s degrees Celsius, while cold winter temperatures can drop to the negative-20s degrees Celsius.

Toronto also experiences a wide range of other adverse weather conditions at various times during the year. High winds, freezing rain and heavy snowfall are rare, but some of these adverse weather conditions can be extreme and have the potential to cause major outages.

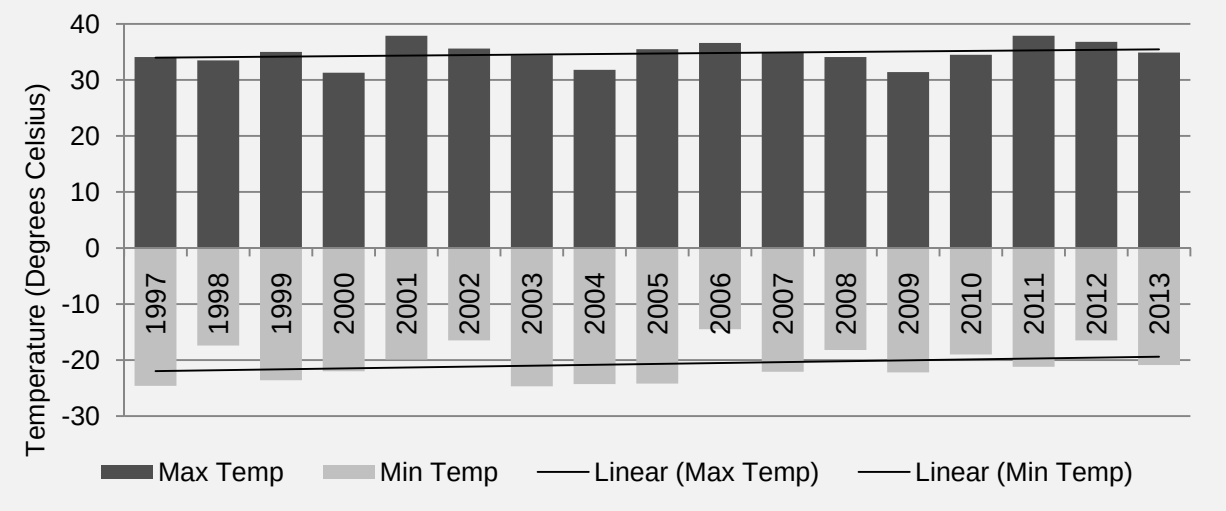


FIGURE 5: HISTORICAL MIN AND MAX TEMPERATURES IN TORONTO (1997-2013) (SOURCE: ENVIRONMENT CANADA)

On July 8, 2013, Toronto saw heavy rainfall and flash flooding which caused a loss of supply due to Hydro One Networks Inc. (HONI) transmission equipment failure. As a result, over half of Toronto Hydro's customers experienced a service outage for more than a day. A freezing rain ice storm on December 21, 2013 caused an outage to nearly half of Toronto Hydro's customers, some of whom were without power for over a week.

FIGURE 6: AFTERMATH OF DECEMBER 2013 ICE STORM SHOWING THE FREEZING RAIN DAMAGE

In order to provide reliable service to its customers in the face of these challenges and major weather events, Toronto Hydro must plan and design around these circumstances. Toronto Hydro does this in several ways, such as replacing assets that are past their useful life, changing the system configuration, or introducing new technologies into the system. Some measures that Toronto Hydro has already put in place include: building new stations with measures to prevent against flooding; converting rear lot infrastructure which is difficult to access for repairs, especially in adverse conditions; and implementing Feeder Automation to help restore customers more quickly. Furthermore, climate adaptation studies are being performed by Toronto Hydro to see what else can be done to the system to mitigate the potential damaging effects of climate change on our system.

D2.1.3 Economic Profile

The City of Toronto is Canada's economic and financial hub. It is home to the Toronto Stock Exchange, as well as the headquarters of five of the nation's largest banks. Toronto produces

11% of Canada's Gross Domestic Product[1] and its GDP growth has outperformed not only the national average, but also the most developed countries in the world in the past year. Toronto is forecast to continue performing better than the national average and either better than or on par with most developed countries over the next two years.[2]

TABLE 1: ECONOMIC GROWTH OF VARIOUS REGIONS AND COUNTRIES

Region or Country	GDP Growth Rates (Estimated or Projected)		
	2013	2014	2015
Toronto	2.4%	2.9%	3.0%
Canada	1.8%	2.5%	2.5%
United States	1.9%	3.0%	3.2%
Euro Area	-0.4%	0.9%	1.4%

Toronto also has a very diverse industrial and commercial base comprised of 11 key sectors such as business and financial services, education, technology, food, entertainment, and tourism.[3] Toronto Hydro's electrical distribution system plays a vital role in the day-to-day operation of services, businesses and industries, as well as the customers who interact with these operations.

D2.2 Asset Demographics and System Configuration

Toronto Hydro's distribution system consists of a mix of overhead, underground, secondary network and stations infrastructure. To provide the best system design taking into account the varying customer densities and conditions that exist in different neighborhoods, local areas often contain a mix of overhead and underground infrastructure. These systems operate at voltages of 27.6kV, 13.8kV, or 4.16kV, and distribute power with approximately 60,600 distribution transformers, 16,000 primary switches, 15,000 km of overhead conductors and 11,200 km of underground cables.

At the feeder level, Toronto Hydro uses two configurations: radial or looped. Radial-connected feeders have no inter-feeder distribution tie points. Should a failure event occur anywhere along a

[1] City of Toronto, Business and Economic Development facts, (Toronto: City of Toronto, 2013), online: City of Toronto <http://www.toronto.ca/toronto_facts/business_econdev.htm>. ["Toronto Business and Economic Development Facts"]
[2] Michael H. Williams, Economic Dashboard – Annual Summary, 2014, (Staff Report) (Toronto: City of Toronto, 2014).
[3] Toronto Business and Economic Development Facts

feeder, the entire feeder and the customers on that feeder would experience an outage until the failure is resolved. Looped-connected feeders have inter-feeder distribution tie points. Should an asset failure occur at either the distribution or station levels, power system controllers can perform sectionalizing and restore parts of the system by either remotely controlling Supervisory Control and Data Acquisition (SCADA) enabled switches, or directing field crews to perform manual switching on the switches that are strategically positioned along the feeder trunk circuits. This allows load to be restored using available capacity in adjacent feeders and or stations. In general, feeders in the Horseshoe area have inter-feeder tie points, while feeders in the central core do not.

Toronto Hydro continues to manage its aging infrastructure and is in the process of renewing its assets to prevent system performance degradation. Approximately 26% of Toronto Hydro's assets are at the end of useful life and an additional 7% expected to reach end of useful life by the end of the decade.

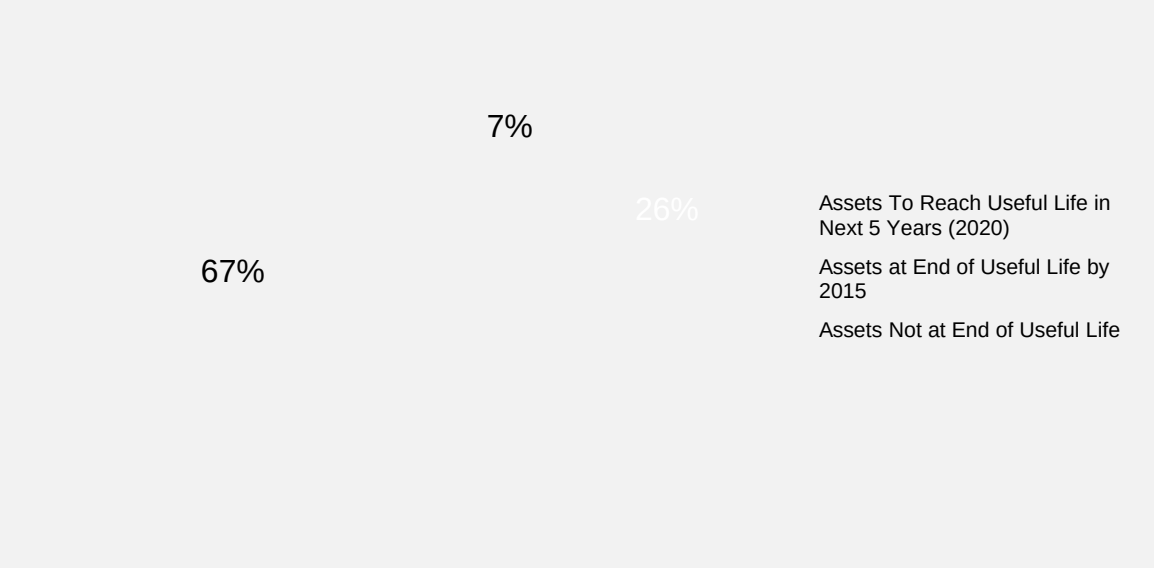


FIGURE 7: ASSETS PAST USEFUL LIFE DEMOGRAPHICS - 2015

Toronto Hydro is not the only utility in Toronto facing this "aging infrastructure" problem. For instance, Toronto Water and Sewage has infrastructure that is over 80 to 100 years old, with 17

per cent of assets past their theoretical service life[4]. Toronto Transit Commission has civil infrastructure that is over 60 years old and that is 20 years past its end of life.[5] The following sections provide a more detailed view of specific portions of Toronto Hydro's electrical distribution system, as well as the associated system challenges.[6]

[4] City of Toronto, Fast Facts about Watermains, (Toronto: City of Toronto, 2013), online: City of Toronto <http://www1.toronto.ca/wps/portal/contentonly?vgnextoid=6d02aa55ee66f310VgnVCM10000071d60f89RCRD&vgnextchannel=6534aa55ee66f310VgnVCM10000071d60f89RCRD>.
[5] Tess Kalinowski, "TTC rejects proposal to close Yonge subway for 2-month repair", The Toronto Star (15 November 2013) online: The Toronto Star <http://www.thestar.com/news/gta/transportation/2013/11/15/ttc_rejects_proposal_to_close_yonge_subway_for_2month_repair.html>.
[6] All asset demographics and asset condition assessment results identified in this section (D2.2) was compiled as of July of 2013. Due to data entry processes, there may be a lag in the records both for asset counts and asset condition demographics.

D2.2.1 Overhead Grid System

The overhead system consists of overhead conductors, overhead transformers, overhead switches and poles. All of these assets are placed above ground in areas where there is sufficient room and free of overhead obstructions such as trees, and tall buildings. This system allows for ease of fault/outage identification as all assets are out in the open and visible to crews. However, this system is prone to foreign interference such as trees, animal or human contact, and weather-related outages caused by conditions such as high winds, or freezing rain.

FIGURE 8: OVERHEAD DISTRIBUTION TRANSFORMER

The majority of the overhead is 27.6kV and 13.8kV, but a subset of the overhead system that is currently being phased out is the 4.16kV overhead Box construction distribution system.

Overall, Toronto Hydro's overhead distribution system consists of approximately 175,000 poles, 8,000 overhead switches, 30,700 overhead transformers, 4,100 circuit km of overhead primary and 10,900 circuit km of overhead secondary conductors. The overhead plant covers approximately 57% of the total distribution system within the City of Toronto. The graphs below show age demographics and asset condition assessment (where available) for overhead distribution assets. Figure 10 shows that there are many assets in the overhead system spanning

all asset classes that are old (40s, 50s and 60+ years old), and deteriorating (asset condition of poor or very poor).

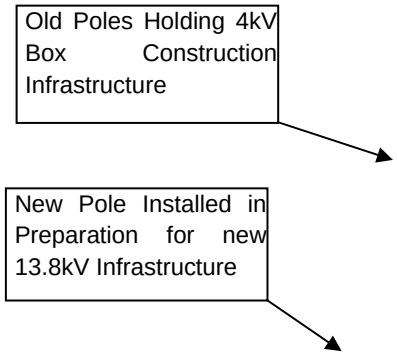


FIGURE 9: POOR CONDITION 4.16KV INFRASTRUCTURE BEING REPLACED WITH NEW 13.8KV OVERHEAD INFRASTRUCTURE

In the overhead system, some of the major challenges facing Toronto Hydro include legacy overhead assets such as porcelain insulators, arrestors and non-standard animal guards, as well as legacy construction types such as rear lot and box construction. These challenges contribute to a poor reliability performance of the system. These assets and construction types are among some of the most problematic issues that must be addressed in the system. Capital investment programs that are planned to target and mitigate challenges within the Overhead Grid System include: Box Construction and Rear Lot Conversion, Overhead Circuit Renewal, Polymer SMD-20 Replacements, Overhead Infrastructure Relocation, Overhead Momentary Reduction, SCADAMATE R1 Renewal, Design and Contingency Enhancements, Feeder Automation, Reactive Capital and Worst Performing Feeder.

Figures 10, 11 and Table 2 provide the age and condition demographics of the major overhead assets.

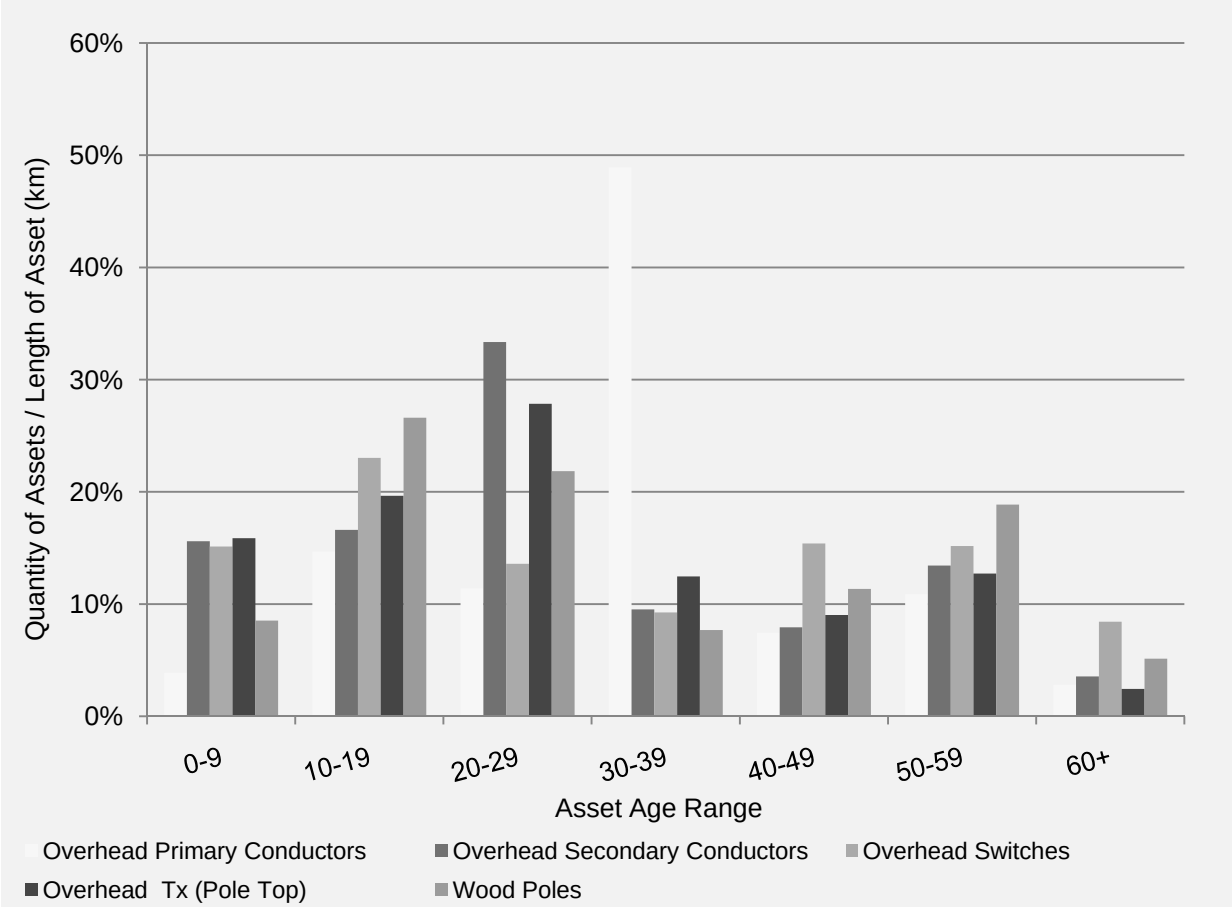


FIGURE 10: OVERHEAD ASSETS AGE DEMOGRAPHICS

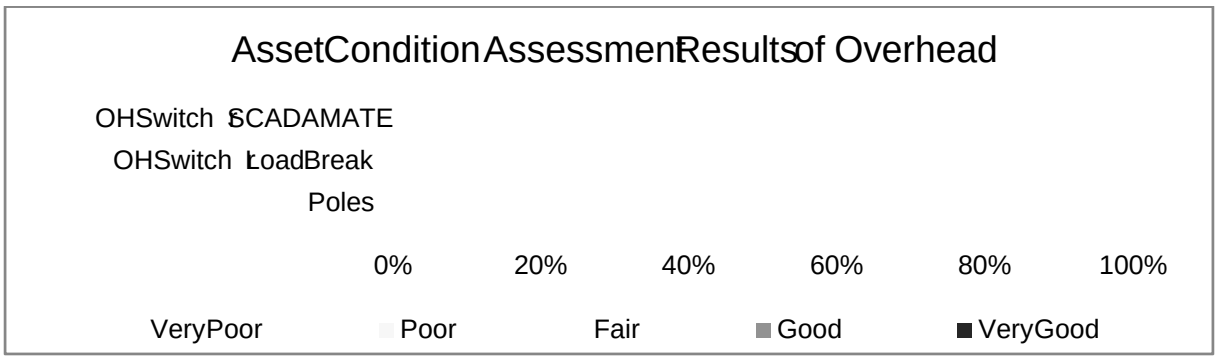


FIGURE 11: ASSET CONDITION ASSESSMENT OF OVERHEAD ASSETS

TABLE 2: OVERHEAD ASSETS SAMPLE SIZE FOR ASSET CONDITION ASSESSMENT

Asset	Sample Size
Poles	46,431
OH Switch – Load Break	365
OH Switch – SCADAMATE	790

D2.2.2 Underground Grid System

The underground system consists of underground cables, underground transformers, underground switches and underground civil infrastructure. All of these assets are placed below grade, at grade, or in building vaults. This system is typically used in areas of higher density where there is not sufficient space to place overhead systems, or in areas where there are a lot of overhead obstructions that would interfere with the electrical distribution infrastructure. The underground system eliminates many non-asset risks present in the overhead system such as foreign interference and weather-related interruptions. However, this system also presents unique non-asset risks, such as flooding and faster deterioration of assets due to moisture build-up. Although this system generally provides better reliability than the overhead system, the causes of outages are more difficult to identify and outage restoration may take longer because the assets are underground and not visible to crews.

FIGURE 12: PAD MOUNTED SWITCH

The main underground system configurations are either radial or looped,. However, as previously mentioned, system types and system configurations are sometimes mixed to provide better reliability or flexibility when repairs are required, as is the case with Underground Residential Distribution (URD). Though URD is not widespread and only appears in limited areas throughout the old Toronto area, the infrastructure still has to be maintained. In URD, primary cables, switches and distribution transformers are placed underground while secondary voltage connections remain overhead. The primary feeders consist of a main-loop, sub-loop and branch circuits. Customers are supplied directly from either the sub-loops or branch circuits, which allows sectionalization within the feeder to minimize interruptions if work is required.

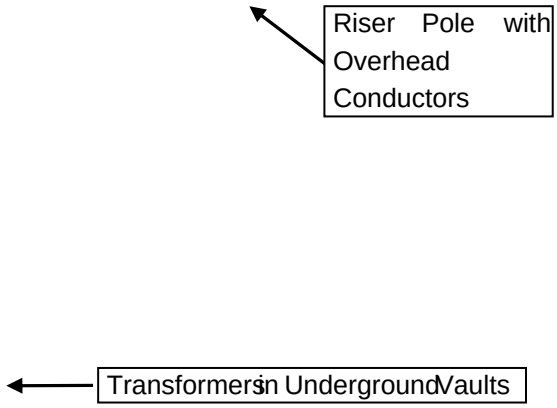


FIGURE 13: TYPICAL LAYOUT OF UNDERGROUND RESIDENTIAL DISTRIBUTION

On Toronto Hydro's underground distribution system, there are approximately 8,000 underground switches, 29,900 underground transformers, 10,900 cable chambers, 5,800 circuit km of underground primary and 5,400 circuit km of underground secondary cables[7]. This underground plant covers approximately 43% of the total distribution system within the City of Toronto. The graph below shows the age demographics of the underground assets. the graph shows that there

[7] Note: Underground asset counts include Secondary Network System asset counts, where applicable, e.g. cables, transformers, etc.

are a number of assets that are old and deteriorating. Although most assets are less than thirty years old, there is still a significant portion that is thirty to sixty years old and require intervention.

In the underground system, some of the major challenges include direct-buried cables, which are rapidly deteriorating and failing, Paper Insulated Lead Covered Cable (PILC), which present a potential health hazard associated with lead material, and Asbestos Insulated Lead Covered Cable, which also presents potential health hazards. Capital investment programs that are planned to target and mitigate challenges within the Overhead Grid System include: Underground Circuit Renewal, PILC Piece-Outs and Leakers, Underground Legacy Infrastructure, Design and Contingency Enhancements, Feeder Automation, Reactive Capital and Worst Performing Feeder.

Figures 14, 15 and Table 3 provide the age and condition demographics respectively of the major underground assets.

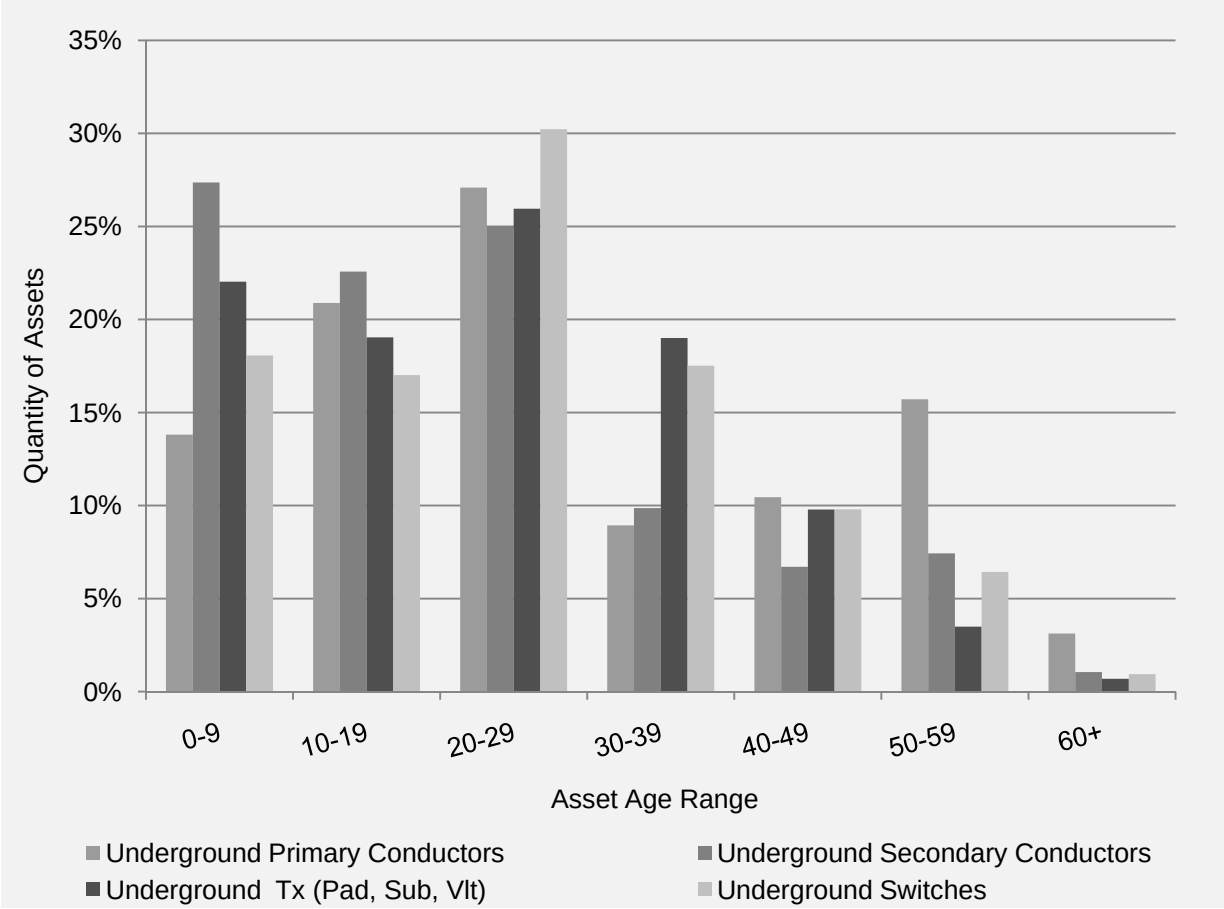


FIGURE 14: UNDERGROUND ASSETS AGE DEMOGRAPHICS

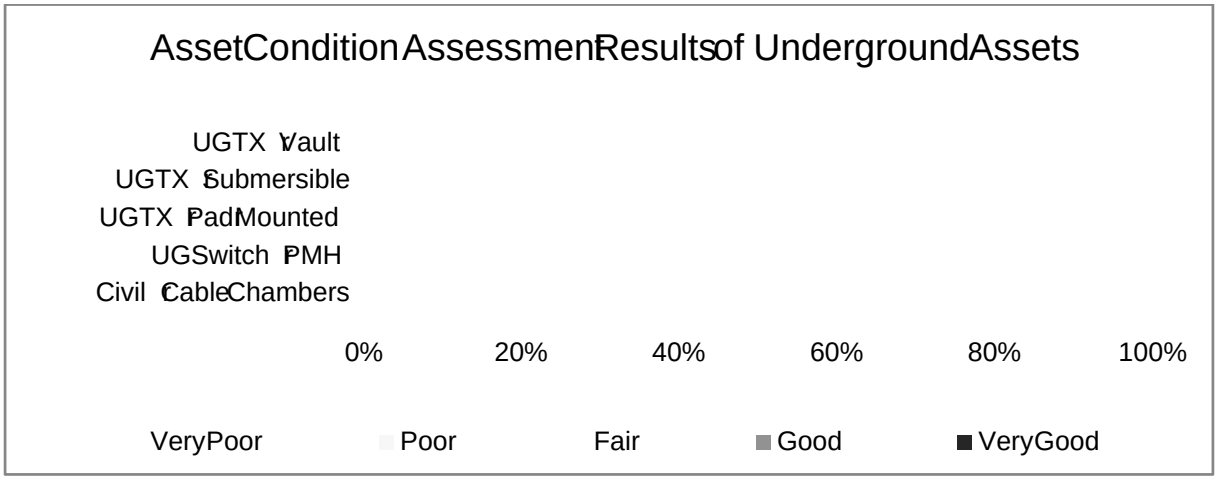


FIGURE 15: ASSET CONDITION ASSESSMENT OF UNDERGROUND ASSETS

TABLE 3: UNDERGROUND ASSETS SAMPLE SIZE FOR ASSET CONDITION ASSESSMENT

Asset	Sample Size
Civil - Cable Chambers	3817
UG Switch - PMH	778
UGTX - Pad-Mounted	6054
UGTX - Submersible	9095
UGTx - Vault	11501

D2.2.3 Secondary Network System

The secondary network system, which is predominantly found in the downtown Toronto area, was initially installed in the early-to-mid 1900s to improve reliability for critical loads in the downtown area. As the system evolved, it became one of the major systems that best serves medium sized loads in areas that have high density and small and narrow sidewalks. Such areas do not have any space above grade for distribution infrastructure. The network system consists of interconnected low-voltage secondary cables, which are installed in grid or mesh configuration. These grids are supplied by multiple network units housed in network vaults fed by different feeders, and offer additional redundancies that the typical Overhead and Underground Distribution Systems do not. Should a single primary feeder encounter an outage, network

connected customers will continue to be supplied from the alternate primary circuits which continue to feed into the secondary grid or mesh. Thus, the secondary network system offers greater reliability than either the underground or overhead systems.

The main difference between a network unit and a conventional radially-configured transformer is the addition of a network protector. The network protector prevents power from the secondary network grid from back feeding to the primary side. Should a fault occur on the primary side of the network unit, the network protector will automatically trip. This protects the grid from the fault, and allows the remaining network units to keep the secondary network grid up and running.

Though this system is better at handling normal failure scenarios, in the case of a catastrophic failure such as a vault fire, the secondary network grid that is connected to the vault must be dropped to allow emergency responders to extinguish the fire safely. In such a scenario, all connected customers are interrupted. Because of this catastrophic failure scenario, network equipment must be kept in good condition to prevent vault fires or other failures from occurring. This is one of the reasons Toronto Hydro plans to take a proactive approach to replacing network units at risk of failure.

FIGURE 16: SUBMERSIBLE NETWORK UNIT

In addition to the failure of the electrical assets, the network vaults – the civil portion of the system – are an important component and must be maintained. If the integrity of the vault is compromised, the equipment inside the vault can be damaged, or the vault may become unsafe for crews to enter. Unsafe conditions mean that crews are unable to complete any maintenance or repairs. As can be seen in the asset conditions and age demographics, there are a significant number of both network units and network vaults that are old and deteriorating that require intervention. Fibertop network units in particular is one asset class that Toronto Hydro plans to target specifically due to their poor condition, age and likelihood of causing a vault fire. Figures 17, 18 and Table 4 provide the age and condition demographics respectively of network unit and vault assets.

Capital investment programs that will target and mitigate challenges within the Secondary Network System include: Legacy Network Equipment Renewal, Network Unit Renewal, Network Circuit Reconfiguration, Network Vault Renewal and Reactive Capital.

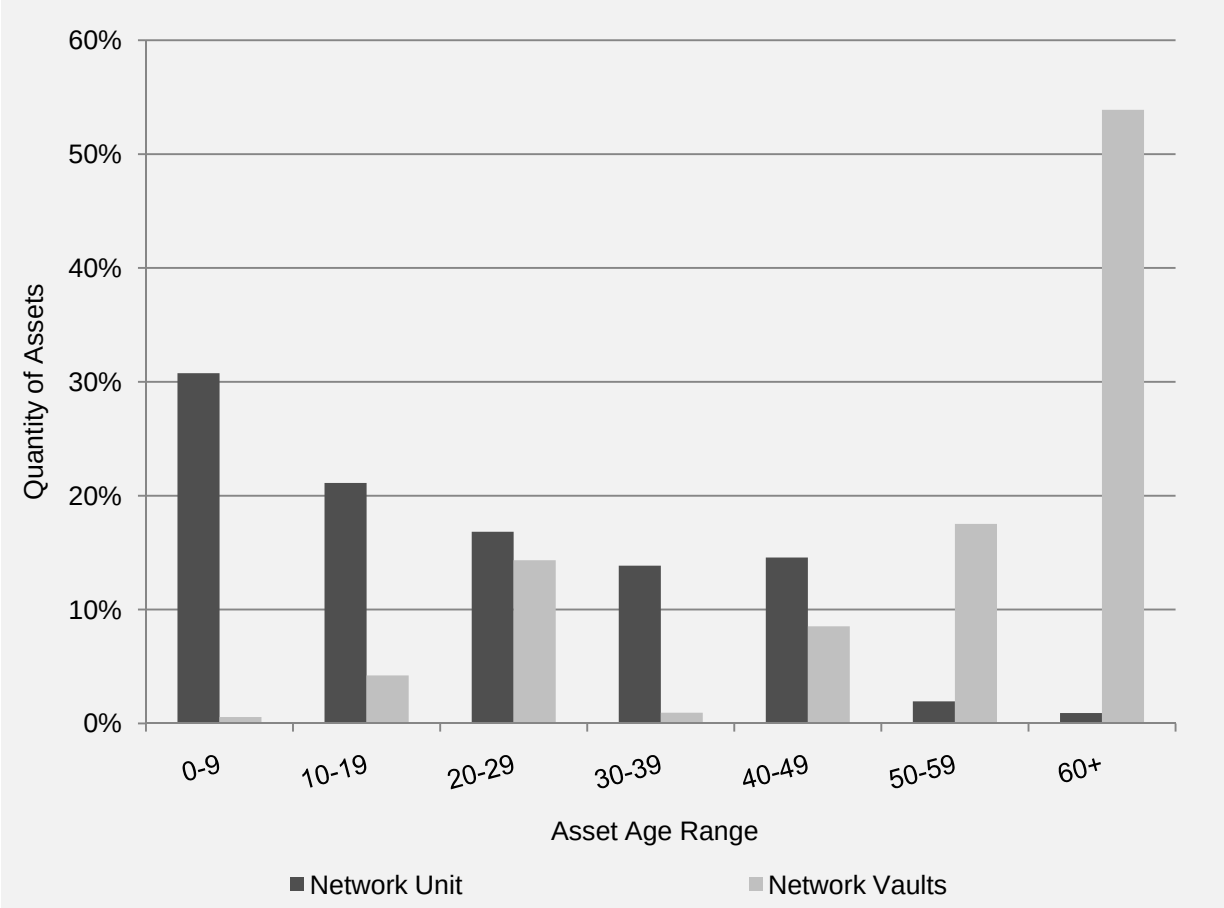


FIGURE 17: SECONDARY NETWORK ASSETS AGE DEMOGRAPHICS

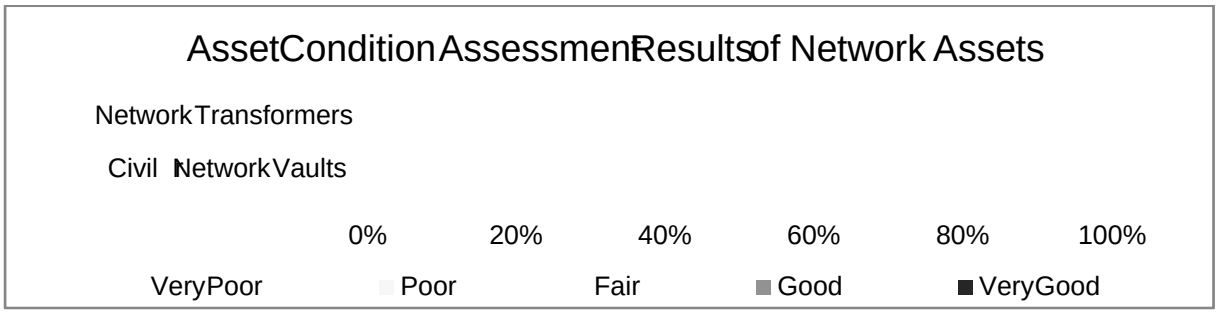


FIGURE 18: ASSET CONDITION ASSESSMENT OF SECONDARY NETWORK ASSETS

TABLE 4: SECONDARY NETWORK ASSETS SAMPLE SIZE FOR ASSET CONDITION ASSESSMENT

Asset	Sample Size
Civil – Network Vaults	1057
UG Network Transformers	1884

D2.2.4 Stations

Toronto Hydro's distribution system receives its transmission supply from Hydro One Networks Inc. (HONI) at various voltages of 230kV, 27.6kV or 13.8kV for use in its distribution system at Transformer Stations (TS). In general, Toronto Hydro owns all the medium voltage equipment up to the circuit breaker at the station. However, each station is different and there are different ownership structures for each station's equipment. The following diagram shows the ownership of station equipment and their associated demarcation point.

FIGURE 19: SYSTEM DIAGRAM OF STATION COMPONENTS OWNERSHIP

In some areas, the voltage may be further stepped down to 13.8kV or 4.16kV at Municipal Stations (MS).

Toronto Hydro owns approximately 170 MS and is supplied by 36 TS (some of which are owned by Toronto Hydro, others owned by HONI). Toronto Hydro also owns and operates some of the approximately 270 power transformers, 2,180 circuit breakers, 250 switchgear enclosures and 190 direct-current (DC) battery systems within these stations.

In the Horseshoe area outside of downtown Toronto, feeders generally have inter-feeder tie points to ensure there are multiple restoration options in case of an outage, or if planned work is required to be done. With regards to interruptions due to loss of supply at the station, feeders tied to other feeder of different stations allow customers to be resupplied provided there is available capacity on the tied feeders. On the other hand feeders in the downtown area rely on a radial configuration and do not have inter-feeder tie points. This configuration limits the restoration options for these feeders in case of a loss of supply at the station. To address this reliability issue, Toronto Hydro is planning on implementing inter-feeder tie points for some downtown feeders in its Downtown Contingency program. In addition, Toronto Hydro is proposing and continuing a number of renewal programs for station equipment to ensure that defective stations equipment is replaced prior to failure, which will also help address reliability issues. Capital investment programs that will target and mitigate Stations-related challenges include: Circuit Breaker Renewal, Power Transformer Renewal, Switchgear Renewal, Stations DC Battery System Renewal, Stations Control and Monitoring, Station Building Infrastructure Renewal, Stations Expansion, Stations Ancillary Systems and Downtown Contingency.

Figures 20, 21 and Table 5 provide the age and condition demographics of the station assets.

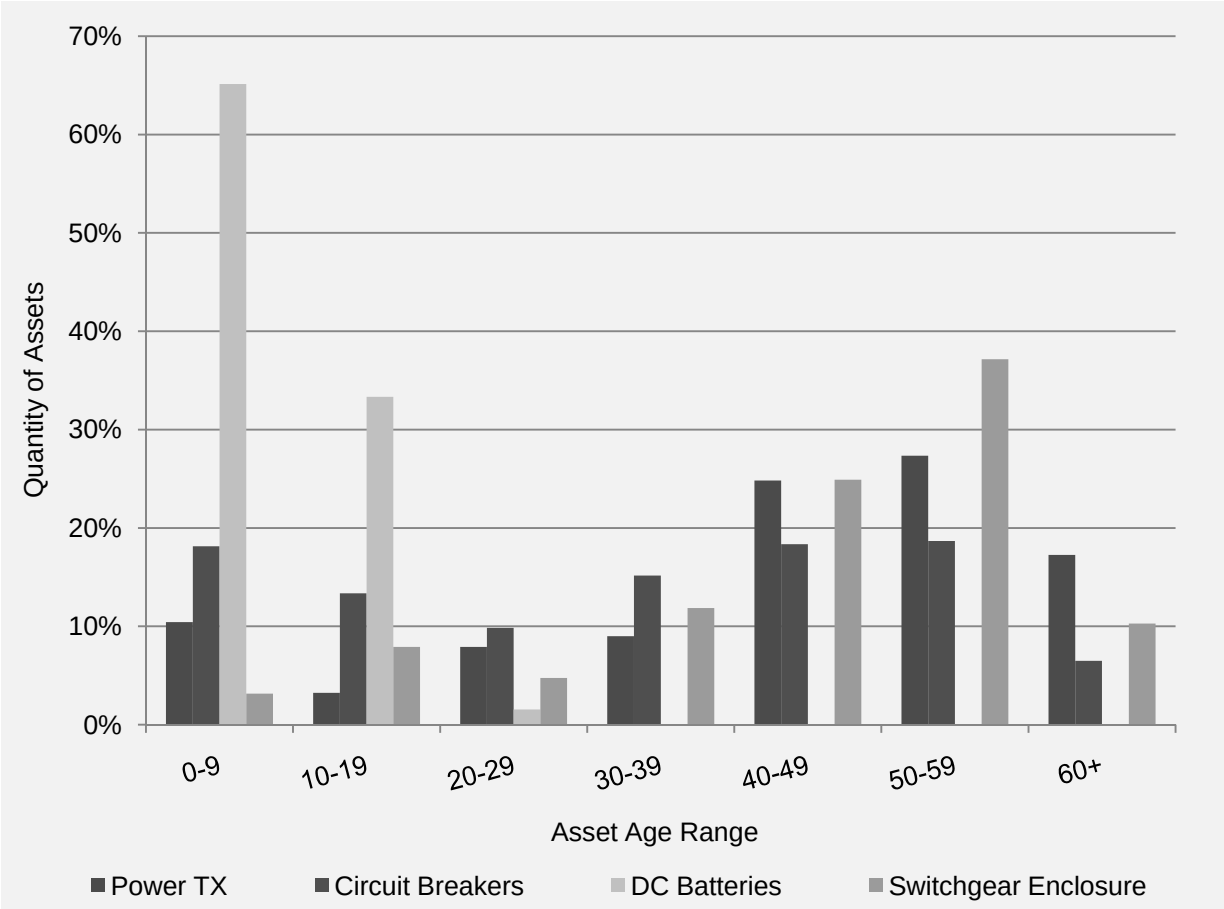


FIGURE 20: STATIONS POWER TRANSFORMER AGE DEMOGRAPHICS

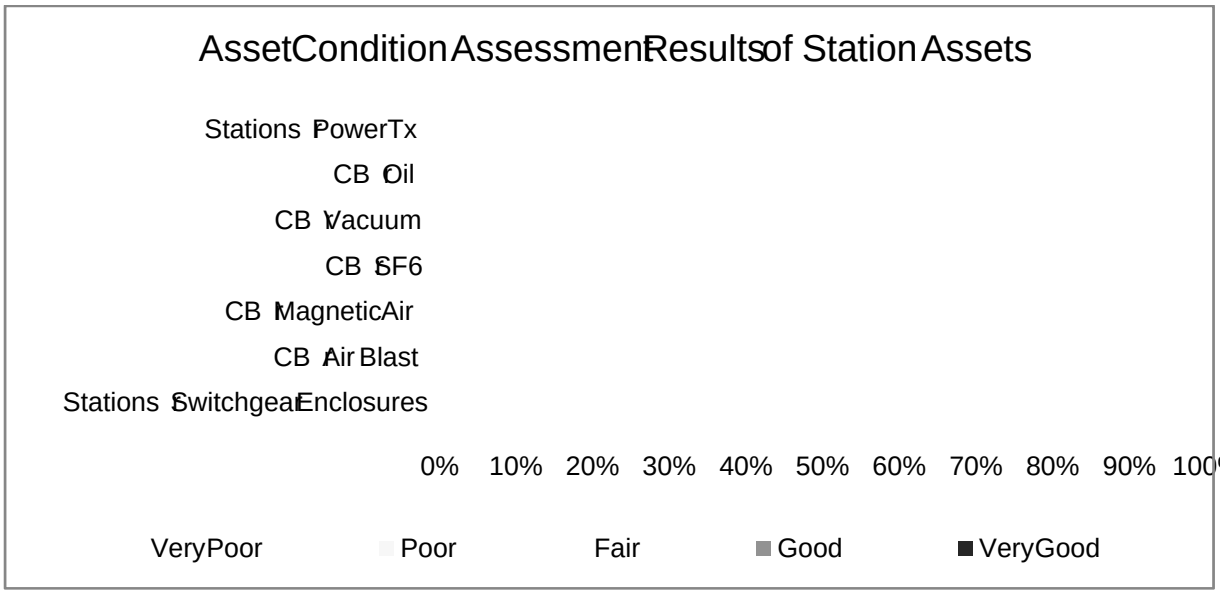


FIGURE 21: ASSET CONDITION ASSESSMENT OF STATION ASSETS

TABLE 5: STATION ASSETS SAMPLE SIZE FOR ASSET CONDITION ASSESSMENT

Asset	Sample Size
Stations – Switchgear Enclosures	248
CB – Air Blast	180
CB – Magnetic Air	466
CB – SF6	65
CB – Vacuum	478
CB – Oil	157
Stations – Power Tx	242

D2.3 System Utilization

Toronto Hydro completes an annual load forecast of station bus capacity to predict short and long term load growth, to plan for additional capacity to serve customers, to plan for contingency scenarios such as planned work or loss of supply, as well as providing long term plan to meet future load growth. This load forecasting process is further explained in Section D3.1.2.1(v). The

peak utilization should not reach or exceed 100%[8] for extended periods of time to prevent system overloading which may lead to asset failures. This assessment is mainly done at the station bus level as this is where Toronto Hydro must adhere to the Limited Time Ratings set by HONI. It is also where the most data is available to provide an accurate loading forecast, which can help predict any near- and long-term capacity constraints.

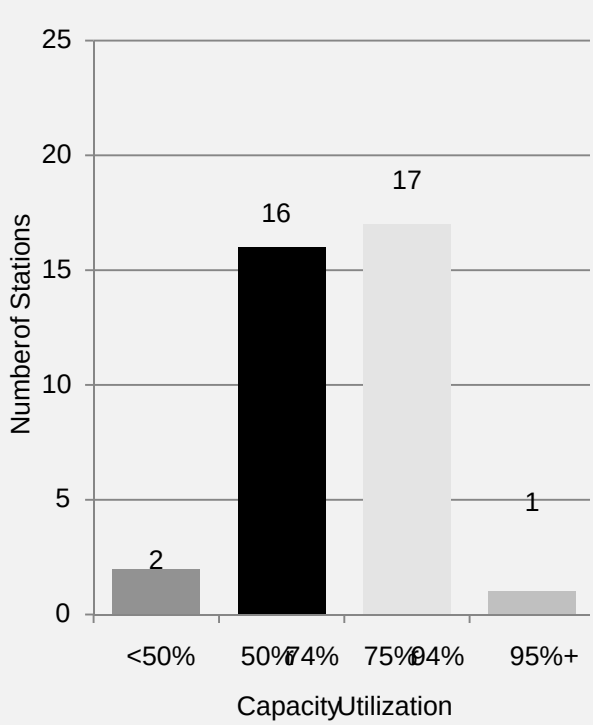


FIGURE 22: FORECASTED STATION LOADING IN 2015

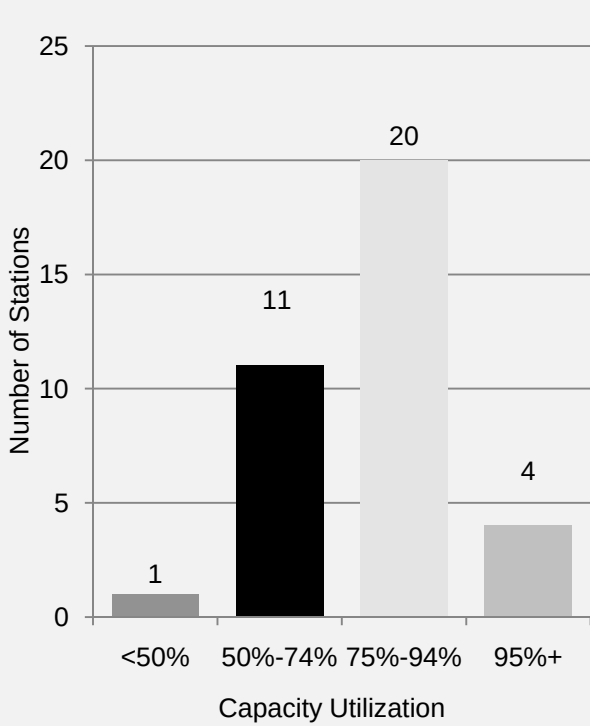


FIGURE 23: FORECASTED STATION LOADING IN 2020

From a station level capacity utilization standpoint, half of Toronto Hydro stations are loaded greater than 75%, with one station that is forecast to be at or near capacity in 2015. Toronto Hydro anticipates that there will be four stations that will be at capacity by the end of the 2020s. It is not prudent to load all assets up to 100% capacity as this would severely limit flexibility to manage abnormal system states (planned or unplanned). In a hypothetical worst case scenario, Toronto Hydro would be unable to transfer load to maintain or replace a failing or failed asset. To

[8] For planning purposes a 95% loading threshold is used for the downtown region, while a 100% bus loading threshold is used for the Horseshoe. This difference in the threshold is due to the fact that there is more load transfer capabilities in the Horseshoe area than the downtown area so more time is required to make plans for downtown capacity constraints, than for Horseshoe capacity constraints. Further details of the load forecasting can be found in section D 3.1.2.1 Decision Support Systems as well as E7.7 Stations Expansion.

mitigate overloading at the stations, engineers analyze the station loading projections as well as available capacity in the area to try to resolve the loading problem. Possible resolutions are to plan load transfers, upgrade existing components, or expand the station.

There are however, a large number of limitations and considerations that must be taken into account in implementing these solutions. They include:

- incompatible system voltages (e.g. 27.6kV vs 13.8kV)
- incompatible system types (radial vs looped, or overhead vs network, etc)
- availability of civil infrastructure
- availability of feeder positions
- environmental/civil barriers (e.g. rivers, highways ravines, etc)
- relative cost of load transfers as opposed to other relief options

Due to all these various considerations, every station must be individually analyzed to determine an appropriate resolution.

On the feeder level, planners typically plan new customer connections or customer load increases by analyzing the area where the additional load requirements are emerging and determining the best solution. Capacity constraints on the feeder level are similar to the capacity constraints at the station level and similar limitations and considerations must be accounted for in the planning process. This process is largely reactive as forecasting feeder loading is difficult because it is difficult to predict where new loads will materialize.

On the asset level, planners are frequently reviewing the system in areas of high capacity utilization or areas of poor reliability to determine what work can be undertaken to improve the system. It is difficult to monitor every asset in the system to ensure it is optimally utilized, however, Toronto Hydro has initiatives in place such as transformer monitors or network automation, which will allow assets to be more closely monitored. These initiatives help prevent overloading which may cause premature equipment failure.

D3 ASSET LIFECYCLE OPTIMIZATION POLICIES & PRACTICES

This section provides further details on Toronto Hydro's Asset Management (AM) policies and practices, which are integrated within the elements of the AM planning process and were first introduced in Section D1. Toronto Hydro strives to optimize its asset lifecycles by balancing the cost associated with the increasing risk of failure as assets age and condition degrades ("risk cost"), against the benefit of delaying the capital spending required for intervention by extending service life for as long as possible. Lifecycle optimization for the assets discussed in Section D2 takes place at the long-term, short-term and maintenance planning levels.

Capital investment practices are influenced at the long-term and short-term planning levels through the use of decision-support systems such as the Feeder Investment Model (FIM), which allow for the optimization of spending at the system investment, program investment, and asset investment levels.

At the long-term planning level, FIM is a key enabler of the risk-based optimization approach, used as part of the Long-Term System Review Process to determine the asset renewal investment timing based upon the economic end-of-life criteria for each asset. It is through this approach that Toronto Hydro plans to eventually achieve a "steady state" at the system-level through the execution of its capital investment plan. As discussed in more detail in Section D3.1.1.2, the steady state represents an optimal balance between required capital investment and aggregate risk costs associated with the existing asset base, such that the total lifecycle cost of the broader asset population is minimized.

Also at the long-term planning level, individual assets are identified and prioritized for replacement through the use of the FIM within capital investment programs and based upon their economic end-of-life criteria as per the Investment Planning process. Using this approach, the FIM balances the costs associated with the increasing risk of failure as assets age and their condition degrades (risk cost) against the benefit of delaying capital spending required for replacement by extending service life for as long as possible. This process is further discussed in Section D3.1.1.3.

At the short-term planning level, the FIM is once again utilized to re-identify prioritized assets for a given capital project as per the Project Development process. This process is further discussed in

Section D3.1.2.2. The FIM is a key enabler of the Business Case Evaluation (BCE) process, which allows the utility to produce a quantified business case for various capital investment programs. This methodology is further discussed in Section D3.3.

Additionally, maintenance investment practices are designed to extract the maximum value from assets through regular inspections, upkeep and repair activities. From these practices, the corresponding outputs are used to produce asset condition results which feed back into enterprise and decision-support systems, which are then used within long-term and short-term planning processes. In this manner, capital and maintenance processes continuously interact with each other.

Interaction points include the fact that capital investment programs are informed through their associated cross-referencing maintenance programs, to ensure that capital investment program spending is above and beyond the life extension benefits produced from the maintenance programs. Maintenance programs also account for changes that are introduced by capital investment programs, including the introduction of new asset classes or elimination of existing asset classes. For instance, the introduction of a new standardized asset class to replace an existing legacy asset class may result in reduction of maintenance costs, thereby introducing cost efficiencies. As such, a balance is ultimately achieved between capital and maintenance investments. Ultimately, maintenance programs are designed to complement the produced capital investment programs by allowing Toronto Hydro to sustain the intended operating condition of its assets and preserve operability.

D3.1 Asset Replacement & Refurbishment Policies

Toronto Hydro's asset replacement and refurbishment policies and practices allow for an optimization and prioritization of spending at the both the asset and system levels.

At the asset level, a proactive risk-based approach is applied to identify the economically optimal intervention time for assets based upon the balance of cost associated with (1) the increasing risk of failure due to asset aging and assets' condition deterioration over time (risk cost), against (2) the benefit of delaying the required spending to mitigate against these risks (capital costs) by extending service life for as long as possible. Maintenance planning further aids in maximizing the service life of assets prior to intervention, such that the maximum asset value is realized.

At the system level, the capital investment approach allows for the eventual achievement of a "steady state", which represents an optimal balance between required system-level capital investment and aggregate risk costs associated with asset failure. Section E2.1 further details the results of the capital investment approach produced for the 2015-2019 Capital Expenditure Plan, which identifies a backlog of investments, mostly comprised of those assets past their economic end-of-life. Achieving backlog mitigation and steady state through a series of stable, moderately paced investments as part of a prudent execution strategy will result in steady and more predictable rates, and the maximization of customer value via the minimization of aggregate asset lifecycle costs.

The asset management practices in the long-term planning process, first defined in Section D1.2.1, allow for the development of capital investment programs and associated investment spending levels, which target prioritized assets and issues at the system level. These practices are further defined in detail in Section D3.1.1.

Similarly, asset management practices contained within the short-term planning process, first defined in Section D1.2.2, allow for the development of discrete projects within each capital investment program. The practice of targeting assets and issues prioritized at the system level through the use of decision-support systems are further defined in detail in Section D3.1.2.

Capital investment spending that is initially established pursuant to long-term planning practices is further refined through the development of projects in Toronto Hydro's short-term planning practices. These spending levels are finalized at the investment program, category and overall levels as part of project scheduling and execution functions which exist outside of the AM

Process. The project scheduling and execution functions that were applied within the 2015-2019 Capital Expenditure Plan are further detailed in Section E2.3.

D3.1.1 Long-Term Asset Management Practices

Long-term asset management practices contained within Toronto Hydro's long-term planning process enable the optimization and prioritization of assets through the development of capital investment programs and associated spending levels. The following sections provide further details into the practices that result in the production of these outputs, including:

- The current-state system analysis (CSA), which provides a foundational set of system and asset data that is used as part of the long-term system review process;
- The long-term system review process, used to evaluate and finalize the capital expenditure approach, execution strategy and expenditure spending levels; and
- The investment planning process, used to produce capital investment programs that target assets prioritized at a system level based upon program drivers.

Further details on each of these practices are provided in the following sections.

D3.1.1.1 Current-State System Analysis

The CSA provides Toronto Hydro with a current-state assessment of the major assets that are currently installed. Key parameters provided from the CSA include:

- Asset registry data (nomenclature, asset class/sub-class, installation type, etc);
- Asset quantity/counts data;
- Age demographics data;
- Condition demographics data;
- Asset-class and system-wide replacement value based upon useful life criteria; and
- Historical reliability data.

The CSA utilizes information from Toronto Hydro's various enterprise systems, including the Geographic Information System (GIS) and Enterprise Resource Planning (ERP) system, coupled with information from AM-specific decision-support systems such as the Interruption Tracking

Information System (ITIS) which stores historical reliability data, and the Health Index (HI) Calculator which stores the generated asset condition assessment (ACA) data. These decision-support systems are further defined and discussed in Section D3.1.2.1. Asset-specific data is retrieved from each of these systems and amalgamated into the CSA.

Through the development of the CSA, Toronto Hydro can quickly establish key information on major assets including age, condition, useful life, and replacement value. This information establishes a foundation that is used in later portions of the long-term and short-term planning processes respectively. Section D2 provides the results from the CSA that was produced as part of the 2015-2019 Distribution System Plan. The CSA ultimately provides the foundation from which the long-term system review process, further explained in Section D3.1.1.2, is executed. Figure 1 illustrates the inputs, contained elements and outputs associated with the CSA.

D3.1.1.2 Long-Term System Review Process

The Long-Term System Review process utilizes the foundational data produced by the CSA in order to produce three deliverables: (i) a proactive capital investment approach that addresses all known system challenges and achieves an optimal balance between required capital investment and risk costs associated with asset failure – also referred to as a "steady state", (ii) an execution strategy that is responsive to customer's price sensitivity while being practical to execute, and (iii) comparison of reliability outcomes for the proactive capital investment approach and execution strategy against a "do nothing"/"run to failure" approach.

Figure 1 illustrates the inputs, deliverables and outputs contained within the long-term system review process.

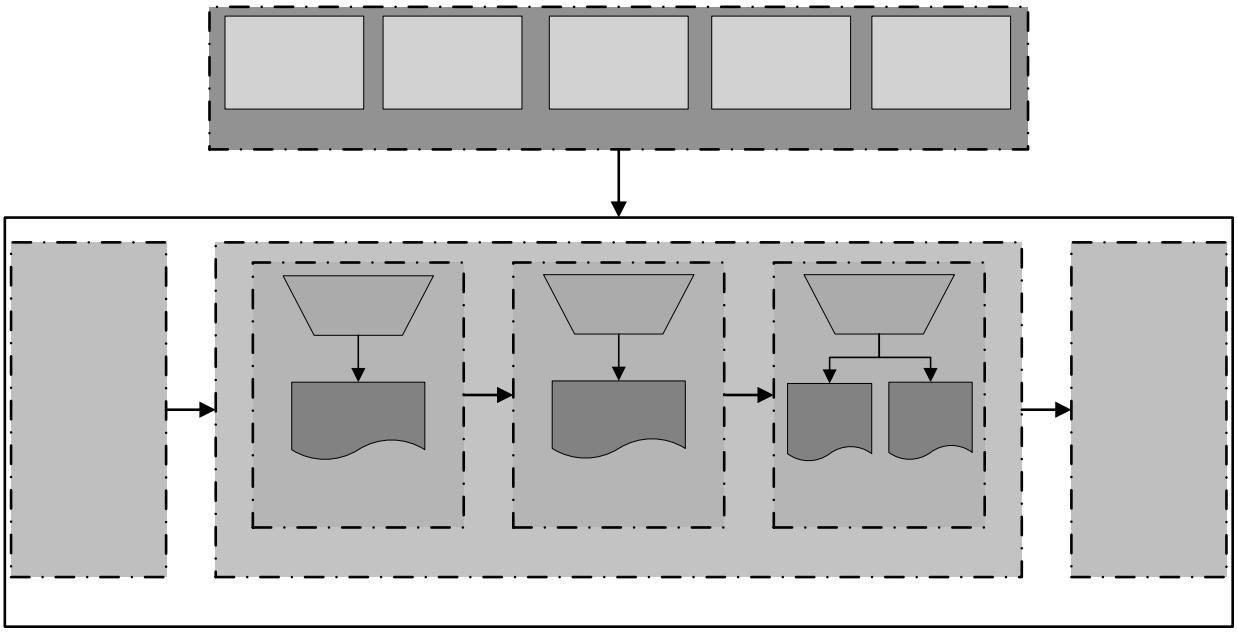


FIGURE 1: LONG TERM SYSTEM REVIEW PROCESS

(i) Derivation of Capital Investment Approach

As part of the first deliverable for the long-term system review process, asset-related information from the CSA is coupled with system-wide information regarding known challenges in order to define the forms of investment that will comprise of the total capital expenditures to take place over the Distribution System Plan (DSP) planning period. These expenditures must lead to the eventual achievement of a steady state, which represents an optimal balance between required system-level capital investment and aggregate risk costs associated with asset failure. In order to achieve a steady state, assets across the distribution system must be evaluated and intervened upon based upon their optimal intervention timing results – also known as the economic end-of-life criteria.

This economic end-of-life calculation is further illustrated in Figure 2, where the increasing annualized risk cost in orange and the decreasing annualized capital cost in green are subtotaled to produce the life-cycle cost in blue – otherwise known as the total operating cost of the new asset in question. Theoretically, the economic end-of-life criteria represents the lowest point of this operating cost across the life-cycle of the asset, illustrated by the orange dot in Figure 2 – otherwise known as the Equivalent Annualized Cost (EAC).

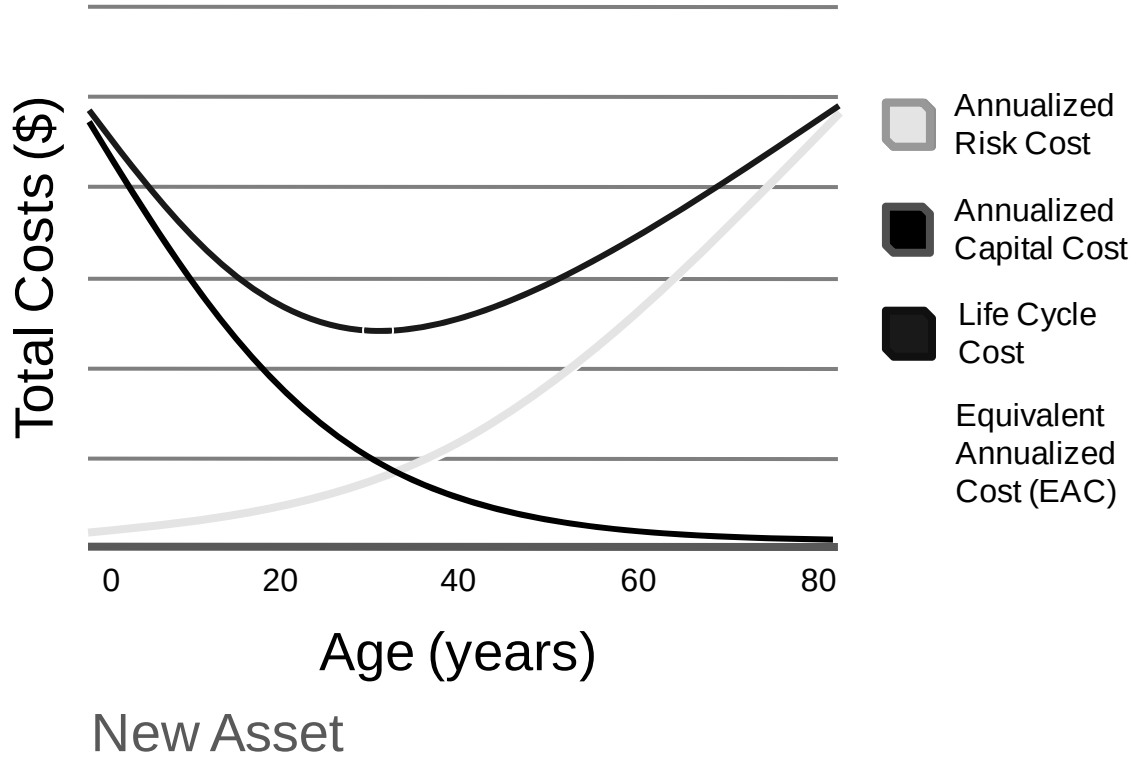


FIGURE 2: LIFE-CYCLE COSTING ANALYSIS

In actual practice, existing assets to be replaced and new assets to be installed possess varying levels of risk. Figure 3 illustrates a practical calculation of an assets' economic end-of-life through the execution of a risk-based optimization approach, enabled via the FIM, whereby the EAC as determined for the new asset is cross-referenced to the existing asset's total costs in order to determine the optimal intervention timing, or economic end-of-life criteria, of the existing asset.

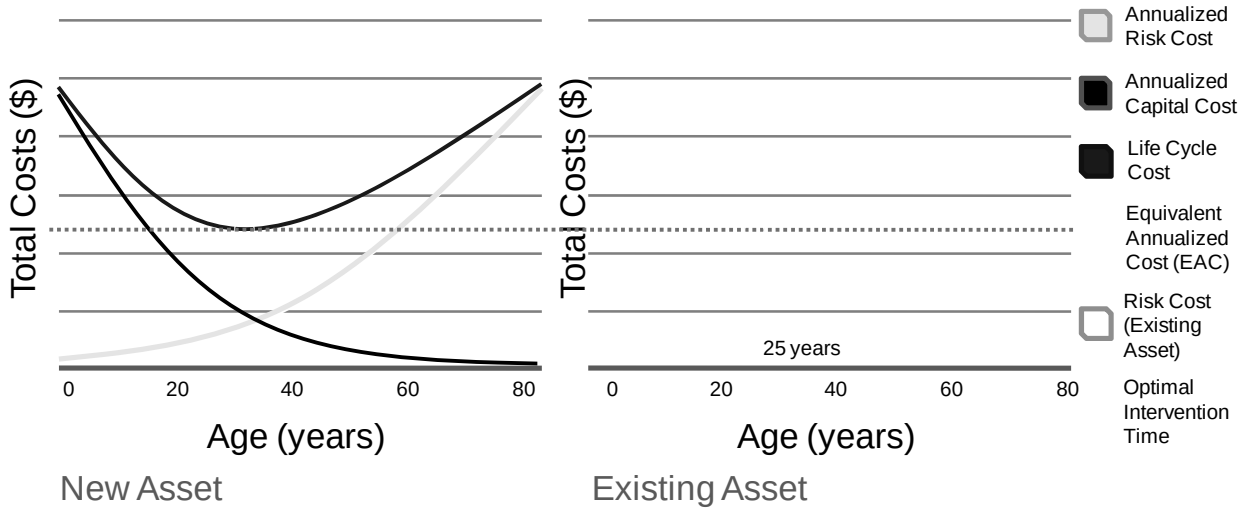


FIGURE 3: LIFE-CYCLE COSTING ANALYSIS (WHERE OPTIMAL INTERVENTION TIME IS A KEY INPUT USED WHEN CALCULATING THE STEADY STATE OF THE DISTRIBUTION SYSTEM AS PER RISK-BASED OPTIMIZATION APPROACH)

By performing this risk-based optimization approach for major distribution assets across the broader population of in-service equipment, such that the timing of asset renewal investments are collectively driven by the respective economic end-of-life results, a capital investment approach is produced that is driven by the system-level objective of achieving steady state, i.e. the condition whereby the total aggregate lifecycle costs of the distribution system is kept at a minimum.

Depending on the forms of investment that are defined within the DSP planning period, varying inputs and information are used to establish the associated capital investment spending levels. As an example, the following forms of investment and associated inputs and information were used as part of the 2015-2019 Capital Expenditure Plan:

- Asset Renewal: Steady state can be achieved through the in-kind replacement of distribution system assets (overhead, underground, secondary network, stations) reaching their economic end-of-life criteria, which is further explained above and illustrated in Figures 2 and 3. A risk-based optimization approach is applied to determine asset renewal investment timing based upon these economic end-of-life results. This approach was applied to those assets evaluated by the FIM, which is further explained in

Section D3.1.2.1(i). For those assets not evaluated by the FIM, asset intervention timing was determined based upon the assets' remaining useful life.

- System-Wide Critical Issues: These are urgent investments relating to safety, capacity and contingency constraints, security-of-supply, operational flexibility and other system-wide issues that go "beyond the asset". These investments were identified with the aid of decision support tools such as ITIS, FIM, ACA and load forecasting coupled with the CSA. These decision-support tools are further detailed in Section D3.1.2.1. Investment spending levels were derived from the costs of the solutions necessary to mitigate these issues.

- Mandatory Operational Investments: These represent the mandatory and necessary day-to-day operational investments associated with metering, customer connections, externally-initiated plant relocations and expansions, information technology, facilities, fleet and capital and maintenance investment support. Investment levels were determined in varying manners depending upon the nature of the activities in question. For example, information technology (IT) investments were derived based upon the IT Asset Management Process which is further detailed in Section D4.

Section E2.1 illustrates how the produced capital investment approach for the 2015-2019 Capital Expenditure Plan contains a backlog of investments for the first year, primarily consisting of assets at or beyond their economic end-of-life or useful life, along with critical issues. Through the elimination of this backlog, the steady state can be achieved, resulting in the mitigation of the corresponding risks. As the execution of this capital investment approach results in this steady state achievement, this balance also creates alignment between the capital expenditure plan and Toronto Hydro's AM objectives.

(ii) Selection of Capital Investment Execution Strategy

The second deliverable as part of the long-term system review process is to evaluate and compare different strategies that can be applied to execute the derived capital investment approach. The selection process will be driven by the need of the strategy to:

- Align to available resources and system constraints such that it can be executed in practice; and

- Result in rate impacts that are responsive to customers' price sensitivities.

The completion of this second deliverable also allows for capital expenditure spending levels to be produced across the DSP filing period at the overall level. These spending levels are further refined through the development of capital investment programs as explained in Section D3.1.1.3, as well as the production of capital projects as part of short-term planning practices further discussed in Section D3.1.2.2. Spending levels are later finalized as part of the project scheduling and execution process, which is explained in Section E2.3.

For the purposes of the 2015-2019 Capital Expenditure Plan, Toronto Hydro selected a "paced" execution strategy that reaches steady state in a gradual manner such that rate impacts remain acceptable and proposed investments align to available resources and system constraints. By pacing the investments in a stable and moderate manner, this ultimately results in smoother rate impacts for customers during the ongoing efforts to reach steady state and beyond. Section E2.1.2 provides further details on this selected strategy.

(iii) Reliability Assessment

The final deliverable as part of the long-term system review process is to compare the reliability outcomes of the proactive capital investment approach and execution strategy against a "do nothing"/"run to failure" approach through the execution of a reliability projection (RP) process, which is further explained in Section D3.1.2.1(iv). The reliability outcomes of the capital investment approach and execution strategy for the 2015-2019 Capital Expenditure Plan is detailed in Section D2.1.3.

D3.1.1.3 Investment Planning

The capital expenditure approach and execution strategy produced by the long-term system review process creates an architecture that can then be populated through the development of capital investment programs as per the Investment Planning process.

Key outputs from the long-term system review process, including the capital expenditure approach and execution strategy, are used within the Investment Planning process in order to produce capital investment programs.

Capital investment programs are produced for each form of investment as established within the long-term system review process. For example, for the 2015-2019 Capital Expenditure Plan, investment programs were developed for: (i) asset renewal; (ii) system-wide critical issues; and (iii) mandatory operational investments.

As per this process, assets and issues are prioritized on a holistic, system-wide basis, for each capital investment program. Prioritization factors vary depending on the drivers associated with the given capital investment program.

For example, asset renewal capital investment programs are typically driven by failure, failure risk, and functional obsolescence trigger drivers. Therefore, prioritization factors such as age, condition, economic end-of-life criteria and historical reliability data are used to identify assets across the system for these capital investment programs.

On the other hand, capital investment programs targeting system-wide critical issues typically have drivers such as safety, capacity constraints, functional obsolescence and system efficiency. For instance, for a safety-driven program all assets of a particular asset type or sub-type may be selected for immediate and equal prioritization due to the potential and in some cases, potentially severe safety risks posed by those assets. For a program driven via capacity constraints, load forecasting processes may be applied in order to prioritize locations across the distribution system with critical load growth concerns.

Capital investment programs that are managing necessary and mandatory day-to-day operational investments are developed based upon their specific scope of activities. For instance, the Metering program, which is described in Section E5.1, contains investments driven by mandated service obligations to customers. The Externally-Initiated Plant Relocation and Expansion program, which is described in Section E5.3, is entirely driven by third-party activities and initiatives.

It is ultimately through this system-wide prioritization process that capital investment spending levels are defined for each individual capital investment program.

As investment programs are developed, inter-relationships between these programs and corresponding maintenance programs are also assessed. For example, if Toronto Hydro plans to replace a sub-standard asset, maintenance activities on this asset type can be phased out. This approach allows Toronto Hydro to maintain assets to utilize an asset's full life-cycle where it is prudent to do so, or replace them, which is expected to achieve maintenance cost savings by reducing maintenance activities. More details about Toronto Hydro's maintenance programs are provided in Section D3.2.

Ultimately, each capital investment program will be assigned to one of the four investment categories (System Access, System Renewal, System Service, General Plant) as defined within

the Ontario Energy Board's (OEB) Chapter 5 Filing Requirements for Electricity Transmission and Distribution Applications.[1] Assignment to a category is dependent on the investment program's trigger driver, and the association of that driver to an investment category as defined in Table 2 of OEB's Chapter 5 documentation.

Once capital investment programs have been established at the long-term planning level, discrete projects are developed within each investment program as per the Project Development process (further explained in Section D3.1.2.2). Following this, a business case evaluation (BCE) will be produced for each capital investment program where it is practicable in order to identify the most cost-effective solution for mitigating the associated challenges and issues to ensure that the program is providing value to customers over its life-cycle. This BCE can only be produced once discrete assets to be intervened upon and/or specific locations where new assets are to be installed have been defined for a capital investment program. For those capital investment programs that are "dynamic" in nature where exact discrete assets cannot be produced or identified, a BCE cannot be practicably produced. For example, a Business Case Evaluation cannot be produced for a capital program such as Customer Connections (Section E5.3) where exact locations cannot be identified for the first year of activities.

The BCE approach is further defined in Section D3.3. Capital investment programs along with their respective BCE results have been provided in Sections E5 through to E8 respectively. Figure 3provides a visualization of the Investment Planning process by which investment programs are created.

As per the Investment Planning process, each produced capital investment program must align to Toronto Hydro's standard design practices and distribution construction standards. All new assets to be installed within each investment program have been reviewed and approved via an equipment approval process to ensure that they are safe and reliable. Standards and regulation adherence information have been provided for each individual investment program declared in Sections E5 through to E8 respectively. An independent review of all Toronto Hydro standards was performed by Power Systems Engineering (PSE) to ensure that these standards fall within typical industry practices and the principles of safety, reliability and efficiency, while applying industry best practices. The PSE report can be found in Appendix B of Section D.

[1] Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications, (Toronto: Ontario Energy Board, 2013). ["OEB Filing Requirements"]

D3.1.2 Short Term Asset Management Practices

Toronto Hydro's applies its short-term asset management process in order to develop discrete capital projects through the use of enterprise data and decision support systems coupled with investment drivers.

The Investment Planning process, as discussed in Section D3.1.1.3, results in the production of capital investment programs, each with holistically prioritized assets and/or issues and associated high-level program spending forecasts. As per short-term asset management policies, these prioritized assets and/or issues are recaptured locally through the use of various inputs, depending on the program driver through the execution of the Project Development process.

Figure 3 provides an overall visualization of the short-term planning process. Section D3.1.2.1 provides further details into the specific decision support systems applied at the local level to produce discrete projects, while Section D3.1.2.2 provides details on the Project Development process.

D3.1.2.1 Decision Support Systems

This section details the various tools that are used to plan system capital investments. The various inputs from the corporate databases discussed in Section D1 are used to assess the risk associated with assets and make system capital investment decisions. A number of tools and processes are utilized for this purpose, including:

- Feeder Investment Model (FIM);
- Asset Condition Assessment (ACA);
- Interruption Tracking Information System (ITIS);
- Reliability Projections (RP); and
- Load Forecasting (LF).

(i) Feeder Investment Model

The FIM is a risk-based analytical model that is used to establish the economic end-of-life for the major asset classes within Toronto Hydro's distribution system. It establishes an optimal time for intervening on a particular asset by balancing the risk associated with asset failure against the capital cost of intervention.

The FIM requires two main inputs to establish a risk analysis of assets: probability of asset failure and the subsequent failure impacts. The probability of asset failure relies on the assets' Hazard Rate Distribution Function (HDF), which represents the conditional probability of an asset failing based on the remaining population that has survived up until that time. The failure impacts, also called the consequence or impact of failure, are quantified by accounting for the direct costs to Toronto Hydro, including materials and labour costs, required to replace an asset, as well as indirect costs.

In addition to the direct costs that are incurred by Toronto Hydro in performing the asset replacement, Customer Interruption Costs (CIC) are also included. CIC values are calculated in two parts: the Event cost and the Duration cost. The Event cost represents the impact due to the occurrence of the outage whereas the Duration cost represents the costs incurred as the length of the outage increases. Toronto Hydro adopted $30 per kVA (peak load) as the Event cost to represent the CIC value due to the initial period of the outage, and $15 per kVA (peak load) per hour to represent the CIC value due to the increasing duration of the outage. These values, which were discussed at length in Toronto Hydro's 2012-2014 rates application, are established through work with consultants as well as the analysis of results from reliability valuation studies. The peak load at the individual asset level is used as a proxy for the number of connected customers as it represents the full load customers may have needed during an outage. In setting these values on a kVA and kVA-hour basis, no distinctions are made between customers by customer class. These values are used to quantify customer interruptions as part of the business case evaluations. As part of on-going enhancements[2] to the Feeder Investment Model, Toronto Hydro is planning to conduct a CIC study to provide more specific breakdown of CIC values within the FIM. Toronto Hydro's proposed spending on this study is outlined in Section E8.8.

The indirect costs account for the full cost of failure to customers and society, such as costs due to physical damage to customer or public property due to an outage, public safety, and environmental clean-up. These represent additional costs that would be incurred in a catastrophic failure of an asset. The total impacts of failure differ from asset to asset because assets operate under varying conditions and loadings.

The product of the probability of failure and the impact cost provides risk quantification for each major asset based on its individual age, condition, typical failure modes, and configuration within

[2] In Toronto Hydro's 2012-2013 rates application, the utility acknowledged that further research could be done to refine the CIC values used by the FIM, examining the types of customers in various areas and the differing effects that an outage may have on them. [EB-2012-0064, Application and Evidence (May 10, 2012).] In its decision, the OEB found that the present limitations of the FIM do not outweigh its usefulness. The OEB also acknowledged that refining the FIM inputs may only come at significant cost. [EB-2012-0064, Decision and Rate Order (April 2, 2013), at page 21.]

the distribution system. In order to determine a life cycle cost, both the estimated risk cost and the replacement cost of an asset are annualized, as shown in Figure 4. The life cycle cost of the asset is then the simple sum of the annualized risk and annualized capital cost. The annualized capital cost is the cost of replacement annualized over its projected life. As shown in Figure 4, the minimum point of the life cycle cost curve, the Equivalent Annualized Cost (EAC) point, defines the life cycle at which the lowest operating cost is incurred and thus the optimal life cycle for a new asset.

By extending the EAC point determined for a new asset to the existing asset within the system (which shares the same configuration), the optimal intervention time (OIT) for that particular asset can be determined, which is detailed in Figure 4.

FIGURE 4: TYPICAL EXAMPLE OF ESTABLISHING THE OPTIMAL INTERVENTION TIME FOR AN EXISTING ASSET

Therefore, by using both the probability of asset failure and the impact to both Toronto Hydro and its customers upon asset failure, the FIM determines a risk cost for a particular asset. Comparing this cost against the capital cost of replacement, the OIT for each asset is established. Thus, the FIM allows Toronto Hydro to evaluate major asset classes within its system and determine a replacement program for each of these asset classes based on a risk mitigation approach.

Further to the direct replacement of an asset, a number of assets have a refurbishment option which involves the replacement of non-standard accessories on overhead assets such as non-standard animal guards or lightning arrestors for overhead transformers and porcelain insulators on poles. The refurbishment option decreases the failure probability of the asset and thus reduces the risk cost of the asset. The FIM considers refurbishment as an option for optimal intervention and weighs the costs of refurbishment against the benefits from the decreased risk achieved by performing the work.

(ii) Asset Condition Assessment (ACA)

Toronto Hydro employs an ACA program to monitor the condition of various key asset classes within its system and produce a health index score to support project planning. The ACA program allows Toronto Hydro to produce a numerical representation of an asset's condition, taking into account key factors that affect its operation, degradation, and lifecycle.

For this rate-setting application, Toronto Hydro asked Kinectrics Inc. to assess the progress that Toronto Hydro has made with its ACA program since Kinectrics' most recent audit in 2012. Toronto Hydro has filed the 2014 Asset Condition Assessment Audit by Kinectrics Inc. as Appendix A to Section D of the DSP.

The basic approach used to develop the health index for each asset class is illustrated in Figure 5.

FIGURE 5: ASSET CONDITION ASSESSMENT PROCESS AS PART OF ACA

The asset classes define the various types of assets within Toronto Hydro's system. The degradation processes and end-of-life criteria are established by subject matter experts based on their understanding of each asset class' causes of failure. The resulting formulation then defines how each condition impacts the health index profile for each asset class. The ACA depends heavily on the inspection of the various assets which is performed as part of the ACA program, thus a health index score can only be produced for asset classes which have sufficient inspection information, examples of asset classes with HI scores are shown in Figure 6 below.

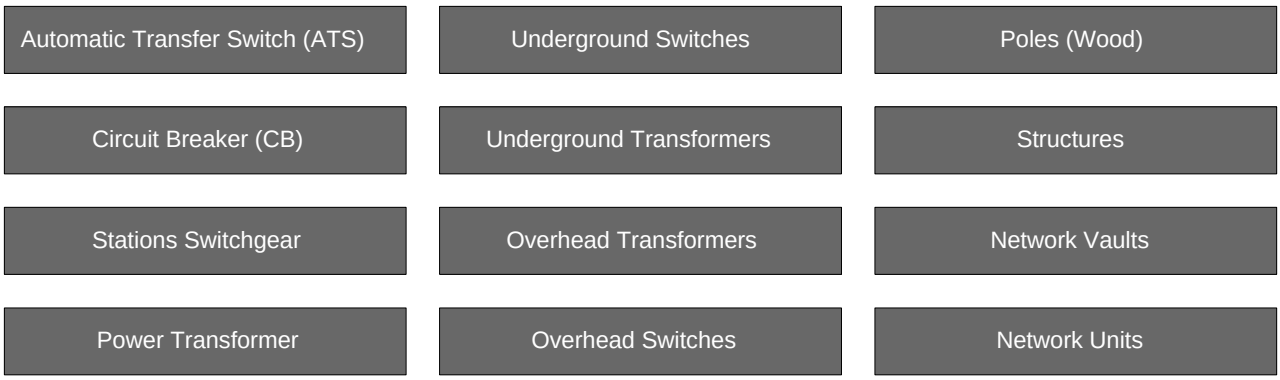


FIGURE 6: EXAMPLES OF ASSET CLASSES EVALUATED IN THE ACA PROGRAM

The resulting health index scoring produced for these asset classes is critical to Toronto Hydro's planning activities. The ACA output is essential in two regards. First, the ACA produces an outlook of the population's condition for each individual asset class within the program. Second, the ACA program highlights trends in the condition of asset classes. These trends can highlight issues that are specific to particular asset classes or subtypes such as manufacturing defects, or design practices. Being aware of these issues and trends allows Toronto Hydro to balance capital investments against continuing maintenance.

(iii) Interruption Tracking In formation System (ITIS)

Toronto Hydro also uses system performance as a key tool in developing capital spending. The state of the distribution system can be understood by analyzing its reliability performance. By continuously analyzing the reliability performance of the circuits within Toronto Hydro's distribution system as well as their substation assets, Toronto Hydro is able to identify areas experiencing reliability issues, which may be caused by asset deterioration or legacy design related issues. The Interruption Tracking Information System (ITIS) is used to store historical outage information. Toronto Hydro utilizes ten major cause codes to classify historical outages within ITIS, including:

- Adverse Environment
- Adverse Weather
- Defective Equipment

- Foreign Interference
- Human Element
- Lightning
- Loss of Supply
- Scheduled Outages
- Tree Contacts
- Unknown

Further, ITIS can provide insight into the number of customers affected by outage events in the system and the duration of each event. This information can then help drive capital investment decisions by identifying assets that are facing continued reliability issues or designs that require a longer to restore. In addition, areas with a high number of outages are then analyzed to determine the root cause of the problem and to identify the most prudent investment decision to alleviate the issues identified.

(iv) Reliability Projections (RP)

In order to conceptualize the impact of investment programs, Toronto Hydro performs an analysis of the historical system reliability and produces a reliability projection based upon:

(a) Asset demographics data produced as part of the CSA;

(b) Historical Reliability performance; and

(c) Planned Programs and their respective impacts to reliability.

The system historical reliability category is broken into individual cause codes, and in some cases such as defective equipment, down to the asset level.

As per the reliability projection process, a Status Quo or “Run to Fail” scenario is produced, in which the progressions of the current system with no proactive intervention is described. The scenario depicts what would happen if technology that exists stays in the system and performs as it does today, with assets naturally reaching an end-of-life point. At the end-of-life point assets begin to fail, leading to worsening reliability. While there are no certain assumptions made about

environment condition changes, the impact of these outages are perceived to increase due to a less robust system as asset degrade.

In addition to the "Run to Fail" approach, Toronto Hydro reviews each of its filed programs for reliability benefits, improved operation flexibility, and asset demographic change. The program level changes are reviewed holistically on a system level, and system impact by sub cause codes is produced. The benefits are then normalized to the full extent of the program level relative to the system.

In general, this conceptual analysis is used by Toronto Hydro to evaluate reliability impact of the proposed capital expenditure plan. It should be noted that this projection does not consider major event days, and the lasting impacts that major weather events can have on asset performance in future years.

(v) Load Forecasting

Toronto Hydro uses a load forecasting process to identify spare capacity at substations or points of constraint within the system. This allows Toronto Hydro to maintain awareness of bus capacity as new connections are made. In order to complete a ten-year load forecast at the substation level, as shown in Figure 7, Toronto Hydro identifies the peak loads (both summer and winter peaks) for each bus that supplies its substations. These peak loads are then normalized based on historical temperatures at which these peaks occurs. This information is then supplemented by historical growth rates based on distinct areas of the system. The areas are distinguished by their distribution system characteristics, demographics, and historical growth. Any information available for customer connections at the time of analysis are included based on the required connection time and the load requested by the customer. However, only 70% of the requested load is applied, because Toronto Hydro has learned from past experience that the load requested is often overstated in the application phase. For larger customers, the load profile is forecasted to grow gradually, based on past observations. The historical growth rates that are calculated are then used to forecast load for future growth.

FIGURE 7: PROCESS TO FORECAST LOAD AT SUBSTATIONS

D3.1.2.2 Project Development

Once capital investment programs are established, as explained in Section D3.1.1.3, the prioritized assets and/or issues identified for each program are intervened upon as part of discrete capital projects. As explained within Section D1.2.2, the project development process can be subdivided into three components: (1) the project study, (2) the project draft and the (3) approved project.

During the study phase, planning engineers analyze discrete portions of the distribution system, such as a neighborhood or street, in order to identify projects that align to the investment program criteria and drivers. Depending on the investment program driver and program type (i.e. core renewal, critical issues or other necessary day-to-day operational investments), enterprise data and decision support systems are applied in order to identify assets at a discrete level such that investment opportunities are identified.

For instance, should a program be driven by Failure Risk, enterprise and decision support systems as discussed in Section D3.1.2.1 will be utilized in order to identify the program-level prioritized assets that align to this driver.

In addition, HI Calculator outputs can be used to identify those assets in very poor and poor condition. The FIM can be used to identify those assets that are nearing, at or beyond economic end-of-life at a particular location. ITIS can be used to cross-reference studied locations against historical reliability events and performance issues. Finally, enterprise systems including the GIS are used to further support the study process, by providing supplementary details such as age, asset type and sub-type information.

For safety or capacity constraint-driven programs resolving critical, system-wide issues, nameplate information or localized data as per the load forecasting process may be used to identify specific investment opportunities.

When an investment opportunity for a project within a particular investment program has been confirmed and verified, a project draft is then produced which confirms the assets to be replaced, and establishes the high-level design for the new assets to be installed. While some projects may involve assets replaced in-kind, other projects may result in non-in-kind interventions, where new assets are installed as per a new configuration. Examples may include the conversion of overhead plant to underground plant in order to minimize non-asset-risk exposure, or the re-configuring of radial circuits to looped circuits and redistribution of load in order to reduce outage duration and impacts accordingly. Ultimately, the high-level forecasts produced via the long-term planning process will be further refined into a capital budget, as more rigorous project estimates are produced.

In tandem with producing the high-level design, the planning engineers also document the scope of work to be performed and produce a high-level cost estimation to execute the project. Efficiency savings are realized by mitigating both the prioritized assets and/or issues along with adjacent assets as a single project, as opposed to replacing these assets individually on a reactive basis. A project study may also be subdivided into multiple project drafts where necessary to allow construction to be executed in manageable pieces that are minimally intrusive to both the general public as well as customers. As part of the project development process, engineers also consider issues such as city road moratoriums, physical restrictions, or particular design related problems that may delay the project or require a redesign.

The project draft then goes through a quality control assessment, where it proceeds into the project finalization stage through the planning supervisor. During this phase, in-field assessments may also take place to verify the accuracy of the data that was used to produce the project.

Ultimately, a series of projects are produced for each investment program, which results in further refinement to the capital investment spending levels for the associated program, since these spending levels are now informed by the discrete project costs. As all of these projects include assets or issues that are of the most urgent nature, these projects will be of equal importance to each other and will be assigned to the first year of the Capital Expenditure Plan. As part of the 2015-2019 Distribution System Plan, capital projects were produced for the 2015 year. These capital projects are detailed in their respective capital investment program sections, located in Sections E5 through to E8.

Once the project finalization is complete, these projects will be scheduled for execution based upon the Project Scheduling and Execution process. Each project is scheduled based upon available resources as well as system constraints such as contingency issues or summer switching restrictions. As part of this process, the detailed project design and estimate are produced which results in the finalization of capital investment spending levels. The applied Project Scheduling and Execution process as part of this 2015-2019 Distribution System Plan is further explained in Section E2.3.

D3.1.2.3 Measurement and Enhancement

Toronto Hydro has developed various metrics to monitor the performance of the DSP through the execution period, which will aid in driving improvements in successive DSP submissions. Section C provides further details on the metrics applied as part of the 2015-2019 Distribution System Plan.

While Toronto Hydro is confident in its Asset Management Process and the rigor underlying its DSP, the utility also adopts the principle of continuous improvement and plans to look for opportunities to enhance its processes. Toronto Hydro sees two central areas where it may be possible to enhance its DSP-related processes: (i) Data Quality Improvement and (ii) Decision Support System Enhancements.

Toronto Hydro plans to review any data gaps or data quality issues identified during the development of the DSP. The utility expects that the feasibility and economic viability of solutions could be considered, in order to attempt to mitigate any data gaps or data quality issues. An optimal solution can then be identified and executed to address the issue in order to improve future planning activities.

Opportunities for improvements are also assessed for the various decision support systems discussed in Section D3.1.2. Based on analyses performed during the development of the DSP, requirements for enhancements may be developed. These improvements could potentially be assessed for feasibility and the enhancements are implemented to the decision support systems over the course of the execution period. Possible enhancements range from how data is handled within a particular system, the user interface, or improved inputs/assumptions within a decision support system.

The results achieved through each of these enhancements allow Toronto Hydro to improve decisions in long term planning, which should lead to continuous improvement in future DSPs.

D3.2 Maintenance Planning Criteria

Toronto Hydro's asset inspection and maintenance program plays an integral role in optimizing the lifecycle of its assets. Inspection and maintenance activities allow Toronto Hydro to monitor the state of assets under operation and undertake actions to keep them operating as designed. Through inspection and maintenance, Toronto Hydro strives to maximize the use of its assets and thereby defer replacement and the associated capital investment where possible and cost-effective.

Asset inspection provides insight into the operating condition of the asset and information regarding premature degradation of assets. The data collected through Toronto Hydro's maintenance and inspection programs allows Toronto Hydro to make key decisions regarding asset renewal, and thus help shape capital investment and maintenance activities. Toronto Hydro's Asset Condition Assessment program, explained in section D3.1.2, is heavily reliant on the information collected through asset inspection and maintenance to determine the condition of the assets. The condition plays a key role in optimizing capital investments. In addition, asset inspection allows Toronto Hydro to identify any safety or environmental risks and initiate the required maintenance activities.

Asset maintenance programs are grouped into four major categories based on their functionality, as shown below:

- Preventive Maintenance
- Predictive Maintenance
- Corrective Maintenance

- Emergency Maintenance

Each of these program types is discussed in more detail in Sections D3.2.1 through to D3.2.4 respectively.

D3.2.1 Preventive Maintenance

This type of maintenance involves inspections and maintenance tasks on a fixed cycle, which emphasizes preserving asset performance over its expected life, and maintaining public and employee safety. Maintenance cycles are defined based on the mean time between failures of a given asset class, and are intended to maintain the asset before it is statistically likely to fail. An example of a preventive maintenance task is the inspection of wooden utility poles, which is carried out on a ten-year cycle. For additional information, please see Exhibit 4A, Tab 2, Schedule 1.

D3.2.2 Predictive Maintenance

This type of maintenance involves the testing and inspection of equipment for predetermined conditions that are indicative of a potential failure, and then undertaking maintenance tasks to prevent those failures. Predictive maintenance is the most effective maintenance approach for those assets that exhibit conditions that can be identified, practically monitored and corrected prior to failure. An example of a predictive maintenance task is Dissolved Gas Analysis of power transformer mineral oil; the presence of dissolved gases and other chemical compounds in the oil indicates failure modes such as overheating, excessive moisture or breakdown of the insulating paper. Corrective maintenance tasks can then be undertaken to correct the deficiencies to avoid equipment failure. For additional information, please see Exhibit 4A, Tab 2, Schedule 2.

D3.2.3 Corrective Maintenance

This type of maintenance involves repairing or replacing equipment after a deficiency has been reported during the execution of preventive or predictive maintenance tasks or other planned work. These tasks typically involve a short planning horizon since a portion of the distribution system is either faulted or isolated, or in a substandard condition thereby putting the system at risk. Since defective equipment is a major contributor to SAIFI and SAIDI, Corrective Maintenance emphasizes restoring assets to an acceptable level of operation, thereby improving system reliability. An example of a corrective maintenance task is Transformer Oil Reclamation; power transformer oil is circulated through filtering devices to eliminate moisture and sludge, the

presence of which would have been identified by the Predictive Maintenance task of Dissolved Gas Analysis.

Corrective Maintenance can also be required as a result of an unplanned system event or emergency. For example, a faulted section of underground cable that had been isolated from the system during an emergency response would be unearthed and replaced as a corrective maintenance action. For additional information, please see Exhibit 4A, Tab 2, Schedule 2.

D3.2.4 Emergency Maintenance

This type of maintenance involves the urgent repair or replacement of equipment that has failed or is in imminent danger of failure, in order to either restore or maintain power. This type of maintenance may also involve an immediate response to a safety or environmental hazard. It emphasizes safe and prompt response to restore service or prevent a service disruption. An example of Emergency Maintenance would be restoration of service to customers that have lost power due to a broken tree branch on the overhead lines. Exhibit 4A, Tab 2, Schedule 2 of the CIR evidence provides further information in this regard.

D3.3 Business Case Evaluation (BCE) Approach

Toronto Hydro uses the FIM to determine optimal intervention timing on an individual asset or the optimal timing for the replacement of a set of assets together. In addition to determining the optimal intervention timing for individual assets, FIM provides a quantification of the estimated risk based benefits of executing a program.

A BCE cannot be produced for capital investment programs which are not “dynamic” in nature (i.e., where discrete assets to be intervened upon and/or specific locations where new assets are to be installed cannot be identified, as explained in Section D3.1.1.3).

There are two types of business case evaluations based on program type that are used to estimate the benefits of a capital investment program:

- Avoided Risk Cost – Capital investment programs with like-for-like renewal of assets
- Cost of Ownership – Capital investment programs with non-in-kind intervention

D3.3.1 Avoided Risk Cost

Like-for-like renewal of assets involves replacing currently installed assets, which are beyond useful life or otherwise require replacement, with new standard equivalent assets. This type of intervention does not necessitate any changes to the configuration of feeders or the distribution system as a whole. Examples include overhead and underground renewals, in which the existing assets are replaced with new standardized assets, with no changes in the overall configuration.

In general, like-for-like renewal of assets is evaluated by estimating the "avoided risk" of performing the work in the first year of the program as opposed to delaying it to the start of the next rate cycle (in the case of this application, 2020). In order to calculate the avoided risk of performing the renewal in first year as opposed to 2020, the various costs and benefits associated with executing the work in a particular year are evaluated.

In essence, the benefit of performing the program is calculated for a set of assets that represent a year's worth of activities in the program. This evaluation is representative of the overall value of performing the work defined within the capital investment program. The avoided risk cost estimation is driven by the economic analyses of one year of individual assets as detailed in Section D3.1.2.1.

When a program analysis is undertaken, assets within the program may be before, at, or beyond their optimal replacement time. Thus, some assets will have sacrificed economic life, which occurs when an asset is replaced before its economic end of life, and others will have incurred excess risk, which occurs when an asset is replaced after its economic end of life. The cumulative sacrificed life and excess risk of the assets involved becomes a cost against the program, which is shown as the red curve in Figure 6. The benefits of the program stem from the savings achieved by performing multiple asset replacements together as opposed to replacing these assets individually. These concurrent intervention benefits include factors such as equipment rentals, transportation of crew and material, excavations, and road moratoriums. The sum of the costs and benefits is the avoided risk cost which captures both the costs and benefits of executing the project immediately rather than waiting to 2020. Note that the program cost is embedded in this analysis and thus the ARC inherently takes into account for the program cost. An example is shown in Figure 8 where the net cost is lower when the project is done in the first year rather than being deferred to 2020.

FIGURE 8: AVOIDED RISK COST AN ALYSIS FOR LIKE-FOR-LIKE PROJECTS

In Figure 8 the area shaded in blue shows the avoided risk cost for a program completed as scheduled in 2015 as opposed to deferring it to 2020. The formula for this calculation is:

Avoided Risk Cost (ARC) = [(PV(NET_COST(2020)) - (NET_COST(First Year of Activity))]

Where:

- NET_COST(First Year of Activity): Represents the estimated net costs in the first year of activities.
- PV(NET_COST(2020)): Represents the present value of the estimated net costs in 2020 for the first year of activities.

The optimal year (blue circle) is the lowest point on the Net Cost curve (blue line). In the optimal year, the Net Cost is calculated as a positive value. This means that the combination of the estimated risk costs and concurrent intervention benefits of the project is lowest in 2015. By

performing the work as scheduled in that year, Toronto Hydro increases the concurrent intervention benefits and lowers the estimated risk costs when compared to the values in 2020.

D3.3.2 Cost of Ownership

Capital investment programs involving non-in-kind interventions are evaluated under a cost of ownership (COO). Capital investment programs with non-in-kind intervention require a change in the overall configuration of the system. There are two major types of non-in-kind interventions. Programs in which existing assets are removed and new assets are installed as part of a new feeder configuration. Examples of this involve work such as the reconfiguration of circuits, the standardization of legacy designs etc. The second type involves the installation of new technology which introduces a benefit to the existing assets, in the form of reduced outage durations and reduced subsequent risks. Examples include the installation of SCADA-technology as well as Feeder Automation in which the existing assets remain intact but the impact of a failure is reduced by the introduction of new technology. The COO calculation is composed of four key factors, including Asset Risk (AR), Non-Asset Risk (NAR), Maintenance Cost (MC), and Additional Quantifiable Benefits (AQB), detailed below.

D3.3.2.1 Asset Risk

In order to establish the Asset Risk, the estimated annualized risk is plotted along with its 'Equivalent Annual Cost' (EAC), as shown in Figure 9. Note that the EAC is the minimum life cycle cost of the asset, including both capital cost as well as future risk as discussed in Section D3.1.2.1. For an existing asset, the AR does not include capital cost since this is a sunk cost that has been already incurred. As such, the asset follows its risk line until it reaches its OIT, at which point it should be replaced and thus, begins to follow the EAC line. The net present value of these costs from the current age onwards, over a 100 year period, represents the AR contribution towards the COO of an asset in a particular design. The COO is represented by the region shaded purple in Figure 9.

FIGURE 9: COST OF OWNERSHIP CALCULATION EXAMPLE FOR AN ASSET

The AR contribution for a program is the sum of all of the individual COO results of the assets within it.

D3.3.2.1 Non-Asset Risk

Non-Asset Risks (NAR) are risks incurred due to any factor that may lead to an outage that is not directly tied to the assets, including animal contact, lightning, adverse weather, and human elements.

These risks are based upon historical failures that were attributed to factors that are considered non-asset related. The information regarding the past failures is derived from 10 years' worth of historical outage data.

Information regarding the number of outages, customer interruptions (CI) and customer hours interrupted (CHI) are captured at the feeder level from this historical outage data. This information is then normalized over the total length of the feeder. This allows for the non-asset risks to be calculated on a per meter basis for a given feeder.

Using this approach, the specific non-asset risks for a particular area of study can then be calculated by multiplying the normalized value times the feeder length in the study area. Toronto Hydro is currently exploring methods to localize historical reliability information to derive more accurate projections. The connected load within the area of study, measured in kVA, is then used

to represent the amount of load that is impacted if an outage were to occur due to non-asset factors, and is subsequently used in calculating the CICs associated with these events.

The Overhead System and the Underground System experience differing outage causes because the non-asset factors that affect an overhead system are different from those that affect an underground system. The applicable non-asset risks for each type of system are used as part of a net present value calculation to produce the final quantified non-asset risks (NAR) associated with the area of study, which represent the NAR contribution to the COO.

D3.3.2.2 Maintenance Cost

Maintenance costs (MC) that are attributed to a particular design also contribute to the overall COO. Therefore, these costs are quantified for both the existing (MC_E) and the new case (MC_N). For example, when a program results in a net reduction in the amount of maintenance required for a system, such as the renewal of an asset to a new standard that requires less maintenance, this change contributes to the difference in the COO, which in turn shown as a benefit of the program.

D3.3.2.3 Additional Quantifiable Benefits

Many programs result in benefits that are not inherently captured in the AR, NAR, or MC values. These are considered to be Additional Quantifiable Benefits (AQB) for a particular program. Some examples of AQBs include operation efficiency savings and the reduction of system losses. Where used for a particular program, AQBs are clearly identified and defined as part of the Business Case Evaluation.

Introduction of AQBs is an enhancement to the business case process as it allows for a broader set of benefits to be considered in the quantified analysis, thereby allowing for a more accurate and robust analysis of the proposed program.

D3.3.2.4 Program Net Present Value and Cost of Ownership

The total cost of ownership for a program is the sum of the net present value of AR, NAR, MC, and AQB for a particular state as shown in Figure 10. The sum of the individual costs of ownership of all assets within the first year of activities of a particular program is used to derive the COO of the program under a particular design or state. The cost of ownership is then determined for both the existing state of the system and the new state that will be established by implementing the proposed program based on the assets for one-year of activities within a capital investment program.

By comparing the COO of a proposed future state based on the first year of activities against the current state for those assets, the benefits of establishing the future state are determined for the capital investment program.

The COO is calculated for each "state" of the assets, existing and proposed as detailed in Figure 10 below.

FIGURE 10: COST OF OWNERSHIP APPROACH FOR BUSINESS CASE EVALUATIONS

As shown in the final line of Figure 10, the Project NPV value equals the difference in the COO between the existing design and new design minus the project cost. If the Project NPV is a positive value, it represents the benefit of carrying out a proposed program.

In summary, where applicable, programs involving like-for-like renewal of assets have an avoided risk cost calculations whereas non-in-kind programs where a business case evaluation can be produced have a cost of ownership approach for the quantification of their respective risk benefits. The quantified business cases for programs are developed using one year worth of program work for the various programs being analyzed. Toronto Hydro utilizes the results of the business case evaluation for each program to assess the benefits of its investments.

D4 INFORMATION TECHNOLOGY ASSET MANAGEMENT METHODOLOGY

Informational technology (IT) is a critical enabler for utility operations. Toronto Hydro relies on IT assets and systems to satisfy its obligations as a distributor, deliver its capital plans and operational programs, and pursue efficiencies and innovation.

The primary objective of Toronto Hydro's IT Asset Management Process is to maximize the value of the IT assets to the utility and ratepayers. IT systems provide optimal value when they deliver expected levels of service in a sustainable manner, and mitigate risks (i.e. impact of failure, cyber security) at optimal costs. This schedule describes the IT asset management principles and IT investment planning methodology that enable Toronto Hydro to achieve this key objective.

IT Asset Management includes the purchase, operation, maintenance, renewal, replacement and disposition of the software and hardware assets. This process is defined by IT Standards, which include:

- requirements for software and hardware assets (e.g., physical, performance, compatibility, security, etc.);
- IT architecture which establishes expected service levels (e.g. performance measurement, reliability requirements, incident/problem management for the assets); and
- lifecycle management schedules for each type of asset.

IT Investment Planning is the process of making the best possible decisions regarding scope and sequencing of asset management and enhancement initiatives. This process is based on well-defined IT standards and up-to-date information about IT assets.

Toronto Hydro's IT Investment Planning Process is divided into two streams: 1) Sustaining Existing Systems, and 2) Enhancement Initiatives. The planning process includes the development of a five-year program of prioritized investments, including a detailed plan for the first year.

D4.1 IT Asset Management

Toronto Hydro developed IT Standards to streamline and optimize IT asset life cycle, define system architecture and to gain operational efficiencies through standardization of IT assets and components. IT Standards are based on information provided by equipment producers (e.g. statistics on mean time to failure), internal historical data of asset failures and industry best practices. Toronto Hydro reviews its IT Standards regularly to ensure that they remain aligned with industry best practices, and relevant for the organization.

As described in more detail below, Toronto Hydro has adopted IT Standards and architecture for both hardware and software assets. Having aligned hardware and software standards enables the implementation of the "Pooled/ Farm-based" environments. A "Pool / Farm" represents a collection of hardware resources which are required to complete desired computing operations that exceed the requirements of a single hardware machine. The implementation of pooled farm based concept provides the following benefits:

- Better management of IT assets, incidents, problems, changes, configurations, security, capacity, and availability of IT assets;
- Enhanced reliability of IT systems;
- Streamlined procurement processes and reduced operating costs;
- Operational efficiencies, such as the rationalization of IT resources;
- Simplified monitoring of the IT assets; and
- Enhanced security.

D4.1.1 IT Hardware Standards

IT Hardware Standards define the management of the physical IT components from acquisition through disposal. Common IT hardware asset management practices include need identification, procurement management, life cycle management, redeployment and disposal management. These practices are applied to the following categories of hardware assets (see Figure 1 below):

(1) Core backend infrastructure assets which are responsible for the computation, storage and communication necessary to support IT systems; and

(2) Endpoint assets which enable end-users to execute, process, complete and review business tasks and operation.

FIGURE 1: IT ASSET MANAGEMENT STRATEGY

IT Hardware Standards and architecture specify what types of hardware assets Toronto Hydro requires to ensure a highly reliable, scalable and manageable platform for business applications, and document the capacity and lifecycle of different assets.

IT hardware must be periodically refreshed to guarantee expected service levels of the systems and to minimize risk of failure impact to the business. Toronto Hydro's IT Hardware Standards seek to define optimal asset replacement timing such that hardware assets operate with the lowest acceptable failure rate at optimal costs. As illustrated in the Figure 2 below, the lifecycle of IT assets generally follows a "bath tub curve" that breaks out into three distinct regions:

FIGURE 2: IT HARDWARE ASSET LIFECYCLE FAILURE RATE OVER TIME

- Decreasing Failure Rate: This is the region of the curve associated with the reducing failure rate over time. This is typical of new IT hardware. The vendor quickly releases service packs, patches and bug fixes that reduce the IT hardware failure rate.
- Constant Failure Rate: As the failure rate decreases it comes to a stage when it stabilizes and it is almost constant. The cost of ownership in this area of the bathtub curve is steady and the considered financially optimal.
- Increasing Failure Rate: As the IT hardware ages beyond useful life, the failure rate starts to increase again. This is attributed to the general operational wear and tear of the asset as well as vendor focus on development of new products, in essence, lack of investment in obsolete products. The system failures and associated maintenance costs start to rise steeply in this portion of the bathtub curve.

Based on the criticality of the infrastructure, industry best practice and vendor specifications, standards define the optimal time to refresh assets before reaching "Increasing Failure Rate" part of lifecycle. This approach minimizes the risk of interruptions to the core processes and technology that the company relies on to execute its capital plans and operational programs in a safe, effective and efficient manner.

D.4.1.2 IT Software Standards

IT Software Standards classify software applications in two categories – Tier 1 and Tier 2 – based on the consideration of the operational criticality of the application, level of complexity, integration with other applications, maintenance costs and number of users.

- Tier 1 applications enable Toronto Hydro's business operations and support company-wide business processes. They are functionally integrated with other applications, and are supported by complex underlying infrastructure such as databases, middleware, storage and network. As a result, Tier 1 applications generally have higher maintenance costs and a large user base. In a disaster scenario, the recovery point objective is less than 4 hours. Examples of Tier 1 applications include the Enterprise Resource Planning System, Inventory Management System and Geo Informational System.
- Tier 2 applications enable specific divisional and departmental processes. These applications have little to no integration with other enterprise applications, and are typically supported by simple infrastructure. In a disaster scenario, the recovery point objective is less than 24 hours. Tier 2 applications generally have lower maintenance costs, and cater to a smaller user base than Tier 1 applications. An example of a Tier 2 application is Hydropedia, a knowledge base system that helps customer service representatives to quickly and accurately address customer questions about Toronto Hydro processes during a phone call.

Regular software upgrades reduce the risk of system failures and cyber security breaches, and align software assets with vendor support cycles. Similar to IT hardware assets, if an application is not upgraded before the vendor support cycle expires, Toronto Hydro may have to procure specialized technical resources to maintain and support the application.

IT Software Standards also seek to maintain the compatibility of software applications and the underlying components (e.g. servers and operating systems) to ensure uninterrupted IT system operations and deliver the desired end user experience and functionality. Because the IT systems and their underlying components are often on different end-of-life and vendor support cycles, maintaining compatibility can be a complex task. Nonetheless, it is a key consideration in mitigating security and failure risks to IT systems from the underlying components.

IT Software Standards take into account average vendor release cycles, as well as the need to minimize incompatibility risks with underlying components. Software asset upgrades could be triggered if the asset reaches its maximum age or number of versions behind latest vendor-released version, or based on compatibility drivers and considerations (e.g. hardware upgrades).

D.4.2 IT Investment Planning

IT Investment planning is the process of developing a five-year program of prioritized investments, including a detailed plan for the first year. Toronto Hydro's IT Investment Planning Process is divided into two streams: Sustaining Existing Systems, and Enhancement Initiatives.

The primary objective of Toronto Hydro's IT investment planning process is to maintain the IT assets that are required to satisfy optimal IT system reliability and availability. This sustainment stream is intended to provide satisfactory levels of service for customers and the utility, and to mitigate IT-related business and operational risks (e.g. non-compliance and failure impact) in a cost efficient manner.

Enhancement initiatives enable Toronto Hydro to leverage technological solutions to optimize or enhance business operations in order to ultimately deliver greater value to customers, and to maximize compliance with new or modified external requirements from entities such as Measurement Canada, the Ontario Energy Board, and the Independent Electricity System Operator.

D.4.2.1 Sustaining Existing Systems

The scope and timing of IT sustainment investments is based on IT Standards and asset specific information that Toronto Hydro stores in its electronic IT assets inventory system. The utility relies on this information to make investment decisions based on structured and up-to-date IT asset information, including: hierarchy of assets and interdependencies; key dates in each asset's lifecycle; vendor, contract and license information; and capacity planning data.

Failure impact or rather IT system criticality is the main consideration that Toronto Hydro takes into account in determining the priority of the investments. Priorities are also influenced by internal program dependencies, asset type complexity, and resource balancing.

In making IT investment planning decisions, Toronto Hydro may also consider additional factors relating to general business growth and associated increased IT requirements, such as process

re-engineering, historic trends of current assets capacity versus utilization by existing information technology systems.

D.4.2.2 Enhancement Initiatives

Further to its commitment to continuous improvement, Toronto Hydro regularly evaluates and considers opportunities to enhance business processes based on new IT solutions.

Prior to investing in new IT systems, Toronto Hydro follows an evaluation process to help ensure that the utility makes well-informed decisions relating to new IT investments. That process includes the following steps:

1. Evaluate: The utility validates the proposed initiative, and works with the relevant business unit(s) to determine the project scope, business requirements, current state business processes, future state business processes, the options to achieve the future state and the preferred approach, costs and benefits.
2. Align: Toronto Hydro reviews the proposed project to help ensure the following:
    - Governance, due-diligence, rationale and accuracy of the project costs and benefits
    - Strategic alignment with Toronto Hydro's objectives (e.g. value for money)
    - Alignment with Toronto Hydro's risk profile (e.g. cyber security)
3. Prioritize: Toronto Hydro prioritizes the project based on a combination of factors, including project dependencies, costs, benefits, strategic alignment and risk assessment.
4. Execute: Project execution typically consists of the following steps:
    - Gathering more detailed user and technical requirements;
    - Mapping the relevant business processes;
    - Developing and/or procuring the application as needed;
    - Provisioning the infrastructure to host the application;
    - Configuring the application(s) to meet the business requirements;
    - Testing the application for compatibility with Toronto Hydro's infrastructure;
    - Engaging users to test that the application meets their business and functional requirements;
    - Training the users about the features and functionality of the application; and
    - Implementing the application across the appropriate utility departments

D.4.3 Five-Year IT Investment Plan

The output of Toronto Hydro's IT Investment Planning process is a five-year IT Investment Plan that, 1) is expected to deliver optimal levels of IT system reliability and availability, 2) complies with the utility's IT Standards and asset management practices, and 3) mitigates risks related to IT assets in a cost efficient manner.

Toronto Hydro's five-year IT Investment Plan for 2015-2019 period includes the following capital investment programs:

TABLE 1: IT INVESTMENT PLAN SUMMARY

Capital Investment Program	Execution Time Frame	Evidence Reference
IT Hardware Refresh Program	2015-2019	Exhibit 2B, E8.04
IT Software Program	2015-2019	Exhibit 2B, E8.05
Enterprise Resource Planning (ERP) Program	2015-2016	Exhibit 2B, E8.06
Voice Radio System Upgrade Program	2015-2016	Exhibit 2B, E8.07

In developing this plan, Toronto Hydro has also considered IT industry best practices, vendors' information, distribution capital program growth and overall business growth as well as historic trends of evolving regulatory requirements. Based on the overall schedule and cost estimates contained in the Five-year IT Investment Plan, the utility develops a detailed plan for the next year (i.e., 2015), which lists, prioritizes, and tracks all the key investment initiatives while in execution.

Toronto Hydro requires flexibility over the five year period to execute its IT capital investment plan. This includes flexibility to manage externally-driven risks, such as the risk that vendors may increase software/ hardware costs over the 2016 to 2019 period or change the release dates for certain applications. Both of these events could affect the cost, timing and pacing of a program in a given year.

In addition, Toronto Hydro requires flexibility because it cannot predict the timing of changes to regulatory requirements from regulatory bodies such as the OEB, Measurement Canada and the IESO. For example, the OEB recently initiated a Policy Review of Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance (EB-2014-0198) which could result in a number of significant changes (e.g. the implementation monthly-billing) to the customer billing system.

Furthermore, the technology landscape evolves at a fast pace with new products frequently entering the market. If new technologies that are relevant to Toronto Hydro become available in the 2015 to 2019 period, Toronto Hydro plans to evaluate these new technologies. The five-year Investment Plan could be affected if Toronto Hydro determines that any of these technologies would be beneficial to its operations or would maximize the value of its IT assets.

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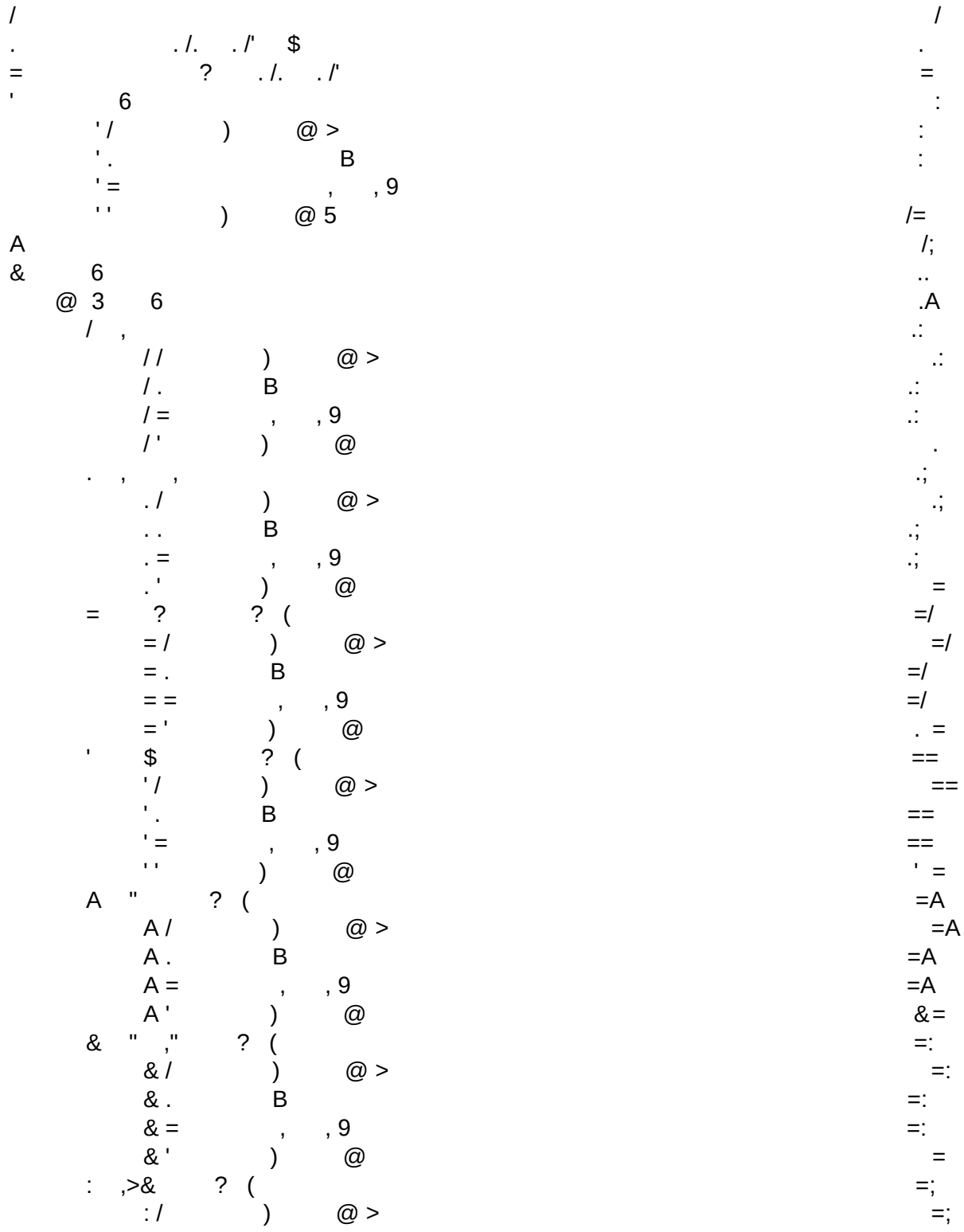
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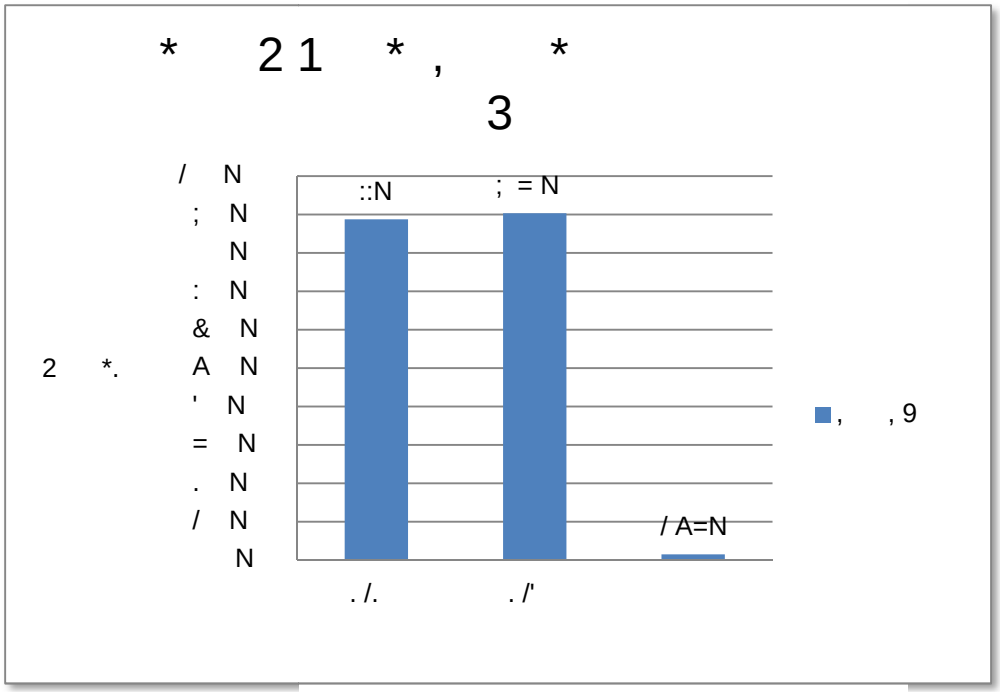
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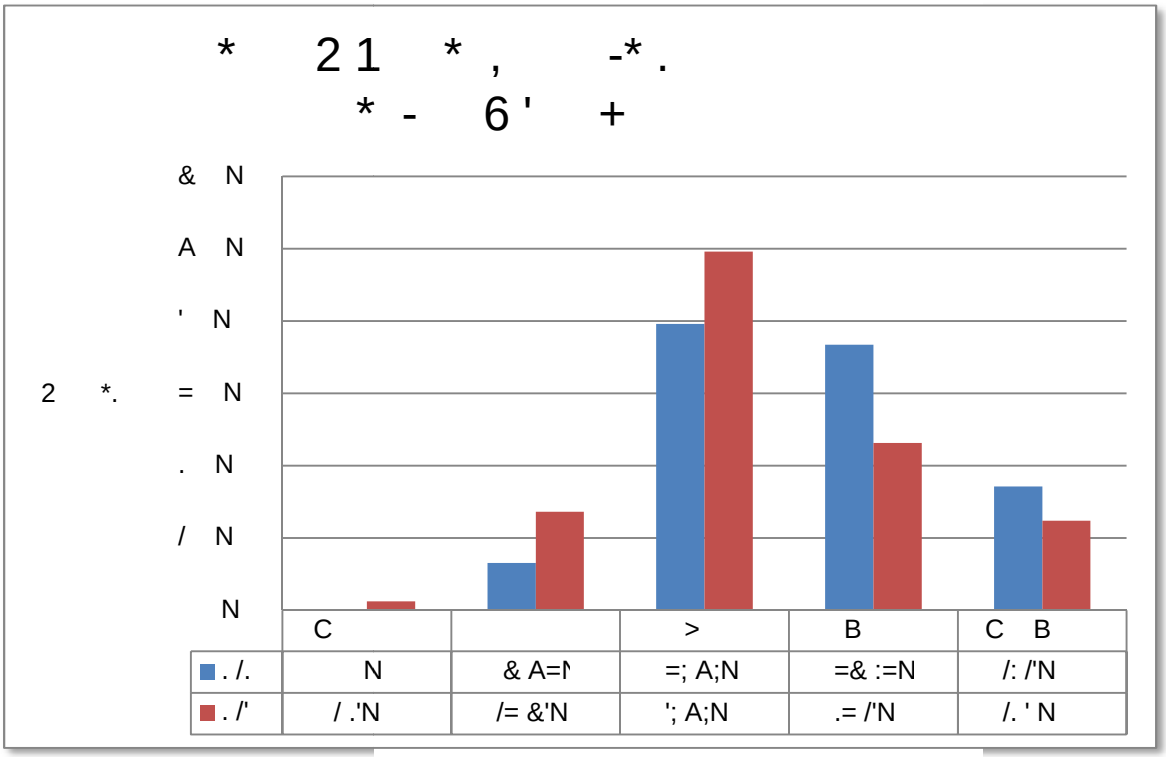
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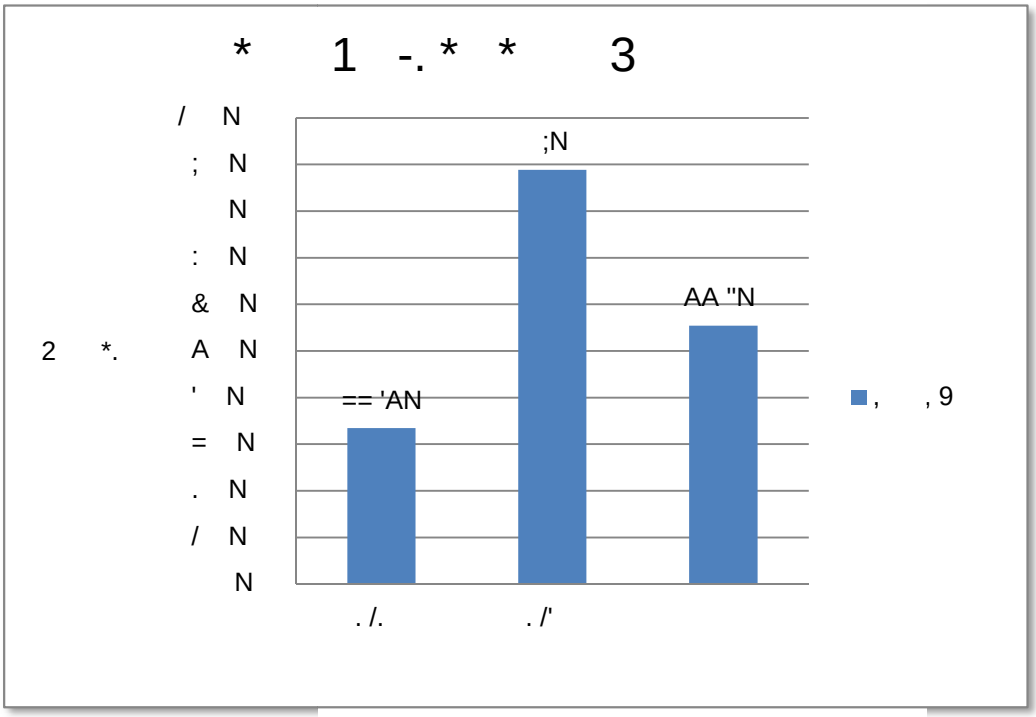
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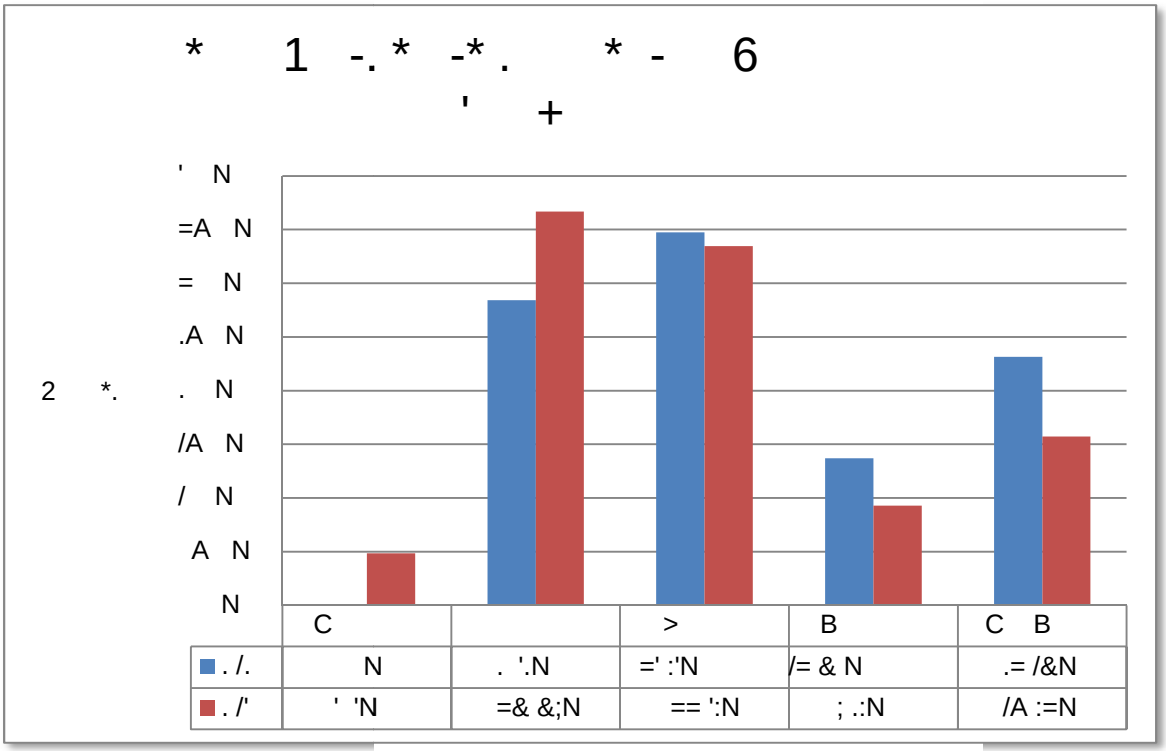
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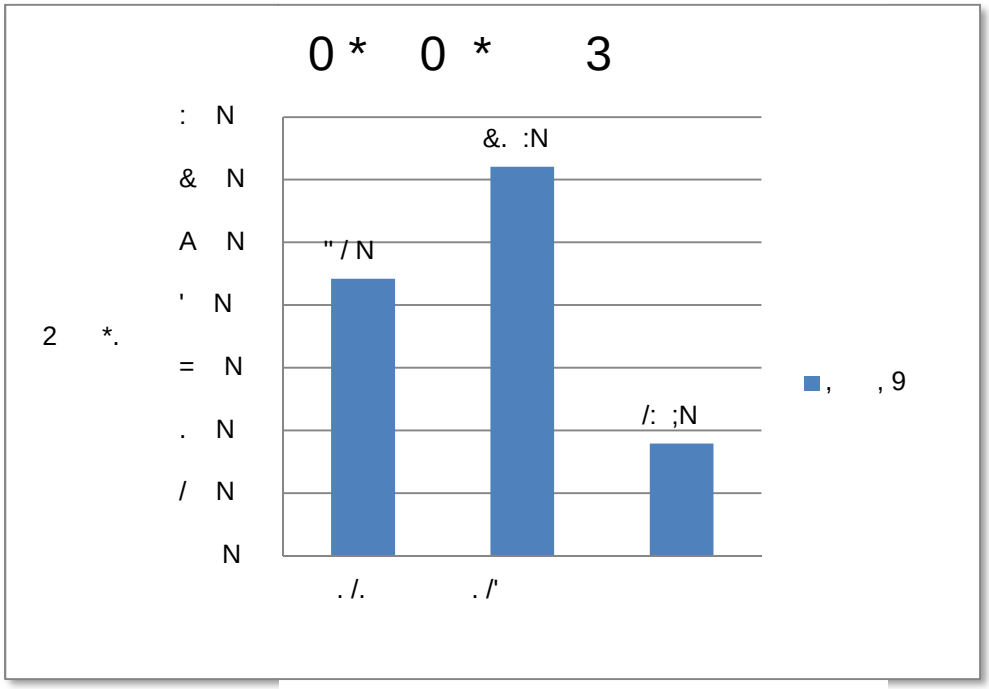
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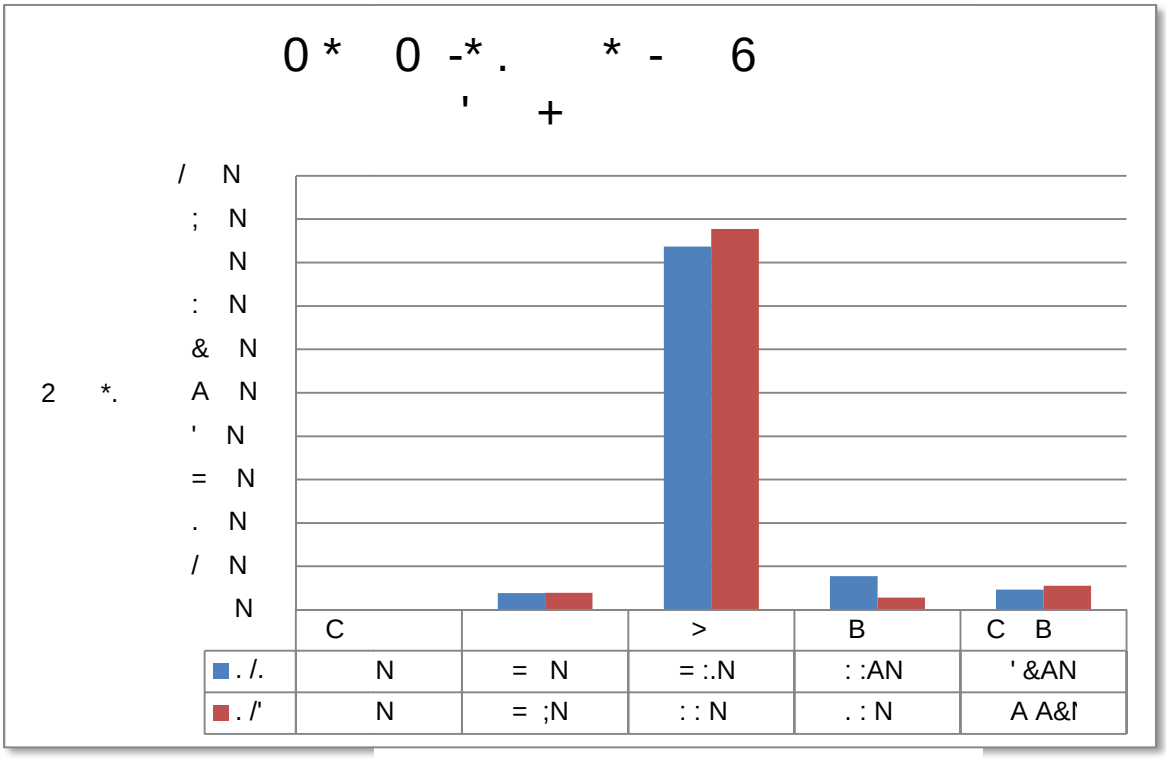
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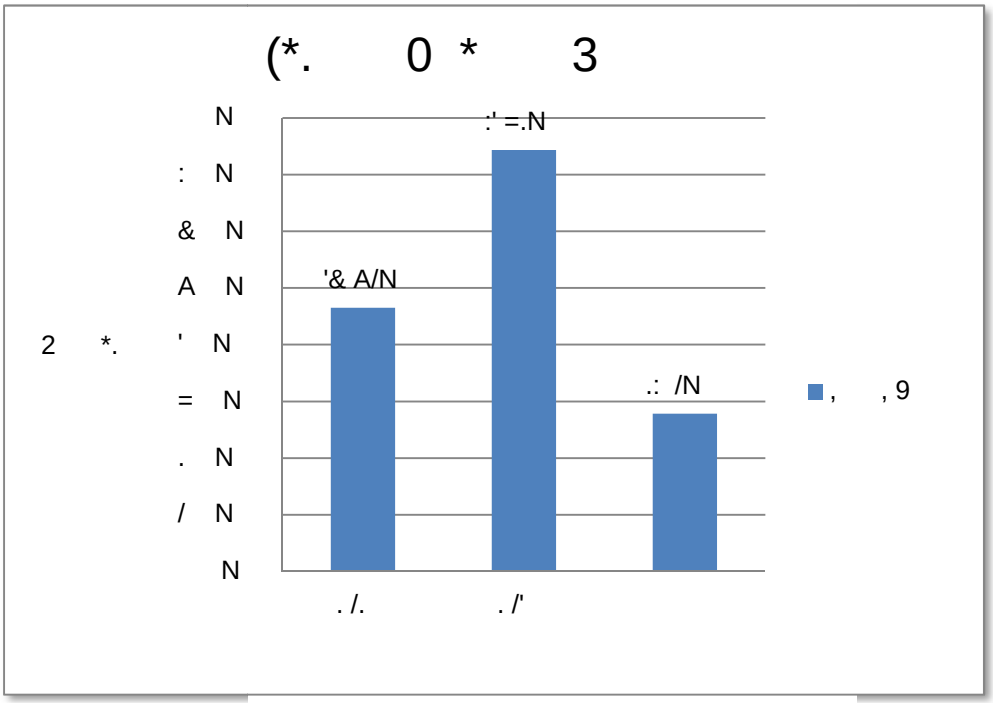
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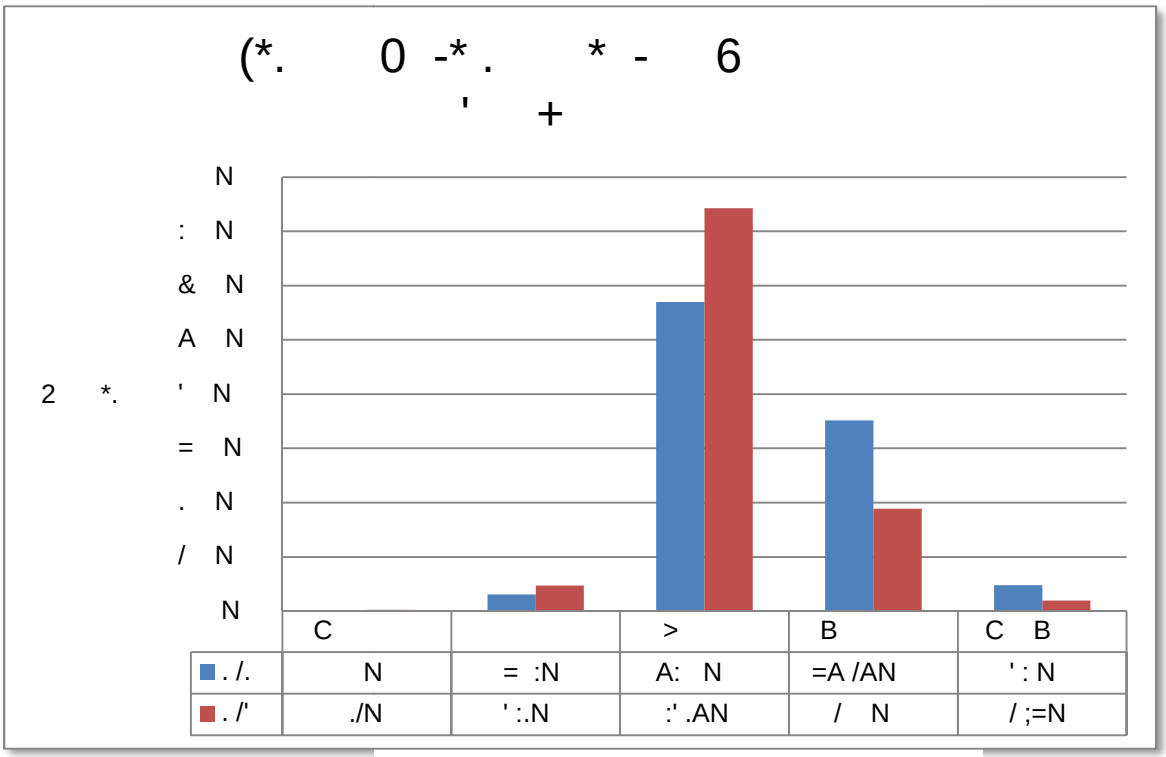
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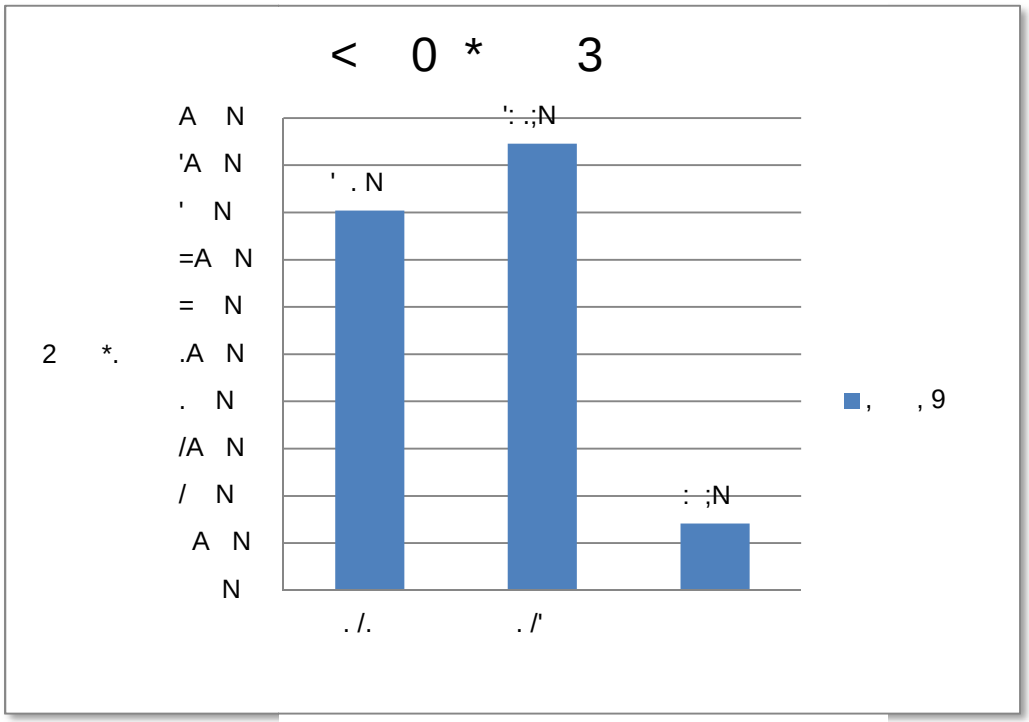
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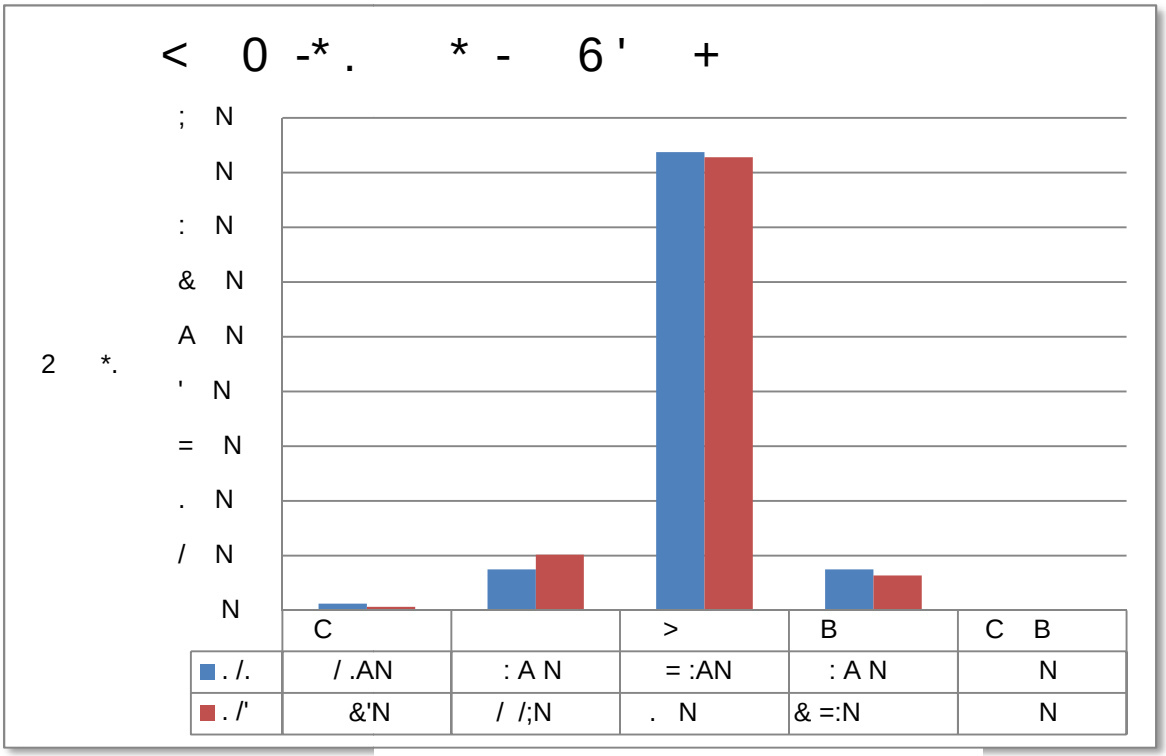
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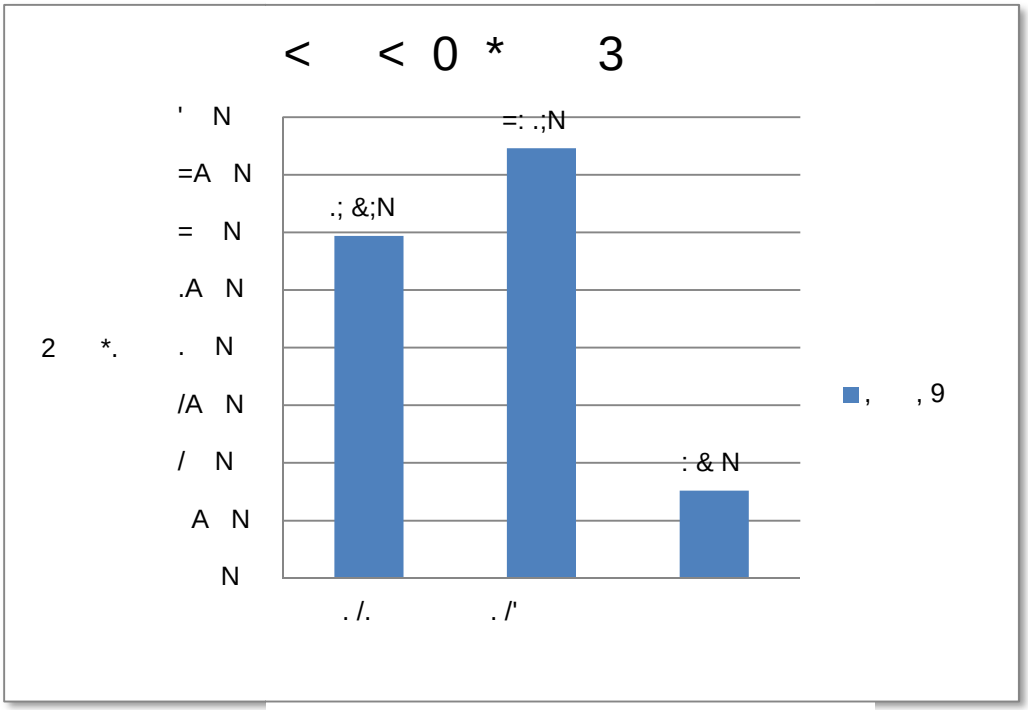
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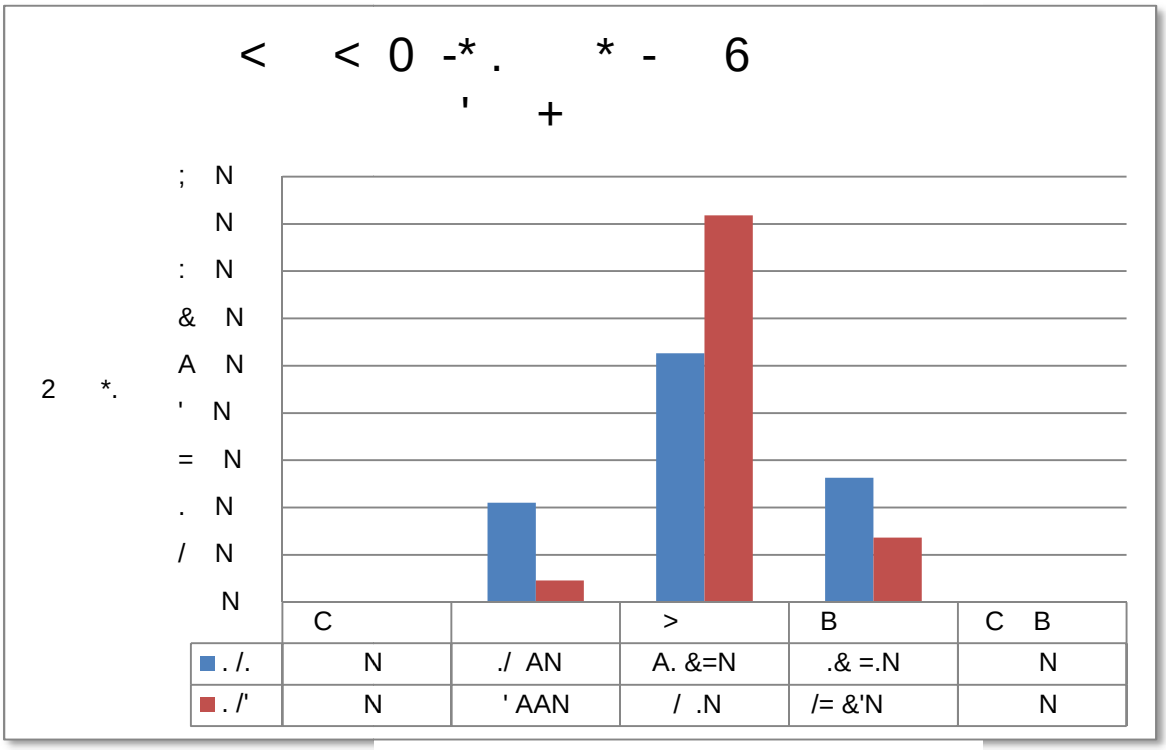
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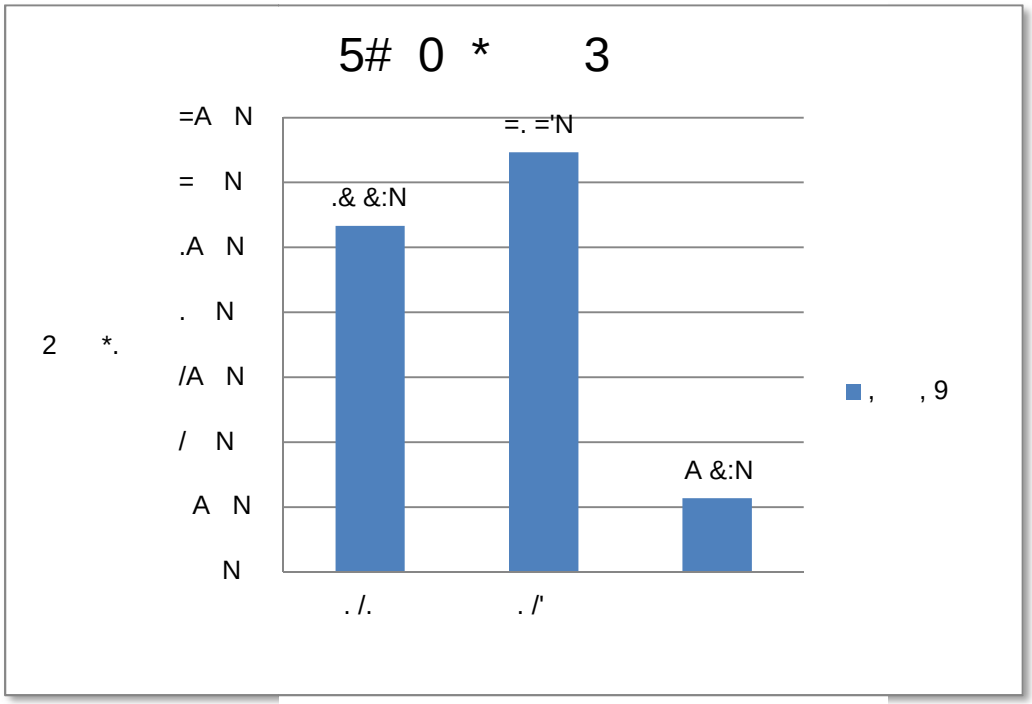
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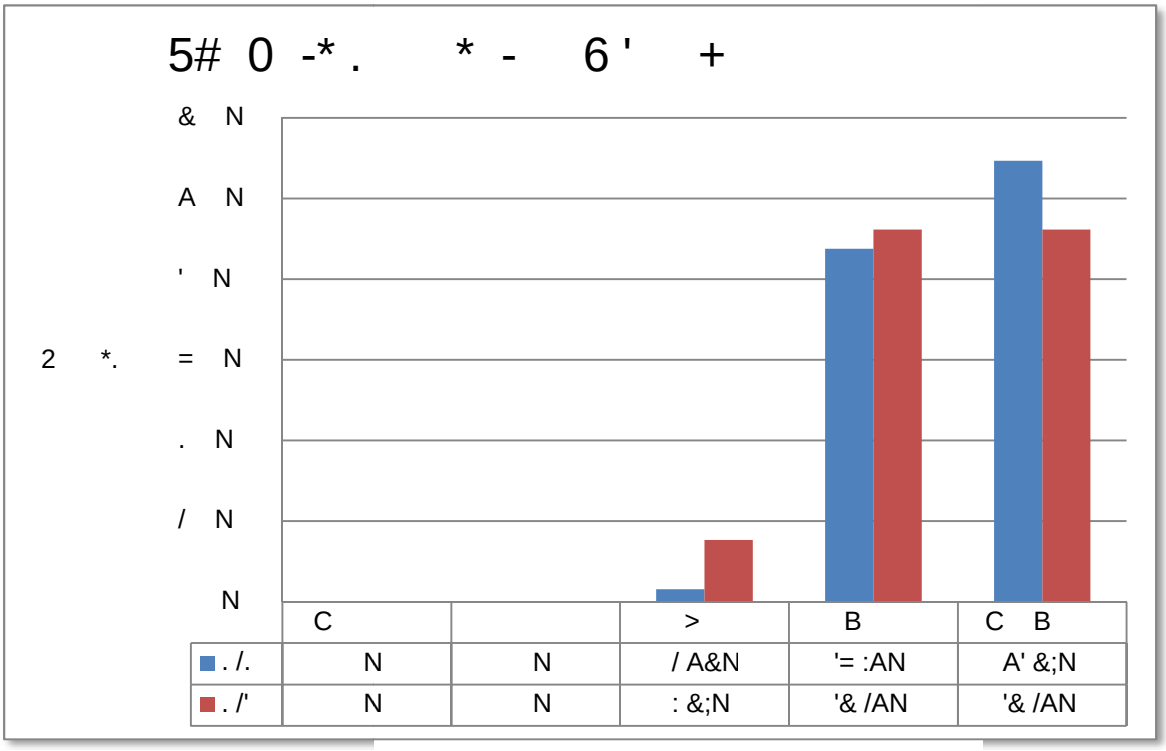
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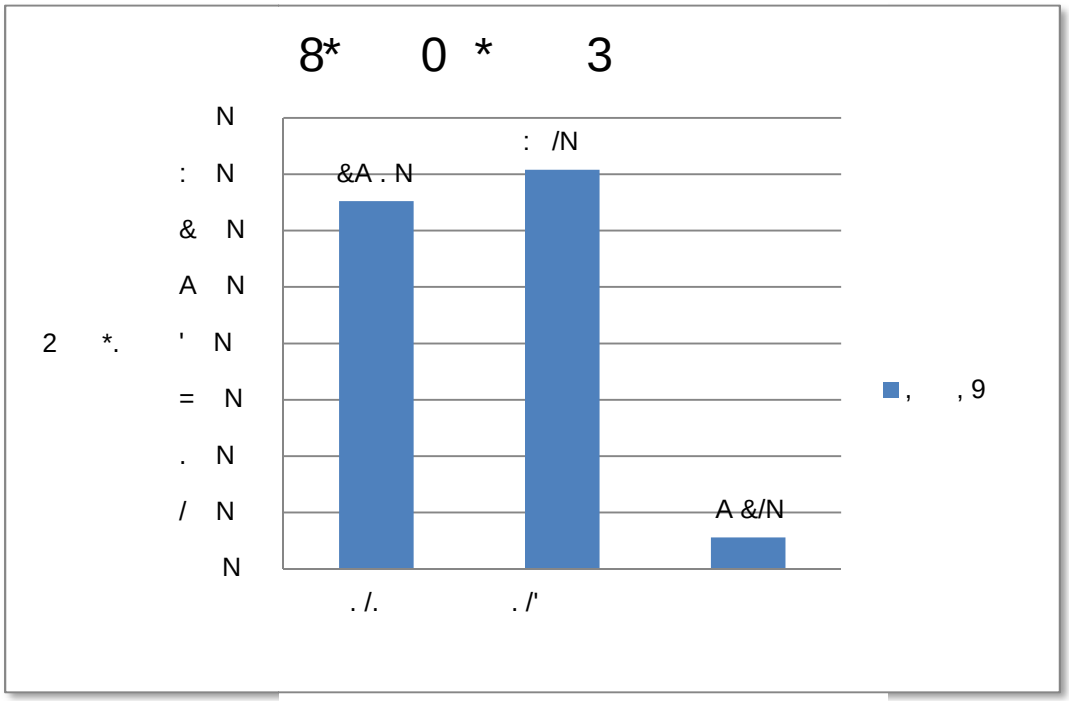
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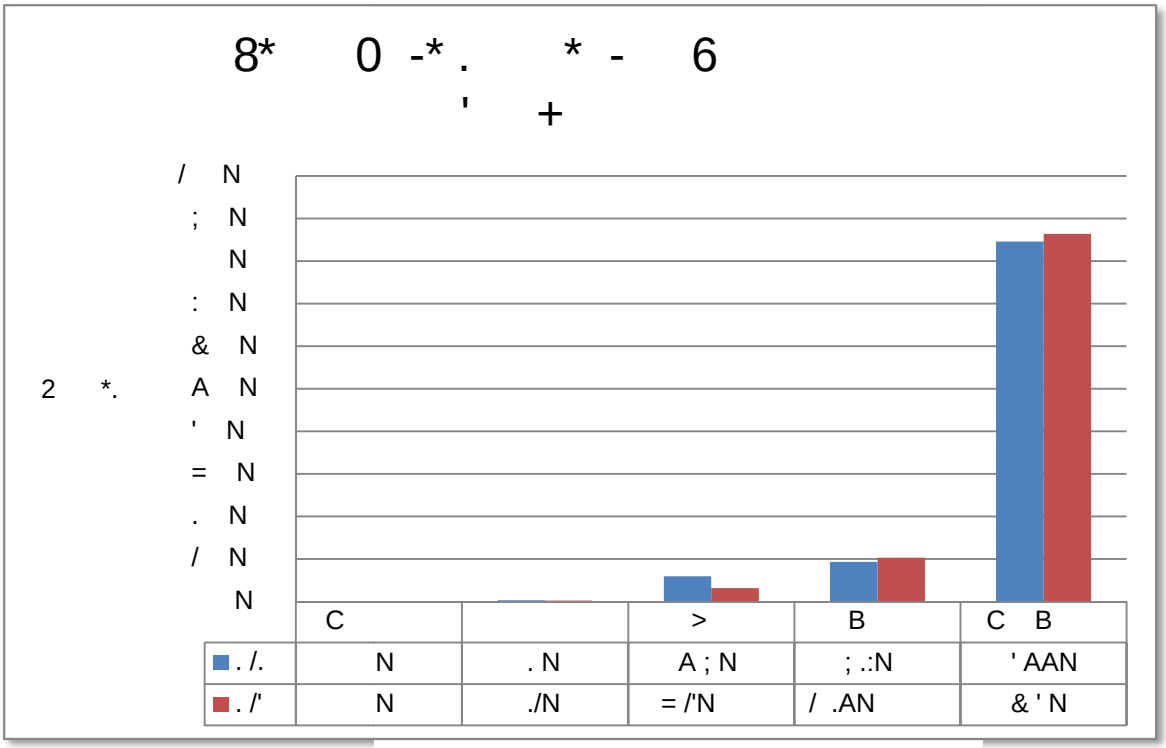


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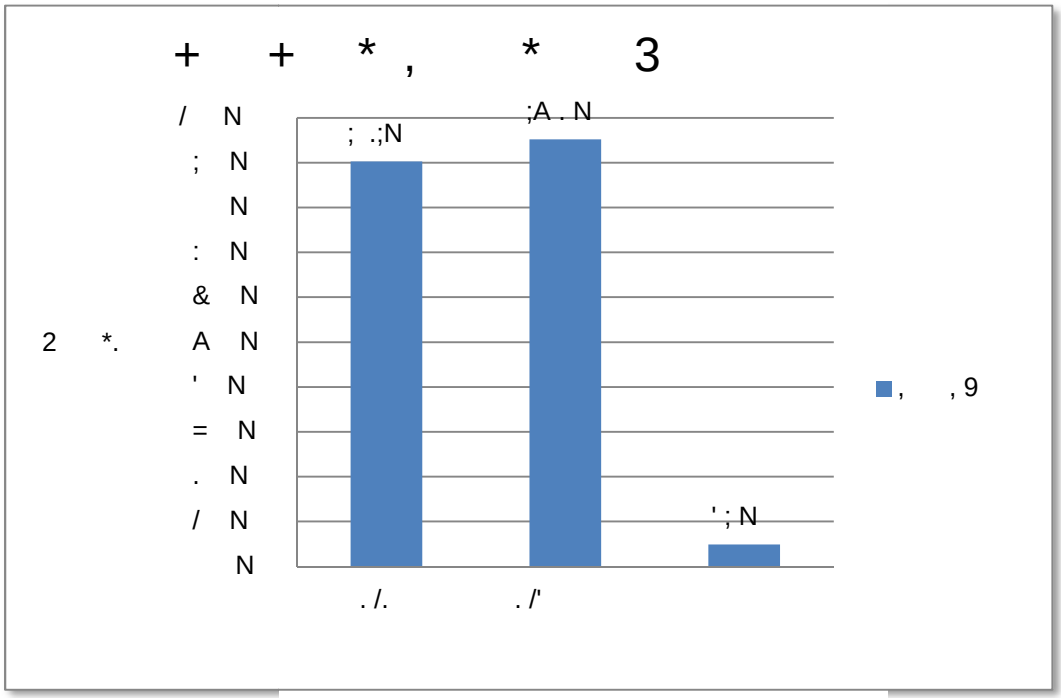
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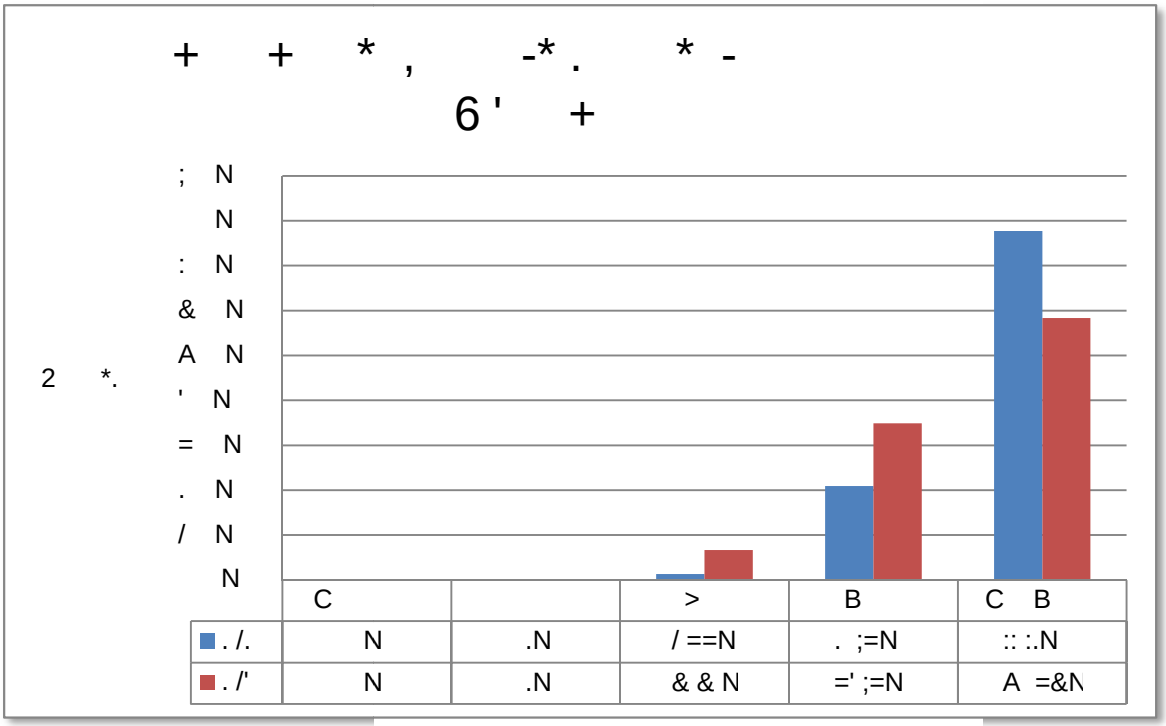
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	N	.N	& & N	=' ;=N	A =&Λ
-* .	N	N	A =&N	/' N	*/; =AN



5 . $ * - 6 ' + *

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/ 2 * +

C

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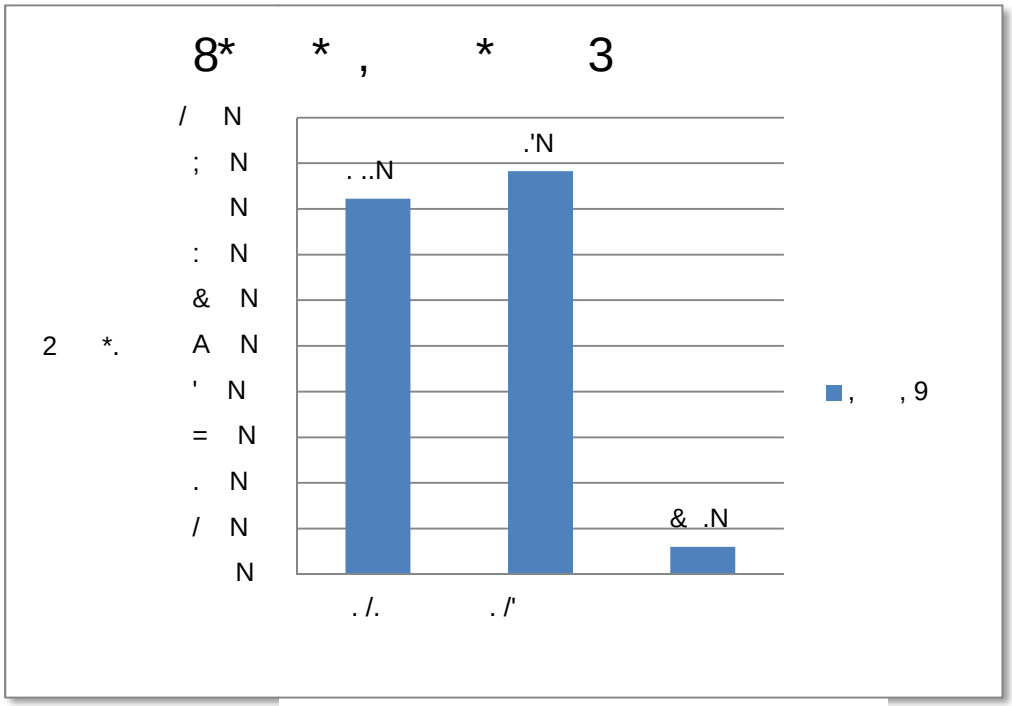
) @

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*+ * 3 *

7 *	* 3		
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-* .	*/ :=N	& .N	*& .N



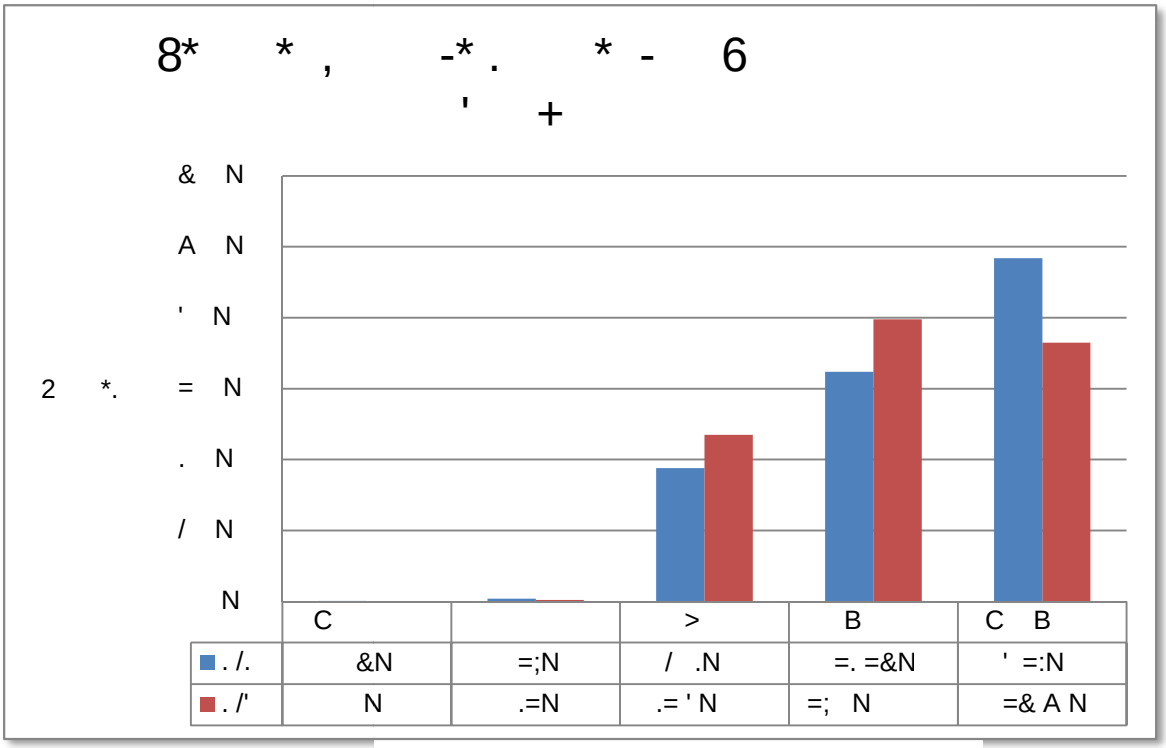
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3 +

. /. . /') @ C
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*+ * - 6 ' + *

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	&N	=;N	/ .N	=. =&N	' =:N
	N	.=N	.= ' N	=; N	=& A N
-* .	* &N	* /:N	' &&N	: ''N	*/ :N



5 . * - 6 ' + *

// # * +

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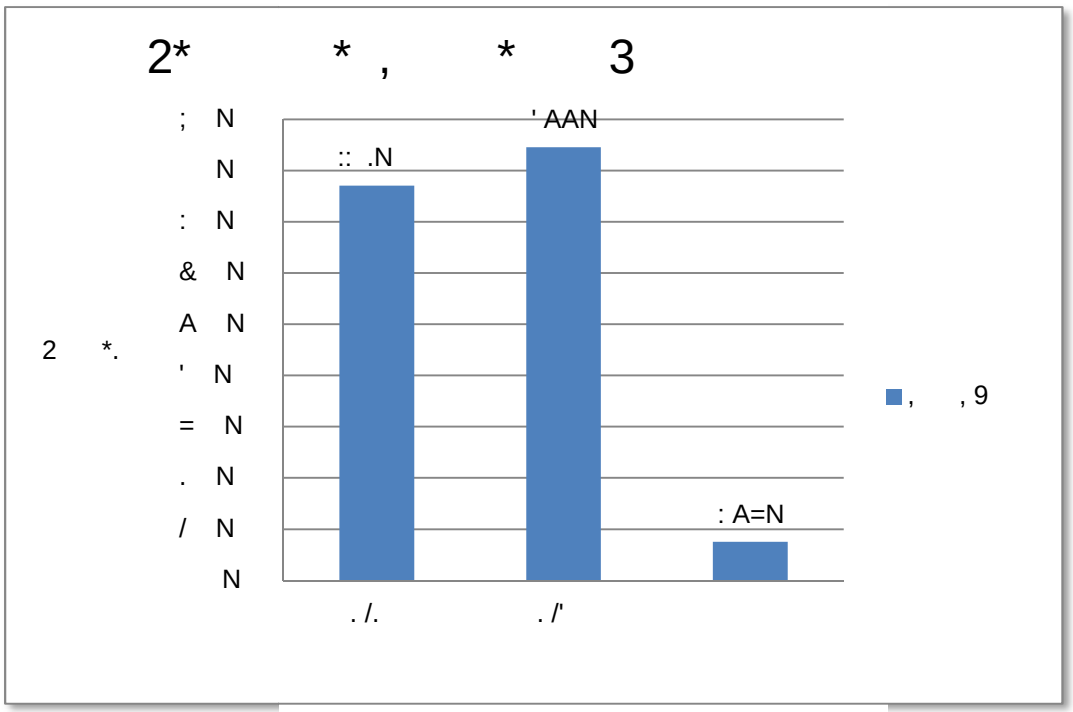
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3 " !

3 % $ % &
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> // */

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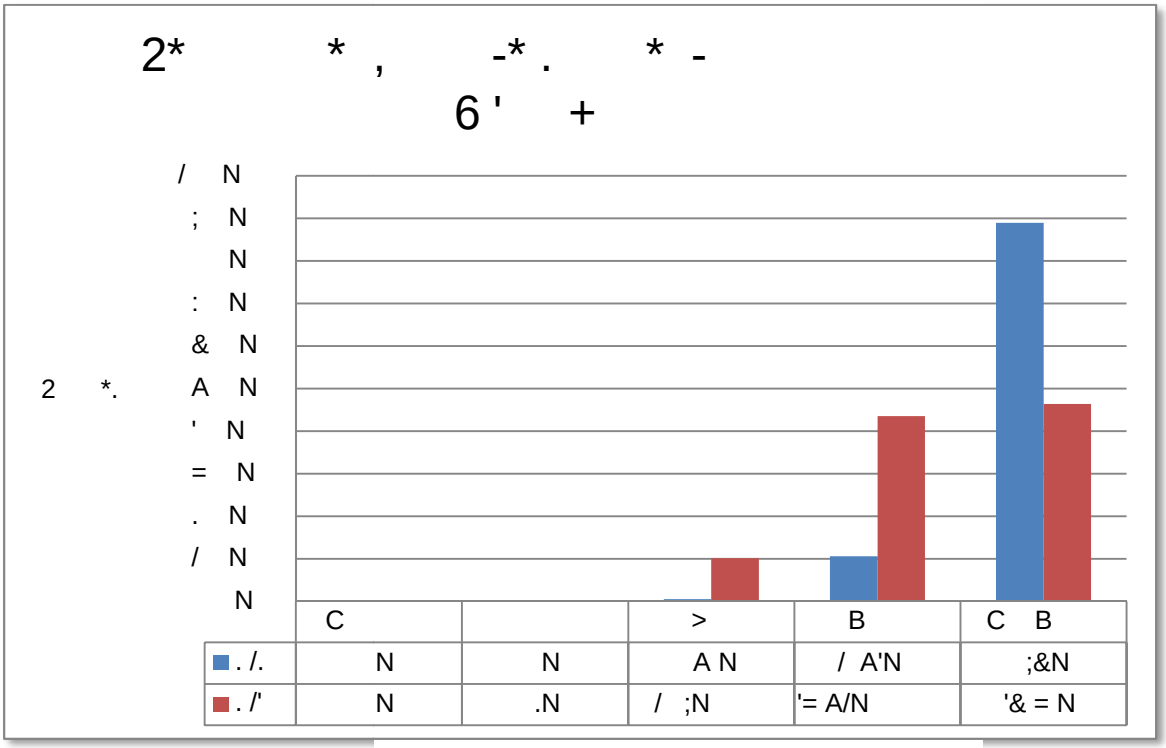
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. /. . /') @
//*. > //*.

*+ * - 6 ' + *

7 *	' +				
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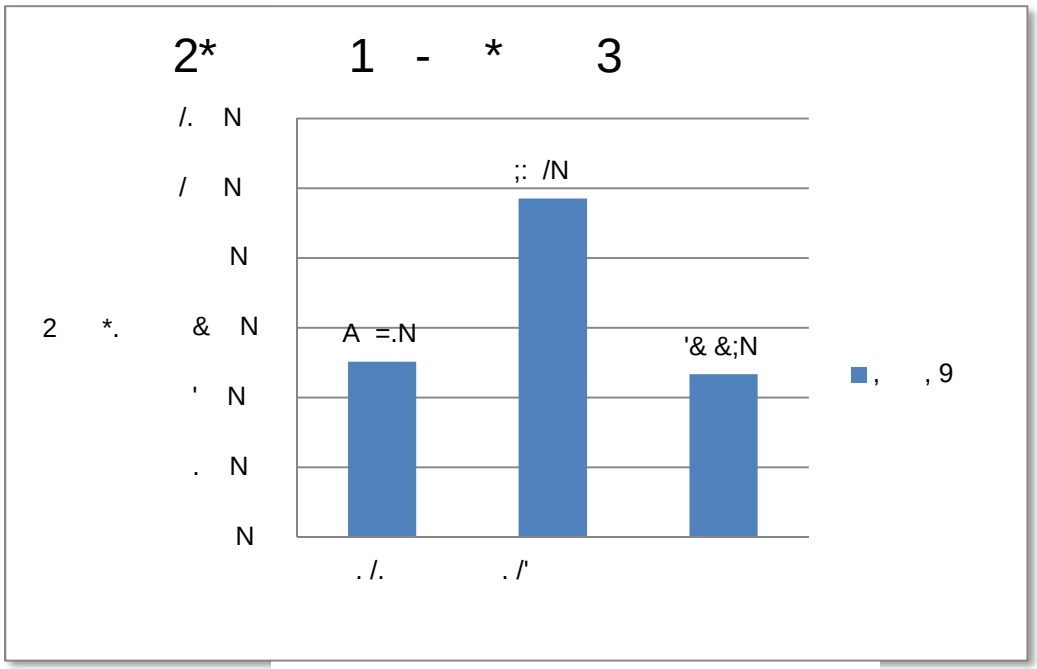
3 " !

3 % $ % &

, , 9 ,
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> /.*/

*+ * 3 *

7 *	* 3		
	2 *	* 3	'' '* *,
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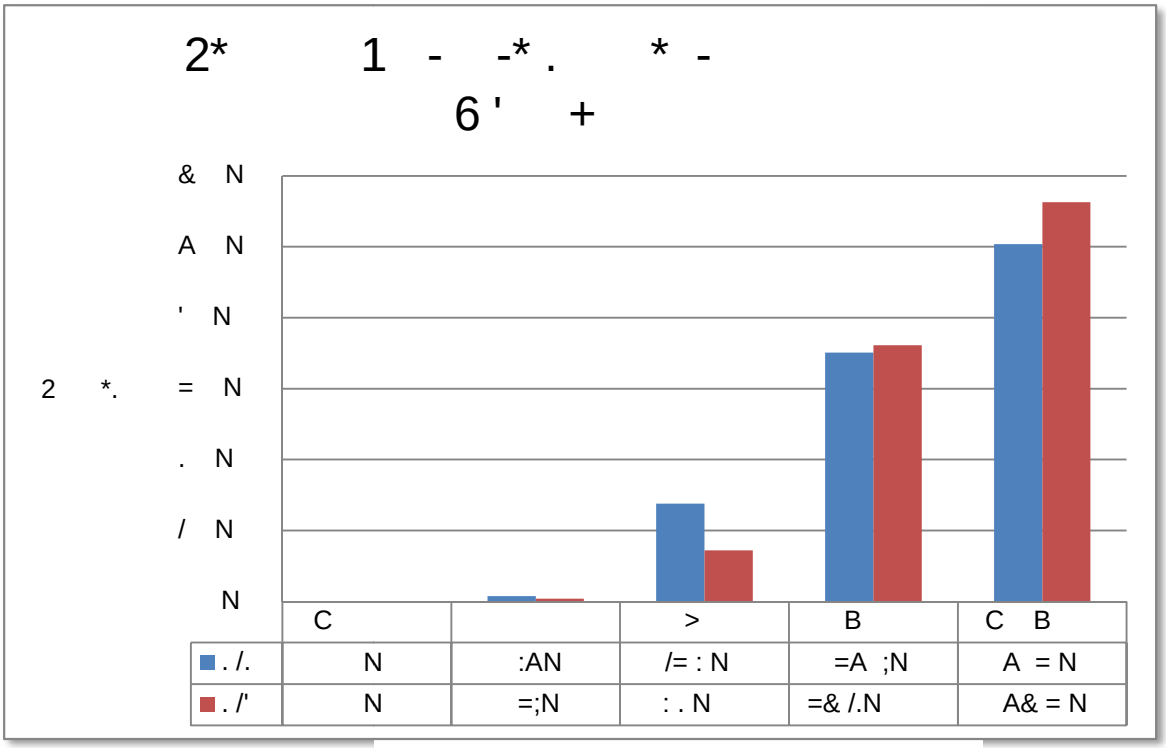
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*+ * - 6 ' + *

7 *	' +				
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	N	:AN	/= : N	=A ;N	A = N
	N	=;N	: . N	=& /.N	A& = N
-* .	N	* =:N	*& A;N	/ =N	A ;.N



5 . * - 6 ' + *

/= * # ./ " 84 9 %)

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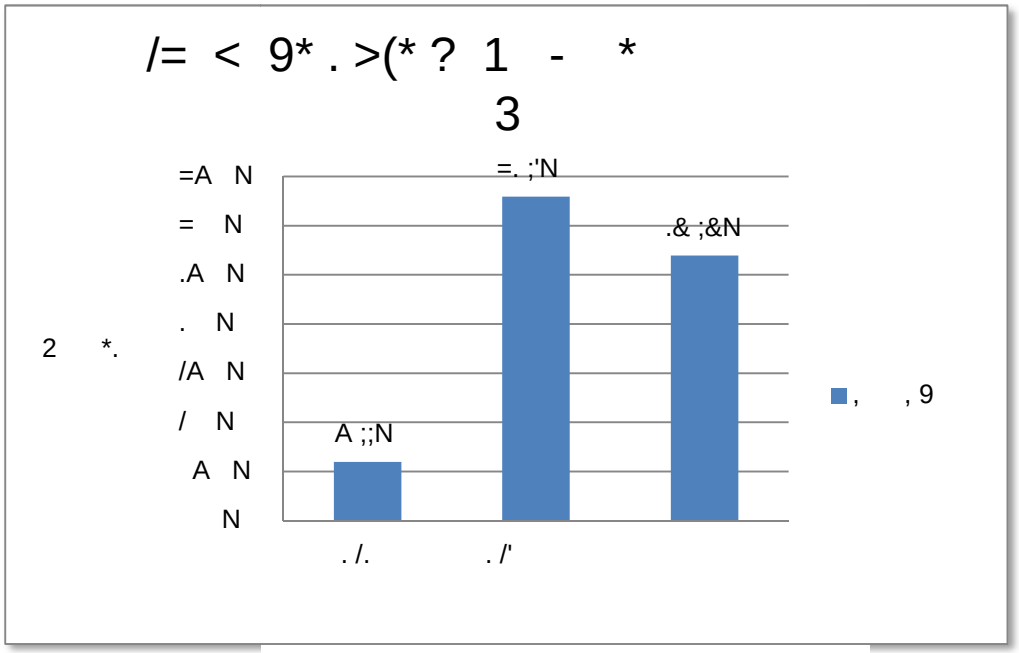
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*+ / * 3 *

7 *	* 3		
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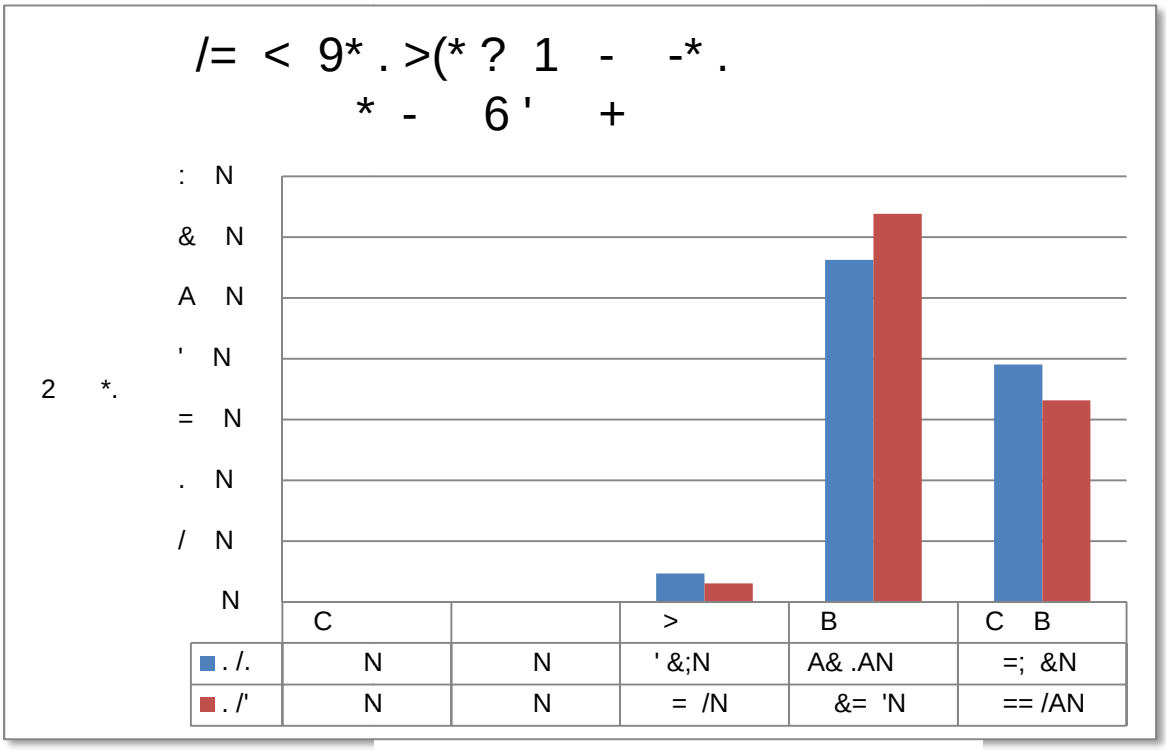
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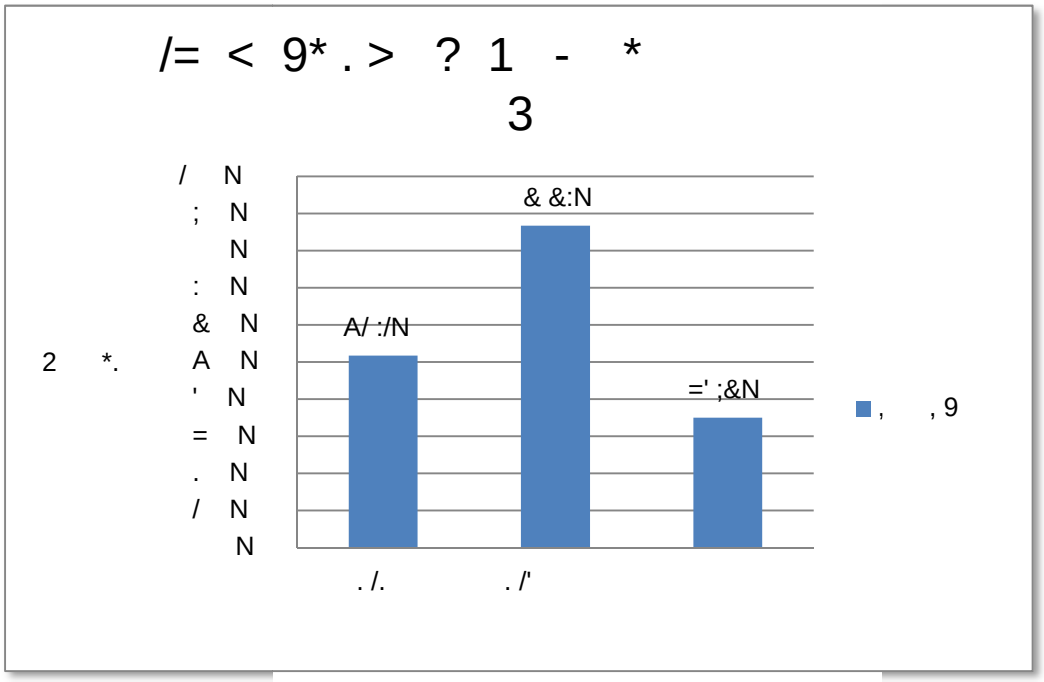
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D6 E , /'*/ J, , 9 K J 5) K

> /'*/

*+ * 3 *

7 *	* 3		
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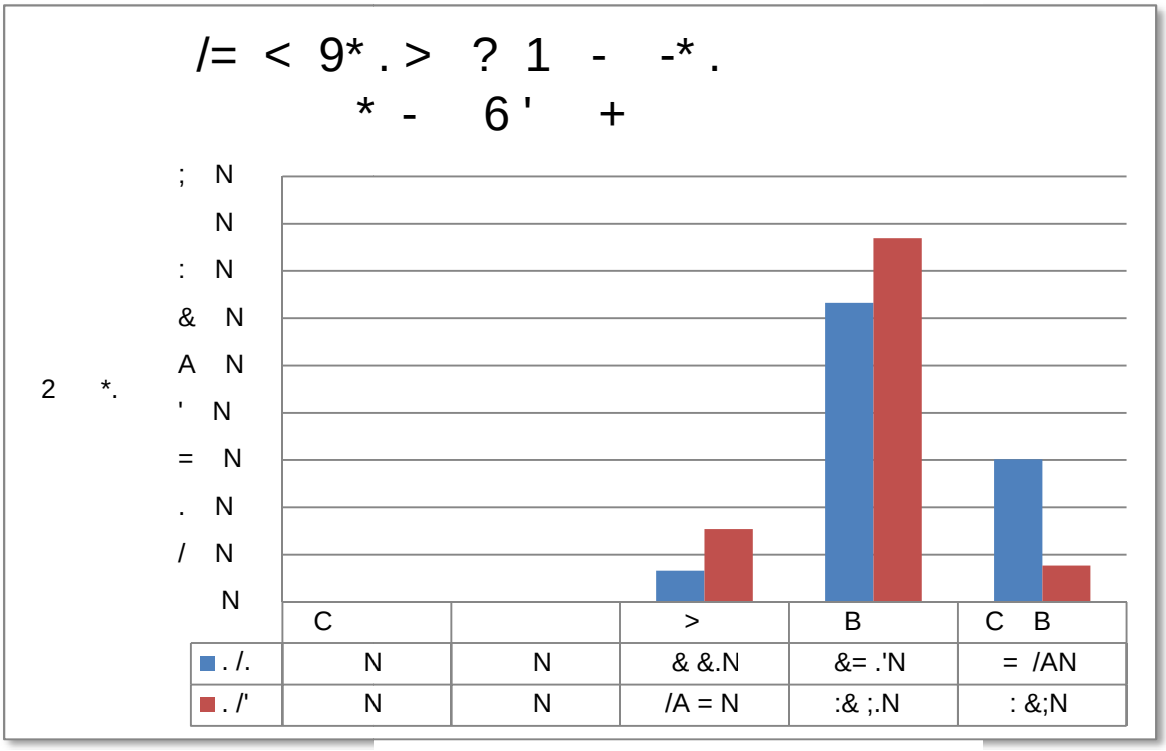
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D6 E , /'*. > /'*.

*+ * - 6 ' + *

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	N	N	/A = N	:& ;.N	: &;N
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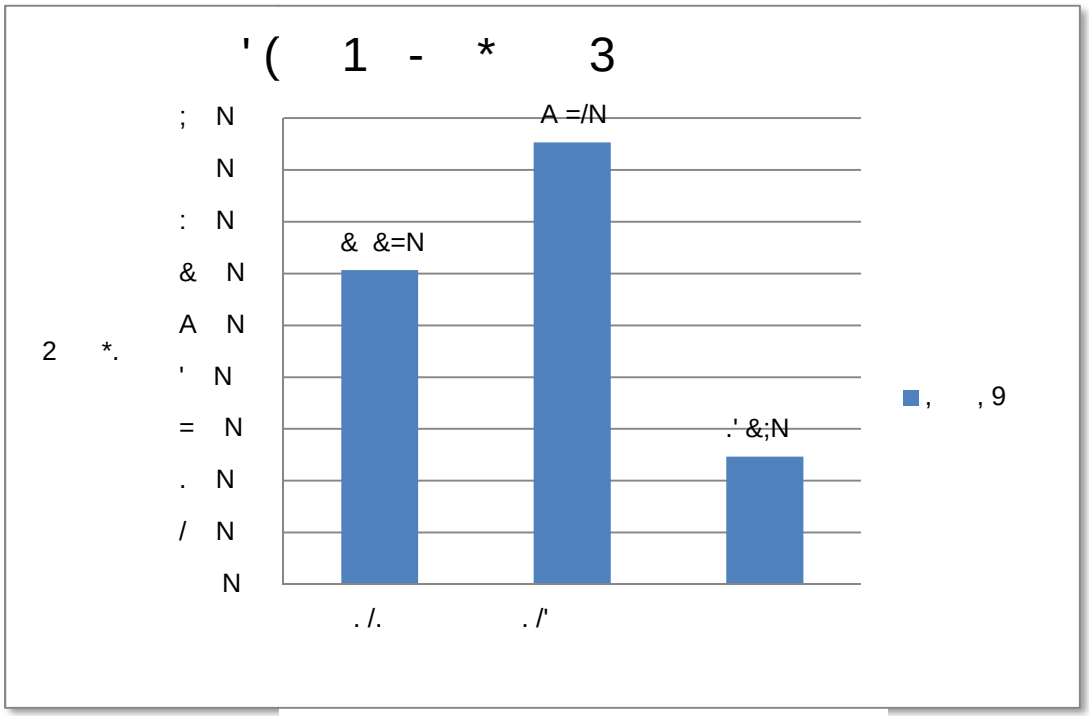
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/A*/ J, , 9 K J 5) K

> /A*/

*+ : * 3 *

7 *	* 3		
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	$ #	A =/N	/' &;N
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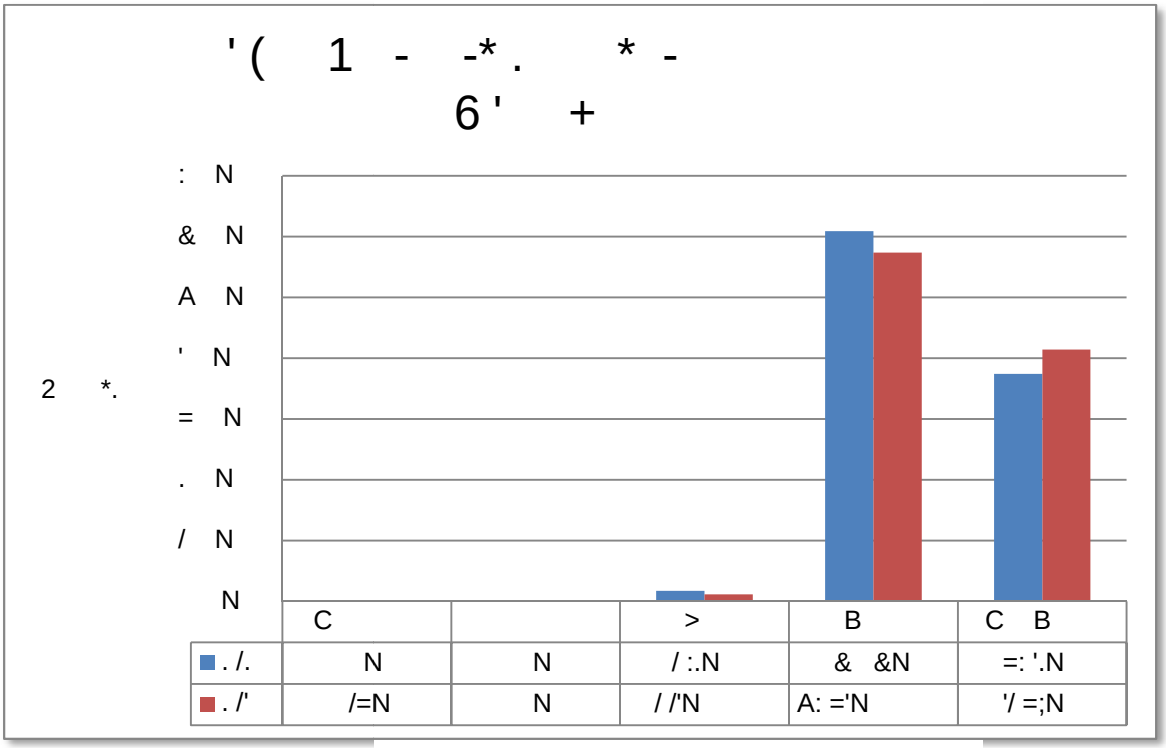
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*+ : * - 6 ' + *

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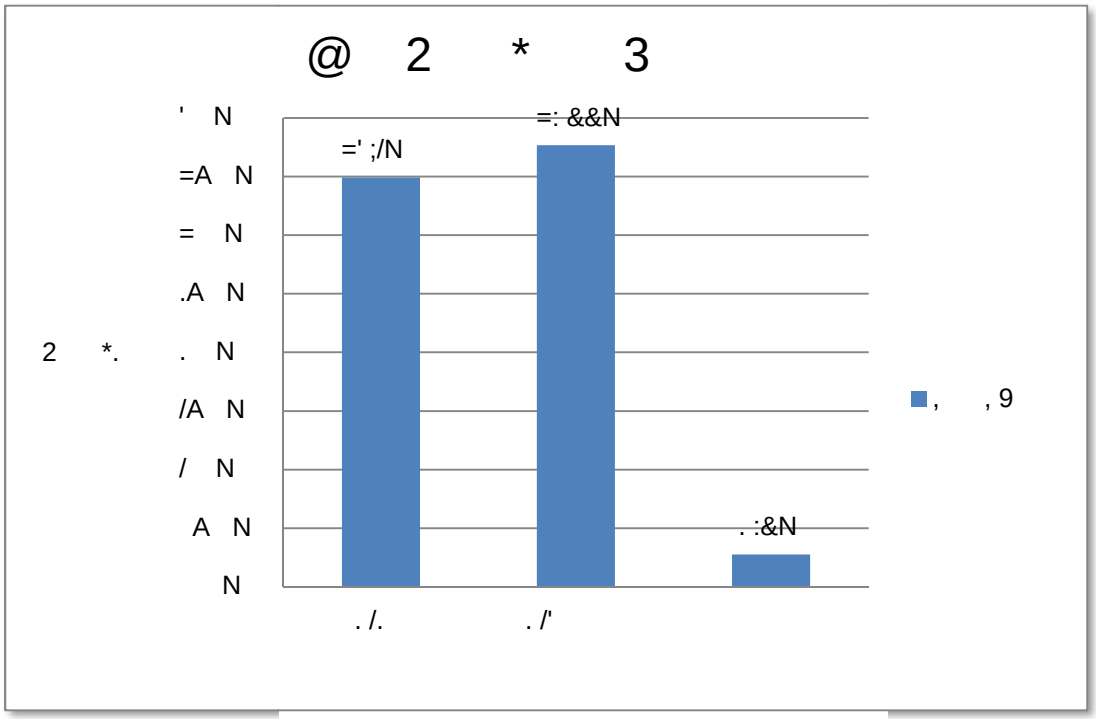
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-* .	*/ "N	. :&N	*. :&N



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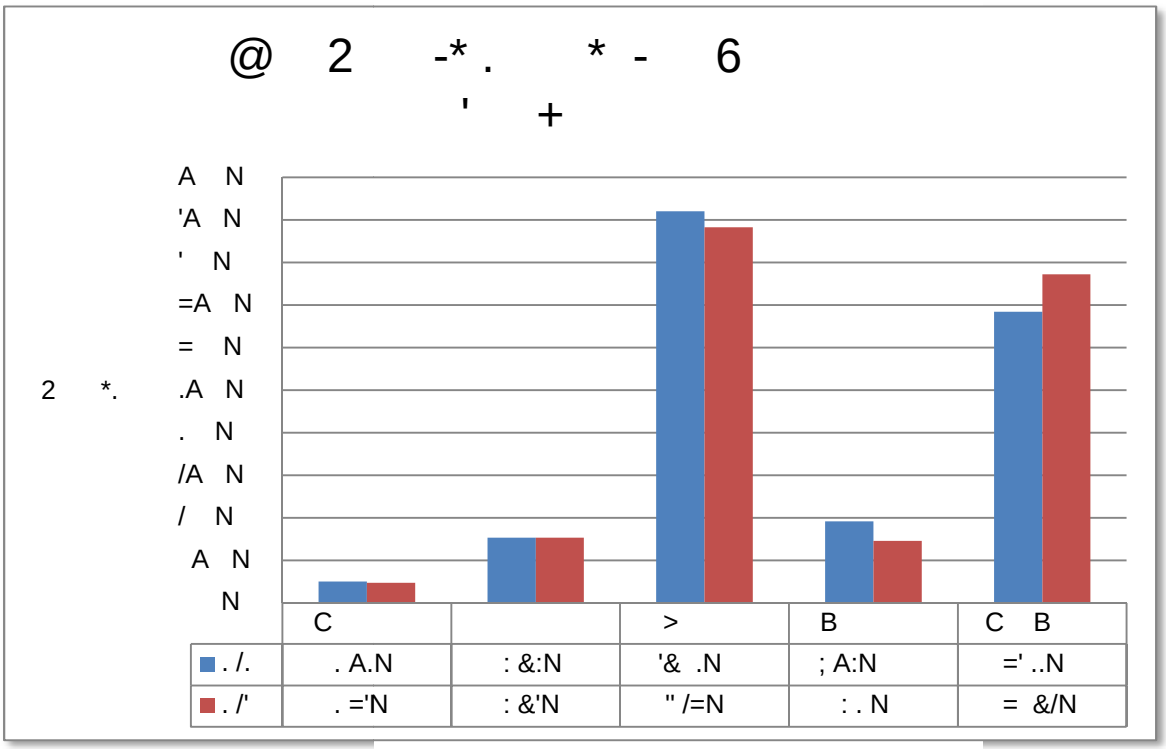
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*+ # * - 6 ' + *

7 *	' +				
	8 2	2	5*	9	8 9
	. A.N	: &:N	'& .N	; A:N	=' ..N
	. ='N	: &'N	'' /=N	: . N	= &/N
-* .	* / N	* 'N	*/ ;N	*. .;N	' ' N



5 . # * - 6 ' + *

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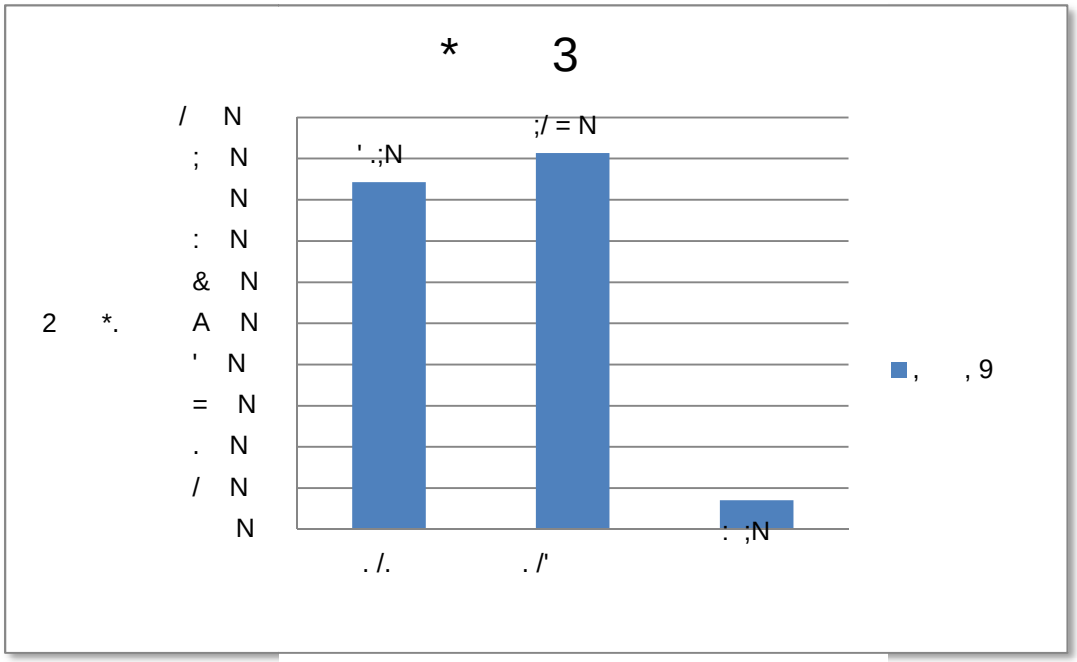
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7 *	* 3		
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5 . ; * 3 , *

A;

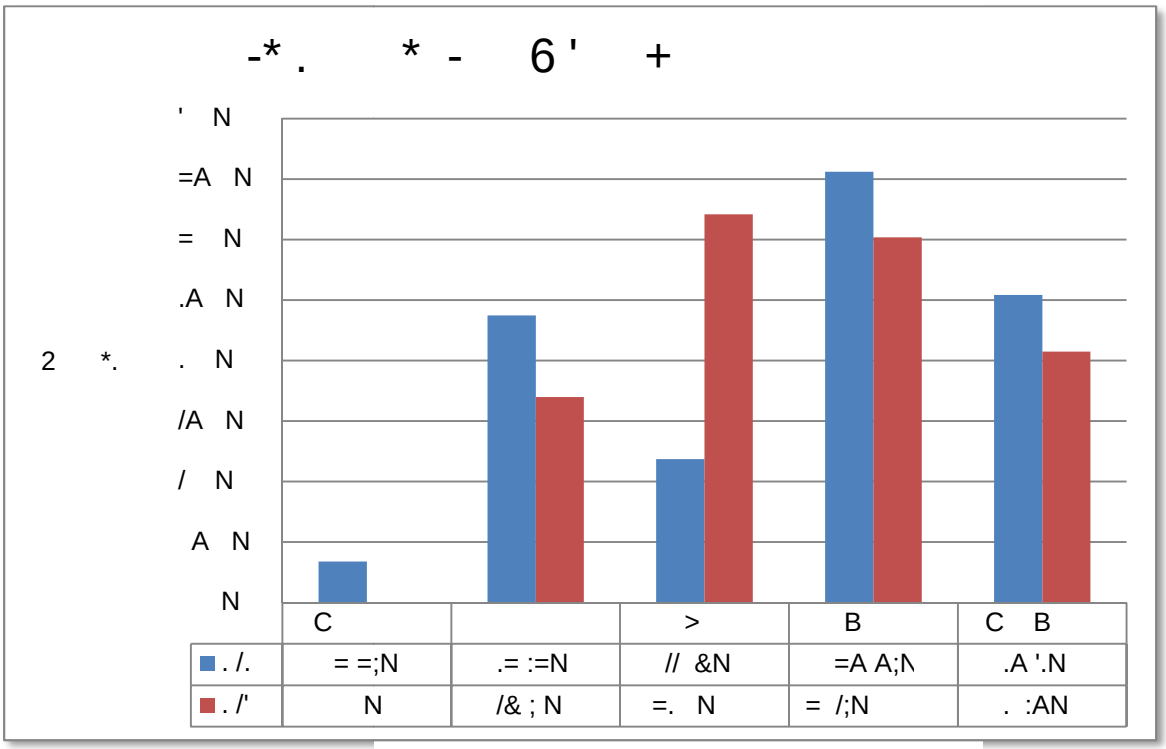
) * + , - ,
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*+ ; * - 6 ' + *

7 *	' +				
	8 2	2	5*	9	8 9
	= =;N	.= :=N	// &N	=A A;N	.A '.N
	N	/& ; N	=. N	= /;N	. :AN
-* .	*= =;N	*& :AN	. ./N	*A ' N	*' &:N



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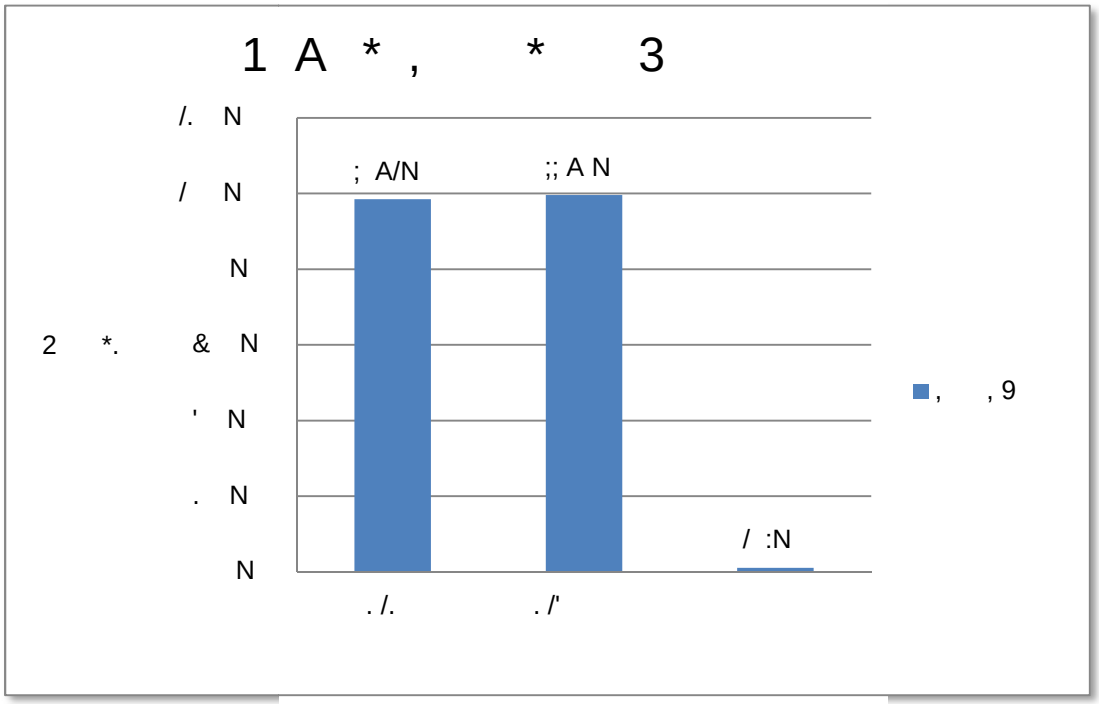
63 " !

63 % $ % &

, , 9 # (
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> / */

*+ " * 3 *

7 *	* 3		
	2 *	* 3	,, '* *,
	""	; A/N	/ ';N
	"$	;; A N	'.N
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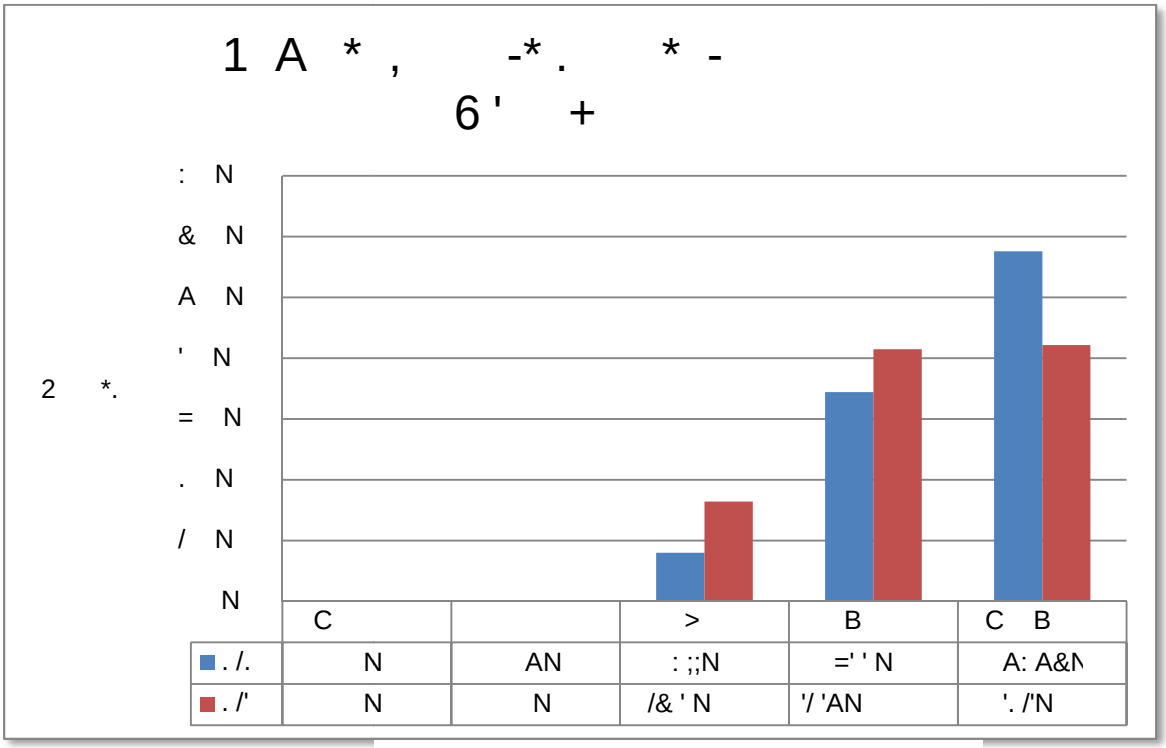
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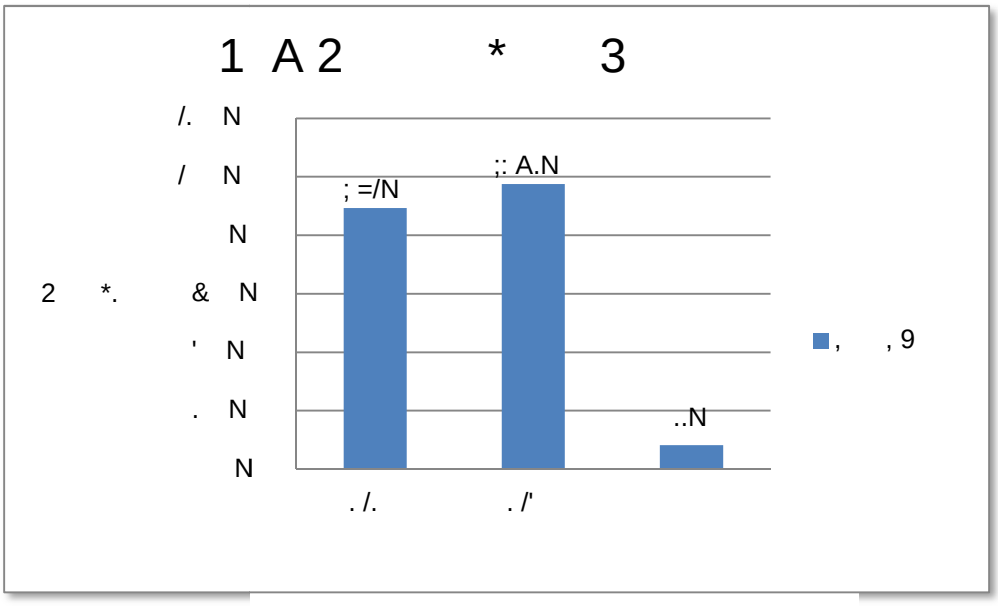
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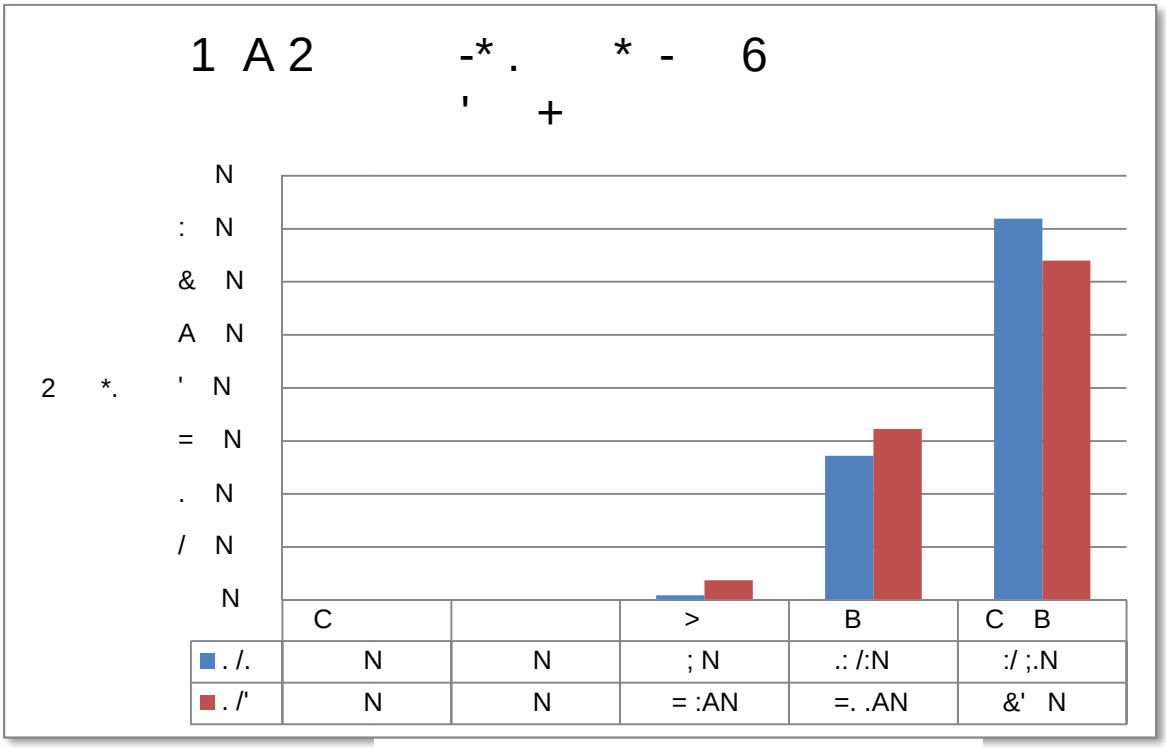
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	N	N	; N	.: /:N	:/ ;.N
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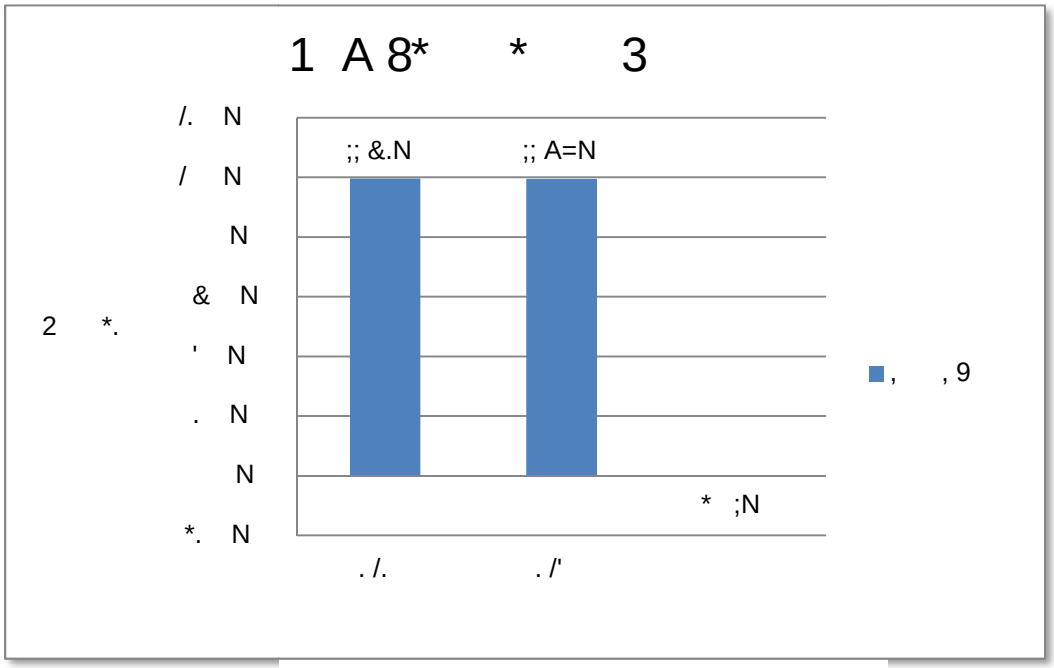
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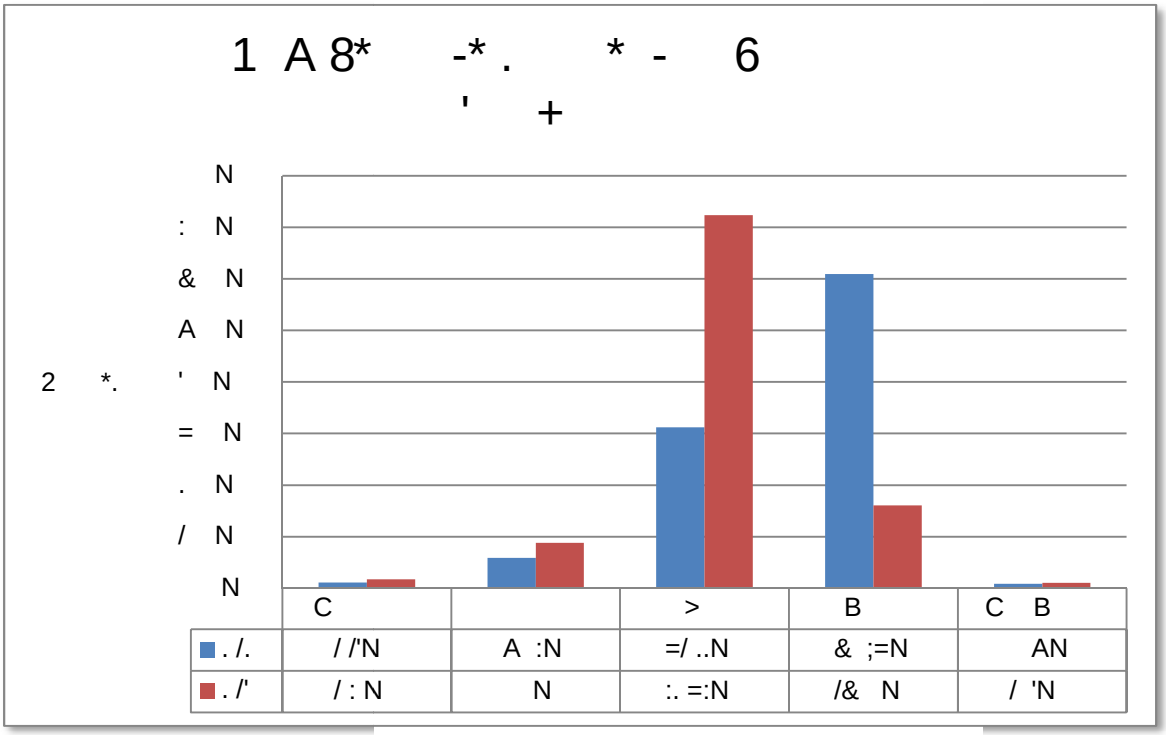


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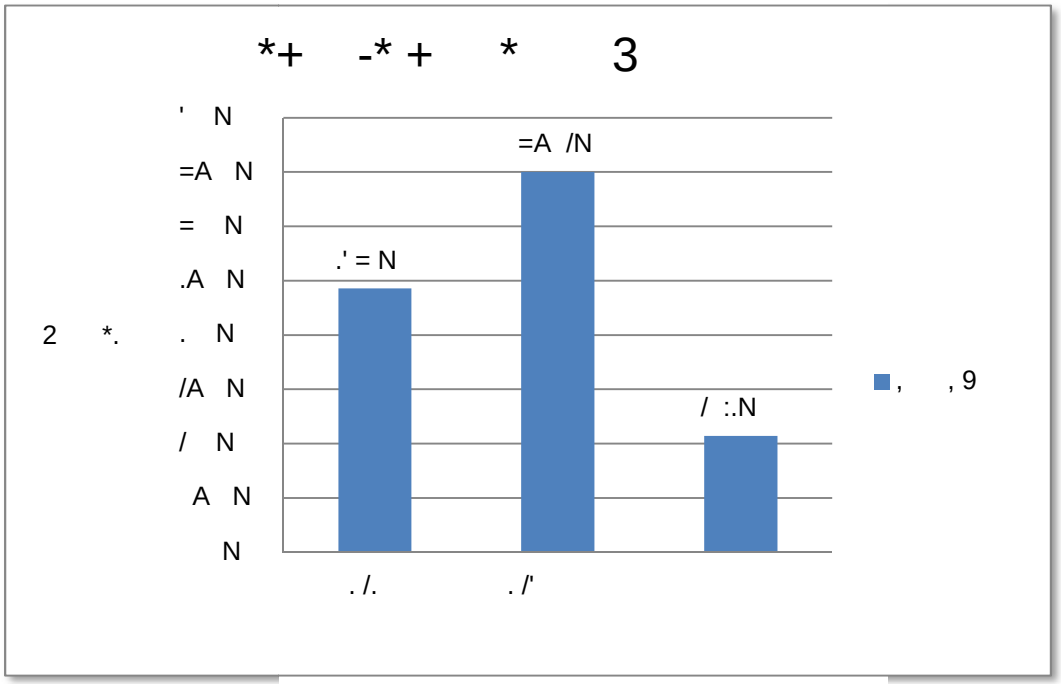
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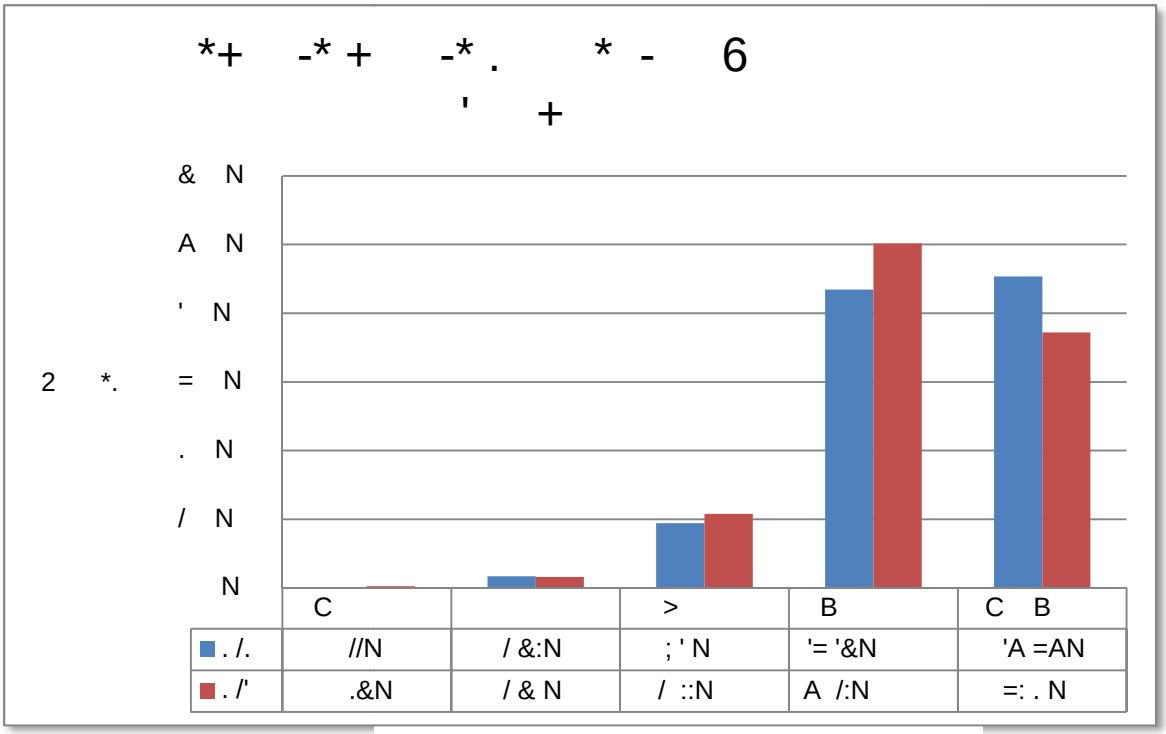
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Power System Engineering, Inc.

Full-service consultants



Standards Review Study

Prepared for:

Toronto-Hydro Electric System Limited

January 16, 2014

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January 16, 2014

Toronto-Hydro Electric System Ltd.
Mr. Tarek Turk
500 Commissioners Street
Toronto, Ontario
Canada

Subject: Standards Review Study Report

Dear Mr. Turk:

I am pleased to present the enclosed Standards Review Study Report for Toronto-Hydro Electric System Limited. Our report reflects knowledge and responses gained from U H Y L H Z L Q J 7 + (6 / ¶ V documented Standards, in-person interviews, and conference calls that were conducted throughout our review.

Respectively submitted,

Erik S. Sonju
Vice President, Power Delivery Planning and Design
Power System Engineering, Inc.

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1.1 3XUSRVH

Toronto-+\GUR (OHFWULF 6\VWHP)/LPLWHG is the largest municipal electrical distribution company in Canada, serving approximately 719,000 customers in the City of Toronto. THESL is the result of six different utilities that amalgamated on January 1, 1998. This amalgamDWLRQ QHDUO\ WULSOHG 7RURQWR +\GUR¶V FXVWRPHU With any merger or acquisition of different companies, there is always the challenge of integrating standards and practices. Nonetheless, THESL has been progressing toward the implementation of the best standards, practices, and processes KHUHLQ UHIHUHQFHG DV ³6 from the previous six utilities and creating a single comprehensive set that promotes the principles of safety, reliability, and efficiency, while applying industry best practices.

In 2010, THESL re-structured its Standards Department and charged it with the major undertaking of HVWDEOLVKLQJ UHILQLQJ DQG PDLQWDLQLQJ WKH the design, materials, construction, and maintenance of the electric distribution system infrastructure. The department is very near the completion stage of a significant task that involves the review and renovation of all major Standards used by 7+(6/¶V engineering and operations personnel. Before fully deploying the results of their efforts, the department determined that there would be value in hiring an outside independent party to review what has been assembled as a method to ensure that the Standards fall within typical industry practices and promote the previously mentioned principles.

Subsequently, 3RZHU 6\VWHP (QJLQHHULQJ, Inc. was retained by THESL on October 21, 2013 to conduct this independent review, of which the results are summarized within this report. The review consisted of interviews with key individuals in the Standards Department and examination of the various Standards that have and will be deployed across the Company. The IRFXV WKURXJKRXW WKH UHYLHZ SURFHVV ZDV WR DGYRFDWH WKH GHWHUP principles of safety, reliability, and efficiency, as well as follow industry best practices. The review itself was intended to be conducted at a high level, while still being comprehensive enough to acquire a thorough understanding of THESL¶V standards.

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The scope of this study focuses on the review and evaluation of four major Standards that heavily influence the design, construction, and maintenance of the THESL¶V electric distribution infrastructure. These four Standards, illustrated in Figure 1, include the Standard Design Practices, the Distribution Construction Standards, the Equipment Approval Process, and the Job Planning Process. Each Standard has a specific focus, yet the four Standards complement each other, creating a comprehensive process for all future activities performed by THESL.

Each Standard is further defined and discussed in later sections of this report.



Figure 1 ±THESL Standard Documents

As earlier indicated, the four Standards were reviewed and evaluated on a number of factors.

- The Standard Design Practices (SDP) document was reviewed to determine if design philosophies and guidelines follow industry best practices.
- The Distribution Construction Standards (DCS) were reviewed to determine if installations are optimized in terms of safety, reliability, and efficiency.
- The Equipment Approval Process was reviewed to determine the existence of an orderly process for selecting cost-effective materials that also optimizes safety and reliability.
- The Job Planning Process was reviewed to determine proper overall quality control of the implementation of the previously mentioned Standards.

All Standards were reviewed in comparison to similar electrical distribution utilities in North America that serve highly dense urban areas with a significant amount of underground infrastructure and network systems, as well as an influence of overhead facilities.

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Based on the volume and the type of information LQFOXGHG LQ 7+(6/PSE 6WDQGL assembled a team of industry experts. The experts at PSE specialize in electric distribution systems, but lack a thorough understanding of underground civil and structural infrastructure, such as vaults and manholes. As such, PSE subcontracted with LHB, a multi-disciplinary engineering, architecture and planning firm, headquartered in Duluth, MN, to focus on the underground civil and structural related Standards.

The following industry experts participated in this review:

- **Erik S. Sonju** *(PSE Vice President ±Power Delivery Planning & Design)*
  Erik is a licensed professional engineer in 16 U.S. States and has over 15 years of experience with electric utilities, with the majority of those years providing professional engineering consulting services to electric power utilities throughout the United States and Canada. His expertise includes transmission and distribution planning, system protection and sectionalizing, transmission and distribution design, power quality investigations, expert testimony and project management.

- **Darren Westby** *(PSE Manager of Substation Design & Distribution Planning)*
  Darren has over 20 years of experience supporting electric utilities with protection and sectionalizing, system planning, substation design, distribution and transmission line design, power quality investigations, connection of large loads, and project management.

- **Duane E. Craig** *(PSE Senior Engineering Consultant)*
  Duane is a licensed professional engineer in the states of Iowa, Minnesota, and Wisconsin and has over 35 years of experience in the areas of electric utility system planning, overcurrent protection, metering, distribution system design, distribution system operation, distribution generation, electric system interference mitigation, and writing equipment specifications.

- **Michael H. Mezera** *(PSE Manager of Line Design)*
  Mike is a licensed professional engineer in the State of Wisconsin and has over 5 years of experience with transmission and distribution line design including development of line design standards, identification of line corridors, development and review of plan and profile drawings and staking sheets, structure loading calculations, conductor sag and tension tables, and material specifications.

- **Steve Hall** *(PSE Senior Designer)*
  Steve is a licensed designer of engineering systems in the State of Wisconsin and has over 25 years of experience with electric cooperative, municipal, and investor owned utilities. Steve has designed, staked, and overseen construction of distribution and transmission line installations.

- **Michael D. French** *(LHB Senior Civil Project Engineer)*
  Michael is a licensed professional engineer in the states of Michigan, Minnesota, North Dakota and Wisconsin and has over 15 years of experience in planning, permitting, design, construction administration, and project management of civil infrastructure projects. He has provided a broad range of civil engineering services for pulp & paper, electric utility, mining, and manufacturing operations.

- **Alan J. Vorderbruggen** *(LHB Structural Engineer)*
  Alan is a licensed professional engineer in eight U.S. States and has over 25 years of experience in structural and civil engineering design and project management.

He has extensive experience in all structural and civil work associated with electrical substations and transmission lines, including structure design, structure spotting, plan and profile drawings, foundation design, specifications, grading plans and general project management.

Each of the abovementioned reviewers focused on the areas of his particular expertise. The review was conducted at a high level with the intention of putting more focus on those Standards that were rated as having a greater deviation from the industry and a higher level of impact on cost, reliability, or safety.

One aspect of the review considered how the Standards are X Q L T X H W R 7 + (6 / ¶ V V \ V W common with industry-wide practices. For Standards found to be unique, the reviewers identified how greatly they deviated from the industry in terms of impact on capital costs, electric infrastructure reliability, and public and worker safety. While all Standards were reviewed, a greater focus and allocation of time was given to those Standards involving design and construction, as these have a greater influence in the abovementioned areas. Along with this approach, the reviewers explored the differences between infrastructure required for metropolitan downtown areas versus suburban and rural areas, and how this applies to THESL ¶ V Standards collection.

In addition to the review of documented Standards as discussed above, an onsite interview of key personnel in the Standards Department was conducted to gain a general understanding of THESL ¶ Vapproach to Standards development and implementation. Following the onsite interviews, there were two conference calls that focused on addressing specific questions and comments from the reviewers that arose during the evaluation period.

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A number of general observations were obtained during the review process.

First, the Standards Department at THESL consists of professionals who have previous experience with outside entities, which has brought the Department various levels and types of expertise. The Department also consists of professionals who have a long-term relationship and understanding of the downtown Toronto electric distribution system. This blend of outside experience and internal knowledge is personified by a diverse group of professionals with the breadth and depth of knowledge that is needed by WKH WUXVWHHV RI WKH &RPSDQ\¶V

Second, the Department¶V engineers also continue to gain industry knowledge by engaging and participating in various associations, forums and initiatives.

One example of this is THESL¶V participation in the Institute of Electrical and Electronic Engineers (IEEE) and Canadian Standards Association (CSA) working groups. IEEE is FRQVLGHUHG WR EH WKH ZRUOG¶V OHDGLQJ professional association that serves technical professionals globally. IEEE has a Standards Association that offers a library of current standards in the electrical industry. THESL is a subscriber to IEEE Explore, which provides web access to all IEEE standards. The Canadian Standards Association is a non-profit standards organization that develops industry standards across 57 areas of specialization, with electrical standards being one area of expertise. CSA develops, updates, and sells standards through their Standards Store. THESL has a significant library of such CSA Standards. THESL is also currently engaged with CSA industry initiatives and committees, currently serving on the Technical Subcommittee for Transformers and the Technical Subcommittee for Reliability Based Design. By participating in both IEEE and CSA initiatives and activities, THESL is actively and continually exposed to the development of standards both locally and globally.

THESL is also actively involved with the Utilities Standards Forum (USF) as well as an Inter-Utility Forum. The USF is an organization representing approximately 50 Ontario electric distribution companies. Its goal is to collaboratively define standards for its members and reduce duplication of efforts. The USF has developed design standards for electricity distribution that meet the requirements of Ontario Regulation 22/04 under the Electricity Act of 1998. The Inter-Utility Forum is made up of a small group of utilities including Enersouce Hydro Mississauga, Veridian Connections, Peterborough Utilities Group, Horizon Utilities, and London Hydro. 7+(6/¶V LQYROYHPHQW and will continue to be crossKDV to coordinate concepts and ideas with other Ontario-based utilities.

THESL is also a member of the Centre of Energy Advancement through Technological Innovation (CEATI International). CEATI International is a user-driven organization that provides technology solutions and training to electrical utility participants. CEATI International is driven by over 120 organizations, including electric utilities, governmental agencies, and research-based organizations. THESL can benefit from this membership by looking to CEATI International as a research and development aid that will help keep personnel current with new technologies, as well as solidify their understanding of existing technical concepts. Information

gleaned from CEATI , Q W H U Q D W L R Q D O ¶V Work and reports can be applied to new and revised THESL Standards.

Third, THESL has a substantial assembly of documented Standards that is equal to, or exceeds, those that are used by similar large electric distribution utilities in North America. 7 + (6 / ¶ V Distribution Construction Standards (DCS) consist of approximately 1200 individual standards. In addition, 7 + (6 / ¶ V 6 W D Q G D U G ' H V L J Q 3 U D F W L F H V (SDP) Document consists of approximately 140 pages conferring the standard practices to be used by designers.

PSE and LHB reviewed and evaluated approximately 1000 of the 1200 individual standards that make up the DCS. As explained by THESL, the 1000 standards reviewed are intended to be applied to new construction across THESL ¶V system. The remaining 200 standards that were not reviewed are representative sketches of unique installations that are being kept on file for reference. This group of 200 sketches also includes obsolete construction methods, such as box construction, that exist in the field but are no longer applied to new installations. These particular standards are only kept on file for maintenance of existing facilities.

PSE and LHB reviewed and evaluated the SDP document in its entirety.

Finally, thr R X J K W K H U H Y L H Z R I 7 + (6 / ¶ V 6 W D Q G D U G V, D Q G L Q W H U Y with key personnel, it was commonly noted that the Standards Department and associated stakeholders consider the aspects of reliability, cost, and safety when developing, modifying, and carrying out their Standards.

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The Standard Design Practices (SDP) document confers 7 + (6 / ¶ V standards as they relate to the design of the electric distribution system.

The SDP document was found by PSE and LHB to be thorough, well documented, and consistent with what is seen in the industry throughout North America as best practices. Only minor comments and questions resulted from the review.

Overall, the standards and specifications contained in the SDP would not be perceived as insufficient or excessive. The SDP address safety and also make accommodations for design and construction considerations that have the goal of managing construction costs, system reliability or otherwise providing construction flexibility.

Generally, civil execution costs are necessarily high simply because the work generally takes place underground, which requires not only excavation of soil, but working around other ground-based infrastructure. The SDP do not appear to make civil construction costs any more significant that they would otherwise be. Certainly there are safety and durability conditions that need to be met, but the requirements set forth in the SDP document do not force the costs to be artificially high compared to typical civil work.

Reliability is the persistence of the system to be able to operate in adverse conditions and under peak demands. 7 + (6 / ¶ V U H V S R Q V L E L O L W \ L V W R H Q V X U H W K D W L W robust and electrically adequate to meet the requirements of its customers who depend on its reliability. The established specifications in the SDP address specific measures to ensure the reliability of both below grade and above grade assets, but in general, once these are constructed (per the specifications) there is little impact on day-to-day electric infrastructure reliability. However, if the infrastructure components are not installed properly, failure could result in impacts to power delivery (if a vault structure were to fail), or a potentially serious safety incident (if conduits were not properly encased in concrete and struck during later excavation work).

With all electric power facilities, the nature of electricity has a component that requires safeguarding from the public and workers. The SDP accomplish this by complying with local codes and best utility practices, ensuring a high level of public and worker safety in the constructed elements. Examples include confirming duct locations during the design stage using test holes or taking into consideration children play areas and traffic exposure in identifying new transformer locations. However, the Standards do not appear to incorporate provisions that are above and beyond generally accepted construction and industry standards with regard to safety.

While every industry has its own unique infrastructure considerations, the items detailed in THESL ¶ V standards are generally common for electric utilities that provide service within dense urban and metropolitan settings. For example, there are specifications that address open trench construction and trenchless/directional drilling construction methods. These apply to power conduits as much as they may apply to sewer or water utility construction within a metropolitan environment. The cast-in-place and precast concrete vaults and chambers also have specific

roles relative to THESL, but are common utility components. THESL also loops the vast majority of feeders and taps, which is both beneficial in terms of reliability and also justifiable due to the close proximity of feeders in a dense load center area. Lastly, there are two separate sections that address duct banks crossing under railroads. Certainly this applies to a power utility in a major metropolitan area, but the requirements for depth of burial and filling void spaces with grout are standards that would be applied in many locations for any type of utility crossing below a set of tracks.

There are a few sections of the SDP that make particular reference to compliance with City of Toronto specifications, which would be a condition unique to THESL. One example of a reference to the City of Toronto is in Section 3.2 of the Standard Design Practices, which addresses General Design Considerations ±Civil. Paragraphs 3.2.1.1, 3.2.1.2, and 3.2.2.1 refer to restrictions and clarifications to be I R X Q G L Q W K H & L W\ Municipal Consent R U R Q W R ¶ V Requirements, specifically for new streets, horizontal and vertical clearances, and excavation and backfill. Another example of a reference to the City of Toronto can be found in Paragraph 4.2.2.1.3, which U H D G V ³' H V L J Q H U V D U H W R U H I H U ± Development O D W H V Infrastructure Policy & Standards (DIPS). ´ The DIPS document is referenced in several other locations as well. There are several other specific references specific to the City of Toronto, similar to the abovementioned sections, but beyond these references, the Standards are fairly common.

The main differences in an electric infrastructure required for a major metropolitan downtown compared to suburban or rural settings include utility installation method (open cutting when space is available compared to trenchless construction in metropolitan areas to minimize surface disturbance and restoration costs), the number of spare conduits to accommodate future needs, setbacks from lot lines, road centerlines (again, a function of suburban or rural areas simply having more space), network systems, multiple overhead circuits, and the need to work around foreign utilities.

Overall, the approximately 140 pages that make up the SDP were found to be what is expected with electric distribution utilities that have similar service areas and environments.

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The Distribution Construction Standards (DCS) provide Standards applicable to construction of the THESL electric distribution system.

Similar to the SDP, the DCS were found by PSE and LHB to be thorough, well documented, and consistent with what is seen in the industry throughout North America. Only minor comments and questions resulted from the review.

In general, the DCS follow industry-wide practices that are standard for overhead framing. Standard installation configurations are also used for underground construction. The DCS reference standard materials that are commonly used throughout the industry for both overhead and underground construction.

The DCS were found to be acceptable as shown, subject to several minor suggested modifications that have been discussed with the THESL staff. Overall, the construction assembly configurations would not be perceived as difficult for an installing contractor to understand. The Standards appear to address design and planning considerations, constructability issues, and flexibility to accommodate field conditions. They also provide appropriate consideration to environmental safety (ex. the use of Petro-Plug devices on chamber drains, and the beneficial reuse of concrete transformer pads).

Very few and minor deviations from what may be considered industry-wide standards were noted during the review and evaluation. Of those noted, the deviations were either reasonably justified by THESL due to local conditions and codes, or were undertaken for review and modification by THESL. For example, split bolt connectors were listed in some of the Standards. It was suggested that minimal use of split bolt connectors be considered for overhead tap connection. Because of the design, split bolt connectors are more likely to fail under high electric current loads. THESL indicated that Ampact connectors are normally used and that the split bolt connectors are only used when the situation is such that the Ampact, or perhaps a squeeze-on connector, cannot be utilized.

Although it is generally minor, the most noteworthy deviation from the industry found throughout the DCS is THESL ¶ V exclusive use of Western Cedar poles. Through our experience, Western Cedar poles are generally superior to most other wood pole species; however, it is not uncommon for distribution systems to consist of other wood species of lower cost. During the course of the review, THESL explained that they prefer cedar wood for poles because cedar is generally more uniform in dimension, easier to climb, and lightweight. These beneficial factors, as well as the life longevity of Western Cedar, may very well offset the typically higher cost. Through discussion, THESL agreed that it would be appropriate to perform a comparison review of other wood species such as Northern Red and Southern Yellow Pine to determine if Western Cedar continues to be the best option in terms of cost, safety, and reliability.

Overall, the approximately 1000 standards reviewed that make up the DCS were found to be neither excessive nor delinquent in terms of construction for a distribution system with a focus on reliability, safety, and cost efficiency.

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THESL has two approval processes for equipment. One is the approval process for major equipment while the other is for non-major equipment.

Major equipment includes items that: are generally higher in cost on a per unit basis, result in significant cost based on the quantity of units annually installed, have a significant impact on system performance and reliability, or have a significant impact on safety. Examples of major HTXLSPHQW LGHQWLILHG LQ 7+(6/¶V HTXLSPHQW DSSURYDO SU

- Conductors
- Poles
- Insulators
- Breakers and Switches
- Transformers

In addition, non-major equipment includes items that support the operation, but are not directly part of the distribution system, as well as items that have received electrical equipment approval from a recognized certification organization accredited by the Standards Council of Canada. Non-major equipment can also be accepted if it is considered approved by a significant portion of the electric utility industry in North America. THESL refers to these items as Good Utility Practice equipment. Examples of non-PDMRU HTXLSPHQW LGHQWLILHG LQ 7 approval process include:

- Sump Pumps
- SCADA Equipment

,Q ERWK FDWHJRULHV 7+(6/¶V approval process provides a reasonable degree of assurance that products applied to the system are safe and reliable. For instance, items that fall under the major equipment category must adhere to THESL technical specifications. These specifications, that are all reviewed and approved by a THESL professional engineer, include industry standards and qualifying tests amongst other elements. Non-major equipment must either be pre-approved by a recognized certification organization, or have a proven historical record of successful use in the industry. Anything falling short of these qualifiers may only be used on a trial basis and after adequate supporting documentation illustrated that the equipment is suitable for a specific application.

THESL also provides an environment in which employees can submit a request to add or change material to their inventory of approved equipment. This approach is encouraging to see. It allows for maximum input on possible improvements through the type of equipment used on the system, as well as fosters a culture that values input from all personnel which pays dividends by standards being supported and followed. When an employee submits a material change request, a change code is identified. The change codes include: safety, code compliance, assembly feasibility, quality improvement, process improvement, new technology, environment, material issue, labor issue, cost reduction, stock reduction, and harmonization. These codes demonstrate

that THESL is consciously working toward constant improvement under the principles of safety, reliability, and efficiency.

Prior to acceptance of new material, THESL conducts an extensive evaluation process that includes the review by stakeholders representing various functions in the company. Stakeholders involved in this process include representatives from Standards, Supply Chain, Quality & Compliance, and Operations. Material is ranked in a scoring matrix by the level of adherence to THESL technical specifications, price, lead time V P D Q X I D F W X U H U ¶ V I L Q D Q F L D O V terms, ISO 9001 certification, quality control and inspection, reliability and failure rate, ease of installation, size and handling, and durability. This process provides a high degree of certainty that the best products are properly evaluated for selection.

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As with any documented standard, the standard must be followed in order to be effective. The IRXUWK GRFXPHQW WKDW 36(UHYLHZHG LV 7+(6/¶V 6-RE 3ODQQ document, discussions during the on-VLWH LQWHUYLHZV PDGH LW FOHDU WK taken seriously, observed, and verified through quality assurance measures.

As can be expected, this process requires collaboration amongst various departments and personnel from the conception of a job to finalizing its documentation after implementation. There are many facets to the purpose of the process; however, four stand out in terms of the adherence to Standards. These include:

- To endorse the use of only certified construction standards, specifications and approved Standards Design Practices in the assembly of project drawings.
- To ensure that construction is consistent with approved project drawings and that only approved equipment is used.
- To ensure that non-standard construction is certified by a professional engineer.
- To ensure that new construction to the distribution system is inspected and certified prior to putting the distribution system into use in accordance with THESL¶V &RQVWUXFWLRQ 9HULILFDWLRQ 3URJUDP

7KH YDOXH RI WKH DERYH VWDWHG SXUSRVHV LQ 7+(6/¶V -RE quality control when it comes to the implementation of the Standard Design Practices, Distribution Construction Standards, and the use of approved major and non-major equipment. The overall responsibility of adopting the process falls to the corresponding business unit Vice Presidents while the responsibility of implementation and execution falls to the Business Unit Managers and Supervisors, respectively. Being that these levels of responsibilities are clearly stated in THESL¶V -RE 3ODQQLQJ 3URFHVV LOOXVWUDWHV WKH FRPS followed.

Through the interview process, the following was noted:

Designs on the THESL distribution system are completed by certified design technicians who are trained and familiarized with both the Standard Design Practices and Distribution Construction 6WDQGDUGV 7KHVH WHFKQLFLDQV DUH DOVR ZHOO NQRZQ WKURXJKRXW WKH Department provides face-to-face training, as well as training through internally published bulletins that are sent out periodically. THESL has also developed various tools, such as a guying model, that are made available to design technicians that help assure that installations meet standards and are consistent amongst designers. Design technicians are accountable to follow standards, use provided tools (ex. guying tool), and properly document their design for supervisor approval.

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review covers the design from an operations and electrical standpoint while also keeping in mind all company Standards. Omissions found during this level of review result in the job being sent back to the designer for corrections. This two level review process of every job provides a reasonable degree of control with regard to design. In addition, an internal audit of designs is performed on designs every six months by the Standards Department.

After a design is fully approved and goes to construction, another level of accountability takes SODFH -RXUQH\PHQ DQG DSSUHQWLFHV DUH UHTXLUHG WR
standards and approved equipment. This is done by on-the-job training by supervisors or more experienced journeymen and ongoing training with the Trades Department. After a job is fully constructed, the crew leader must sign off on the as-built documents indicating that the job was properly built, IROORZHG WKH GHVLJQ DQG FRQVHTXHQWO\ PHHWV 7

For jobs that are designed and constructed by outside contractors, THESL requires the designs to EH VWDPSHG E\ D 3URIHVVLRQDO (QJLQHHU DQG FRQVWUXFW
competent person ´

The level of quality assurance control that THESL demonstrates through the construction process is very common in the utility industry and has proven to be successful. One additional step that THESL may consider is to perform periodic internal audits of construction, similar to what is done with the design phase, as a more formal measure.

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documented, and consistent with what is seen in the industry throughout North America. The composition of the Standards Department and the motivation of the personnel interviewed were IRXQG WR EH FRPSOHPHQWDU\ 7KH UHVXOWV RI 36(¶V DQG
only minor questions and comments, which have been discussed with the THESL staff. Of these questions and comments, THESL was either able to sufficiently provide supporting justification to uphold a specific standard or set into action further review for change of a specific standard.

Distribution System Plan (DSP)

E

CAPITAL EXPENDITURE PLAN

ID	Section
E1	Summary
E2	Capital Expenditure Planning Process Overview
E3	System Capability Assessment for Renewable Energy
E4	Capital Expenditure Summary
E5	System Access Investments
E6	System Renewal Investments
E7	System Service Investments
E8	General Plant Investments

E1 SUMMARY

E1.1 Overview of Capital Expenditure Activities

As explained in Section D, Toronto Hydro's AM Planning Process consists of three key stages: Long-Term Planning, Short-Term Planning & Maintenance Planning, which collectively result in the creation and development of capital expenditure plans and associated investment programs.

Toronto Hydro's Long Term Planning processes led to the creation of the 2015-2019 Capital Expenditure Plan (summarized in Section D1.2.1 and explained in detail in Section D3.1.1). This process produced a series of investment approaches and execution strategies (described in detail in Section E2.1). Based upon the selected investment approach and execution strategy, Toronto Hydro generated three forms of capital investment programs, including

(i) "**Core" asset renewal programs**: This area of investment is made of in-kind replacement of assets reaching or exceeding their end-of-life or economic end-of-life criteria.

(ii) **Programs managing system-wide critical issues**: This includes those broader investments of the utmost urgency, designed to target issues that go "beyond the asset", such as load growth and contingency constraints, operational flexibility and accessibility, safety and security of supply issues.

(iii) **Programs that continue to manage necessary day-to-day operational investments**: This includes necessary mandatory day-to-day investments that support the 24/7 operations of Toronto Hydro, including customer-service requests, mandated service obligations, capital and maintenance support.

The utility positioned these investment programs into one of the following four investment categories prescribed by the Ontario Energy Board's (OEB) Chapter 5 *Filing Requirements for Electricity Transmission and Distribution Applications (July 17, 2013)*[1]::

- System Access Investments (Section E5)

[1] Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications, (Toronto: Ontario Energy Board, 2013). ["OEB Filing Requirements"]

- System Renewal Investments (Section E6)
- System Service Investments (Section E7)
- General Plant Investments (Section E8)

Toronto Hydro categorized each investment program as one of four investment categories, based upon:

- Alignment between program scope and the investment category definition
- Trigger driver associated with this program

Short Term Planning processes (summarized in Section D1.2.2 and explained in detail in Section D3.1.2) were then executed in order to produce discrete projects for the 2015 year for each of the produced investment programs.

E1.2 Expenditure Summary Tables

This section provides breakdowns of the investments contained within Toronto Hydro's Distribution System Plan (DSP) based upon investment categories and drivers.

E1.2.1 Expenditures by Investment Category

Table 1 shows the capital expenditure for the 2015-2019 period for each category. The System Renewal category has the highest spending of around $1.26 billion ($250 million annually) due to Toronto Hydro's continual renewal and replacement of aging distribution assets. The other CAPEX category has the lowest spending of around $147 million ($29 million annually) as it includes costs related to Engineering Capital, Road Cuts, Allowance for Funds Used During Construction (AFUDC), Major Tools and inflation. Section 4.2 provides the details around the spending profiles for all these categories and the major variances within them along with the inter-relationships between each of these elements. In addition, Sections E5-E8 provides the details of the capital programs in these categories.

TABLE 1: CAPITAL INVESTMENT BY CATEGORIES

CATEGORY	Forecasted Spend ($M)						
	Avg.	2015	2016	2017	2018	2019	Total
System Access	$91.29	$86.13	$93.54	$100.93	$90.41	$85.47	**$456.47**
System Renewal	$251.73	$251.74	$234.99	$246.35	$260.08	$265.49	**$1,258.64**
System Service	$66.41	$76.45	$69.60	$62.51	$49.54	$73.95	**$332.05**
General Plant	$58.60	$104.63	$99.44	$28.93	$32.13	$27.88	**$293.01**
Other CAPEX	$29.86	$12.18	$21.22	$28.65	$37.89	$49.37	**$149.31**
Total	**$497.90**	**$531.13**	**$518.79**	**$467.36**	**$470.05**	**$502.16**	**$2,489**

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E1.2.2 Expenditures by Investment Drivers

Table 2 shows the capital expenditure for the 2015-2019 period for based on the primary drivers. The three primary drivers with the highest investment are failure risk, functional obsolescence, and customer service requests. The combined investments for these drivers is approximately $1.45 billion due to the System Renewal and System Access programs such as Overhead and Underground Circuit Renewal, Box Construction, Rear Lot Conversion, Customer Connections and Externally Initiated Plant Relocations and Expansion. Conversely, the three primary drivers with the lowest investments are Safety, System Efficiency and Reliability. However, it should be noted, as seen in Table 3, both Safety and Reliability are secondary drivers for 29 and 18 programs respectively.

TABLE 2: CAPITAL INVESTMENT BY PRIMARY DRIVERS

Drivers	Forecasted Spend ($M)						
	Avg.	2015	2016	2017	2018	2019	Total
Customer Service Requests / Third Party Requests	$71.27	$55.31	$71.74	$82.94	$76.58	$69.77	**$356.34**
Mandated Service Obligations	$20.03	$30.82	$21.80	$17.99	$13.83	$15.69	**$100.14**
Functional Obsolescence	$82.81	$80.61	$105.54	$78.31	$75.05	$74.54	**$414.05**
Failure	$33.10	$31.90	$32.71	$33.11	$33.61	$34.18	**$165.51**
Failure Risk	$146.07	$156.91	$130.31	$134.93	$151.42	$156.76	**$730.33**
Safety	$15.11	$16.50	$13.73				**$30.22**
Reliability	$13.07	$10.97	$9.38	$13.83	$13.81	$17.36	**$65.35**
System Efficiency	$12.99	$11.68	$16.20	$11.58	$13.23	$12.24	**$64.93**
Capacity Constraints	$38.39	$43.98	$44.02	$37.10	$22.50	$44.35	**$191.94**
System Maintenance & Capital Investment Support	$44.27	$80.26	$52.14	$28.93	$32.13	$27.88	**$221.35**
Other	$29.86	$12.18	$21.22	$28.65	$37.89	$49.37	**$149.31**
Total	**$497.90**	**$531.13**	**$518.79**	**$467.36**	**$470.05**	**$502.16**	**$2,489.48**

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TABLE 3: COUNT OF PRIMARY AND SECONDARY DRIVERS

Drivers	Application	
	Primary	Secondary
Customer Service Requests / Third Party Requests	3	0
Mandated Service Obligations	2	2
Functional Obsolescence	13	2
Failure	1	0
Failure Risk	10	8
Safety	3	29
Reliability	5	18
System Efficiency	2	7
Capacity Constraints	2	0
System Maintenance & Capital Investment Support	5	2
Cyber Security	0	3
Business Operations Efficiency	0	3
IT Systems Compatibility	0	1
Regulatory Compliance	0	1
Substandard Performance	0	1
Operational Constraint	0	1
Power Quality	0	1

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E1.3 Forecasted System Development

Toronto Hydro recognizes that Toronto's development and infrastructure growth will have an impact on the electrical distribution grid. Load growth is experienced in certain areas of the grid which is based on land development such as condominium buildings being constructed. This growth will likely have an impact on Toronto Hydro's peak demand, as is detailed in section E1.3.1. Toronto Hydro's smart grid development is expected to help the utility respond to the increase in load growth and will provide relief to pockets of the distribution grid under heavy demand. Various programs are planned to support aging infrastructure and the increase in load growth, as described in section E1.3.2. In 2015-2019, the forecast system development will accommodate over 625 MW of distributed generation (DG) connections to Toronto Hydro distribution system. The total capacity of Renewable Energy Generation (REG) connections on the Toronto Hydro system is expected to reach 202 MW by the end of 2019 (see section E1.3.3). In order to accommodate the REG projects for the forecasted development period, Toronto Hydro requires the Generation Protection Monitoring and Control program (section E5.5) to be implemented. In short, Toronto Hydro has programs planned to accommodate the growth in its distribution system to provide more benefit to customers and Toronto Hydro.

E1.3.1 Load and Customer Growth

Based on Toronto Hydro's database of pending customer connection requests, Toronto Hydro planners anticipate annual load growth of approximately 4.0% (gross) across the entire service area between 2013 and 2015. Beyond that, based on historical growth rates, Toronto Hydro forecasts annual system wide load growth rate of 1.3% (gross) between 2015 and 2019. Refer to section D3.1.2.1 for more details regarding the bus peak load forecasting process. Toronto Hydro currently serves approximately 733,000 customers. Peak system load in 2013 was 5378 MVA.

A forecast of anticipated distributed generation (DG) connections includes both non-renewable generation sources, such as gas powered generators, and Renewable Energy Generation (REG) sources, such as solar photovoltaic or wind turbines. By the end of 2014, a total of 176.2 MW (nameplate capacity of DG) is expected to be connected to Toronto Hydro's system. This will be comprised of a combination of Feed-In Tariff (FIT) projects, Combined Heat and Power (CHP) resources and other distributed generation. The impact that distributed generation resources have on peak demand is less than the nameplate capacity (as there is no guarantee that it will be operating at 100% rated output coincident with system peak demand). That said, Toronto Hydro expects that distributed generation resources will continue to put downward pressure on future load demand growth at a system level.

Load growth is highly localized based on land development and the economic circumstances of existing customers. The relatively high system load growth of 4% anticipated between 2013 and 2015 is primarily driven by a significant amount of condominium and office tower development, and construction of large, electricity-intensive data centres. A large share of this activity has occurred and continues to occur in the downtown core, and in pockets of the former Cities of Etobicoke and Toronto. Additionally, there are a number of large infrastructure projects under way to construct electrically powered transit within the City of Toronto. These projects, which range in status from "proposed" to "in construction", include the Eglinton LRT, electrification of the Union-Pearson rail link, the Sheppard East LRT project and the Finch West LRT project.

E1.3.2 Smart Grid Development

Toronto Hydro has various programs that enable the development of smart grid technology within its distribution system. Smart grid technology is expected to enhance customer service by, among other things, allowing Toronto Hydro to reduce outage restoration times for customers. In addition, this technology is expected to help Toronto Hydro manage the impacts of aging infrastructure by increasing the responsiveness of the distribution system. A modern distribution system ultimately delivers value to customers by providing reliable and high quality service. Toronto Hydro expects that a smarter grid will help address current challenges by enabling automated responses to outages, reducing outage restoration times, increasing monitoring on system assets, and allowing better visibility and control for customers over their energy usage.

Programs within this filing that contribute to Smart Grid development include, but are not limited to:

- ***Feeder Automation*** - Facilitating faster and less labour intensive system restoration efforts, thus reducing the impact of trunk outages on customers by isolating faulted sections of the feeder. Section E7.3 provides further details on this investment program.

- ***Overhead Momentary Reduction*** - Providing flexibility to the system, fault protection and improving the distribution feeder reliability performance by limiting outage times and containing the outage to a minimal area. Section E7.4 provides further details on this investment program.

- ***Local Demand Response*** - Providing medium-term capacity relief to the Cecil TS by implementing a targeted and localized demand response strategy which primarily leverages new and existing demand response resources to prudently defer distribution system capital investments. Section E7.10 provides further details on this investment program.

- ***Distributed System Communication Infrastructure*** – Providing a reliable telecommunications system that is the backbone of Toronto Hydro's distribution system. Identifying and rectifying gaps in availability, performance, and functionality in the telecommunications backbone caused by the functional obsolescence of the SONET technology at substations and legacy wireless SCADA platforms for infield SCADA. These planned investments are expected to mitigate the loss of SCADA functionality,

which can increase outage duration. Section E6.22 provides further details on this investment program.

- ***Stations Control and Monitoring*** - Replacing aging and obsolete Radio Transmission Units and installing SCADA systems at substations currently without SCADA capabilities. Section E6.16 provides further details on this investment program.

- ***Metering*** - Enabling Toronto Hydro to meet its mandatory service obligations with respect to revenue metering and wholesale metering. Section E5.1 provides further details on this investment program.

- ***Network Unit Renewal*** – Replacing old and obsolete Network Units with new Submersible Network Units, which possess sensors for enhanced load monitoring capabilities. These capabilities allow power system controllers to visibly assess the condition of these assets at the control centre. Section E6.10 provides further details on this investment program.

- ***Overhead Circuit Renewal*** – Replacing existing SCADAMATE switches using the obsolete Motorola radio communication system (DARCOM radio system and MOSCAD terminals) with new switches utilizing standardized communications technology. Section E6.4 provides further details on this investment program.

E1.3.3 Renewable Energy Generation Accommodation

The *Green Energy and Green Economy Act, 2009*,[2] encouraged the use of new energy generation sources, including solar photovoltaic (PV), biogas and wind power generation, to connect to the distribution system as distributed generation (DG). The existing electric grid was designed and constructed to distribute unidirectional power from large and distant generating stations, through the transmission system to its typical distribution loads. The interconnection of renewable energy and DG sources in general introduces a variety of electricity sources dispersed throughout the distribution grid and places new demands on the present infrastructure.

In response to customer requests, Toronto Hydro has completed over 890 DG connections representing over 110 MW to the distribution grid. The connected DG resources in terms of quantities are mostly solar photovoltaic (PV) facilities, along with some cogeneration (combined heat and power), biogas, wind turbines and closed transition generators. The historical approach,

[2] S.O. 2009, C.12. ["GEGEA"]

with large and distant generating stations linked by transmission systems to distribution systems is adapting to accommodate bi-directional flow from DG sources, which are located in close proximity to distribution loads.

Toronto Hydro anticipates over 625MW of DG will connect to the distribution system by the end of 2019. In terms of total capacity of Renewable Energy Generation (REG), the Toronto Hydro system will be able to accommodate 202 MW by the end of 2019. Currently, there are several immediate and long-term challenges from connecting the forecasted DG to the Toronto Hydro system. These issues as discussed in Section E5.5.3 include:

- Short Circuit Capacity Limitations;
- System Thermal Limits; and
- Limited Load Transfer Capabilities.

In order to accommodate the forecasted amount of DG into Toronto Hydro's distribution system, the following solutions have been identified for the 2015 to 2019 period.

- Installation of advanced protection systems at Leslie TS, Wiltshire TS and Basin TS,
- Installation of a bus-tie reactor at Richview TS, and
- Installation of monitor and control equipment at DG sites throughout the distribution system.

E1.4 Regional Planning Considerations

Three regional planning consultations were considered when developing the Distribution System Plan. The Central Toronto Integrated Regional Resource Plan is in-progress. Needs Screening reports were completed for the Metro Toronto Northern Sub-region and Greater Toronto Area (GTA) North Western Sub-regions respectively.

The Central Toronto Integrated Regional Resource Plan is still in progress but the Ontario Power Authority (OPA) has confirmed a long identified issue of capacity shortfalls in the Runnymede TS, Manby TS and Copeland TS areas. Toronto Hydro has been planning remedies for these shortfalls and has discussed and shared alternatives with the OPA and Hydro One Networks Inc. (HONI) as part of the planning effort. The projects contained within the Stations Expansion capital investment program, further detailed in Section E7.9, reflect the regional planning consultations to date for Central Toronto.

HONI's Metro Toronto Northern Sub-region Needs Screening was completed on June 11, 2014 and is attached in Appendix F6.1. The net demand forecast did not identify any station capacity issues within the study period and no further action is recommended at this time. There is no impact to the Distribution System Plan due to the Metro Toronto Northern Sub-region Needs Screening.

The GTA North North-western region Needs Screening was completed on June 27, 2014 and is attached in Appendix F6.2. Transformer stations and transmission facilities in the Sub-region have sufficient capacity to accommodate the expected load over the study period. There is no impact to the Distribution System Plan due to the GTA North Western Sub-region Needs Screening.

E1.5 Customer Connections Capabilities

Toronto Hydro connects customers based on two types of connections: load growth and distributed generation. Each customer connection type has its own existing capabilities and programs to enhance Toronto Hydro's capacity to handle connections.

Load Growth Customers

Toronto Hydro is obligated to connect residential, commercial and industrial customers through the utility's overhead and underground infrastructure. On average, Toronto Hydro receives over 10,000 requests a year. Toronto Hydro anticipates that the number of customer service requests and the size of the customers requesting connection will continue to trend upwards. This upward trend is reflected in the projected spending over the 2015-2019 period, where Toronto Hydro has taken into account the number of new building permit applications and the forecasted development numbers from the city and commercial developers. The slight depression in 2015 is due to the anticipated slowing in construction projects due to the Pan Am Games being hosted in Toronto during the main construction season. In addition to the baseline amounts, a number of major projects with multi-year construction schedules are considered in the spending forecasts. These projects are considered to be extensive customer connections that require planning and work beyond the typical basic connection and that usually have a defined scope of work entering each budget year.

To help enable the city's continued economic success and its ability to serve the growing population, Toronto Hydro is investing in expanding the capacity of its stations and feeders. Connections include typical work associated with providing customer access to the distribution system such as extending underground cable or the installation of an overhead transformer to supply a new service. Toronto Hydro performs expansion work in order to connect customers when required.

For available capacity to be at hand when connecting new customers, Toronto Hydro's ability to do the necessary work is found in the completion of the following programs:

- Customer Connections (section E5.2)
- Load Demand (section E5.4)
- Station Expansion (section E7.9)

- Externally-Initiated Plant Relocation and Expansion (section E5.3)

The Customer Connections program creates benefits from a customer value perspective by fulfilling Toronto Hydro's obligations to provide prompt service to customer service requests, ensuring a reliable distribution system for all customers while connecting new buildings, and efficiently building the system by considering future load growth where applicable. The Load Demand program enhances customer value by increasing Toronto Hydro's ability to promptly address customer service requests, while also adding operational flexibility to improve system efficiency and to accommodate future load requirements. Upgrades found within the Station Expansion program allow Toronto Hydro to address customer connection requirements and loading by addressing system limitation imposed by existing stations equipment. This program will also alleviate system limitations and allow for new load connections to the distribution grid system. Expansion work, within the Externally-Initiated Plant Relocation and Expansion program, is typically needed for larger industrial or commercial connections, or requests in areas of the city that are capacity constrained. Expansion work involves the installation or upgrade of distribution assets such as new circuits or civil infrastructure that is required to accommodate new customer loading. Without this work, the existing distribution system could not accommodate the customer.

Renewable Generation Customers

As of Q2 2014, Toronto Hydro has responded to over 3,000 inquiries from customers and developers through the Feed-in-Tariff Program (FIT) pre-assessments. A wide-range of proponents have submitted project applications, including many schools, housing, large grocery stores and department stores. Toronto Hydro's present rate of inquiry for individual FIT customers is estimated at 7.5 MW per month spread over 50 inquiries. Schools have received over 300 pending offers to connect renewable generation from the Ontario Power Authority (OPA) with over 40 MW of capacity. Distributed Generation (DG) connections are expected to reach over 625 MW of capacity by 2019. These connections represent an additional 450 MW over the five year planning period.

Figure 1 demonstrates the cumulative forecast scenarios for renewable energy and DG connections, and provides a breakdown of renewable generation programs and their contribution to the overall forecast. Table 4 and Figure 1 provide the total DG capacity forecast which includes DG connected, in progress and projected. There is a significant demand and potential to connect renewable energy sources to Toronto Hydro's distribution system. The key responsibility of Toronto Hydro is to offer enabling options to ensure the ability of the DG projects to integrate

with the distribution grid. Toronto Hydro capability to connect new generation customers will be enabled as outlined in the program description of section E5.5.2.

To enable the forecasted connection of DG, Toronto Hydro proposes a Generation Protection, Monitoring and Control (GPMC) program (section E5.5). The objective of this program is to provide uniform access for connecting the projected DG installations across Toronto Hydro's service territory. The work in this program involves the installation of the following protection, monitoring and control equipment for enabling DG facilities:

- Advanced Protection Systems,
- Installation of Bus-Tie Reactor on the Station Bus, and
- Monitor and Control of DG Projects.

The GPMC program (section E5.5) is instrumental in enabling DG connections within Toronto Hydro's distribution system. Adding advanced protection systems and installation of bus tie-reactor enables Toronto Hydro to connect additional DG where distribution constraints presently exist. Furthermore, the real-time monitoring and control system provides the ability to acquire real-time information of DG's connected to Toronto Hydro and facilitates planning and operating a safe and reliable distribution system.

TABLE 4: DG CONNECTION FORECAST BY MW ACCORDING TO PROGRAM TYPE (2015-2019)

Program	Existing (Includes 2014 Planned)	2015	2016	2017	2018	2019	Total (MW)
FIT 1.0 - 2.0	53.9	31.2	0.0	0.0	0.0	0.0	**85.0**
FIT 3.0 - 7.0	0.0	10.7	23.9	25.8	27.7	29.7	**117.8**
CHP	59.6	35.5	28.2	27.3	24.0	104.0	**278.6**
Other DG	62.7	32.9	18.0	8.0	15.0	8.0	**144.6**
Total	**176.2**	**110.3**	**70.1**	**61.1**	**66.7**	**141.7**	**626.0**

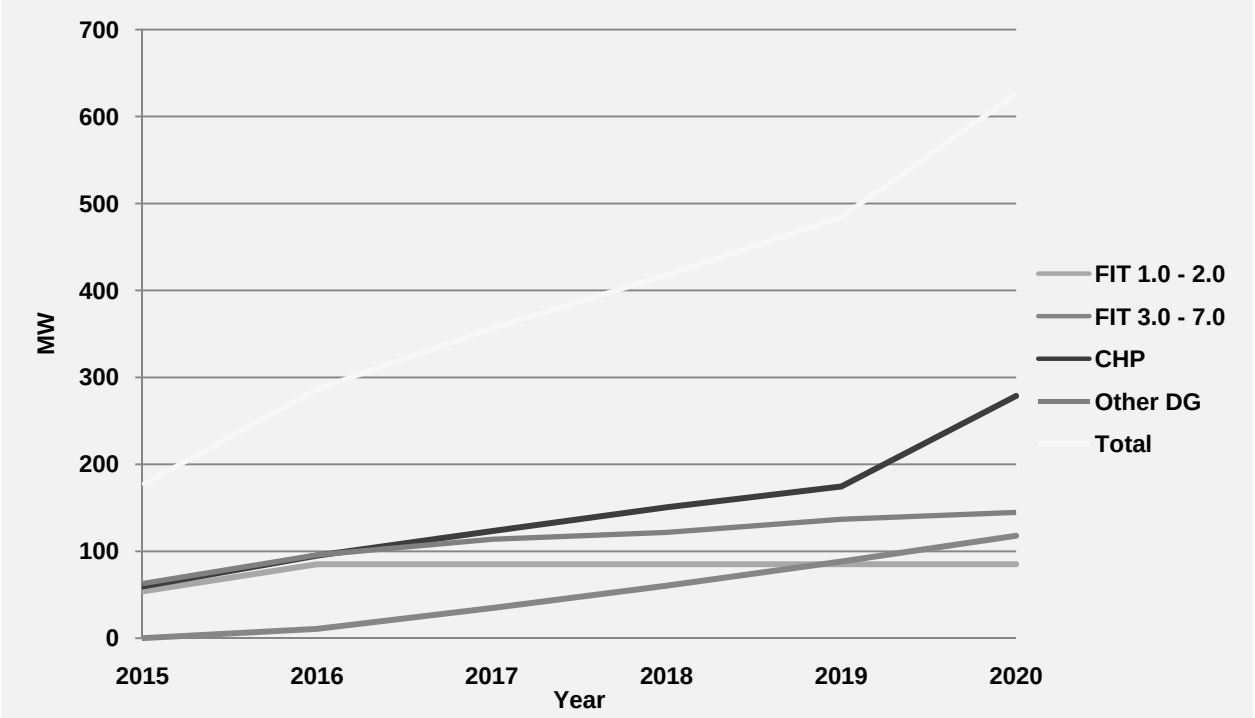


FIGURE 1: GRAPH OF DG CONNECTION FORECAST BY MW ACCORDING TO PROGRAM TYPE (2015-2019)

In accordance with the forecasted grid connected MW, during system peak conditions a projected 185 MW of renewable and clean energy generation will be realized in the next five years, as shown in Table 5.

The peak operation forecast takes into account the effects of DG contribution during system peak conditions. Given the wide range of generation sources and their corresponding capacity, these units typically operate below their maximum rating. Furthermore these distributed energy resources may go off-line due to various factors such as operating, maintenance and other in-service conditions. An operation peak capacity factor was applied for synchronous DG's while accounting for the fact that some DGs may be operating at less than the connected capacity due to various factors such as in-service conditions. A coincident capacity factor was also applied to the solar PV connections to account for solar output given irradiance levels and other factors during system peak conditions. This factor was based on OPA and Toronto Hydro data from simulated and installed connections. For rotating machines, a factor of available DG capacity was estimated to be running to account for maintenance and other contingencies. This five year projection takes into account known and projected renewable and clean energy generation

connections. The projected coincident peak capacity contribution of DG has been estimated at 185 MW.

TABLE 5: DG PEAK OPERATION FORECAST BY MW ACCORDING TO PROGRAM TYPE (2015-2019)

Program	Existing (Includes 2014 Planned)	2015	2016	2017	2018	2019	Total (MW)
FIT 1.0 - 2.0	21.5	12.4	0.0	0.0	0.0	0.0	**33.9**
FIT 3.0 - 7.0	0.0	4.2	9.5	10.3	11.0	11.8	**46.8**
CHP	24.4	17.4	13.8	13.4	11.8	6.9	**87.6**
Other DG	3.8	12.7	0.0	0.0	0.0	0.0	**16.5**
Total	**49.7**	**46.6**	**23.3**	**23.7**	**22.8**	**18.7**	**184.8**

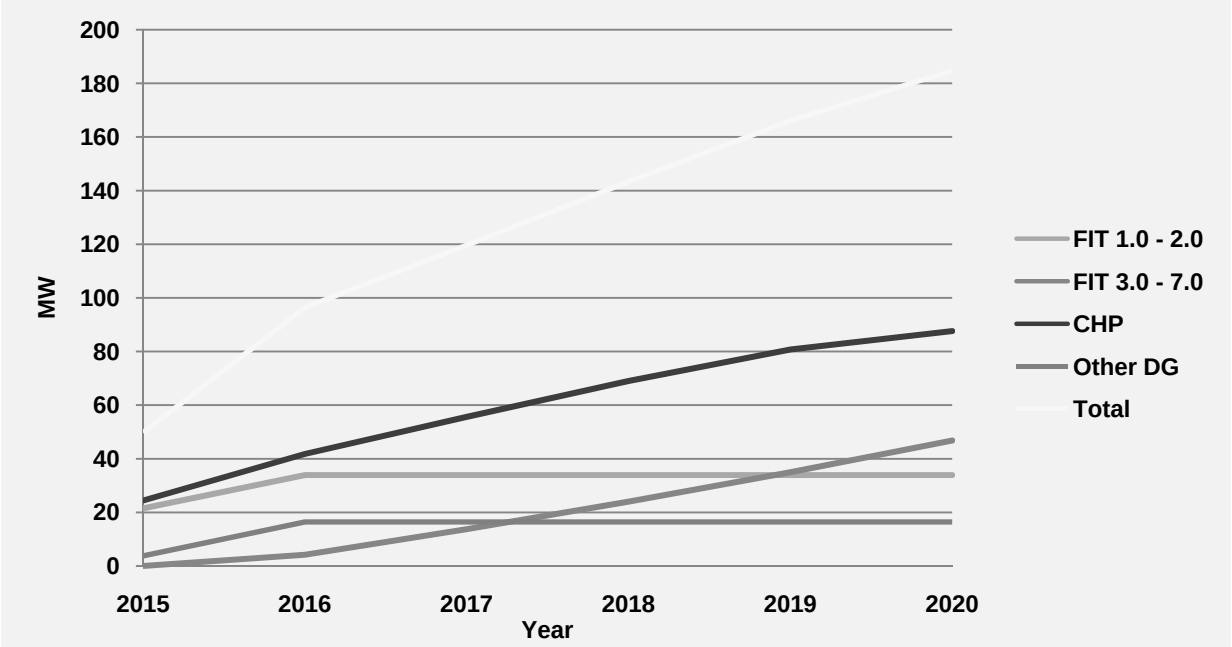


FIGURE 2: GRAPH OF DG CONNECTION FORECAST BY MW ACCORDING TO PROGRAM TYPE (2015-2019)

E1.6 Customer Engagement Activities

In order to better understand customers' preferences and values, Toronto Hydro carried out an extensive consultation on the utility's DSP. As explained in detail in Exhibit 1B, Tab 2, Schedule 7, Toronto Hydro engaged Innovative Research Group Inc. ("Innovative"), a national consultancy with expertise in public opinion research, to design and carry-out a consultation process intended to provide the utility with meaningful information to assist in preparing the DSP.

Toronto Hydro asked Innovative to bring key aspects of the utility's DSP to its most populous rate classes (Residential and General Service < 50 kW) as well as the utility's most populous larger customer market segments (Commercial and Industrial / Manufacturing), and to assess how customers' values and preferences align with the utility's proposed capital work. The consultation also included customers who live in condominiums or other multi-residential buildings. Innovative used a multi-faceted approach to gathering and assessing the needs and preferences of these customers, including the following methods:

1. an online workbook, accessible to any Toronto Hydro customer;
2. randomly recruited focus groups of residential and GS < 50 kW customers, facilitated by Innovative and based on a workbook describing the central pillars of Toronto Hydro's 2015-2019 DSP;
3. consultation with randomly recruited Commercial and Industrial / Manufacturing customers, including a panel discussion with Toronto Hydro staff moderated by Innovative, and focus groups using the same workbook;
4. a statistical telephone survey of 1,206 Toronto Hydro customers from both residential and GS < 50 kW rate classes.

Innovative's final report (available as Appendix B to Exhibit 1B, Tab 2, Schedule 7) documents the process and findings of this consultation in detail. A discussion of how the results of this consultation are reflected in Toronto Hydro's 2015-2019 Distribution System Plan is provided in section E2.4.

Innovative's customer engagement scope did not include Toronto Hydro's very large customers[3]. The utility engages its very large customers with respect to capital work as part of its regular meetings with those customers. During these meetings, Toronto Hydro invited all of its very large customers to submit letters of comment on the utility's ongoing, renewal-focused capital investment plans. Copies of all comment letters received since the utility's last distribution rates application are attached as Appendix A to Exhibit 1B, Tab 2, Schedule 7.

[3] A group including customers whose demand exceeds 5 MW, whose demand exceeds 1 MW and who are served by feeders that have been experiencing a high frequency of outages, and some customers with multiple accounts whose combined demand exceeds 5 MW.

(in green) are subtotalled to produce the life-cycle cost (in blue) – otherwise known as the total operating cost of the new asset in question. Theoretically, the economic end-of-life criteria represents the lowest point of this operating cost across the life-cycle of the asset, illustrated by the orange dot in Figure 1 – otherwise known as the Equivalent Annualized Cost (EAC). However, in actual practice, existing assets to be replaced and new assets to be installed will have different risk profiles. Figure 2 therefore illustrates a pragmatic calculation of the economic end-of-life criteria for a given asset through the execution of a risk-based optimization approach, whereby the EAC as determined for the new asset is applied to the existing asset's risk cost curve in order to calculate the optimal intervention timing, or economic end-of-life criteria, of the existing asset.

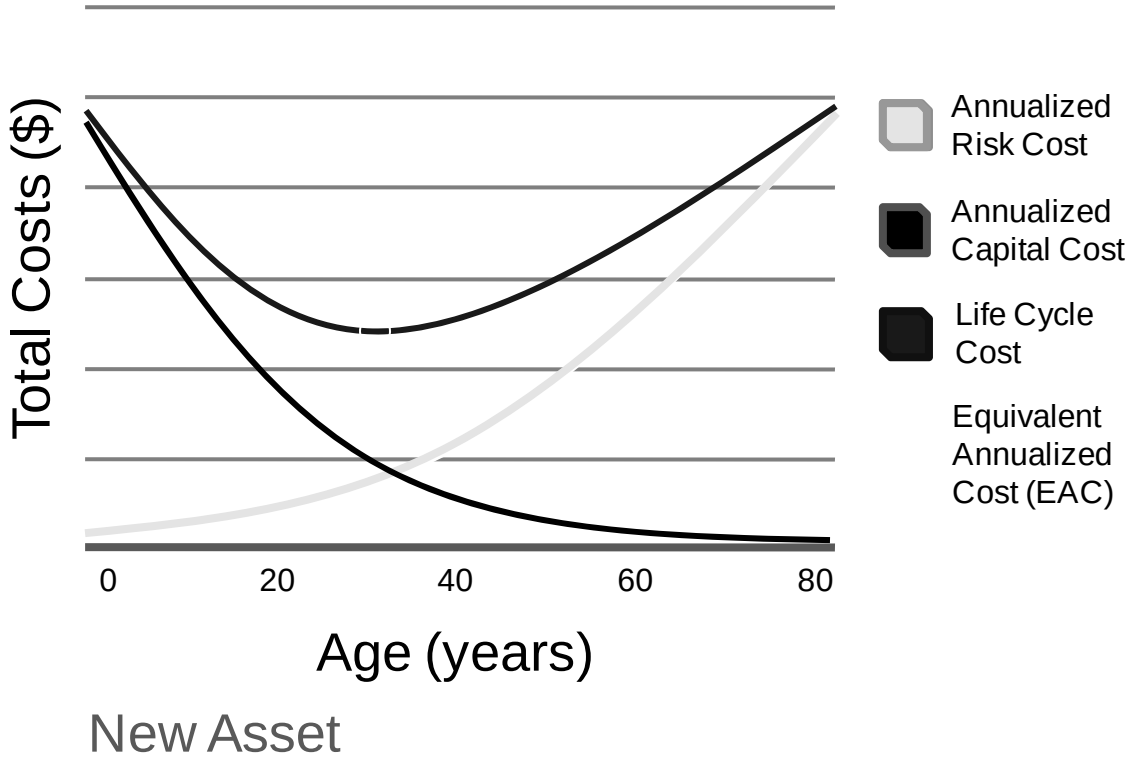


FIGURE 1: LIFE-CYCLE COSTING ANALYSIS (WHERE EAC REPRESENTS THE THEORETICAL STEADY STATE)

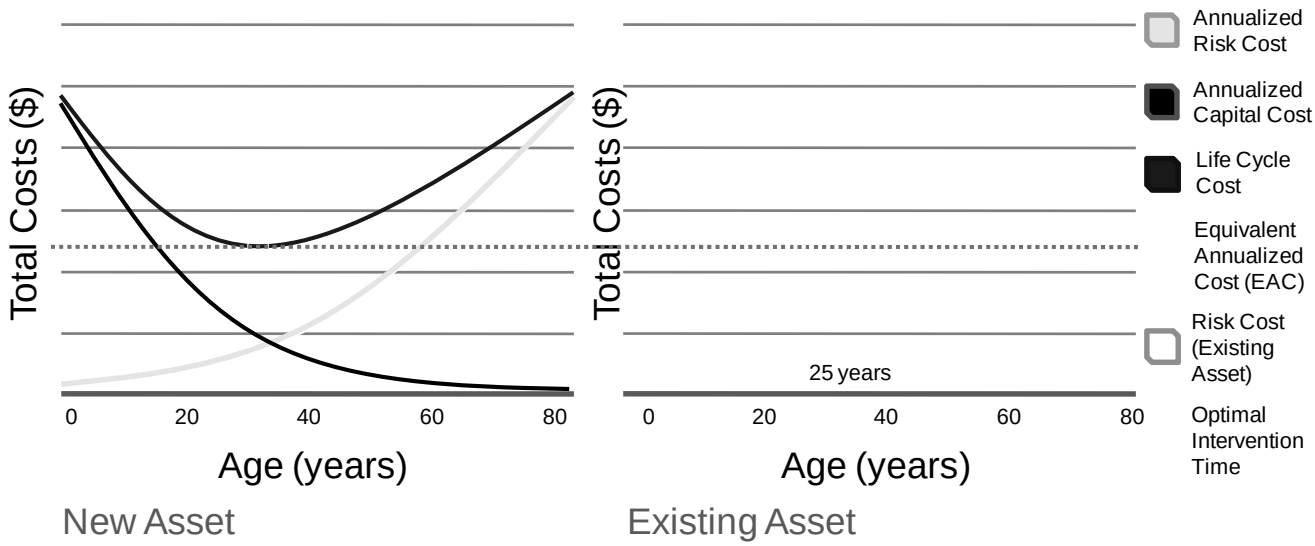


FIGURE 2: LIFE-CYCLE COSTING ANALYSIS (WHERE OPTIMAL INTERVENTION TIME IS A KEY INPUT USED WHEN CALCULATING THE STEADY STATE OF THE DISTRIBUTION SYSTEM AS PER RISK-BASED OPTIMIZATION APPROACH)

By applying this risk-based optimization approach to the broader population of major distribution assets across the system – such that the actual timing of asset renewal investments is, on average, aligned to the economic end-of-life criteria – a capital investment approach can be produced that allows for a optimal steady state to be achieved. Maintaining a steady state investment program is the most prudent approach to system investment, as it ensures that, on average, total life cycle costs of the assets across the system are minimized.

Outputs produced by the long-term system review process include the establishment of overall capital investment levels, which are then populated with capital investment programs as per the Investment Planning process, as defined in Section D3.1.1.3. This Section outlines the results of the long-term system review process as part of this 2015-2019 capital expenditure plan.

The first deliverable in this review process – the derived capital investment approach for the five-year planning horizon from 2015 onwards to 2019 – can be broken down into three areas of investment as illustrated in Figure 3 and further detailed below.

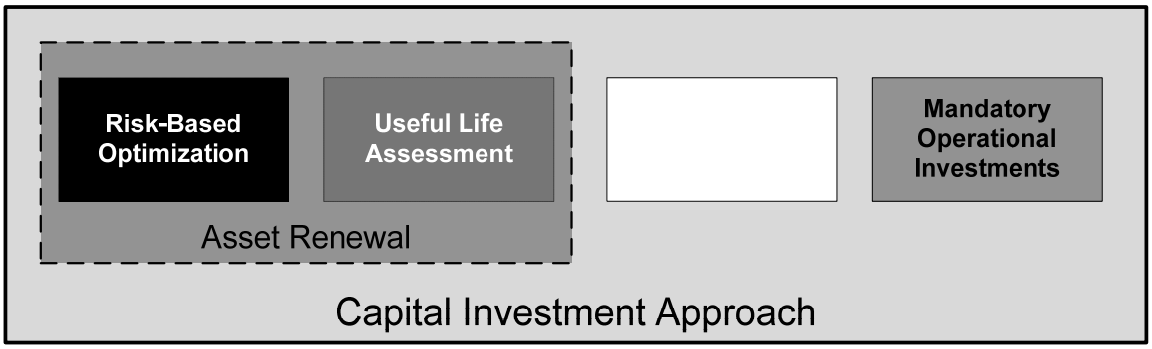


FIGURE 3: CAPITAL INVESTMENT APPROACH (2015-2019)

(a) **Asset Renewal:** To achieve steady state, in-kind replacement must be performed for those assets reaching or exceeding their economic end-of-life criteria. The Feeder Investment Model can be applied as to identify the economic end-of-life criteria and investment timing for all evaluated assets as per a risk-based optimization approach. For those asset classes not evaluated by the FIM, asset investment timing was determined based upon the assets' remaining useful life.

(b) **Critical System-Wide Issues:** This area of investment includes those broader investments of the utmost urgency, designed to target issues that go "beyond the asset", such as load growth, capacity and contingency constraints, operational flexibility and accessibility, safety and security of supply issues.

(c) **Mandatory Operational Investments:** This area of investment includes those necessary and mandatory day-to-day investments that support the 24/7 operations of Toronto Hydro, including customer-service requests, mandated service obligations, capital and maintenance support and non-system physical plant investments associated with Information Technology, Fleet and Facilities.

The spending requirements produced by this capital investment approach, illustrated in Figure 4, reveal a substantial investment backlog of approximately $2.56 billion that would optimally be spent in 2015, followed by approximately $1.55 billion in investment from 2016 through 2019 (in aggregate). The backlog is comprised predominantly of assets that are past their economic end-of-life and end-of-useful life respectively, as well as critical issues that must be urgently addressed. This backlog exposes Toronto Hydro's distribution system to immediate risks. /C

Toronto Hydro's assessment is that the spending requirements reflected are ultimately representative of an economically optimal capital investment approach: execution of these investments would mitigate this backlog and allow for an immediate achievement of steady state. This approach would minimize the operating costs to which customers are exposed when considering capital and risk costs.

However, Toronto Hydro recognizes that executing a capital investment approach of this magnitude in a single year would constitute an unprecedented level of investment, and would result in large step-increases in rates. Moreover, the utility could not reasonably expect to execute this magnitude of investment in a single year considering current system constraints and available resources.

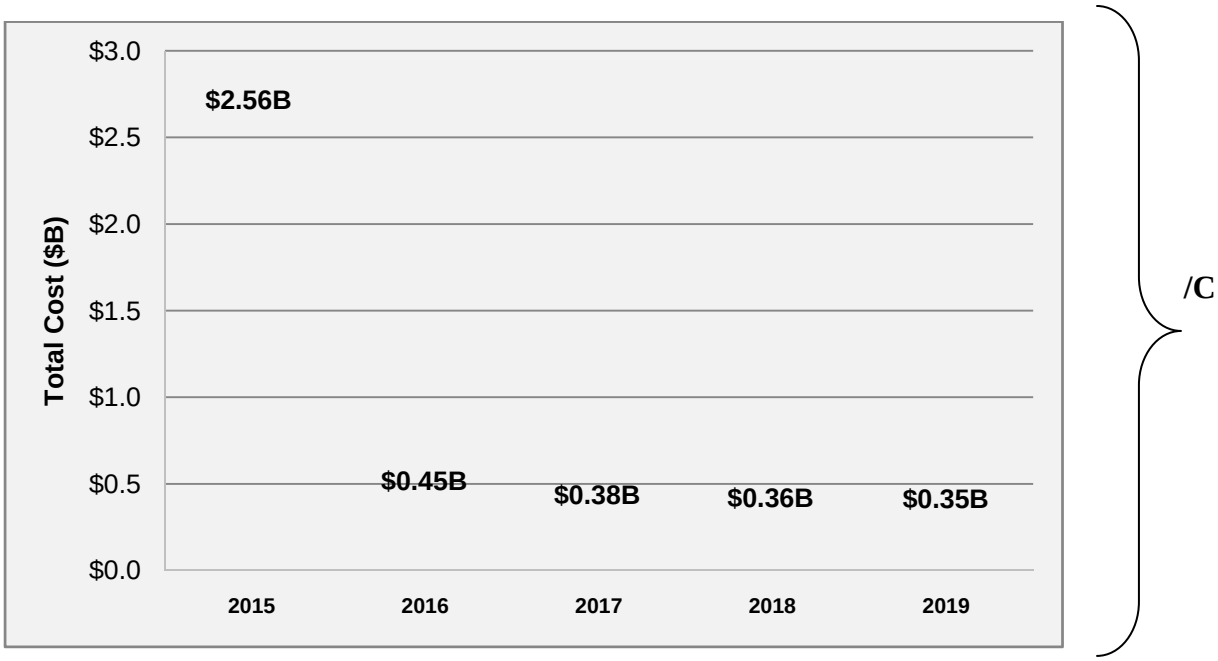


FIGURE 4: ECONOMICALLY OPTIMAL CAPITAL INVESTMENT APPROACH (2015-2019)

Recognizing the infeasibility of completing this work in a single year, Toronto Hydro considered two alternative timelines in which to carry out this work: an "accelerated" strategy as well as the proposed "paced" strategy. The accelerated strategy would allow for the backlog of investments to be managed over the five-year DSP period, such that steady state is achieved by 2019 with a

level of investment of approximately $830 million on average per year, for a total of $4.17 billion over five years.

However, this accelerated strategy would still contain levels of investment that do not align to Toronto Hydro's resources or system constraints, and would result in step-increases in rates for customers.

While Toronto Hydro has determined that the ideal investments in Toronto's distribution system exceed those proposed in this capital expenditure plan, the utility acknowledges customers' price sensitivity and therefore has proposed a more gradually paced 2015-2019 capital expenditure plan intended to arrive at the economically optimal steady state in a gradual manner. The proposed strategy addresses the backlog of investments in a manner that achieves the steady state by 2037. The paced strategy entails a proposed level of investment of $2.49 billion over 2015-2019, or an annual average of just under $500 million. Under this strategy, the backlog of investment remaining after 2019 will continue to be managed between 2020 and 2037, alongside new investments. Such new investments will be planned to manage assets that will reach or exceed their economic end-of-life or useful life criteria, as well as new critical issues that could emerge during this same 2020-2037 period. Toronto Hydro estimates that continuing at this average pace beyond 2020 would result in achievement of steady state by approximately 2037. /C

This gradually paced strategy aligns to Toronto Hydro's resource and system constraints, and is therefore practical to execute. Figure 5 illustrates the required capital investments of both the "accelerated" strategy (on the left) and the "paced" strategy (on the right).

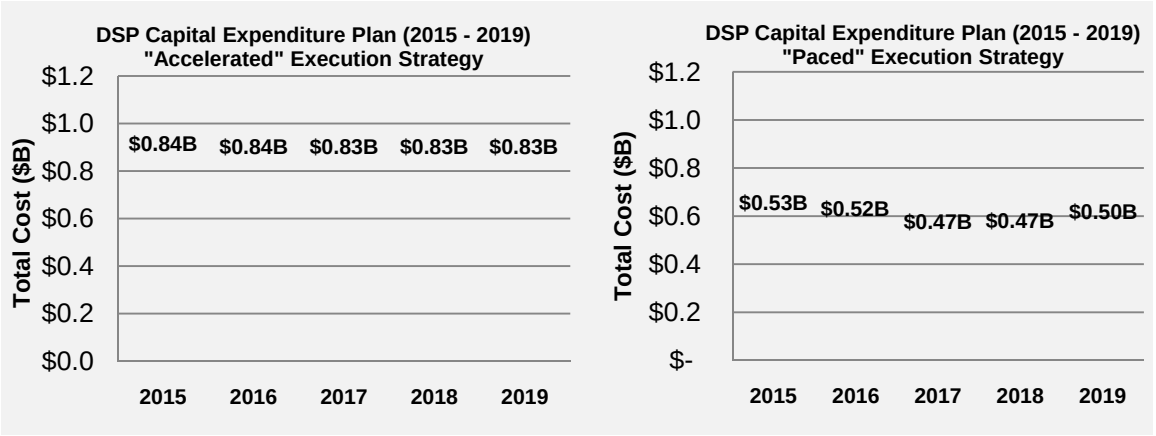


FIGURE 5: ACCELERATED VERSUS PACED CAPITAL INVESTMENT EXECUTION STRATEGIES (2015-2019)

As previously explained, the steady state is the economically optimal condition for the distribution system and ratepayers. By reaching the steady state in the proposed "paced" manner, the fluctuations in capital investment spending, which are driven by uneven depreciation of the asset base and necessitate periods of significantly large multi-year capital investment above historic levels, can be mitigated, leading to more consistent system-wide performance and smoother rate impacts beyond the initial achievement of steady state in 2037. As noted in the results of Toronto Hydro's customer engagement activities (Exhibit 1B, Tab 2, Schedule 7), some focus group and workshop participants, while accepting of the need for significant capital investment above historic levels and the associated bill impacts, felt that the uneven approach to investment over time could have been avoided had Toronto Hydro been building a reserve of capital funds beforehand. While Toronto Hydro is not able to operate a capital reserve fund of this nature, the paced execution strategy described here could, over the long-term, help mitigate the rate increases that can accompany uneven capital investment commitments.

Under the proposed "paced" execution strategy, SAIFI is projected to be reduced from 1.53 outages in 2014) to 1.13 outages in 2019, and SAIDI is projected to be reduced from 1.21 hours in 2014 to 0.97 hours in 2019 respectively. In contrast, should Toronto Hydro not execute this investment approach and instead adopt a run-to-failure approach, SAIFI and SAIDI are forecasted to worsen by another 30%, and 24% respectively over the period from 2015 to 2019. A run-to-failure approach would force Toronto Hydro to manage assets in a reactive manner, exposing customers to associated outages and higher reactive costs associated with the replacement of assets and the restoration of the system.

In summary, Toronto Hydro's distribution system already faces a significant level of risk as evidenced by the backlog of required capital investments. For every year of investment delay, the backlog will increase in size and result in a proportional increase to risk. Toronto Hydro recognizes that the proposed execution strategy carries a greater level of risk due to the longer period of time in which the backlog must be managed. However, this is an execution strategy that will still allow Toronto Hydro to achieve steady state in a manner that is responsive to customer price sensitivity while being immediately executable. This "paced" approach has the benefits of mitigating large fluctuations in system performance over time and helping to smooth future capital investments and corresponding rate impacts. The achievement of steady state allows Toronto Hydro's capital investment approach to align to AM objectives.

E2.1.1 Historic Investment & Demographics

The backlog of required spending as derived within the economically optimal capital investment approach, and illustrated in Figure 4, is the product of historical development, expansion and renewal of Toronto Hydro's system, which has resulted in investment peak periods followed by periods of depreciation and reduced investment.

Much of Toronto Hydro's system was constructed and expanded upon following the Second World War, with investment first peaking in the 1950s and 1960s. This was a period of unprecedented population growth, as illustrated by the blue bars respectively in Figure 6. For the downtown core, this was characterized largely by growth in the commercial, industrial and office sectors. For the former municipalities that make up the "Horseshoe" area around downtown Toronto today, the growth was primarily due to residential development, with associated commercial and retail space. Toronto Hydro's distribution system followed these trends, with intensification in construction of the Secondary Network System and the rapid construction of first overhead equipment, followed by increasing amounts of underground in the Horseshoe, utilizing first-generation direct-buried (DB) cross-linked polyethylene (XLPE) cables.

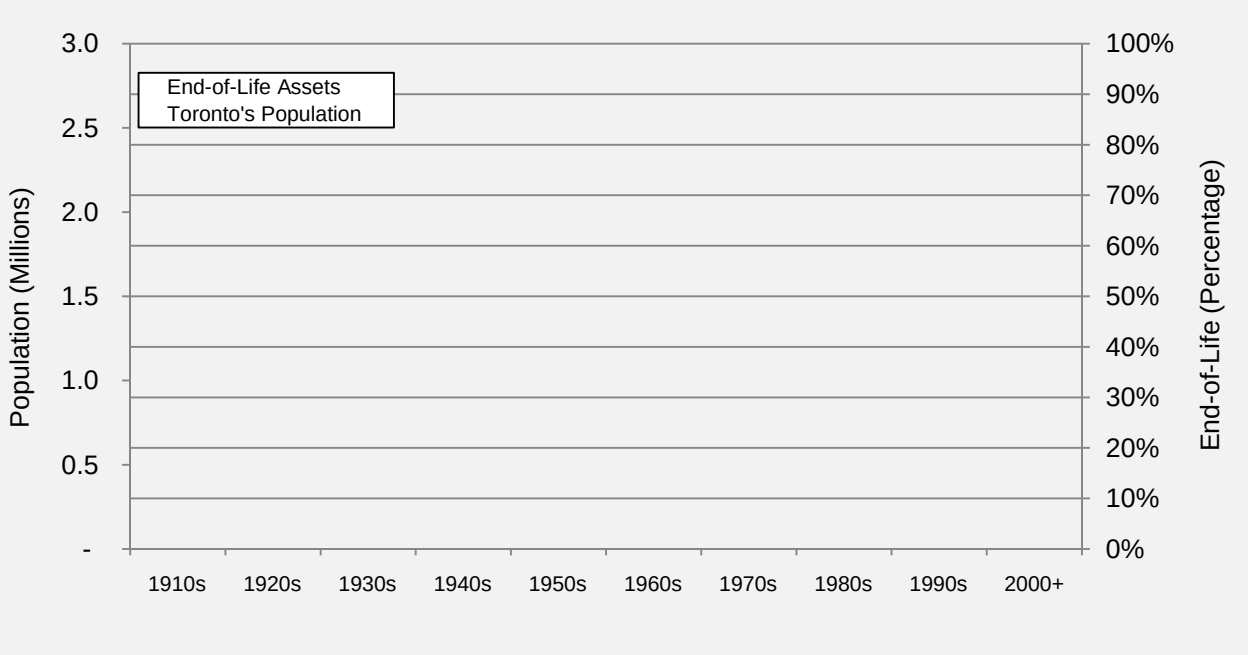


FIGURE 6: TORONTO'S POPULATION AND END-OF-LIFE ASSET DEMOGRAPHICS

This growth period involved the construction of new distribution plant in order to service new customer loads. As such, most of the capital investments involved a commensurate increase in distribution revenues, which enabled Toronto Hydro to finance the capital construction of assets over their lifespan. Eventually, land use reached a saturation point and population growth in both the downtown and Horseshoe areas began to slow down at the end of the 1960s and into the 1970s. While development continued in other areas of the Greater Toronto Area (GTA), the six utilities that would become Toronto Hydro entered into a period of depreciation and reduced spending, during which both revenue growth and capital expenditures slowed. Consequently, the amount of new electricity infrastructure being installed decreased substantially, and rates were kept relatively low.

As the investment peak period results in a large population of assets being installed within a similar time period, future investment peak periods are inevitably required to manage those same populations of assets when they simultaneously reach their economic end-of-life or end-of-useful life criteria respectively, thus producing a pattern of investment peaks followed by periods of reduced spending and depreciation. Toronto Hydro is currently managing its largest investment

peak period to date, which includes infrastructure that has reached or is exceeding its useful life criteria as illustrated by the bars in red in Figure 6.

Figure 7 further illustrates how capital investments necessary to manage this current investment peak period have been on the rise since 2006.



/C

FIGURE 7: HISTORICAL SYSTEM INVESTMENT

From 2012 to 2014, this third peak of investments was managed through a series of OEB-approved Incremental Capital Module (ICM) segments filed as part of Toronto Hydro's 2012-2014 rates application[2]. Many of the DSP programs proposed for 2015-2019 include capital work that is comparable to approved ICM segments, including "core" asset renewal investments for each of the grid systems (overhead, underground, secondary network and stations), the replacement of functionally obsolete infrastructure such as rear lot and box construction, and the replacement of legacy infrastructure currently posing safety issues, including SCADAMATE R1 and Polymer SMD-20 fused switches.

As originally further illustrated in Figure 8 below, approximately 26% of the replacement value Toronto Hydro's asset base will be past its useful life criteria by 2015.

[2] EBr2012r0064.



FIGURE 8: USEFUL LIFE DEMOGRAPHICS – 2015

It is critical that Toronto Hydro is able to manage this backlog as per a capital investment approach and execution strategy that allows for the steady state to be achieved, while also being responsive to customer's price sensitivity and practical to execute when accounting for available resources. The following sections provide further details and breakdowns on the capital investment approach as well as the execution strategies that may be applied in order to eliminate this backlog.

E2.1.2 Capital Investment Approach

The first milestone of the long-term system review process is to derive a proactive capital investment approach. Toronto Hydro's capital investment approach produced as part of the 2015-2019 capital expenditure plan includes three forms of investments:

- Asset renewal investments designed to target those assets nearing, at or beyond their economic end-of-life or end-of-useful life criteria within Toronto Hydro's grid systems (overhead, underground, secondary network, stations).
- System-wide critical issues that are of utmost urgency and go "beyond the asset", introducing challenges associated with safety, operational and capacity constraints, security of supply and load growth.

- Mandatory operational investments that support Toronto Hydro's operations, including Fleet, Facilities, IT, customer-service requests and mandated service obligations, capital and maintenance support.

Toronto Hydro has produced a proactive capital investment approach as part of the 2015-2019 capital expenditure plan that includes details on the challenges being mitigated through the resulting investments, as well as information on the timing of those investments.

E2.1.2.1 Asset Renewal Investments

Asset renewal investments represent in-kind replacements of assets across the four grid systems (overhead, underground, secondary network, stations), that the utility derived for the 2015-2019 period based upon their economic end-of-life criteria as per a risk-based optimization approach rooted in value-based reliability planning, as well as their end-of-useful life criteria based upon the assets' age.

In order for the proactive capital investment approach to achieve a steady state, a risk-based optimization approach was applied through the use of the Feeder Investment Model (FIM) such that the asset renewal investment timing was driven by the economic end-of-life results for each evaluated asset. Once these assets have reached their economic end-of-life criteria, they will be replaced with their standardized equivalents. Economic risks within this approach reflect various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, the costs of emergency repairs and replacement, and the indirect costs associated with asset failures.

Major distribution assets evaluated through the FIM in order to produce these results include overhead and underground distribution transformers and switches, poles, underground primary cables and secondary network units. Section D3.1.2.1 provides further details on the FIM and its inputs.

Figure 9 illustrates the system-wide results of the FIM. Results have been colour-coded based upon their respective economic end-of-life results. Assets that must be addressed immediately have been highlighted in red.

For those assets that Toronto Hydro did not evaluate within the FIM,[3] asset investment timing was then determined based upon the assets' end-of-useful life criteria.

Toronto Hydro employed the use of Hazard Rate Distribution Functions (HDF) in order to forecast the quantity of assets approaching their end of their useful lives and associated costs over a five-year period, from 2015 to 2019. The Hazard Rate methodology is explained in further detail in Section D3.1.1.2.

The collective use of these two approaches allowed Toronto Hydro to derive the asset renewal investment timings and associated spending levels for each of the four major grid systems across the five-year period from 2015-2019, including:

- Overhead circuit renewal investments for poles, overhead pole-top transformers and switches, conductor, poles & associated accessory hardware. The Overhead Circuit Renewal investment program is further defined in Section E6.4.
- Underground circuit renewal investments for underground cables (direct buried and conduit), transformers and switches. The Underground Circuit Renewal investment program is further defined in Section E6.1.
- Secondary network renewal investments for network units, vaults and associated primary & secondary network cables. The Network Vault Renewal investment program is further defined in Section E6.9, while the Network Unit Renewal investment program is further defined in Section E6.10.
- Stations renewal investments for power transformers, circuit breakers, switchgear and DC battery systems. The following stations renewal investment programs target these assets for intervention:
    - Stations Switchgear Renewal (Section E6.13)
    - Stations Power Transformer Renewal (Section E6.14)
    - Stations Circuit Breaker Renewal (Section E6.15)

[3] The risk-based optimization approach that is performed via an FIM evaluation requires for the entire population of assets within a given asset class to be evaluated. Each individual asset within a given asset class must possess mandatory inputs required to produce an economic end of life result. There are certain asset classes that currently cannot be evaluated in this manner, either due to (i) insufficient data, or (ii) lack of a developed FIM evaluation model for that particular asset class.

- Stations DC Battery Renewal (Section E6.19)

It should be noted that those assets that cannot be replaced in-kind (e.g. rear lot and box construction) were treated as critical issues, which are further discussed in Section E2.1.2.2.

FIGURE 9: OPTIMAL INTERVENTION TIMING MAP

E2.1.2.2 Investments to Mitigate System-Wide Critical Issues

Apart from the "core" asset renewal spending, there are also investments that go "beyond the asset", to target critically urgent issues across the distribution system. Examples of system-wide critical issues include:

- Asset infrastructure introducing safety-related issues and challenges (handwells, polymer SMD-20 fused switches, etc.).
- Load growth and capacity constraints
- Security-of-supply risks
- System and downtown contingency issues
- Operational constraints and inflexibilities

Investments required in order to mitigate these issues include:

- Upgrading and re-configuration of existing feeder infrastructure to improve operating flexibility, contingency and restoration capabilities. Associated investment programs include:
  - Contingency Enhancement (Section E7.1)
  - Design Enhancement (Section E7.2)
  - Feeder Automation (Section E7.3)
- Installation of new infrastructure to manage downtown contingency and security-of-supply risks. Associated investment programs include:
  - Downtown Contingency (Section E7.7)
  - Stations Expansion (Section E7.9)
- Standardization of key legacy asset classes and components in order to mitigate functional obsolescence and safety issues along with operational constraints. Associated investment programs include:
  - Customer-Owned Station Protection (Section E7.8)

- Polymer SMD-20 Renewal (Section E7.6)
- Handwell Upgrades (Section E7.5)

- Installation of new technologies designed to reduce outage duration periods, monitor asset performance and provide capacity relief. Associated investment programs include:
  - Energy Storage Systems (Section E7.11)
  - Local Demand Response (Section E7.10)

This category of investment also includes renewal-based investments for functionally obsolete infrastructure that cannot be replaced in-kind, including rear lot and box construction, automatic transfer switches and reverse power breakers, underground legacy infrastructure such as Sachsenwerk switch and fuse units, along with infrastructure installed in inaccessible locations. This infrastructure no longer aligns to Toronto Hydro's current operating practices or procedures, resulting in accessibility and serviceability conflicts, which can result in increased failure risk, reliability and/or safety-related risks.

All critical issues are considered to be of the most urgent nature and therefore are expected to be delivered within the first year of the capital investment approach.

E2.1.2.3 Mandatory Operational Investments

Apart from capital investments to manage "core" asset renewal requirements and mitigate system-wide critical issues, there are also necessary and mandatory investments to support Toronto Hydro's 24/7 operations. This includes:

- Mandated service obligations with respect to Metering investments
- Customer service requests with respect to the connection of new customers and the need to relocation and and/or expand infrastructure in response to third-party requests
- Non-System physical plant investments associated with Information Technology, Fleet and Facilities which form an essential part of Toronto Hydro's operations
- Ongoing capital and maintenance support for asset management systems and standards

The timing of these investments was derived based upon the scope and scale of the associated investment programs and projects.

E2.1.3 Capital Investment Execution Strategy

The capital investment execution strategy represents the second deliverable as part of the long-term system review process. For the 2015-2019 capital expenditure plan, an execution strategy must be derived that allows the derived capital investment approach to be executed in a manner that is responsive to customer's price sensitivity while still being practical to execute.

E2.1.3.1 Pacing: How to Reach the Steady State?

As illustrated in Figure 4, the economically optimal capital investment approach includes a substantial investment peak totaling $2.56 billion in 2015, followed by an additional $1.55 billion of investments from 2016 onwards to 2019. This initial peak is mostly comprised of a backlog of asset renewal and system-wide critical issues that must be mitigated in the first year. /C

The current backlog of assets and the current investment peak period can be effectively ended by executing upon the economically optimal capital investment approach as illustrated in Figure 4. Doing so would result in a steady state achievement by 2016. However, it is clear that the associated expenditures in 2015 would result in large step-increases in customer rates. This investment approach also would not align to Toronto Hydro's available resources and system constraints.

Therefore, Toronto Hydro investigated two execution strategies capable of mitigating this backlog in a manner that would result in capital expenditures that are responsive to customer price sensitivity and are practical to execute:

- The "accelerated" strategy, focused on mitigating the backlog over the five-year DSP period, thus reaching the steady state by 2020. This accelerated strategy provides an improved value for customers through the immediate reduction in risk, thereby allowing the distribution system to spend less time in a sub-optimal (and therefore more expensive) state.

- The "paced" strategy, where steady state is achieved at a more moderate pace beyond the five-year DSP period, resulting in slightly higher aggregate costs, since the distribution system would spend more time in a sub-optimal state, but with more restrained rate increases from 2015 onwards to 2019.

- These two strategies are explained in further detail within the following sections.

(i) "Accelerated" Execution Strategy

The "accelerated" execution strategy is focused on mitigating the backlog of investments within the 5-year DSP period, such that steady state is achieved by 2020.

As illustrated in Figure 10, this strategy requires significant capital investments of approximately $830 million on average per year, with a total five-year investment of $4.17 billion. The advantage of this strategy is that steady state can be achieved in more rapidly, therefore mitigating the risks associated with the backlog within the five-year period. However, it is clear that the rate impacts from this strategy would be substantial for customers. Furthermore, the required investments do not align to Toronto Hydro's available resources and system constraints, and therefore there would likely be execution-related complexities.

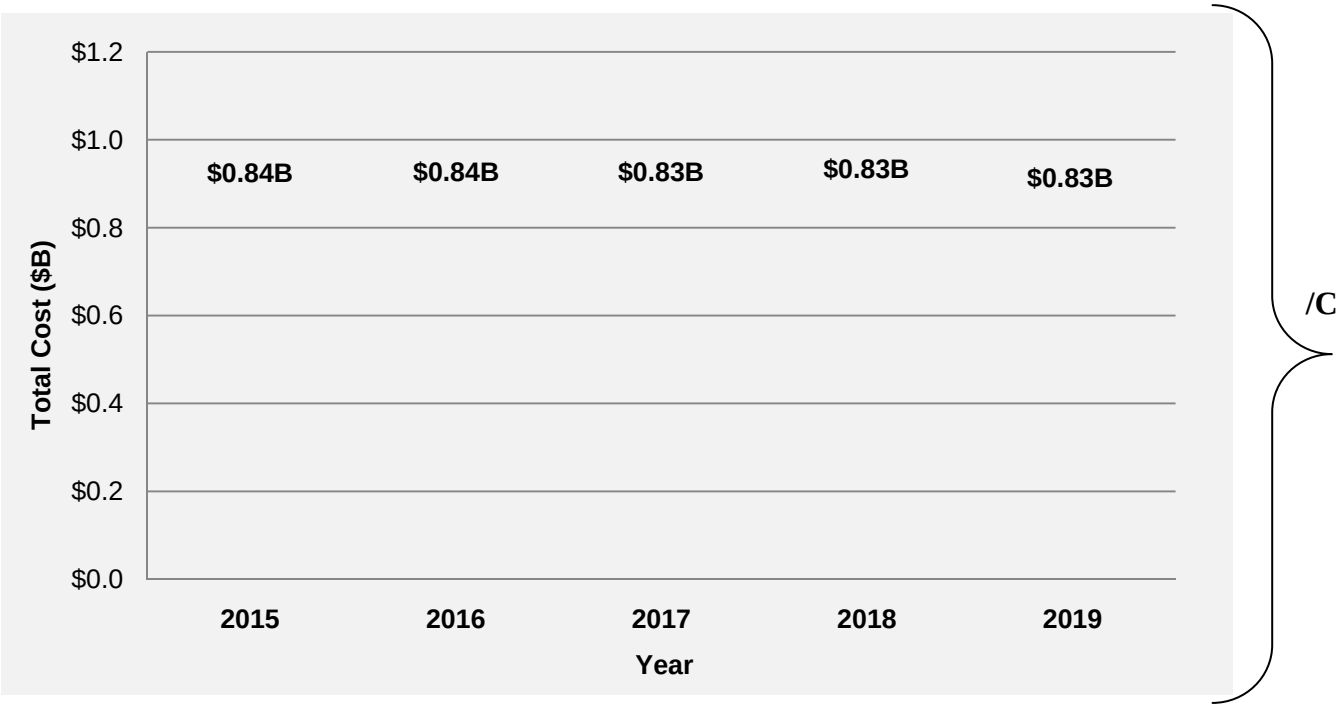


FIGURE 10: CAPITAL INVESTMENT APPROACH AS PER "ACCELERATED" EXECUTION STRATEGY

(ii) Toronto Hydro's Proposed "Paced" Execution Strategy

The "paced" execution strategy, as illustrated in Figure 11, is focused on eliminating the backlog in a manner that remains responsive to customer price sensitivities. This strategy results in a spending requirement of $2.49 billion over the period from 2015-2019, or an average annual investment of just under $500 million. The "paced" execution strategy eliminates the backlog by 2037, thereby allowing for steady state to be achieved. /C

The remaining backlog would necessarily be managed beyond the five-year DSP period. Assuming a similar average annual pace of investment as the 2015-2019 period, this strategy would result in the achievement of steady state by approximately 2037. From 2020 onwards to 2037, not only is the backlog being addressed, but new investments will be made to manage assets reaching their economic end-of-life or useful life criteria or new critical issues that will emerge during this same time period.

As per this strategy, customers are exposed to a greater amount of risk as opposed to the "Accelerated" strategy. However, this strategy still allows for that risk to be eliminated in a reasonable timeframe, with the added benefit of mitigating fluctuations with respect to capital investments and corresponding rate impacts during the 2015-2037 period and beyond. This stabilization of capital investment needs is a product of the steady pace in which investments are being made over this time period. This strategy also aligns to Toronto Hydro's resource allocations and system constraints.



FIGURE 11: CAPITAL INVESTMENT APPROACH AS PER "PACED" EXECUTION STRATEGY (2015-2019)

Toronto Hydro believes that the benefits of reduced rate impacts and execution complexities associated with the "Paced" execution strategy outweigh the benefits of the "Accelerated" execution strategy in terms of reaching the steady state within the five-year period. Based upon these results, Toronto Hydro has selected the "Paced" execution strategy as part of the 2015-2019 capital investment plan. Ultimately, the execution of the capital expenditure plan as per this strategy will result in predictable rates over the five-year DSP term due to the "paced" nature of the investments, and will ultimately allow for steady state achievement by 2037.

Figure 12 illustrates the useful life demographics following the achievement of steady state as per the "paced" execution strategy in 2037. The results illustrate how the replacement value associated with assets past their useful life decrease from 26% as of 2015 to 11% by 2037. Similarly, assets not exceeding their useful lives will increase from 67% as of 2015 to 80% by 2037.

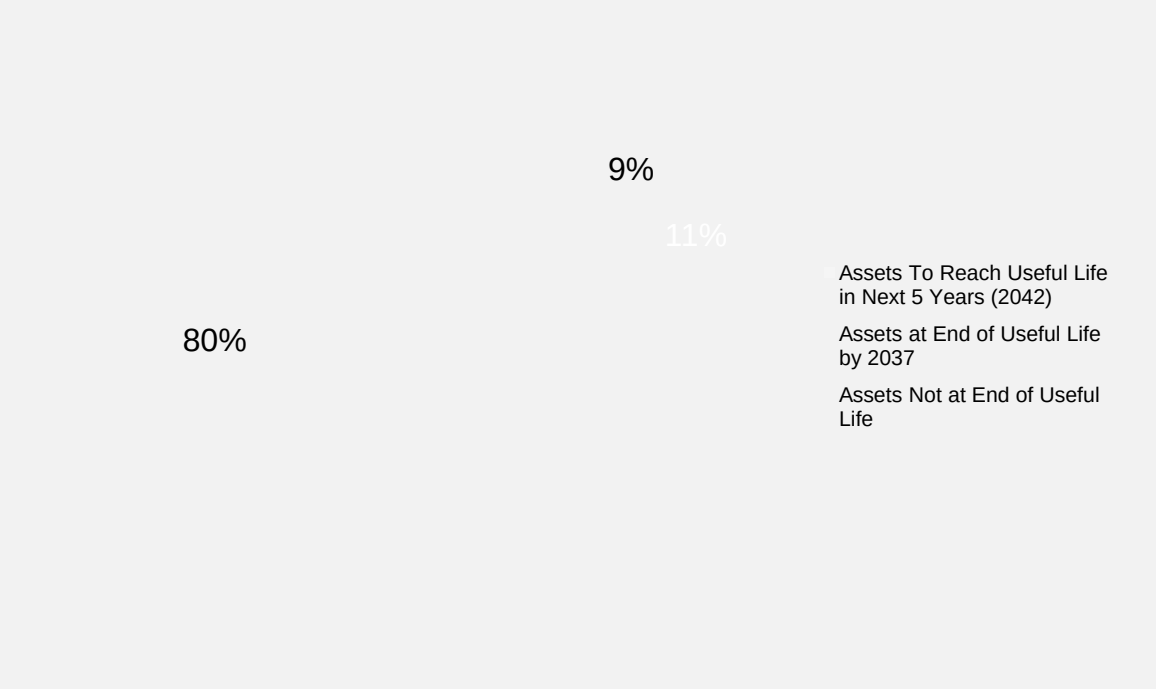


FIGURE 12: USEFUL LIFE DEMOGRAPHICS – 2037

E2.1.3 Reliability Projection

The final deliverable of the long-term system study process is to evaluate and assess the system performance impacts as a result of executing this proactive investment approach as per the "paced" execution strategy, as opposed to the run-to-failure or "do nothing" approach. Figures 13 and 14 respectively illustrate the year-over-year projected reliability comparison between the proactive investment approach and the run-to-failure/status quo approach. This investment program will address the majority of causes, with SAIFI projected to be reduced from 1.53 outages in 2014 to 1.13 outages in 2019, and SAIDI projected to be reduced from 1.21 hours in 2014 to 0.97 hours in 2019 respectively. In contrast, should Toronto Hydro not execute this investment approach and instead adopt a run to failure approach, SAIFI and SAIDI are projected to end the five year CIR period at a value of 1.50 and 1.99 respectively over.

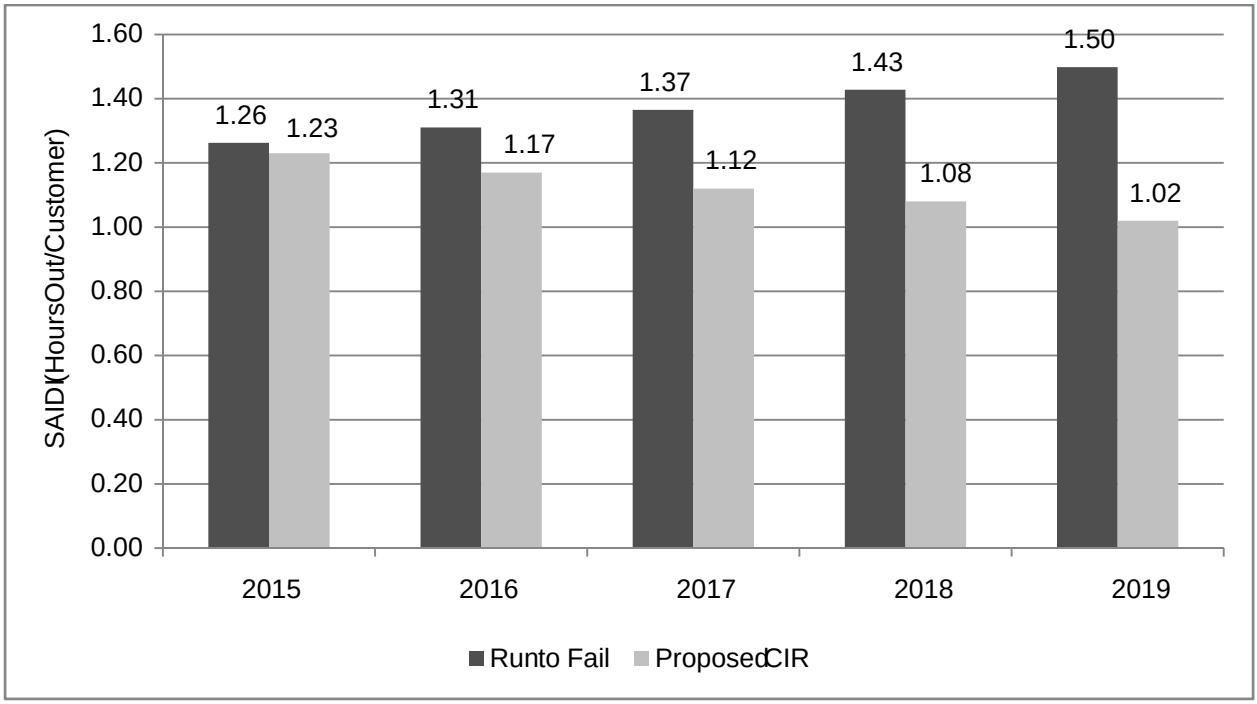


FIGURE 13: FIVE-YEAR SAIDI PROJECTION

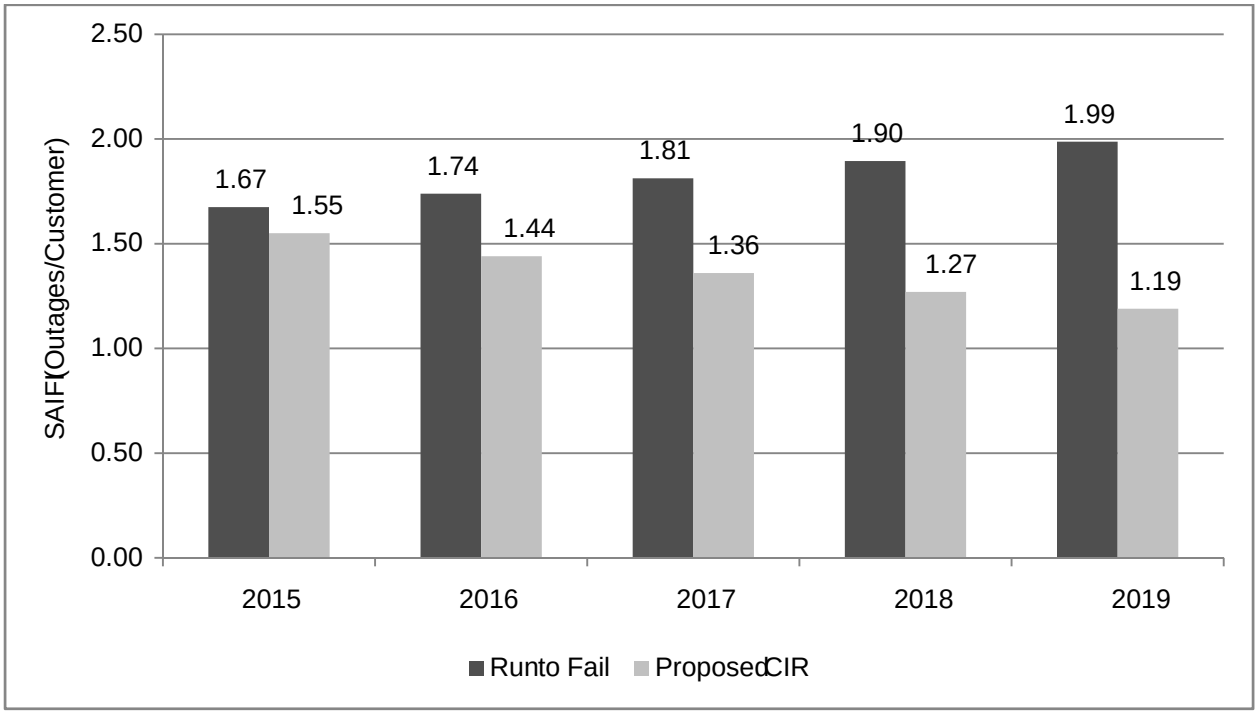


FIGURE 14: FIVE-YEAR SAIFI PROJECTION

It should be noted that this projection does not consider major event days, and the lasting impacts that major weather events can have on asset performance in future years.

The run-to-failure approach assumes that Toronto Hydro will cease all proactive work at a system level and essentially allow assets to fail before replacing them. As per a proactive capital investment approach, Toronto Hydro is able to replace those same assets via a planned outage or series of planned outages, where the customer impacts are minimized and isolated through optimal switching to backup supply feeders. In general, Toronto Hydro will have the new infrastructure in place prior to de-energizing the existing assets to make the transition as seamless as possible.

As per a run-to-failure approach, customers connected downstream from a fuse or connected anywhere on the feeder will be impacted by the resulting asset failure. Asset failures can impact anywhere from ten customers connected to a single transformer, up to 5000 customers connected to a feeder. Once the cause of outage has been established, Toronto Hydro field crews will have to perform fault locating and switching around the identified fault(s), such that the affected location is safely isolated and asset replacement activities can take place. During this time, customers can be adversely affected in their daily routine and are left without power.

Once the impacted asset(s) has/have been replaced, the feeder can be restored to a normal state. However, this approach will eventually lead to possible supplier shortfall or feeders being left in an abnormal state. This “Worst Case Scenario” can lead to entire feeders with no contingency options and leave thousands of customers without power as Toronto Hydro works to replace a single failed asset.

E2.1.4 Capital Investment Program & Project Development

Using the completed outputs from the Long-Term System Review process, including the finalized capital investment approach and execution strategy, Toronto Hydro executed the Investment Planning process as defined in Section D3.1.1.3 in order to produce capital investment programs. These programs align to the three forms of investment considered as part of the Long-Term System Study process, including asset renewal, system-wide critical issues and mandatory operational investments.

As illustrated in Figure 15, these three forms of investments are further integrated into the four investment categories: System Access, System Renewal, System Service & General Plant.

These integrations were performed depending on the nature of the investments coupled with the "trigger" drivers that are associated with each category.

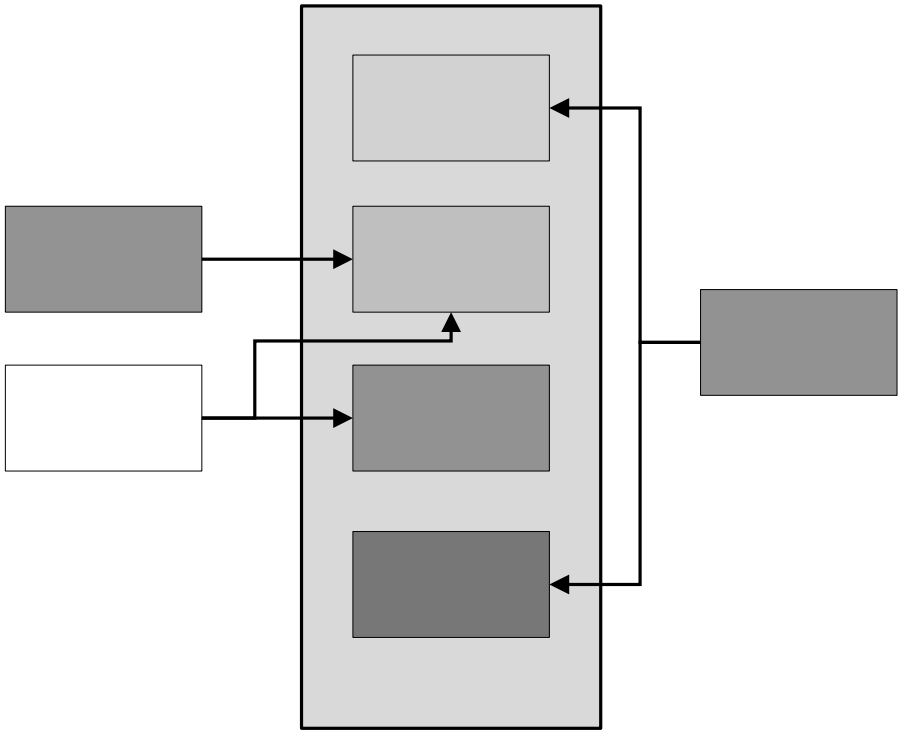


FIGURE 15: MAPPING OF CAPITAL INVESTMENTS TO INVESTMENT CATEGORIES

Asset renewal investments are integrated into the System Renewal investment category. System-wide critical issues are predominantly integrated within the System Service investment category, with the exception of investments targeting functionally obsolete infrastructure such as rear lot and box construction, automatic transfer switches and reverse power breakers, underground legacy infrastructure and infrastructure in inaccessible locations. Those investments have been integrated into the System Renewal category because functional obsolescence is an identified trigger driver within this investment category.

Mandatory operational investments have been integrated into both the System Access or General Plant investment categories, depending on the associated trigger drivers and the corresponding investment category.

As per the process defined in Section D3.1.1.3, capital investment programs and associated spending profiles for the 2015-2019 period have been produced by prioritizing system assets and issues based upon their alignment to their associated program trigger drivers. Sections E5 through to E8 provide further details into the System Access, System Renewal, System Service and General Plant investment categories and drivers respectively.

The project development process, defined in Section D3.1.2.2, has been applied to produce discrete investment projects for the 2015 year. As per this process, prioritized program-level assets and/or issues have been recaptured at the project level through the use of various inputs, including decision-support systems as defined in Section D3.1.2.1, depending on the associated program drivers. As the assets contained and issues to be resolved in these discrete projects have already been prioritized as per the Investment Planning process, all 2015 projects can be considered to have equal priority relative to each other. Projects from 2016 and onwards include a lesser priority of assets for intervention relative to 2015.

Capital investment spending from 2015-2019 has also been further refined as per this process, due to the high-level capital project implementation designs and capital project estimates that have been produced. Investment spending has been finalized for 2015 as per the Project Scheduling & Execution process, which also determines how individual capital investment projects are scheduled and executed within the 2015 year. This process is further detailed in Section E2.3.

Figure 16 provides the final expenditures associated with the 2015-2019 Capital Expenditure Plan, based upon the described capital investment approach and selected execution strategy.



1 **FIGURE 16: CAPITAL INVESTMENT REQUIREMENTS AS PER "PACED" EXECUTION STRATEGY (2015-2019)**

E2.2 Non-Distribution System Alternatives for Capacity Relief

Toronto Hydro does not currently have a policy or procedure for the treatment of non-distribution system alternatives to relieving capacity or operational constraints. "Non-wires" solutions are being examined as part of the Central Toronto Integrated Regional Resource Plan (IRRP) which is underway as described in Section B2.4. Further, "non-wires" solutions to relieving capacity or operational constraints are being proposed as part of the Local Demand Response investment program, described in section E7.10. The outcome of the Central Toronto IRRP and of the Local Demand Response investment program will contribute towards any future policy and procedure for the treatment of non-distribution system alternatives for capacity relief.

E2.3 Project Scheduling and Execution

Capital investment projects declared within the 2015-2019 Capital Expenditure Plan go through a scheduling and execution analysis process. When deciding upon project scheduling, projects are divided by execution groups comprised of internal and external contractors. These execution groups consist of field crews with different skill sets, geographical regions (east, west, and centre) and work types (planned, reactive, and customers' plans). The construction schedules for these execution groups are updated on a regular basis and rebasing of the plan line is performed typically on a quarterly basis or as needed, depending on the number of changes that have taken place since the forecast was issued. There are several factors that impact project scheduling (i.e. determining the sequencing order of projects as well as start and finish times). These factors include:

(1) Project scope and Requirements : The nature of the project (e.g., asset classes being replaced, project locations, impacted feeders, etc.) can have an impact on its scheduling (e.g., certain assets, such as large stations assets, can take time to be delivered to site, and certain project locations or feeders can create different execution complexities).

(2) Project Scope Changes : Changes in the project scope due to unforeseen field conditions can impact its scheduling during the course of the year.

(3) External Constraints : External constraints come from agencies whose planed timelines Toronto Hydro may have limited visibility into, but that Toronto Hydro must consider when scheduling work. These external groups include Metrolinx, TTC, Pan-Am Games, City of Toronto, HONI, and other utilities.

(4) Permitting and Moratoriums : Project schedules will be interdependent on road moratoriums during the course of the year alongside the receipt of permits from the City of Toronto to execute the projects. The permitting process can take months for the City to perform, which must be factored into the final scheduling.

(5) Customer Engagement and Contribution : Project scheduling must account for the necessary time to engage with affected customers and communities. Additional lead time may be necessary to account for changes to a project design if customer/community consensus cannot be reached.

(6) Project Coordination : In several cases, there are identified interdependencies between one project and another, which may result in specific scheduling requirements (i.e. in series or parallel). For example, civil duct work would be done sequentially as a Phase 1 to installing and energizing electrical cable into the duct as Phase 2. In addition, work often requires coordination with other projects in the area so as to minimize outages to customers. Similarly, projects often require coordination of work with HONI or third-party agencies such as TTC or Metrolinx.

(7) System Requirements : System requirements consider feeder availability. For example, the downtown area can be limited by seasonal restrictions, such as summer switching restrictions due to high system loading.

(8) Seasonal Requirements : Seasonal requirements result in some projects being executed at certain times of the year, forcing other projects with more flexible requirements to be scheduled at differing times. These requirements include avoiding trucks on soft soil in spring and fall, and avoiding pole installations or civil work when the ground is frozen in winter.

(9) Resource Availability : Resource availability considers labour constraints, including both internal labour and external contract labour. It also looks at optimal use of critical trades. Critical trades are those not commonly found and include resources such as Certified Power Cable Persons who work on lead cable and the downtown network system.

(10) Reactive Work : Activities where failed assets are being replaced as part of restoration activities may have scheduling impacts on existing proactive projects, particularly if assets within a project happen to fail prior to their scheduled execution. Such failures may result in changes to the scope of the project.

In general, project scheduling and execution must be dynamic in order to manage and account for all of these key elements, while maintaining deployment of resources.

Please see Exhibit 1B, Tab 2, Schedule 4, Appendix A for a detailed description of the complexities in carrying out a large-scale construction project or program in Toronto's dense urban environment.

As per this process, the capital investment plan for 2015 has been based upon Toronto Hydro's current work plan schedule as it stands during the preparation of this evidence.

E2.4 Customer Needs, Preferences and Priorities

As explained in Section E1.6, Toronto Hydro engaged Innovative Research Group ("Innovative") to design and carry-out a consultation process intended to provide the utility with meaningful information to assist in preparing the DSP. The consultation process included randomly recruited, workbook led focus groups, an online workbook accessible to all customers, facilitator led workshops with commercial and industrial users, and finally a statistical telephone survey. Innovative's final detailed report on the process and findings of this consultation is available in Appendix B to Exhibit 1B, Tab 2, Schedule 7.

These findings have provided valuable insight into the needs and preferences of Toronto Hydro's customers and their perception of the utility's priorities. A summary of how key findings are reflected in the DSP follows. The information discussed in the following sections is largely based on results of the final telephone survey, which was administered for the residential and General Service (GS) < 50 kW customer classes. The telephone survey gave Toronto Hydro a detailed view of the preferences of its most populous customer classes. The results of the GS > 50 kW Commercial and Industrial / Manufacturing workshops ("mid-market GS workshops") are referenced below as well, as this was the primary method by which Innovative engaged these larger customer segments.

E2.4.1 Overall Acceptance of Capital Plan

The telephone survey was designed to simulate the experience of customers who had participated in the earlier online workbook and workbook-led consultation sessions. Customers were educated on the state of the system, system challenges and the key aspects of Toronto Hydro's proposed DSP. They were invited to reflect on their personal experience with the system, and were asked to make "value judgments on trade-offs between system reliability and bill

impacts."[4] Customers were presented with forecasted bill impacts for the average user in their rate class based on the investments proposed in the DSP for the 2015-2019 period and forecasted operating expenditures (OPEX).

In general, residential and General Service (GS) < 50 kW customers accept the proposed rate increases associated with the DSP and planned OPEX amounts for 2015-2019.

- 58% of residential customers accept the proposed rate increases.[5]
- 48% of GS < 50 kW customers accept the proposed rate increases.[6]

For the mid-market GS workshops, 36 of 41 participants accepted the proposed rate increases.[7]

While the rate of acceptance of the plan is strong, Toronto Hydro notes that the majority of acceptance is from individuals who chose the "I don't like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard" response. Toronto Hydro's proposed capital execution strategy is inherently sensitive to this difficult balance between current system needs and the level of tolerance for price increases. As explained above in Section E2.1, Toronto Hydro has developed a "paced" capital execution strategy that has been deliberately restrained in order to align with expectations regarding acceptable price increases. (The estimated bill impacts presented to customers in the telephone survey were based on this "paced" strategy.) Ultimately, Toronto Hydro interprets these survey results as validation that the proposed strategy strikes an acceptable balance, and reflecting that the majority of customers accept the need for the proposed level of investment in the DSP.

Customers who most enthusiastically accept the rate increases in both the residential and GS < 50 kW classes cite the avoidance of a future infrastructure crisis, the desire for better service, and the reasonableness of the forecasted price increases as reasons for their responses,[8] all three of which align to Toronto Hydro's asset management policies and chosen objectives as described in Section D of the DSP. Customers who are more reluctant in their acceptance share similar views, but also feel that the rate increases are necessary.

[4] Innovative Research, Exhibit 1B, Tab 2, Schedule 7, Appendix B, p. 112
[5] Ibid., p. 108
[6] Ibid.
[7] Ibid., p. 85
[8] Ibid., pp. 147-148

E2.4.2 System Challenges & Priorities

(i) System Reliability

The following survey results describe the recent reliability performance of the system as experienced by the bulk of Toronto Hydro's customers.

- Over half of all customers in both the residential and GS < 50 kW classes have experienced outages during extreme weather events in the last twelve months.[10]
- Not including extreme weather, about half of all customers in these classes have experienced other power outages in the last twelve months.[11]
- 64% of GS < 50 kW customers report direct costs to their businesses as a result of outages.[12]
- Most participants in the mid-market GS workshops had experienced power service interruptions at their businesses in the previous twelve months. Both commercial and industrial customers experienced revenue and productivity losses due to these outages.[13]

As discussed in Sections D and E, Toronto Hydro's asset management policy with respect to system performance is focused primarily on risk-based decision making, where inferred customer interruption costs (CICs) are quantified as one of several risk costs associated with operating aging assets beyond their useful lives. The utility's chosen pace of system renewal is based largely on the objective of balancing these risks against the capital costs of asset replacement so that the total cost of operating the system is minimized over time. While Toronto Hydro does not set specific reliability targets as part of this process, it does project and track the reliability outcomes of its plan and considers adjustments to the prioritization of projects within and across programs if reliability outcomes are tracking below forecasts.

Customer expectations with respect to future reliability performance were captured through the telephone survey. Customers were informed of the current system average outage frequency (i.e. "the average Toronto Hydro customer experiences between one and two power outages per

[10] Ibid., p. 123
[11] Ibid.
[12] Ibid.
[13] Ibid., p. 84

year"[14]) and duration (i.e. "the average Toronto Hydro customer is without power for one to one-and-a-half hours per year"[15]) statistics, excluding extreme weather, and were asked about their preferences with respect to these benchmarks and their own experience.

- 70% of residential customers think Toronto Hydro should spend what is needed to reduce or maintain the frequency of interruptions.[16]
- 67% of GS < 50 kW customers think Toronto Hydro should spend what is needed to reduce or maintain the frequency of interruptions.[17]
- 74% of residential customers think Toronto Hydro should spend what is needed to either reduce or maintain the length of power outages.[18]
- 67% of GS < 50 kW customers think Toronto Hydro should spend what is needed to either reduce or maintain the length of power outages.[19]

Of the participants in the mid-market GS workshops, service-based commercial users and larger industrial businesses in the manufacturing sector wanted Toronto Hydro to focus on limiting the duration of power outages, as longer outages can have significant consequences for productivity.[20] Other manufacturing business wanted Toronto Hydro to focus on limiting the frequency of outages, as every interruption forces their production equipment to shut down.[21]

Toronto Hydro's proposed "paced" execution strategy, discussed in Section E2.1 above, is projected to improve both SAIDI and SAIFI over the five year planning horizon. As illustrated in Figures 13 and 14, the investments in this period are expected to reduce SAIFI from 1.53 outages in 2014 to 1.13 outages in 2019, and SAIDI from 1.21 hours in 2014 to 0.97 hours in 2019. While part of this projected reliability improvement is the result of basic like-for-like asset renewal, Toronto Hydro is also anticipating significant reliability benefits from investment in high value-for-money improvements in programs such as Feeder Automation (E7.3), Design Enhancement (E7.2) and Contingency Enhancement (E7.1). These relatively low cost enhancements to the existing system are helping Toronto Hydro to maintain a more moderate pace of renewal while

[14] Ibid., p. 130
[15] Ibid., p. 132
[16] Ibid., p. 128
[17] Ibid., p. 129
[18] Ibid., p. 130
[19] Ibid., p. 131
[20] Ibid., p. 84
[21] Ibid.

delivering desired improvements to reliability performance and restoration efficiency during the 2015-2019 period.

With respect to customers experiencing especially poor reliability service, Toronto Hydro continues to administer a targeted and highly responsive Worst Performing Feeder program (E6.21) to manage the number of feeders experiencing seven or more sustained outages in a 12-month rolling period. The utility is also proposing to initiate an Overhead Momentary Reduction program (E7.4) in the 2015-2019 period to improve service to customers on feeders experiencing an especially high frequency of momentary interruptions.

These investments are expected to benefit both residential and business customers of all sizes. Toronto Hydro is also planning to modify and expand the use of secondary network style configurations for delivering a high standard of reliability service to the increasing number of building developments over 25-stories tall across the City, particularly in the downtown core and financial district. Furthermore, Toronto Hydro's dedicated engagement program for very large users or "key account" customers (discussed in Exhibit 1B, Tab 2, Schedule 7) will continue to identify service reliability needs that can be accommodated within the suite of planned capital programs in the DSP.

(ii) System Investment Priorities

Customers were asked a series of values-based questions regarding their preferences with respect to the investment priorities outlined in Toronto Hydro's proposed DSP.

Investment in Aging Infrastructure

- 60% of residential customers think that Toronto Hydro should spend what it takes to renew the system's aging equipment to lessen the impact of power outages, even if it means higher bills.[22]

- 51% of GS < 50 kW customers think that Toronto Hydro should spend what it takes to renew the system's aging equipment to lessen the impact of power outages, even if it means higher bills.[23]

Most participants in mid-market GS workshops felt that the proposed pace of system renewal is appropriate and was balanced with customer bill impacts.[24]

[22] Ibid., p. 133
[23] Ibid., p. 134

As discussed throughout the DSP, the single most significant driver of Toronto Hydro's capital investment commitments over the 2015-2019 period is the need to renew the backlog of aging and obsolete infrastructure. Toronto Hydro's DSP demonstrates that the proposed amount of System Renewal investment, combined with complimentary or otherwise necessary investments in other investment categories, represents the minimum amount of investment appropriate given the distribution system's current and longer-term needs and the operational needs of the business. The telephone survey results summarized above demonstrate that customer preferences and needs are aligned with this approach, as the majority of customers across the broader customer base acknowledge the need for a sustained renewal program and consider the maintenance or improvement of system performance a priority over the avoidance of price increases. As discussed in Section E2.4.2 above, this prevailing view is seemingly based on the fact that customers consider the costs of the proposed DSP to be reasonable, and that a majority of customers believe that proactive investment is a prudent choice now to avoid future infrastructure challenges.

Investment in New Technology

- 67% of residential customers agree with the view that investments in new technology will increase system reliability, make the local distribution system more efficient and save money in the long run. (19% held the opposing view, that new technologies are a luxury and will cost customers more than they are willing to pay.)[26]

- 61% of GS < 50 kW customers agree with the view that investments in new technology will increase system reliability, make the local distribution system more efficient and save money in the long run. (20% chose the opposing view.)[27]

This survey question was intended to capture customer preferences with respect to System Service investments in programs like Feeder Automation (E7.3) and Energy Storage Systems (E7.11), which Toronto Hydro has included as part of its capital expenditure plan in order to enhance customer value through the mitigation of failure impacts and the targeted enhancement of system performance and efficiency. Customer preferences appear to be in alignment with these objectives.

[24] Ibid., p. 85
[26] Ibid., p. 135
[27] Ibid., p. 136

Investment in Equipment and Tools

- 66% of residential customers agree with the view that Toronto Hydro should be wise with its spending, but that it is also important that staff have the equipment and tools needed to manage the system efficiently and reliably.[28]

- 56% of GS < 50 kW customers agree with the view that Toronto Hydro should be wise with its spending, but that it is also important that staff have the equipment and tools needed to manage the system efficiently and reliably.[29]

This survey question was intended to capture customer preferences with respect to General Plant investments. Most customers recognize the importance of investing in effective and efficient business operations and are comfortable paying for these investments as part of the overall DSP.

(iii) Other Feedback

Innovative also asked telephone survey participants for their reaction to various statements that customers had made in previous phases of the consultation process (e.g., during randomly recruited focus groups). The results of these questions provided additional insight into customer values and preferences with respect to capital investment and other issues.

Of the topics most relevant to Toronto Hydro's mandate, the following received strong agreement (ranging from 57% to 81%) from survey respondents. (The respondent reaction results for all of the following quoted statements can be found on pages 140 and 142 of the Innovative Report, Exhibit 1B, Tab 2, Schedule 7, Appendix B.)

- "A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly" (statement for residential class only). Most of the investments in Toronto Hydro's DSP address potential outage causes that could affect service to the elderly, individuals relying on life-support equipment, and those who are otherwise vulnerable. Lengthier outages are likely to have a greater negative impact on vulnerable members of the population. A number of Toronto Hydro's proposed programs for the 2015-2019 period are expected to (i) shorten the length of outages and significantly improve restoration efforts (e.g., Feeder Automation (E7.3); Contingency

[28] Ibid., p. 137
[29] Ibid., p. 138

Enhancement (E7.1)) and (ii) mitigate the reliability risks associated low probability, high impact loss of supply events (e.g., Downtown Contingency).

- "Nobody likes to pay more for electricity, but I think we have an obligation to maintain reliability of our local grid for future generations." As explained above in Section E2.1, Toronto Hydro's proposed capital expenditure plan is designed to deliver long-term value to customers by working toward the objective of substantially clearing the accumulated backlog of end-of-life assets. Toronto Hydro is executing this plan in a "paced" manner intended to limit bill impacts in the short-term while helping to ensure more predictable year-over-year bill impacts and system performance outcomes in the long-term. Part of this strategy involves the expansion of cost-efficient, reliability enhancing technologies like Feeder Automation.

- "We should invest in our electricity system now or we will end up paying more the longer we delay our system renewal." This view also aligns to Toronto Hydro's overarching pacing strategy and the timing and pacing rationale that appears in many of the program business cases. Toronto Hydro has a limited number of skilled resources available at any given time to execute a large capital program. Deferral of the distribution system's renewal needs is likely to result in a growing gap between investment needs and execution capacity, potentially resulting in greater capital costs and deteriorating system performance due to resource constraints.

- "Although waiting until electric equipment breaks down is a good way to get full value out of Toronto Hydro's assets, an important city like Toronto cannot afford the associated service interruptions and should have a higher standard of system reliability" (GS < 50 kW customers were presented with a business-specific variation on this statement). The proposed DSP is projected to deliver system-wide reliability improvements over the course of the plan. A comparison of reliability outcomes for this plan versus the "run-to-failure" approach can be seen in Figures 13 and 14 above. Again, some of the most cost-effect improvements to reliability over this period are expected to come from System Service type investments, such as Feeder Automation and Design Enhancement. Leveraging high-value technologies like Feeder Automation will help maximize the value that residential and business customers derive from the City of Toronto's distribution system.

- "The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities" (GS < 50 kW were presented with a business-specific variation on this statement). As explained in Section E2.1 above, Toronto Hydro has chosen a "paced" execution strategy for its 2015-2019 capital expenditure plan that considers customer expectations with respect to bill impacts. The suite of programs that constitute this plan were chosen to maximize customer value derived from the system while mitigating the required pace of renewal in the short-term and long-term.

E3 SYSTEM CAPABILITY ASSESSMENT FOR RENEWABLE ENERGY GENERATION

This section provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation (REG) and other distributed generation (DG) connections. This information includes REG applications, their number and capacity, the distribution system's ability to connect, as well as known constraints on the distribution and transmission systems. As well, to obtain the complete picture in terms of cumulative generation connections, overall DG projections are presented.

E3.1 Applications

Toronto Hydro has connected over 890 unique DG connections to the distribution grid since 2009. Figure 1 provides an overview of existing DG connections within Toronto Hydro's distribution system. This represents over 110 MW of generation capacity made up of various types of DG technologies.

FIGURE 1: TORONTO HYDRO DG CONNECTIONS (AS OF MAY 31ST, 2014)

For REG in the "over 10 kW" in size category, there are presently 420 applications representing 53.5 MW of capacity that are in progress for connections within Toronto Hydro's service area. The total REG connections expected as of year-end 2014 and 2015 are 53.9 MW and 85 MW, respectively.

E3.2 Forecasted Connections

In order to determine the number of generation connections in the period covering 2015 to 2019, Toronto Hydro developed a DG connection and capacity forecast. The forecast for 2015 through to 2019 was developed using the historical DG connection rate from 2009 to present. The DG forecasting takes into account historical connection trends with respect to various DG programs, projects presently in progress and Feed-In Tariff (FIT) procurement targets. Forecasting uses a linear approximation to forecast the total generation from 2015 through 2019. The forecast

connection rates of DG and REG are consistent with expectations from the Long-Term Energy Plan and OPA procurement plans.

DG includes both non-renewable generation sources, such as gas powered generators, and REG sources, such as solar photovoltaic or wind turbines. An overview of both DG and REG are important to understand the distribution system impact and integration issues. By the end of 2014, a total of 176.2 MW (nameplate capacity of all DG) is expected to be connected to Toronto Hydro's system. This will be comprised of a combination of FIT projects, Combined Heat and Power (CHP) resources and other distributed generation.

A wide range of proponents have submitted project applications for REG, including many schools, housing, large grocery stores and department stores. Toronto Hydro's present rate of inquiry for individual FIT customers is estimated at 7.5 MW per month spread over 50 inquiries. Schools have received over 300 pending offers to connect renewable generation from the Ontario Power Authority (OPA) with over 40 MW of capacity. The total number and capacity (in MW) of REG connections anticipated over the forecasted five-year period are 972 connections with a corresponding 148.9 MW as shown in Figure 2.

Overall, DG connections are expected to more than triple in total capacity by 2019, reaching over 625 MW as shown in Table 1. This represents an additional 450 MW over the five year planning period on top of the 114 MW of existing DG and 62 MW of DG planned for connection by the end of 2014.

TABLE 1: BREAKDOWN OF DG CONNECTION FORECAST (BY MW) PER PROGRAM TYPE (2015-2019)

Program	Existing (Includes 2014 Planned)	2015	2016	2017	2018	2019	Total (MW)
FIT 1.0 – 2.0	53.9	31.2	0.0	0.0	0.0	0.0	85.0
FIT 3.0 – 7.0	0.0	10.7	23.9	25.8	27.7	29.7	117.8
Combined Heat and Power (CHP)	59.6	35.5	28.2	27.3	24.0	104.0	278.6
Other DG	62.7	32.9	18.0	8.0	15.0	8.0	144.6
Total	176.2	110.3	70.1	61.1	66.7	141.7	626.0

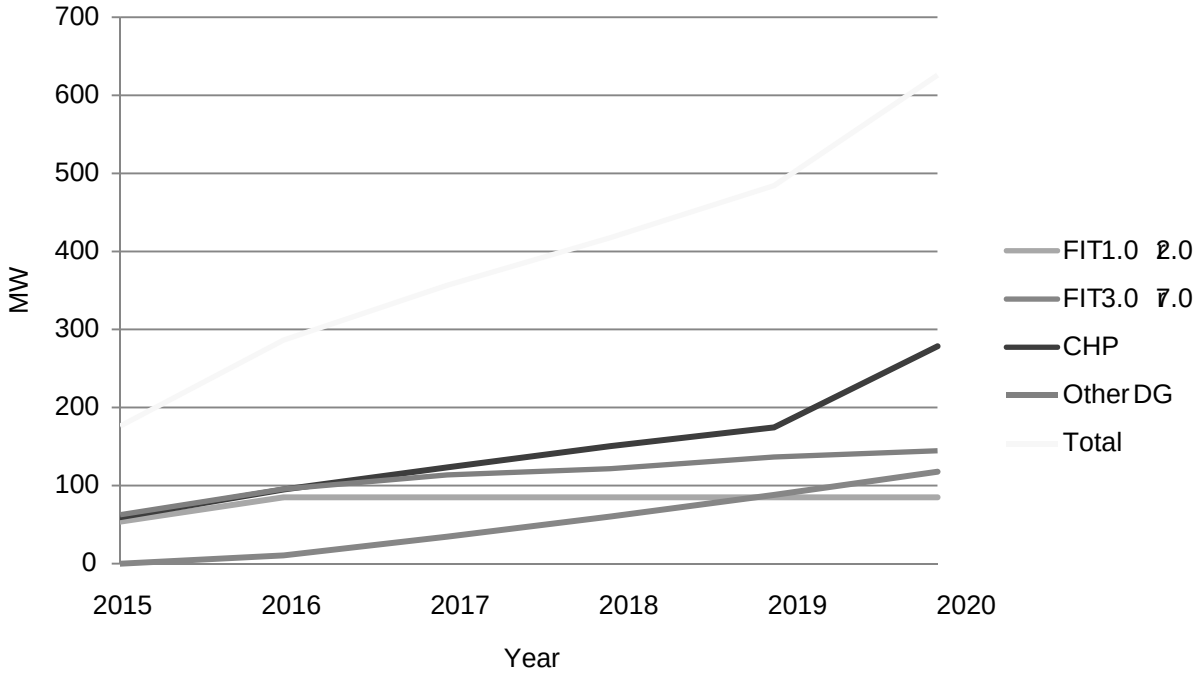


FIGURE 2: GRAPH OF DG CONNECTION FORECAST PER PROGRAM TYPE (2015-2019)

E3.3 Capacity to Connect REG

This section addresses the capacity to connect renewable energy within the service area of Toronto Hydro. Toronto Hydro projects that 626MW of DG will connect to the distribution system by the end of 2019. This capacity will be available for connecting the forecasted DG and REG projects given implementation of the proposed solutions in Section E3.3.3.

E3.3.1 Existing Capacity to Connect

There are several immediate and long-term challenges associated with connecting the forecasted 626 MW of DG to the Toronto Hydro system. As discussed later in section E3.4 Constraints, Toronto Hydro is currently affected by two types of constraints: distribution constraints and transmission constraints. On the distribution level, short circuit capacity is the main constraint that prevents new DG connections to certain stations.

E3.3.2 Existing Constraints to Connect

There are a number of constraints limiting Toronto Hydro's ability to connect DG, including fault current, thermal limits, minimal flows and the ability to transfer loads between feeders in the event of a contingency. The primary constraint at this time is short circuit capacity. At present, the ability to connect new DG is limited by constraints within the Toronto Hydro distribution system and externally in Hydro One Networks Inc.'s (HONI) transmission system.

E3.3.2.1 Transmission Constraints

Presently, transmission constraints pose a DG connection challenge to a significant area within Toronto. The identified transmission constraints at both Manby and Leaside Transformer Stations affect Toronto Hydro's ability to approve requests for DG interconnection. HONI's identified system constraints include the following:

(a) Short circuit capacity constraints per Transmission System Code (TSC) limits;

(b) Thermal Capacity on Station Transformers that limits reverse power flow;

(c) Minimum bus load requirements to limit reverse power flow; and,

(d) Short circuit capacity constraints due to transmission breaker capacity.

As shown in Figure 3, the constrained stations are in the areas of the downtown Toronto 115 kV system and East Scarborough 230 kV system. In 2015, the completion of the planned HONI

capital upgrades on these 115 kV and 230 kV systems is expected to address transmission system short circuit and thermal capacity issues within Toronto Hydro's service area. Toronto Hydro anticipates these constraints will be eliminated as an impediment to the forecasted DG projects in the beginning of 2015.

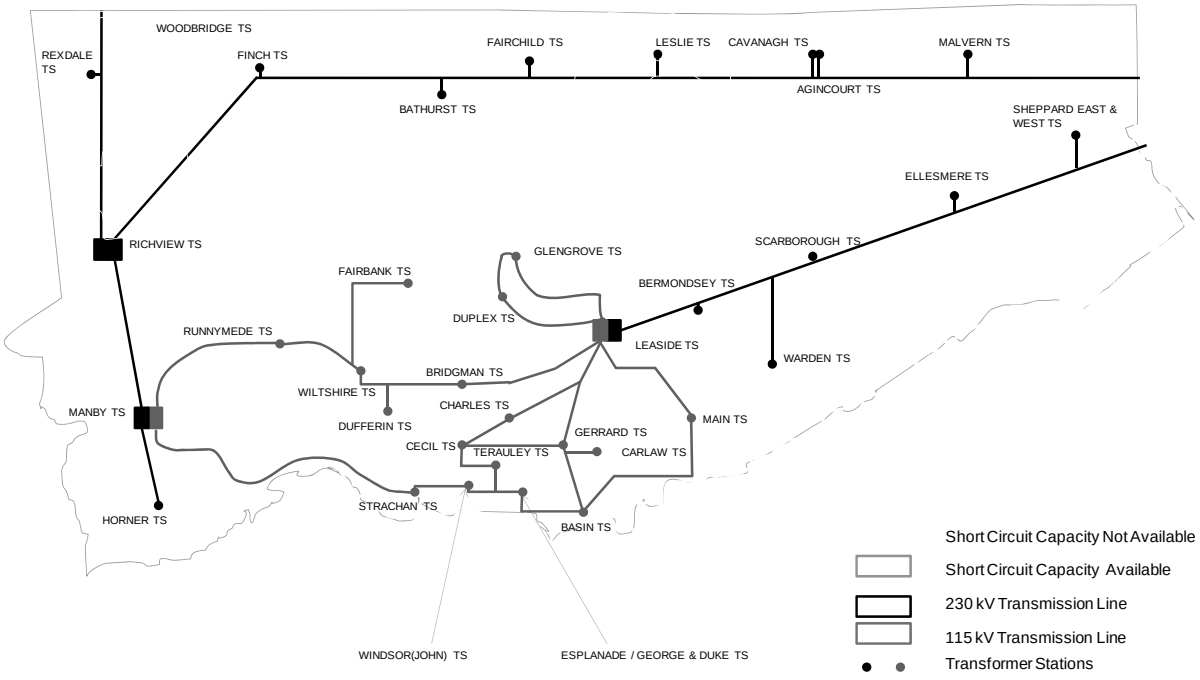


FIGURE 3: SHORT CIRCUIT CONSTRAINTS – PRE-HONI LEASIDE/MANBY/HEARN UPGRADES

E3.3.2.2 Distribution Constraints

The safe and reliable operation of the distribution system prevents Toronto Hydro from connecting DG in situations where short circuit capacity limitations exist. The existing distribution based short circuit capacity constraints are identified as shown in Figure 4. This map displays the areas within Toronto that are presently constrained due to short circuit limits at individual stations. These stations are supplied by HONI transformers and directly connect to Toronto Hydro feeders. The distribution based constraints will remain even after HONI has addressed the transmission constraints at the 230 kV and 115 kV level. As discussed earlier in Section E3.1 (Capacity to Connect), Toronto Hydro proposes advanced high speed protection systems to mitigate the existing short circuit capacity constraints and to satisfy system thermal thresholds, which are

expected to allow the distribution system to accommodate the new REG connections. More detailed information could be found in Sections E5.5.

FIGURE 4: DISTRIBUTION SYSTEM SHORT CIRCUIT CAPACITY CONSTRAINTS MAP

E3.3.3 Planned Solutions to Eliminate Constraints

In order to accommodate the forecasted amount of DG into Toronto Hydro's distribution system, the following solutions have been identified for the 2015 to 2019 period:

(1) Advanced protection systems which are expected to provide the ability to connect additional renewable energy by ensuring system thermal thresholds and short circuit design ratings are satisfied.

(2) A bus-tie reactor that is expected to provide the ability to connect additional DG by lowering the short circuit current on the station bus and distribution system.

(3) Real-time monitoring and control is expected to allow Toronto Hydro to connect the forecasted amount of DG sites, and continue to meet the mandated requirements of the Distribution System Code.

By implementing these solutions, Toronto Hydro expects to be able to provide uniform access across the distribution system, allowing renewable energy generation to connect on a grid-wide basis. In addition, Toronto Hydro forecasts that these investments will permit the utility to connect the forecasted 625MW of DG to the distribution system by the end of 2019. For more detailed information regarding generation protection, monitoring and control, please refer to Section E5.5.

E4 CAPITAL EXPENDITURE SUMMARY

This section summarizes historical and forecasted system capital and system operating and maintenance (O&M) expenditures and their respective drivers for the period 2010 to 2019.

E4.1 Investment Summary (10-Year Comparison)

Table 1 shows the level of spending for the System Access, System Renewal, System Service and General Plant investment categories, as well as the System O&M expenditures, over the historical period from 2010 to 2014, and over the forecasted period from 2015 to 2019. This table aligns with "Table 2 – Capital Expenditure Summary" as specified in Chapter 5 of the Ontario Energy Board's (OEB) *Filing Requirements for Electricity Distribution Rate Applications* (July 17, 2013).

TABLE 1: CAPITAL EXPENDITURE SUMMARY

CATEGORY	Historical Spend ($M)					Forecasted Spend ($M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System Access	$44.37	$58.31	$53.15	$86.62	$76.01	$86.13	$93.54	$100.93	$90.41	$85.47
System Renewal	$215.00	$219.25	$157.25	$231.08	$286.37	$251.74	$234.99	$246.35	$260.08	$265.49
System Service	$35.32	$75.63	$38.35	$83.67	$101.34	$76.45	$69.60	$62.51	$49.54	$73.95
General Plant	$55.53	$67.71	$29.28	$33.77	$109.47	$104.63	$99.44	$28.93	$32.13	$27.88
Other CAPEX	$50.36	$24.63	$9.92	$10.52	$12.73	$12.18	$21.22	$28.65	$37.89	$49.37
Total	**$400.58**	**$445.53**	**$287.95**	**$445.66**	**$585.92**	**$531.13**	**$518.79**	**$467.36**	**$470.05**	**$502.16**
System O&M	$114.64	$111.89	$109.03	$119.84	$118.94	$128.76	-	-	-	-

/C

Expenditures within the 2010-2013 historical period are actual expenditures, whereas expenditures for 2014 (i.e. bridge year) are planned expenditures, as the 2014 year has not yet concluded as of this writing.

Section E4.2 provides further details on the capital investments and associated trends for each investment category and the relationship between capital investment and System O&M expenditures.

E4.2 Explanatory Notes on Variances

This section discusses spending profiles for the four capital investment categories and the relationship between capital spending and System O&M expenditures.

E4.2.1 System Access Spending Profile

Toronto Hydro's capital expenditures under the System Access investment category are driven by statutory, regulatory or other obligations that require Toronto Hydro to provide customers with access to the distribution system or to otherwise respond to service requests.

Key investments within the System Access investment category include:

- the connection of new customers and management of those new customer loads through the enablement of load transfer, switching and restoration activities;
- ongoing renewal of metering assets;
- relocation and expansion of plant in response to third party activities; and
- installation of protection and control schemes to manage distributed generation investments (including renewable enabling improvements).

Section E5 provides further details on the nature of this investment category along with full details and justification for the individual capital expenditure programs within. Table 2 outlines the year-over-year spending profile of the System Access investment category from 2010 to 2019.

TABLE 2: SYSTEM ACCESS EXPENDITURES – HISTORICAL & FORECASTED

CATEGORY	Historical Spend ($M)					Forecasted Spend ($M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System Access	$44.37	$58.31	$53.15	$86.62	$76.01	$86.13	$93.54	$100.93	$90.41	$85.47

/C

Investments for the System Access investment category were lower in 2010 due to a relatively low level of work executed in the Customer Connections, Metering and Externally-Initiated Plant Relocation & Expansion programs that year. In the subsequent historical years, the total spending in these three programs increased to a peak in 2013 and is anticipated to decrease again in 2014 due to the following:

- The Customer Connections program increased between 2010 and 2013 due to an increasing number of real estate developments. The number of major projects with multi-year construction (e.g., projects related to the Pan Am Games) also increased over this period.

- The amount of work requested by third-party agencies caused an increase in the Externally-Initiated Plant Relocation & Expansion program during the 2010 to 2013 period. In 2013, the scale of projects requested by external parties also increased.

- System Access spending in 2014 is forecasted to be less than in 2013 due to a decrease in Pan Am Games-related Customer Connections work.

- There was also a decrease in the scale of the projects requested by external parties in 2014 compared to 2013.

Toronto Hydro forecasts that expenditures will increase from 2015 onwards to 2017 due to the following factors:

- Continued growth in new developments in Toronto requiring new customer connections.

- Major projects required by agencies such as Metrolinx are forecast to drive increased customer connections.

- Expenditures needed for metering renewal in the Metering program are forecast to significantly increase from the 2014 spend.

- Forecasted expenditures needed for the Load Demand program are forecasted to significantly increase.

- The addition of the Generation Monitoring, Protection & Control program to Toronto Hydro's capital plan. The first period from 2015 to 2017 is addressing existing distribution system constraints while also keeping pace with future connections. Therefore, spending levels are at their highest in 2015 due to the need to address the most urgent existing constraints.

From 2017 onwards to 2019, the overall spending patterns for System Access investments remain the same, with the exception of the Customer Connections and Generation Monitoring, Protection & Control investment programs:

- From 2017 onwards to 2019, there are forecast spending reductions to Customer Connections due to the impact of the Metrolinx activities, which are heavily influencing the spend profile. Toronto Hydro's involvement in these activities is scheduled to reduce and eventual come to completion during the 2018-2019 timeframe, resulting in decreased spending.

- As all existing distribution system constraints within the Generation Monitoring, Protection & Control program are forecast to be addressed by 2017, the final two years of this program focus on addressing only the new distributed generation (DG) connections, which results in spending reductions.

E4.2.2 System Renewal Spending Profile

Toronto Hydro's capital expenditures in the System Renewal investment category are driven by the need to maintain distribution system asset performance at an acceptable standard. These investments will serve to renew those assets that are nearing, at, or exceeding their useful life criteria, along with assets that are functionally obsolete due to accessibility or serviceability deficiencies.

Key investments within the System Renewal investment category include:

- the ongoing renewal of grid systems assets, including overhead, underground, secondary network and stations assets;

- replacement of functionally obsolete legacy infrastructure with infrastructure that meets current standards;

- replacement of failed assets as per reactive processes; and

- continued management of assets along worst performing feeders.

Section E6 provides further details on the nature of this investment category along with full details and justification for the individual capital expenditure programs within. Table 3 outlines the year-over-year spending profile of the System Renewal investment category from 2010 to 2019.

TABLE 3: SYSTEM RENEWAL EXPENDITURES – HISTORICAL & FORECASTED

	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System Renewal	$215.00	$219.25	$157.25	$231.08	$286.37	$251.74	$234.99	$246.35	$260.08	$265.49

In 2010, investment in System Renewal activities was concentrated on renewing and replacing Toronto Hydro's aging distribution assets and managing Toronto Hydro's worst performing feeders. With the exception of 2012, Toronto Hydro continuously increased annual renewal investments throughout the historical period. This trend was due to the need to proactively manage, through renewal and replacement, the growing backlog of distribution assets that are at or beyond their useful lives. The decrease in spending in 2012 was due to the immediate ramp-down in renewal/replacement capital work following the OEB's decision in Toronto Hydro's Cost of Service application[1] in January 2012.

The decrease in spending from the peak in 2014 to the investments levels from 2015 to 2019 is the result of several factors, including:

- Increased System Service-related investments from 2015 to 2019 targeting critical issues within the overhead, underground and secondary network systems, thereby offsetting core renewal investments within that same time period in order to maintain a "paced" execution strategy.
- Increased Load Demand investments from 2015 to 2019, thereby offsetting core renewal investments within that same time period in order to maintain a "paced" execution strategy.
- Increased System O&M expenditures in 2015, thereby offsetting overall capital investment expenditures within this same time period.

The combined annual amount of System Renewal and System Service expenditures over this period is a result of Toronto Hydro's efforts to establish a prudent balance between (1) ongoing efforts to manage, and eventually clear, the end-of-life and obsolete asset backlog and (2) high value investments that are expected to improve customer value by addressing critical

[1] EB-2011-0144, Decision with Reasons (January 5, 2012).

performance and safety issues (e.g. Stations Expansion) and by improving system operational efficiency (e.g. Feeder Automation). System Service is further discussed in the following section.

E4.2.3 System Service Spending Profile

Toronto Hydro's capital expenditures under the System Service investment category are driven primarily by the need to resolve critical system-wide issues, including capacity and operational constraints, security-of-supply risks, potential safety risks, system reliability deficiencies and other inefficiencies within the existing grid. Beyond the safety and capacity-driven investments in this category, a number of the programs were selected as cost-effective means of delivering significant customer value (in the form of improved service and service efficiency) during the 2015-2019 period while maintaining a relatively modest pace of System Renewal work.

Key investments within the System Service investment category include:

- re-configuration and re-design of feeders to improve restoration capabilities, tree contact resistance and coordination of protective devices;
- installation of assets and technologies to improve restoration capabilities and system efficiencies and mitigate capacity constraints;
- expansion of station infrastructure to mitigate capacity constraints and security-of-supply risks;
- installation of tie points and upgrading of feeder cable sizes to improve load transfer and contingency management capabilities; and
- replacement of legacy assets that pose potential safety risks to crew workers and the general public.

Section E7 provides further details on the nature of this investment category along with full details and justification for the individual capital expenditure programs within. Table 4 outlines the year-over-year spending profile of the System Service investment category from 2010 to 2019.

TABLE 4: SYSTEM SERVICE EXPENDITURES – HISTORICAL & FORECASTED

CATEGORY	Historical Spend ($M)					Forecasted Spend ($M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System Service	$35.32	$75.63	$38.35	$83.67	$101.34	$76.45	$69.60	$62.51	$49.54	$73.95

/C

System Service investments between 2010 and 2014 mainly consisted of investments in the Handwell Upgrades and Stations Expansions programs. There is relatively little historical System Service spending related to the overhead, underground and secondary network systems in the form of re-configuration and re-design of feeders, installation of assets and technologies, and installation of tie points and upgrading of feeder cable sizes. Investments for System Service started off at minimal levels in 2010 due to minimal spending related to Stations Expansions. Most of the 2010 spending was made up of capital expenditures in the Handwell Upgrades program.

System Service investment began to increase in 2011 and, with the exception of 2012, continued increasing through 2014, mainly due to Toronto Hydro's investments in the Stations Expansion program – in particular, Phase 1 of construction of the new Copeland Transformer Station (TS). Fluctuation in spending in the Stations Expansion program is due to the fact that the program consists of a small number of significant projects.

The decrease in spending in 2012 was due to the immediate ramp-down capital investments that year following the OEB's decision in Toronto Hydro's Cost of Service application (EB-2011-0144) in January 2012. This ramp-down had a direct impact on the scheduling, execution and resulting spend levels in 2012 associated with Copeland TS.

From 2015 onwards to 2019, System Service investments transition towards the management of critical issues within the overhead, underground and secondary network systems in the form of re-configuration and re-design of feeders, installation of assets and technologies, installation of tie points and upgrading feeder cable sizes. In this same time period, associated investments for Handwell Upgrades and Stations Expansion continue to decrease, resulting in an overall reduction of System Service investments.

The Handwell Upgrades program is planned for completion in 2015. Accordingly, Toronto Hydro does not forecast further spend for this program in the 2016 to 2019 period. The utility also forecasts a decrease in the Stations Expansion program mainly due to the anticipated completion of the Copeland Transformer Station Phase 1 project in 2016. Phase 2 of the Copeland Transformer Station is forecasted to begin in 2019, hence the increase in spending in that year. ***IC***

E4.2.4 General Plant Spending Profile

Toronto Hydro's capital expenditures under the General Plant investment category represent necessary routine and one-time investments into the backbone assets that support Toronto

Hydro's operational activities, including the execution of the capital and O&M related activities and expenditures discussed herein.

Key investments within the General Plant investment category include:

- routine renewal and upgrade of Information Technology hardware and software;
- replacement of the obsolete Enterprise Resource Planning (ERP) system;
- routine renewal and rehabilitation of fleet vehicles and equipment;
- renewal and rehabilitation of building and facilities components and enhancement of security infrastructure in key locations;
- consolidation of operating centres; and
- support programs for ongoing capital and maintenance activities.

Section E8 provides further details on the nature of this investment category along with full details and justification for the individual capital expenditure programs within. Table 5 outlines the year-over-year spending profile of the General Plant investment category from 2010 to 2019.

TABLE 5: GENERAL PLANT EXPENDITURES – HISTORICAL & FORECASTED

CATEGORY	Historical Spend ($M)					Forecasted Spend ($M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
General Plant	$55.53	$67.71	$29.28	$33.77	$109.47	$104.63	$99.44	$28.93	$32.13	$27.88

/C

Historical spending in the General Plant category was elevated in 2010 and 2011 due to a number of specific needs in several General Plant programs in those years. For example, 2010 and 2011 saw elevated Fleet and Equipment Services costs due to an ongoing fleet renewal program that was required to accommodate the increasing capital program. The spending level decreased significantly in 2012 in accordance with the timing of the OEB's decision in Toronto Hydro's Cost of Service application (EB-2011-0144) in January 2012, and remained at a comparable level in 2013 due to the stabilization of investment requirements across most General Plant programs during the ICM/IRM period. The sharp increase in 2014 spending is attributed to the initiation of Toronto Hydro's Operating Centres Consolidation Program.

Toronto Hydro forecasts that the spending profile will continue at elevated levels for 2015 and 2016 due to several relatively large, one-time IT and facilities investments, including replacement of the obsolete and no longer vendor supported Enterprise Resource Planning (ERP) system, replacement of the obsolete voice radio system, continued execution of the Operating Centres Consolidation Program, and several major asset replacements related existing facilities (e.g. HVAC renewal at Toronto Hydro's 500 Commissioners location). With the completion of these one-time projects, planned spending from 2017 to 2019 is anticipated to taper off significantly.

E4.2.5 Other Capital Expenditures Spending Profile

Toronto Hydro's capital expenditures under the Other Capital Expenditures investment category include the following elements:

- Engineering capital, which represents labour costs associated with engineers, technologists, design technicians and power system controllers (PSCs) for non-discretionary engineering, design and planning work performed on distribution assets that are put in-service. These labour costs are capitalized although they are not directly attributable to specific distribution system assets or projects.
- Historical road cut repairs, which represents the outstanding costs related to temporary and permanent pavement repair work following the execution of application capital investments dating back as far as 30 months.
- Allowance for funds used during construction (AFUDC), which represents the cost to the utility for funds used for the purposes of construction which are allowable for capitalization as defined within the Accounting Procedures Handbook Section 4102.
- Inflation for future expenditures from 2016 onwards to 2019.
- Other miscellaneous capital expenditures, including major tools and pre-capitalized inventory. Expenditures in 2014 also include rental payments to Hydro One Transmission for use of idle transmission facilities. /C /C

Table 6 outlines the year-over-year spending profile of the Other Capital Expenditures investment category from 2010 to 2019.

[2] Ontario Energy Board, Accounting Procedures Handbook for Electricity Distributors, (Toronto: Ontario Energy Board, 2011) at section 410.

TABLE 6: OTHER CAPITAL EXPENDITURES (CAPEX) – HISTORICAL & FORECASTED

CATEGORY	Historical Spend ($M)					Forecasted Spend ($M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
Other CAPEX	$50.36	$24.63	$9.92	$10.52	$12.73	$12.18	$21.22	$28.65	$37.89	$49.37

/C

Spending reductions in this category from 2010 to 2011 are largely attributed to reductions in engineering capital spending, as certain overhead costs were deemed to be no longer directly attributable to assets as per the 2011 accounting update, therefore resulting in a reduced amount of engineering capital being eligible for capitalization in 2011. The full details associated with the 2011 accounting update and impacts are further explained and defined within Exhibit Q1, Tab 2, Schedule 1 as part of Toronto Hydro's 2011 cost-of-service EDR application (EB-2010-0142).

Engineering capital expenditures are only included within this investment category between 2010 and 2011, and from 2012 and onwards, these costs are integrated within capital investment programs, which therefore drives further reduction in this category between 2011 and 2012 respectively. Increases in this spending category from 2015 onwards to 2019 are largely the product of spending inflation. Furthermore, the AFUDC rate applied by Toronto Hydro from 2010 onwards to 2014 is based on the OEB prescribed rate, whereas the forecasted expenditures from 2015 and onwards are based on MIFRS and thus include AFUDC calculated based on Toronto Hydro's weighted average cost of debt.

From 2016 onwards to 2019, inflation costs are also included within this category, which result in the year-over-year increases.

E4.2.6 System Operating & Maintenance (O&M) Spending Profile

System Operational and Maintenance (O&M) expenditures represent the following five functional areas:

- Supply Chain Services;
- Control Centre;
- Operations Support;
- Distribution Maintenance Programs; and

- Fleet and Equipment Services.

O&M programs within these areas are outlined in greater detail in Exhibit 4A, Tab 02.

Operational programs that support Toronto Hydro's capital and maintenance programs include:

- Supply Chain Services , which supports the execution of Toronto Hydro's asset management plans and other operating programs that rely on procurement and warehousing activities. The overarching goal of the program is to facilitate timely and cost-effective acquisition of services, materials and equipment at requisite quality, while also maintaining an optimal amount of inventory to support uninterrupted work execution and manage materials handling costs.

- The Control Centre , which allows Toronto Hydro to safely and reliably operate the utility's distribution grid through real-time system control and monitoring activities carried out from a single location. The control room coordinates the necessary system switching and restoration work to mitigate the impact of emergency outages, enables load transfers for capital and maintenance work, and monitors the flow of electricity across Toronto Hydro's distribution plant.

- Operations Support , which provides functions such as program and work management, planning, contractor administration, trades training, and engineering support.

Maintenance programs, which assess the condition and prolong the useful life of Toronto Hydro's assets include:

- Distribution Maintenance Programs , which are designed to maintain asset performance (i.e. reliability) and mitigate risks associated with asset failures. The core philosophy at the heart of many of the programs is Reliability-Centered Maintenance (RCM). RCM defines maintenance tasks for a particular asset class to maximize its reliability based on its function and its criticality to the distribution system, while minimizing costs. Programs are also designed to account for risks and other factors such as the safety of Toronto Hydro's employees and the public, obligations found in environment, health and safety legislation and regulations, equipment performance and failure data, manufacturers' recommendations, and industry best practices. Distribution Maintenance programs are executed under four categories which include:

- Preventive Maintenance: Typically cyclical inspection and maintenance tasks, which emphasize assessing asset condition, preserving performance over the expected life of the asset, and maintaining public and employee safety.

- Predictive Maintenance: Testing or auditing of equipment for a predetermined condition (or conditions) that anticipates failures and enables further maintenance tasks to prevent those failures.

- Corrective Maintenance: Repairing or replacing equipment after a deficiency has been reported. Corrective Maintenance actions typically arise from deficiencies discovered during the execution of Preventive or Predictive Maintenance tasks, or temporary repairs that have been made during Emergency Maintenance to restore power.

- Emergency Maintenance: Responding to unplanned and urgent events that occur on the distribution system including the repair or replacement of equipment that has failed and caused a power disruption to Toronto Hydro customers.

f Fleet and Equipment Services , which oversees procurement, maintenance and disposal of Toronto Hydro vehicles, associated equipment, and employee personal protective gear. It is also responsible for ensuring that certain safety equipment and implements are tested and/or repaired in accordance with the requirements of the Occupational Health and Safety Act, 1990, [3] the Infrastructure Health & Safety Association, and other applicable standards.

The expenditures for System O&M are as follows:

TABLE 7: SYSTEM OPERATION & MAINTENANCE EXPENDITURES – HISTORICAL & FORECASTED ($ MILLIONS)

CATEGORY	Historical Spend ($M)					Forecasted Spend ($M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System O&M	$114.64	$111.89	$109.03	$119.84	$118.94	$128.76	-	-	-	-

During the 2010 to 2012 period, System O&M expenditures decreased primarily due to reductions in Operation Support services from 2010 to 2011 and reductions in Corrective Maintenance from 2011 to 2012. In 2013, expenditures increased due to costs associated with Toronto Hydro's

[3] R.S.O. 1990, C.O.1. ["OHSA"]

emergency storm response following the December 21, 2013 ice storm. In 2014, expenditures are forecasted to increase from 2012 spending levels due to additional Operation Support services for Toronto Hydro's capital and maintenance programs. In 2015, expenditures are planned to increase primarily due to increases in Distribution Maintenance programs. The projected budgets from 2016 to 2019 are expected to increase in line with inflation.

The number of assets that are approaching or are beyond their expected useful lives has been and will continue to grow during the 2015 to 2019 period. Aging assets necessitate robust maintenance programs to mitigate a wide variety of potential risks associated with possible asset failures including public and employee safety, environmental, system reliability and financial risks. As a result, Toronto Hydro expects that it will be necessary to sustain an increased level of System O&M expenditures during the 2015 to 2019 period in order to allow Toronto Hydro to detect deteriorating equipment conditions and deficiencies prior to equipment failure.

In addition, Toronto Hydro expects that a sustained increase in expenditures will allow the utility to:

- reduce vegetation management cycles;
- conduct PCB testing at below-grade structures, pad-mounted equipment locations and customer locations;
- expand the usage of modern and new technologies, tools and testing methods such as ultrasonic testing to detect partial discharge (corona), infrared scanning to detect thermal anomalies, oil testing to monitor transformer health, and cable testing to detect degradation of underground cables;
- increase proactive maintenance activities at customer locations and substations; and
- enable Toronto Hydro to maintain assets that were formerly part of the street lighting system in Toronto.

Capital and System O&M programs are interrelated, as ageing and deteriorated assets that are not replaced through capital work will result in deteriorating conditions over time. These conditions must be managed through System O&M work, including inspections, tests, and corrective maintenance to mitigate elevated risks of failure. These activities place upwards pressure on expenditures within certain segments of System O&M programs. The opposite also holds true as increases in capital work can result in reductions in some System O&M work.

Examples of this include capital replacements and enhancements for legacy distribution assets such as fibertop network units, reverse power breakers, and porcelain insulators. Examples also include corrective maintenance expenditures, which during the 2010 to 2013 period, experienced a reduction in part due to increases in planned capital expenditures on ageing and deteriorated assets. For 2014 and 2015, corrective maintenance is expected to rise, however it will remain below the peak levels experienced in 2011.

Although System O&M and capital investments are interrelated, a significant portion of System O&M expenditures are directed to activities that are independent of particular capital expenditure levels, including routine maintenance to preserve asset performance over its expected life; vegetation management to maintain minimum clearance requirements for overhead conductor and equipment; cyclical patrols and inspections undertaken to comply with minimum Distribution System Code requirements; corrective maintenance activities to address deficiencies caused by animal, pest, or tree contacts; and emergency maintenance following severe weather and storm damage. In addition, System O&M programs are necessary to provide the information that is used to plan Toronto Hydro's capital programs such as asset health and condition information. This is particularly important given Toronto Hydro's ageing asset base, which cannot be feasibly replaced through capital work in a short time frame due to a variety of factors such as resource and logistic constraints. The information captured through Toronto Hydro's System O&M programs is necessary to enable the prioritization of assets for capital work and to maximize the likelihood that assets that remain in-service have not surpassed end-of-life.

E4.2.6 Overall Trends

As illustrated in Table 11 above, with the exception of 2012, Toronto Hydro's historical capital expenditures have generally increased over the five-year historical period from 2010 to 2014 in the System Access, System Renewal, and System Service investment categories. This increase in investment was made because of Toronto Hydro's gradually worsening distribution system reliability due to a large number of aging and deteriorating infrastructure assets. Also, an increase in investment was required for the capacity growth seen between 2010 and 2014 and the increase in real estate developments and large infrastructure projects during that period.

General Plant spending was elevated in 2010 and 2011, partly due to the corresponding ramp-up in distribution system capital spending. Routine General Plant investments were stable from 2012-2014, but spending increase sharply in 2014 due to the initiation of the Operating Centres Consolidation Program. Spending in the General Plant category appears front-loaded during the 2015-2019 due to a number of larger, one-time investments required in the early years. ***IC***

Generally, the forecasted capital expenditures for the planning horizon of 2015-2019 reflect the continued long-term need for significant capital commitments in order to deliver safe and reliable service to Toronto Hydro's customers. A large portion of Toronto Hydro's infrastructure is expected to deteriorate and become obsolete between 2015 and 2019. At the same time, Toronto Hydro projects that the number of customers and system capacity will continue to grow over the same period. A corresponding increase in capital expenditures is required in order for Toronto Hydro to provide safe and reliable service in these future years.

flow of electricity because DG sources are located in close proximity to the distribution loads that they serve.

Finally, System Access Investments include investments related to the relocation of existing Toronto Hydro plant in order to accommodate third party requests for facility relocation. Third parties requesting plant relocation are typically public agencies responsible for development of public infrastructure. Distribution expansion activities, where implemented in concert with such relocation work, are also included in this category. Table 1 provides the trigger drivers for capital investments in this category.

TABLE 1: TRIGGER DRIVERS FOR SYSTEM ACCESS CATEGORY

Driver	Description
Customer Service Requests	ƒ The fulfilment of Toronto Hydro's obligation to connect a customer to its service. This includes both traditional demand customers and distributed generation (DG) customers. The obligation to connect holds as long as there are no safety concerns for the public or employees and there is no adverse affect on the reliability of the distribution system. ƒ Expansion or enhancements to the system when a connection cannot be made with existing infrastructure.
Mandated Service Obligations	ƒ Compliance with all legal and regulatory requirements and government directives. ƒ Measurement Canada, the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO) impose regulations concerning metering that Toronto Hydro must comply with.
Third Party Requests	ƒ Mandated system modifications for property or infrastructure development by government agencies and other entities.

Table 2 provides a brief description for each investment program within the System Access narrative along with total expenditures for each program from 2015 onwards to 2019. Individual section numbers for each investment program are also provided in this table.

TABLE 2: DESCRIPTIONS OF SYSTEM ACCESS INVESTMENT PROGRAMS

Program Index and Name		Descriptions	Total (5 yrs)
E5.1	**Metering**	Enable Toronto Hydro to meet its mandatory service obligations with respect to revenue metering and wholesale metering. This will be accomplished by testing meters, replacing damaged and obsolete meters, and upgrading the under-capacity and obsolete collector stations. Upgrading Toronto Hydro's Interval Metering MDM software will help customers manage their energy use and costs by providing them with timely access to their data.	**$82 M**
E5.2	**Customer Connections**	Toronto Hydro is obligated to connect new customers or upgrade existing customers to a larger service if requested, as required under the terms of Toronto Hydro's distribution license, the Distribution System Code and the *Electricity Act, 1998*. On average, 10,000 requests for new services, upgrades, and removals are made each year and the amount is expected to increase with current and proposed development.	**$261 M**
E5.3	**Externally-Initiated Plant Relocation & Expansion**	Toronto Hydro is required to modify/relocate its system to accommodate property or infrastructure development (e.g., requests from a road authority to move a pole line). Toronto Hydro works with the external agency in question to accommodate the project, and investigates opportunities for cost-efficient expansion work.	**$20 M**
E5.4	**Load Demand**	With increased load in concentrated areas due to the city's growth, equipment (such as undersized cables) in the system must be upgraded in the short-term to address contingency issues to accommodate this increased demand. The problem is expected to be addressed by transferring loads to stations with available capacity, upgrading undersized equipment and cables, and ensuring civil infrastructure can support increased demand. This will allow Toronto Hydro to continue connecting customers in these areas without harming system reliability, customer value, and operational flexibility.	**$75 M**
E5.5	**Generation Projects Protection and Control**	Toronto Hydro is mandated to make every reasonable effort to connect distributed generation users. This program involves installation of bus-tie reactors at station buses, advanced protection systems, and monitoring and control systems to handle the increasing DG penetration in the City of Toronto, including renewable energy generation (REG) projects.	**$19 M**

/C

/C

The following Sections E5.1 though to E5.5 contain the details and justification for each capital investment program contained within the System Access investment category.

E5.1 Metering

TORONTO HYDRO CREW ASSESSING RESIDENTIAL METER

E5.1.1 Summary

Program Description

There are two components to the Metering Program: Revenue Meter Compliance (RMC) and Wholesale Meter Compliance (WMC). Each of these initiatives is designed to ensure that Toronto Hydro remains in compliance with legal and regulatory requirements.

Revenue metering refers to the meters Toronto Hydro uses to measure each customer's energy use in order to accurately bill its customers using time-sensitive rates. Revenue metering is governed by the Gas and Electricity Inspection Act[1] and associated regulations administered by Measurement Canada. The RMC initiative is needed to maintain and manage metering and data collection systems for lawfully and accurately billing customers. Revenue Meter Compliance includes:

- Revenue Meter Replacement
    - Meter Compliance Sampling and Re-verification

[1] R.S.C. 1985, c. E-4. ["Gas and Electricity Inspection Act"].

- Meter Re-verification for Large User Class

- Interval Metering System Upgrade
- SmartSynch Interval meters Replacement
- Suite Metering System Upgrade
- Suite Meter Installations
- Provincial MDM/R Integration

Wholesale metering refers to the metering of electricity supplied to Toronto Hydro at the HONI transmission network grid supply points. This information provides data for the IESO administered Wholesale Market. The accurate measurement of electricity supply to Toronto Hydro is vital to its operation because the utility depends on the measurements to determine the commodity cost that it passes on to consumers. In addition, Toronto Hydro is obligated to remain in compliance with the IESO Market Rules, which define the meter data transmission requirements from LDCs as Market Participants to IESO.

Wholesale Meter Compliance includes:

- Wholesale Metering and Transformer Replacement

The following is a summary of the anticipated benefits associated with this program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	• Testing and re-verifying meters will help to ensure that all customers are billed accurately. • Replacing data collection and processing systems is expected to provide timely access to granular energy use data and allows customers to manage and control their energy costs. • Maintaining the accuracy of Toronto Hydro's Wholesale meters impacts the invoice Toronto Hydro pays to the IESO, and directly impacts all of Toronto Hydro's non-interval greater than 50 KW demand customers.
Reliability	• Installing high-end meters for Toronto Hydro's largest customers will provide Toronto Hydro with ground fault data and power quality monitoring information • The Metering Program is expected to improve the reliability of Toronto Hydro's distribution system by maintaining and improving data collection and communication from smart meters and integrating the data with the utility's Outage Management System (OMS).

Efficiency	ƒ Upgrading the Large User MDM system will allow the daily collection and processing of interval data for 9,500 interval meters that at the present time, are manually read because of limitations of the current system's processing time and capacity. ƒ Installation of remote disconnects and reconnects is expected to reduce demands on labour and vehicles, as Toronto Hydro will be able to perform these activities remotely. ƒ Interval metering MDM Software and hardware upgrades for Large Users will include system functionality that allows for more efficient power outage management by providing information for each metering point on outage and restoration notifications. Improved field dispatch efficiency should be achieved, since power outages can be verified before field crews are dispatched to the customer location, reducing power outage duration (SAIDI).
Other Benefits	ƒ The Metering program is expected to provide environmental and economic benefits. Conservation has a direct impact on Toronto Hydro's carbon footprint and the cornerstone of conservation is offering interval data. Conservation programs require the validation of energy savings. In particular, Large Users rely on the detailed meter data to identify the potential areas for saving, and subsequently to confirm that the reduction in electricity usage has been achieved. Contracts between Energy Services Companies (ESCO) and customers will use the energy data to validate and pay for the conservation targets met. ƒ In terms of economics, Interval Metering MDM system upgrade for Large Users is expected to provide information to facilitate contract obligations, support for DR3 and make data available at five minute intervals for the entire group of qualifying customers. This program is also expected to provide information and processing for OPA's distributed generation programs such as FIT and microFIT data collection and credit generation.

Program Drivers

The trigger and secondary drivers for the Metering Program are listed in the table below.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Mandated Service Obligations	ƒ In order to operate as a LDC, Toronto Hydro needs to comply with all legal and regulatory requirements and government directives related to revenue metering and wholesale metering. o For revenue metering, Toronto Hydro is governed by the Gas and Electricity Inspection Act, as well as provincial legislation as governed by the IESO, SME and OEB. o For wholesale metering, in addition to meeting the above regulations, IESO Market Rules specifications also apply.
Secondary Driver	Reasoning

Failure Risk	***f*** Failed or inaccurate meters tend to not measure or under-measure the electricity consumed by the customers. It is incumbent upon Toronto Hydro to ensure meters are systematically tested and re-verified so that failed meters do not remain in service.

Preferred Alternative

As discussed above, Toronto Hydro is required by law to ensure that electricity usage information is collected accurately for the purposes of billing customers. As such, there are no alternatives to this program.

Timing and Pacing

The timeline for the Metering Program's initiatives and projects is driven by regulatory obligations and compliance requirements with respect to the IESO and the OEB. Planned spending for the period 2015 to 2019 is outlined below.

TABLE C: HISTORICAL AND FORECAST SPENDING

	Historical Spending					Future Spending				
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	$28.4	$22.1	$12.1	$12.2	$14.0	$24.7	$16.6	$14.7	$11.7	$13.7

/C

E5.1.2 Program Description

There are two components to the Metering Program: Revenue Meter Compliance (RMC) and Wholesale Meter Compliance (WMC). While revenue metering is the basis for how Toronto Hydro bills its customers, wholesale metering is the foundation for the bill that IESO issues to Toronto Hydro for wholesale settlement. Each initiative in the Metering Program includes projects designed to keep Toronto Hydro compliant with legal and regulatory requirements.

Revenue metering refers to the meters Toronto Hydro uses to measure each customer's energy use in order to accurately bill its customers using time-sensitive rates. Residential and low volume Commercial Smart Meters and Suite Meters are billed on Time-Of-Use (TOU) rates while larger C&I customers utilize interval meters and are billed on their HOE at the HOEP market price. Revenue metering is governed by the *Gas and Electricity Inspection Act* and associated regulations administered by Measurement Canada. The RMC initiative includes projects needed to maintain and manage metering and data collection systems so that Toronto Hydro can lawfully and accurately bill its customers.

Wholesale metering refers to the metering of electricity supplied to Toronto Hydro at the HONI transmission network grid supply points. This information provides data for the IESO administered Wholesale Market. Measurement Canada regulations and IESO specifications offer meter compliance requirements. The accurate measurement of electricity supply to Toronto Hydro is vital to its operations because the utility depends on the measurements to determine the commodity cost that it passes on to consumers. In addition, Toronto Hydro is obligated to remain in compliance with the IESO Market Rules, which define the meter data transmission requirements from LDCs as Market Participants to IESO.

The Metering program's primary purpose is to enable Toronto Hydro to meet its mandatory service obligations with respect to revenue metering and wholesale metering. The estimated total capital budget for this program is $81.5 million for the 2015-2019 forecast period. The following subsections explain the various initiatives and projects that constitute Toronto Hydro's planned Metering program. /C

E5.1.2.1 Revenue Meter Replacement

Revenue meter replacement is part of the RMC component of this program and consists of the following initiatives:

- Meter compliance sampling and re-verification;
- Meter re-verification for Large User Class

(i) Meter Compliance Sampling and Re-verification

Measurement Canada has sole jurisdiction with respect to the administration and enforcement of the Weights and Measures Act[2] and the Electricity and Gas Inspection Act. These Acts and related regulations govern Toronto Hydro's ability to bill its customers for electricity usage. The requirements state that all meters must be resealed at specified intervals to ensure that a customer's electricity use is metered accurately. Once a seal expires, the meter cannot legally be used for billing purposes and must either:

(1) have its seal period extended (via compliance sample-testing); or

(2) be replaced (i.e., "re-verified" and resealed).

Toronto Hydro has submitted its 2015-2019 meter sampling and re-verification program to Measurement Canada in order to remain compliant with its regulatory obligations. Under the sampling and re-verification program, Toronto Hydro plans to test approximately 3% of its smart meters. Figure 1 below depicts a typical residential smart meter. Measurement Canada regulations permit LDCs to form sample groups of meters with homogeneous meter characteristics and test randomly selected meters from within each sample group for accuracy. In order to form sample groups, several characteristics are taken into account, including the meter's mechanism for measuring electricity usage, as well as when the meters were manufactured, tested and sealed. The meters forming a sample group must be of the same type and have the same meter characteristics. The seals of meters within a sample group may be extended for an additional eight years depending on the results of the meters tested within that sample group.

[2] R.S.C., 1985, c. W-6. ["Weights and Measures Act"]

FIGURE 1: TYPICAL RESIDENTIAL SMART METER

Meters that do not belong to any sample group must be individually removed for re-verification. These meters are made up of a variety of meter types and rate classes and are typically used for C&I customers that require greater functionality, such as peak demand measurement and short interval energy measurements (i.e., intervals as small as five minutes in length). Meters removed for re-verification that have seals expiring between 2015 and 2019 must be removed and replaced before their seals expire.

In all, Toronto expects to remove 31,571 out of a total of 644,000 meters from the field for sample-testing or re-verification from 2015-2019 (see Tables 2 and 3 below). Not included in these figures are the 635 meters for Large User Class C&I customers and the 8,500 SmartSynch interval meters, which are managed under other initiatives of the Smart Meter program. Taking into account the exclusions, the total estimated cost of the meter compliance sampling and re-verification initiative is $12.14 million. /C

TABLE 1: METERS WITH SEALS EXPIRING IN 2015-2019 FOR SAMPLE-TESTING

Year	Seal-Expiring Meters	Sample Meters
2015	14,527	436
2016	194,000	5,820
2017	214,652	6,440
2018	146,498	4,395
2019	55,563	1,667
Total	**625,240**	**18,758**

TABLE 2: METERS TO BE REMOVED FOR RE-VERIFICATION

Year	Large C&I Meters	Small/Medium C& I Meters	Suite Meters
2015	310	39	219
2016	100	86	45
2017	180	170	1,250
2018	15	16	4,134
2019	30	68	6,152
Total	**635**	**378**	**11,800**

Toronto Hydro undertakes electric service disconnections due to customers' payment delinquency. The installation of remote disconnects is expected to result in fewer on-site field work, which saves labour and vehicle costs, thereby reducing Toronto Hydro's operating expenditures and removing the need to physically attend to a property to cut-off the service.

Based on historical trends (see Table 3 below), 31,350 smart meters with remote disconnect switches are projected to be installed between 2015 and 2019 under the delinquent account program. The total incremental cost for the remote connect disconnect switch function is estimated to be $4.83 million for the delinquent account program, or $967 K, per year. The total savings generated from avoiding service disconnection and reconnection field visits is estimated to be $5.9 million over the life of the installed meters. These meters will only be installed when a visit is required to cut the service off due to non-payment. At the time of the disconnection, a remote connect/disconnect meter will be installed to disconnect the service. The installation of this meter will avoid the second site visit to reconnect the service after payment for the account is made, since this meter is capable of reconnecting the service remotely from Toronto Hydro's offices. /C

TABLE 3: ESTIMATED FIELD COLLECTION DISCONNECTIONS

Year	Number of Disconnects Per Year	Estimated Number of Services that Need Remote Disconnect Meters
2015	7,780	6,150
2016	7,860	6,200
2017	7,940	6,270
2018	8,020	6,340
2019	8,100	6,390
Total	**39.700**	**31,350**

(ii) Meter Re-verification for Large User Class

Out of all meters that will be removed for re-verification between 2015 and 2019 (Table 2), 635 meters serve 530 customers that have average monthly demands over one megawatt (1 MW). As a group, these Large User Class customers represent 0.09% of Toronto Hydro's customers, yet they generate approximately 28% of Toronto Hydro's total yearly revenue. These customers also require more sophisticated information requirements for their meters as compared to other customers. For reasons to be explained in Section 5.1.3, the meters will be replaced with higher accuracy meters that have additional features such as three-phase power measurement, meter diagnostic and power quality functionality, as well as ten channels of five minute intervals to support Ontario Power Authority (OPA) conservation and program initiatives.

The estimated cost for this initiative is $6.02 million between 2015 and 2019, or $1.20 million per year. /C

E5.1.2.2 Interval Metering System Upgrade

The interval metering system upgrade project is another element of the RMC component of the Metering program. Toronto Hydro plans to upgrade the interval metering system, including the meter data management system, in order to comply with regulatory requirements and IESO Market Rules.

Toronto Hydro's existing legacy interval metering and complex billing Advanced Metering Infrastructure (AMI) software and hardware and its related components will be completely replaced with a competitively procured advanced AMI solution. Related components include:

- MV90Xi - for interval meter data collection,
- MVSTAR - for interval meter data management, and
- MVWEB - for interval metered customer data web access and web presentment, which provides customers with the ability to (i) download their data, (ii) graph their usage profiles and (iii) display power factor information and various energy bar graphs, line graphs and daily, weekly and monthly comparisons of their energy use.

While the rationale for this project is provided in Section 5.1.3, it merits mentioning here that the replacement system is expected to serve all C&I customers with average peak demand greater than 50 kW (Table 4) given that the current interval metering system is used for Toronto Hydro's largest customers. The interval metering system upgrade should align Toronto Hydro's operations

with the OEB's Proposed Amendments to the DSC, Board File No. EB-2013-0311[3] to amend section 5.1.3 that requires a distributor to install a Metering Inside the Settlement Time Frame (MIST) meter for any installation greater than 50 kW. In order to qualify as MIST meters, interval data must be collected and validated within the designated settlement period. The interval metering system upgrade will enable Toronto Hydro to perform these activities.

> *"The Board is of the view that, given the current metering and pricing environment, it is appropriate to amend section 5.1.3 of the DSC to require a distributor to install a MIST meter on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW."*[4]

The new system has the scalability to process up to one million metering points. It will provide interval metered customers access to their previous day's energy use. Toronto Hydro's expected processing time for its 12,500 total meters (3,000 current interval meters and the additional 9,500 not on the current system due to the exorbitant processing time and capacity limitation – the system is 12 years old and cannot be scaled any further) should be less than five hours in total for the data collection, validation and monthly billing processing, with the ability to scale the processing time further if required.

This project, including software installation, hardware upgrades, system interfaces and training, will take about 18 months to implement between 2015 and 2016. The estimated cost of the project is $5.28 million. /C

TABLE 4: CUSTOMERS SUPPORTED BY INTERVAL METERING SYSTEM

Year	Total Meters Impacted	Total Annual Revenue ($M) Read by System
2015	3,000	$147
2016	12,500	$204

[3] EB-2013-0311, Notice of Amendment to a Code (May 21, 2014).
[4] EB-2013-0311, Notice of Proposal to Amend a Code – Proposed Amendments to the Distribution System Code (January 16, 2014) at page 2.

E5.1.2.3 SmartSynch Interval Meters Replacement

SmartSynch interval meters replacement is another element of the RMC component of the Metering Program. Toronto Hydro plans to upgrade SmartSynch interval meters in response to 2G wireless network obsolescence.

Toronto Hydro uses 8,500 SmartSynch Interval Meters that possess wireless GPRS read capability to retrieve billing information on the 2G wireless network. The interval meters are remotely read and the data is made available for customer access the morning after the billing period. However, Rogers Communications Inc. (Rogers) has announced that it is planning on abandoning its 2G wireless network platform in 2018, rendering Toronto Hydro's 8,500 interval meters using a SmartSynch Rogers GPRS module obsolete. Accordingly, these meters will need to be upgraded prior to 2018 so that Toronto Hydro can maintain wireless communications. Given that the operational cost of using wireless technology is about 25% of the cost of using a standard phone line, it is the preferred option in locations where a GPRS signal can be used. Toronto Hydro is working to create a communication network that will be ready by the first quarter of 2015.

Toronto Hydro expects to take the SmartSynch meters out of service, return them to the manufacturer so that they can be retrofitted with a new SIM card and cellular hardware for the 3G network, tested and re-certified at the same time (extending the seal period) and then re-installed. Toronto Hydro estimates that the total cost of this upgrade is $5.27 million and that it should be completed in 2015. /C

E5.1.2.4 Suite Metering System Upgrade

The suite metering system upgrade is another element of the RMC component of the Metering Program. Toronto Hydro plans to upgrade the suite metering MDM system so that the utility can continue to meet the IESO's functional specifications for an AMI.

While the interval metering system described in Section 5.1.2.2 is used to collect and manage interval data for C&I customers, the suite metering system is used for residential customers in apartment or condominium buildings. These multi-suite residential buildings contain multiple suites that are metered individually, with the meter data being transmitted through the building's electric wiring to a computer. A central AMI system at Toronto Hydro collects and manages the meter data from the computers of these multi-suite residential buildings.

The current Primeread system is used to access the building's centralized computer and collect the hourly energy use data from the Power Line Carrier (PLC) computers in the multi-suite

residential buildings was implemented in 2012 when Toronto was downloading data for approximately 26,000 suite meter billing accounts. In the 2015-2019 period, the number of suite meter accounts requiring download is expected to rise from 26,000 to 93,000 (see Table 5). The 93,000 figure is predominantly based on signed contracts that Toronto Hydro has made with developers for new buildings as well as the introduction of a small number of new suite meters in 2015 and 2016. The number of suite meters requiring download from 2017 to 2019 is based on new condominium sales and Toronto Hydro's historical market share. Both the hardware and software of the Primeread system will need to be upgraded to handle the projected higher volume of meter data.

This project's total estimated cost is $1.42 million and is expected to be completed in 2019.

TABLE 5: GROWTH OF SUITE METERS BILLING ACCOUNTS

Year	Number of Suite Meter Accounts
2012	26,000
2013	34,400
2014	45,000
2015	56,000
2016	64,000
2017	73,000
2018	83,000
2019	93,000

E5.1.2.5 Suite Meter Installations

The suite meter installation initiative is another element of the RMC component of the Metering Program.

Specific meters are needed for condominium suites, which are different from smart meters used in residential houses, such as detached houses or townhouses. These condominium suites require the installation of meters that can upload the meter data to a computer in the building, which in turn can be collected by the suite metering system at Toronto Hydro. The developer, owner, or condominium board has the choice to either use a LDC to provide metering services or a unit sub-metering provider. The Energy Consumer Protection Act[5] also mandates that Toronto Hydro provide these services to developers and existing multi-residential buildings where they

[5] S.O. 2010, c.8. ["ECPA"]

have not chosen a unit sub meter provider. The LDC is defined by the ECPA as the suite meter installation meter service provider of last resort in the event that the condominium cannot secure a meter service provider. The developer may also directly request that Toronto Hydro install suite metering for the condominium suites

Instead of bulk-metering all the residential suites of a condominium building as an equivalent single consumer, suite meters are installed so that the electricity usage of the condominium residential suites can be measured separately for billing. The ECPA requires that residential units in new condominiums be metered individually as further explained in Section 5.1.6.

Based on condominium construction projects already scheduled in Toronto, as well as other projected condominium development as referenced in section 5.1.2.4 above, the estimated numbers of condominium suites from 2015 to 2019 that will require suite meter installation by Toronto Hydro are shown in Table 6. The total capital cost estimate for this initiative is $35.61 million. /C

TABLE 6: PROJECTED SUITE METERS TO BE INSTALLED

Year	Number of Suite Meters	Estimated Cost($M)
2015	12,000	$8.58
2016	8,500	$6.22
2017	9,000	$6.56
2018	9,500	$6.98
2019	10,000	$7.27
Total	**49,000**	**$35.61**

/C

E5.1.2.6 Provincial MDM/R Integration

The provincial Meter Data Management Repository (MDM/R) integration initiative is another element of the RMC component of the Metering Program. The objective of this initiative is to integrate Toronto Hydro's customer care and billing system (CC&B) and smart meter data management system (Operation Data Store or ODS) with the provincial MDM/R operated and maintained by the provincial Smart Metering Entity (SME). The following explain each of these elements:

- The ODS is Toronto Hydro's MDM system and the CC&B is used by Toronto Hydro to bill its customers.

- The Provincial MDM/R is the smart meter data management and database system operated by the SME, which is used to manage the smart meter data from all of the LDCs in the province.
    - The Provincial MDM/R retrieves smart meter data from the LDCs' MDMs, and validates and corrects the meter data through a standard Validation, Estimation and Editing (VEE) process to ensure the validity of the meter data for billing. The validated meter data is then be transmitted to the LDCs for billing their customers.
    - The SME is a business unit granted exclusive authority over smart meter data services in the province as well as the maintenance and operation of the provincial MDM/R.

In order for the smart meter data to be retrieved by the provincial MDM/R from the LDCs' MDM systems, and to later be transmitted back to the LDCs' billing systems for billing the customers, it is necessary for the LDCs' MDM and billing systems to be integrated with, or interfaced to, the provincial MDM/R system. The integration, or interfacing, must be implemented based on the protocols and specifications defined by the SME. Extensive testing is required in performing the integration to ensure the proper transmission of data between the LDC's systems and the provincial MDM/R. Business processes of the LDC also need to be modified to allow proper control and management of the meter data transfer to the provincial MDM/R and the validated data being sent back to the LDC in order to bill customers. Both the system related and the business process changes require careful planning and execution, as well as the close coordination of efforts between the LDC and SME personnel.

This program initiative, at an estimated cost of $8.08 million, should allow Toronto Hydro to plan and implement the integration with the provincial MDM/R over the 2015-2017 period so that it can meet its regulatory obligations. The estimated cost includes the re-configuration of Toronto Hydro's billing system and its Enterprise Service Bus (ESB), which is Toronto Hydro's standard enterprise software architecture for systems integration. It will also include system development and testing, particularly with respect to the validation, estimation and editing (VEE) standards[6] established by the SME. /C

[6] O Reg 393/07, at section 1(1): "validation, estimating and editing services" means those validation, estimating and editing services, as specified by the Smart Metering Entity, that are performed on smart metering data to identify and account for missed or inaccurate smart metering data.

E5.1.2.7 Wholesale Metering and Transformer Replacement

Wholesale metering and transformer replacement is part of the WMC component of the Metering Program. Wholesale metering refers to the meters and instrument transformers installed at the transmission grid supply points that track electricity supplied to an LDC or a major power consumer. When the wholesale electricity market opened on May 1, 2002, responsibility for wholesale metering operations was transferred from HONI to each individual Metered Market Participant (MMP), one of which is Toronto Hydro.

Toronto Hydro plans to replace wholesale meters and instrument transformers so that it can comply with IESO requirements. Existing legacy meters and related meter transformers will be replaced with equipment that meets current Measurement Canada and IESO requirements for wholesale metering. The actual metering upgrade involves deæegistering the existing wholesale revenue metering points, preparing the site for new fullyæompliant IESO wholesale metering installations and carrying out the installation work. Toronto Hydro plans to undertake this project so that it can complete full metering point upgrades at all applicable 223 wholesale metering points by 2021, in accordance with proposals previously approved by IESO.

While the project includes upgrading 223 wholesale meters by 2021, of which 141 are scheduled to be completed by the end of 2014, only 14 metering points are proposed to be worked on between 2015 and 2019. These 14 replacements will predominantly occur at “difficult” sites where switchgear replacements and electrical upgrades are needed to rectify the metering layout. As a result, these replacements, which will need to be coordinated with HONI capital projects, will generate higher costs and will be installed at a slower pace.

The estimated cost of this project upgrade within 2015 to 2019 period is $1.25 million. See Table 7 for all of the wholesale metering points that will be addressed from 2015 to 2019. /C

TABLE 7: WHOLESALE METER REPLACEMENT LOCATIONS

Wholesale Metering and Transformer Replacements Projection 2015-2019		
Year	Metering Points	Location
2015	2	Windsor TS (A5,6,9,10)
2016	2	Wiltshire TS (A5,6)
2017	4	Windsor TS (A3,4,7,8) Strachan TS (A5,6)
2018	4	Duplex TS (A1,2) Carlaw TS (A4,5)
2019	2	Windsor TS (A11,12)
Total	14	

TABLE 8: METER ASSETS TO BE REPLACED

Assets (Units)	2015	2016	2017	2018	2019	Total
Compliance Sampling Program Sample Meters Representing Meter Groups with Seals Expiring in 2015-2019	436	5,820	6,440	4,395	1,667	18,758
Re-verification: C&I Meters with Seal Expiring in 2015-2019	39	86	170	16	68	378
Re-verification: Large User Meters with Seal Expiring in 2015-2019	310	100	180	15	30	635
Re-verification : Suite Meters with Seal Expiring in 2015-2019	219	45	1,250	4,134	6,152	11,800
Smart Synch Interval Meters with Obsolete 2G Wireless Module	8,500					8,500
Wholesale Meters and Instrument Transformers to be Replaced	2	2	4	4	2	14
Installation of Remote disconnect reconnects for delinquent Accounts	6,150	6,200	6,270	6,340	6,390	31,350

The following table summarizes the anticipated benefits of the Metering program.

TABLE 9: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Testing and re-verifying meters will help to ensure that customers are billed accurately. ƒ Replacing data collection and processing systems is expected to provide timely access to granular energy use data and allows customers to manage and control their energy costs. ƒ Maintaining the accuracy of Toronto Hydro's Wholesale meters impacts the invoice Toronto Hydro pays to the IESO, and directly impacts all of Toronto Hydro's non-interval greater than 50 KW demand customers. ƒ Upgrading metering at Large User buildings (over 1 MW) is an important customer service initiative; these customers regard this data as a critical component to the maintenance and management of their electrical plant. Large users are often very sensitive to power quality issues in addition to power outages. As well, public safety may be affected by the reliability of the system for certain customers, such as hospitals and public health facilities. These customers are susceptible to the following power quality issues that are only measured by these higher quality metres: harmonics, over voltage, flicker, voltage dips and supply voltage unbalance. ƒ More detailed information will help customers manage their system and will help Toronto Hydro identify the root cause of issues for more speedy resolution as well as preventive maintenance support. ƒ Upgrading Toronto Hydro's Meter Data Management system will provide energy use information through the web for 9,500 customers that are currently using an antiquated model. These customers will be able to view their hourly energy use daily.
Reliability	ƒ Installing high-end meters for Toronto Hydro's largest customers will provide Toronto Hydro with ground fault data and power quality monitoring information, including harmonic content, over/under voltages, phase failure, etc. This information may be used by both the customers and Toronto Hydro to help analyze and identify power quality and other supply problems, as well as root causes for power outages for which Toronto Hydro can take preventative measures. ƒ The Metering Program is expected to improve the reliability of Toronto Hydro's distribution system by maintaining and improving data collection and communication from smart meters and integrating the data with the utility's Outage Management System (OMS).

Efficiency	ƒ Upgrading the Large User MDM system will allow the daily collection and processing of interval data for 9,500 interval meters that at the present time are manually read because of limitations of the current system's processing time and capacity. ƒ Installation of remote disconnects and reconnects is expected to reduce demands on labour and vehicles, as Toronto Hydro will be able to perform these activities remotely. ƒ Installing meters that can be remotely disconnected when customers move out or are delinquent will help to ensure that all customers pay their fair share. Also, delinquent customers will be reconnected remotely, improving service. ƒ Interval metering MDM Software and hardware upgrades for Large Users will include system functionality that allows for more efficient power outage management by providing information for each metering point on outage and restoration notifications. Improved field dispatch efficiency should result because power outages can be verified before field crews are dispatched to the customer location, reducing power outage duration (SAIDI).
Other Benefits	ƒ The Metering program is expected to provide environmental and economic benefits. Conservation has a direct impact on Toronto Hydro's carbon footprint and the cornerstone of conservation is offering interval data. Conservation programs require the validation of energy savings. In particular, Large Users rely on the detailed meter data to identify the potential areas for saving, and subsequently to confirm that the reduction in electricity usage has been achieved. Contracts between Energy Services Companies (ESCO) and customers will use the energy data to validate and pay for the conservation targets met. ƒ In terms of economics, Interval Metering MDM system upgrade for Large Users is expected to provide information to facilitate contract obligations, support for DR3 and make data available at five minute intervals for the entire group of qualifying customers. This program is also expected to provide information and processing for OPA's distributed generation programs such as FIT and microFIT data collection and credit generation. ƒ Metering data will be used to support Toronto's largest customers, employing thousands of Ontarians. This group consists of auto manufacturers, office towers, entertainment complexes, such as Rogers Centre and Air Canada Centre, hospitals and industrial manufacturing plants with sensitive equipment. Toronto Hydro's ability to troubleshoot and provide a stable, uninterrupted supply may be improved with the data that the utility collects from revenue metering, and is important for these customers to remain competitive in the marketplace by minimizing their operational costs due to power interruptions.

E5.1.3 Why the Program is Needed

Toronto Hydro is obligated to meet various legal and regulatory requirements that pertain to revenue metering and wholesale metering. Accordingly, the Metering Program was designed to enable Toronto Hydro to meet these requirements. For revenue metering, Toronto Hydro's legal and regulatory obligations are prescribed under the Electricity and Gas Inspection Act, and the associated regulations issued and administered by Measurement Canada. The OEB and IESO also publish requirements pertaining to smart meters and meter data management. Similarly, wholesale metering falls under Measurement Canada jurisdiction, and Toronto Hydro must also comply with IESO specifications as well.

E5.1.3.1 Program Drivers

The trigger and secondary drivers for each Metering Program are listed below in Table 10. Metering is a System Access initiative, because all of the listed projects are triggered by regulatory obligations.

TABLE 10: DRIVERS FOR METERING PROGRAM

Trigger Driver	Reasoning
Mandated Service Obligations	ƒ In order to operate as a LDC, Toronto Hydro needs to comply with all legal and regulatory requirements and government directives related to revenue metering and wholesale metering. o For revenue metering, Toronto Hydro is governed by the Gas Electricity Inspection Act, as well as provincial legislation as governed by the IESO, SME and OEB. o For wholesale metering, in addition to meeting the above regulations, IESO Market Rules specifications also apply.
Secondary Driver	**Reasoning**
Failure Risk	ƒ Failed or inaccurate meters tend to not measure or under-measure the electricity consumed by the customers. It is incumbent upon Toronto Hydro to ensure meters are systematically tested and re-verified so that failed meters do not remain in service.

(i) Revenue Meter Replacement

Toronto Hydro is required to meet the obligations set out in Sections 9, 11 and 12 of the Electricity and Gas Inspection Act. These requirements state that all meters must be re-sealed at specific intervals to ensure that a customer's electricity use is metered accurately. Once a seal expires, the meter cannot legally be used for billing purposes and must be resealed or re-verified (replaced). There are three revenue meter replacement initiatives as described in Section 5.1.2:

- Meter compliance sampling and re-verification.
- Systematic meter replacement, and
- Meter re-verification for Large User Class.

Meter compliance sampling and re-verification, remote connect and disconnect meters

For large homogenous batches of meters, Measurement Canada permits a sampling protocol to verify the accuracy of the meters as discussed earlier. Between 2015-2019, some of Toronto Hydro's meters have seals that are due to expire (refer to Tables 2 and 3). If the statistical accuracy results from the sample testing are within acceptable levels, all the meters in the meter group will receive a seal extension. The rules and regulations on the formation and testing of the group and sample size are specified in Measurement Canada's S-S-02 Bulletin Implementation Schedule for the Application of Statistical Sampling Requirements (Appendix A) [7] and Measurement Canada's S-S-06 Bulletin Sampling Plans for the Inspection Lots of Meters in Service (Appendix B)[8].

Certain meters need to be "re-verified". Re-verified meters are tested individually because they do not fit within the sampling program are required by law to be removed for testing and replaced with new meters.

Another element of this initiative is the installation of meters that have remote connect and remote disconnect switches. The installation of these meters should result in significantly reduced reconnection times following a disconnection for unpaid bills when the bills are finally paid, since field personnel will not have to be dispatched to the customer's location to manually reconnect the electrical service. Customers should benefit from a speedy reconnection and Toronto Hydro should benefit from improved operational productivity of not having to dispatch a field crew to perform the reconnection. This initiative is expected to free up service teams, leading to improved responsiveness to other service requests.

Further efficiency and productivity could result if there is recurring payment delinquency, since Toronto Hydro will not have to make additional visits to the meter for service disconnections and

[7] Measurement Canada, S-S-02 Bulletin – Implementation Schedule for the Application of Statistical Requirements (Appendix A) (Markham: Measurement Canada,).
[8] Measurement Canada, S-S-06 Bulletin –Sampling Plans for the Inspection Lots of Meters in Service (Appendix B) (Markham: Measurement Canada, 2010).

reconnections. Toronto Hydro will also be able to disconnect services when customers move out and no one has taken responsibility for the service. Based on historic data, approximately 50% of delinquent accounts on will become repeat offenders over the life of the meter.

Once the seals of a meter group have expired, it is illegal for Toronto Hydro to use the meters in the group to bill its customers. The use of meters with expired seals could result in the incorrect billing of customers due to inaccurate meters. Also, in the event that the meters with expired seals remain in use, Toronto Hydro could face financial penalties. Violations concerning the use of meters that do not comply with seal verification regulations fall under the very serious category and would be fined on a per-meter violation basis.

Meter re-verification – for Large User Class

As indicated in Section 5.1.2, the 635 customers making up the Large User Class represent about 25% of Toronto Hydro's total yearly revenue. These customers are key contributors to Toronto's and Ontario's economy and they typically have loads that are sensitive to power quality, and the implications of service interruptions can be severe. These customers include auto manufacturers, office towers, entertainment complexes that host national and international entertainment and sporting events, hospitals and industrial manufacturing plants with sensitive equipment.

The Large User Class customers require meters with enhanced functionality. Results from a survey of Large Use Class customers indicate that customers that current have online access to their detailed electricity usage use it to analyse their consumption and make use of advanced features such as graphing and downloading energy use information. All of these features will be enhanced with additional functionality that is not provided by the existing standard interval meters. These meters will provide voltage information, harmonics for power quality information and will detect ground fault scenarios and the estimated location of the fault. As well, the meters are equipped with an auxiliary power supply and will continue to communicate and measure energy, provide power outage and meter or service health errors and warnings even when power to the meter is lost.

In addition, customers requested several future enhancements and improvements, including: automation and scheduling of data retrieval, the ability to retrieve data for longer periods, the ability to aggregate loads, additional granularity, benchmarking, enhanced hierarchy, privileges for access (multiple buildings) and access to a larger pool of meters. The new meters will provide all of the above functions providing 10 channels of five minute interval data for additional

granularity and power quality information versus their current meter's capability of four channels of 15 minute data, with no power quality information. These customers qualify for Class A global adjustment or OPA programs such as DR3 whereby actual data is required for their account settlement. The new meters are equipped with auxiliary power backup ensuring that any meter issues (the loss of a phase voltage which can have a drastic affect on the energy measured 33% or 1/3 of the energy) can be identified immediately and error messages sent back to Toronto Hydro's office to resolve. Current meters cannot be able to sense that a problem exists.

Replacing meters currently in use by Large Use Class customers at the time of meter re-verification with meters that have added functionality should be beneficial for Large Use Class customers. In addition, these meters provide three-phase power quality information to Toronto Hydro that can be used to investigate distribution system issues related to power quality, in order to take preventative actions.

(ii) Interval Metering System Upgrade

The interval metering system or MDM system manages large C&I customers' interval meter data so that Toronto Hydro can fulfill its obligations to bill these customers based on spot market pricing under the OEB's Standard Supply Service Code (the Code) for Electricity Distributors. Clause 3.2.2 of the Code states:

> "The commodity price for electricity payable by a non-RPP consumer or an electing spot consumer that has an interval meter or another eligible time-of-use meter that is capable of providing data on at least an hourly basis shall be the spot market price determined in accordance with the Retail Settlement Code, with such adjustment as may be made by the IESO in accordance with the Electricity Act and the regulations."[9]

Existing MDM software is obsolete, as system fixes and upgrades are no longer provided by vendors of the software.

Toronto Hydro currently operates the suite of ITRON legacy MV Systems (MV-90, MV-STAR and MV-WEB) making up Toronto Hydro's Large User Interval MDM, or MDM system. These legacy systems are relied on to collect, validate and manage billing data of more than half of the total revenue billed by Toronto Hydro to its customers. The same older systems are also used for

[9] Ontario Energy Board, Standard Supply Service Code for Electricity Distributors (Toronto: Ontario Energy Board, 2011) at section 3.2.2. ["Standard Supply Service Code"]

retrieving data from Toronto Hydro's wholesale revenue meters at the grid supply points to monitor electricity supply to Toronto Hydro for wholesale settlement reconciliation. Due to system limitations, wholesale settlement reports and validation cannot be automated, which makes this process manual, requiring careful redundancy to avoid the potential for errors that arise from a manual process. The interval metering system upgrade is critical because it will enable Toronto Hydro to continue to meet its regulatory obligations, mitigate the risks of billing its largest customers improperly and reconciling the IESO wholesale settlement amounts correctly. In addition, the new software should improve customer access to their interval data, and to promote billing accuracy, since there will be fewer instances of manual entry errors resulting from manual reads and estimates when meter reads are not obtainable due to limited access. The software upgrade and integration with other Toronto Hydro systems, such as the outage management system (OMS), geographical information system (GIS), CC&B, and Asset Management system, is expected to improve Toronto Hydro's ability to maintain asset life and power outage response, thereby improving SAIDI and SAFI, while also reducing costs by continuously improving the utility's efficiency through technology and data management.

In summary, this project is critical to Toronto Hydro's efforts to mitigate the risk of having an obsolete system handle data collection for billing customers and to improve the monitoring of grid supply points. As well, Toronto Hydro expects to be able to provide better customer service and improve Toronto Hydro operational effectiveness.

(iii) SmartSynch Interval Meters Replacement

Toronto Hydro's regulatory obligations include making daily interval data available for access by 8:00 am the next day for its 8,600 SmartSynch meter customers. Remote meter reading is necessary for these interval meters. These meters currently operate on the 2G wireless networks that are scheduled to be phased out by Rogers in 2018. If SmartSynch meters with the 2G wireless module are left in service past 2018, the meters will not be remotely accessible for interval meter data retrieval. Consequently, Toronto Hydro would not be in compliance with the OEB regulation that requires that customers' billing data be available the day after the billing period. Accordingly, SmartSynch interval meters replacement is required to upgrade the communication module to 3G so that Toronto Hydro can continue to meet its regulatory obligations and bill these customers based on the Hourly Ontario Energy Price spot market price for complex billing.

(iv) Suite Metering System Upgrade

The City of Toronto is experiencing significant condominium development. To continue to meet IESO Smart Meter data regulations, Toronto Hydro requires software upgrades to its current data collection system. As specified in the IESO's functional specifications for an Advanced Metering Infrastructure (AMI), it is required that "All Meter Reads collected during the Daily Read Period shall be received by the AMCC and transferred to the MDM/R no later than 5:00 a.m. local time following the Daily Read Period."[10] In the MDM/R V1.0 Technical Interface Specifications, there is the requirement that "Meter Read data (be) received by the MDM/R by 05:00 EST for the prior Daily Read Period shall be available by 07:10 EST on the day following the Daily Read Period"[11].

Currently, Toronto Hydro's Primeread AMI system retrieves data from the 38,000 suite meter customers to facilitate billing. The Primeread AMI system is one of the few systems that support PLC technology for meter data communication. PLC allows the building wiring for electricity distribution to be used for transferring meter data to a computer located in the building, which is subsequently transmitted to a data collection system at Toronto Hydro. Although the current system was implemented in 2012, anticipated growth in the number of suite meters will necessitate adding additional processing capability in the period from 2015 to 2019, as illustrated in Tables 6 and 7.

Additional capacity is needed for Toronto Hydro to meet its IESO data transmission timeline obligations for TOU billing. The Ontario government mandated TOU billing for all residential and small commercial customers in Ontario and the growth in suite meter installations requires upgrades to existing systems to maintain basic functionality so that Toronto Hydro can meet its responsibilities to the Ontario government and to its customers. Toronto Hydro requires hardware and software upgrades to the PLC AMI to maintain its ability to meet IESO obligations by providing the IESO with hourly data by 5:00 am, ensuring that hourly and TOU data can be posted on a customer-accessible website by 8:00 am local time. As can be seen in Table 11, when the number of suite meters is at 73,000 in 2017, there will not be enough hours to retrieve and process the meter data to meet the IESO specifications with the existing system, given that meter data retrieval can only begin after midnight.

[10] Independent Electricity System Operator, AMI to MDM/R Data Transfer, (Toronto: Independent Electricity System Operator, 2006) at page 16.
[11] Independent Electricity System Operator, Meter Data Management and Repository – MDM/R Technical Interface Specifications, (Toronto: Toronto: Independent Electricity System Operator, 2011) at section 2.11.7.

TABLE 11: SUITE METER DATA PROCESSING HOURS ON EXISTING SYSTEM

Year	Suite Meter Accounts	Processing Time (Hour)
2013	34,400	3
2014	45,000	3.5
2015	56,000	4
2016	64,000	4.5
2017	73,000	5
2018	83,000	6
2019	93,000	7

(v) Suite Meter Installation

When a new condominium is built, the ECPA mandates that individual suites be metered separately. Specifically, the ECPA Subsection 33 (2), Installation of Suite Meters Required, states:

> "such persons or classes of persons as may be prescribed shall, in such circumstances as may be prescribed and subject to such conditions as may be prescribed, have a suite meter installed by a suite meter provider in such properties or classes of properties as may be prescribed and for such consumers or classes of consumers as may be prescribed.".[12]

Toronto Hydro is legally obligated to provide suite meter installation service. While the developer may use its own meter service provider or request that Toronto Hydro directly install suite metering, the ECPA states that the LDC is the meter service provider of last resort in the event that the condominium cannot secure its own meter service provider.

In the Suite Metering Regulations under the EPCA and the Ontario Energy Board Act, 1998, [13] for the purposes of subsection 33(2) of the EPCA with respect to units belonging to a class of units described in "Class of Units" in Table 12, the owner or individual responsible for unit is required to have a suite meter installed for that unit by a suite meter provider retained. Toronto Hydro is legally required to be in compliance with the requirements in providing suite metering when requested by the party concerned.

[12] ECPA, at s. 33(2).
[13] S.O. 1998, c. 15. ["OEB Act"]

TABLE 12: SUITE METERING REQUIRED BY SUITE METERING REGULATIONS

	Class of Units	Circumstances	Conditions
1.	Rental unit in a residential complex	Before completion of construction of the residential complex in which the rental unit is located.	Installation must take place in the rental unit before the rental unit is occupied.
2.	Common elements of a residential complex	Before completion of construction of the residential complex.	Installation must take place before any rental unit in the residential complex is occupied.
3.	Condominium unit in a condominium building	Before completion of construction of the condominium building in which the condominium unit is located.	Installation must take place in the condominium unit before the condominium unit is occupied.
4.	Common elements of a condominium building.	Before completion of construction of the condominium building.	Installation must take place before any condominium unit in the condominium building is occupied.
5.	Member unit of a non-profit housing co-operative building	Before completion of construction of the non-profit housing co-operative building.	Installation must take place in the member unit before the member unit is occupied.
6.	Common elements of a non-profit housing co-operative building	Before completion of construction of the non-profit housing co-operative building.	Installation must take place before any member unit in the non-profit housing co-operative building is occupied.

(vi) Provincial MDM/R Integration

The Government of Ontario granted the SME exclusive authority over smart meter data services in the province, as well as the maintenance and operation of the Provincial MDM/R.[14] In order for the SME to exercise such exclusive authority, Toronto Hydro must integrate its billing system and ODS, along with the business processes and practices, with the provincial MDM/R. Toronto Hydro has a statutory obligation to do so, pursuant to s. 53.15 of the Electricity Act, 1998[15]. In addition, it has a license obligation under s. 5.3.13 of the OEB's DSC to comply with the VEE processes set out by the SME. Collectively, these distinct provincial obligations under the OEB require Toronto Hydro to integrate its customer billing system with the MDM/R system operated by the SME. Toronto Hydro currently utilizes an in-house ODS that has the functionality to VEE interval data from its smart meters, and then frame and process the data for Time of Use billing as well as web presentment.

[14] Ontario Regulation 393/07, Smart Metering Entity, at section 5.
[15] S.O. 1998, c. 15. ["Electricity Act"]

(vii) Wholesale Metering and Transformer Replacement

The metering upgrades are required so that Toronto Hydro remains in compliance with the requirements and criteria set forth in the Market Manuals (MDP_PRO_0022)[16] and the Market Rules (MDP_RUL_0002_06[17] and 19 MDP_RUL_0002_06A[18], which define the metering requirements that Toronto Hydro must meet to continue operating as a distributor of electricity and as a MMP. More specifically, Toronto Hydro must replace its legacy transformers with modern instrument transformers that have an approved accuracy class as specified in the MDP_PRO_0022 and MDP_RUL_0002_06 and 19 MDP_RUL_0002_06A. In addition, Toronto Hydro is responsible to ensure that every meter and instrument transformer used for settlement purposes has been approved for this use by Measurement Canada.

To maintain its status as a MMP, Toronto Hydro has committed to a long-term plan with the IESO to complete full meter upgrades at all applicable delivery points. This plan was initiated by a letter submitted to the IESO on August 11, 2009, and approved by the IESO on November 27, 2009. In addition, HONI has committed additional resources for the period of 2015 to 2019 to achieve the upgrade of meters for the sites noted.

The rules related to wholesale metering were developed to ensure a high degree of accuracy, which is of significant importance due to the large volume of electricity being delivered through these meters. The requirements are set out in detail in Chapter 6 of the Market Rules titled Wholesale Metering Compliance Requirements.[19] Many of Toronto Hydro's legacy installations will require investments in order to meet these requirements. In addition, many existing legacy transformers used for wholesale metering require the proposed investments in order to meet American National Standards Institute (ANSI) 0.3% accuracy class required by Section 1.7 of Market Rules- Chapter 6 Wholesale Metering - Appendices. Furthermore, due to requirements imposed by Measurement Canada as detailed in the Electricity and Gas Inspection Act, Toronto Hydro must upgrade some of its legacy wholesale meter installations to increase accuracy by ensuring that a separate meter is installed at each delivery point.

[16] Independent Electricity System Operator, Market Manual 2: Market Administration – Part 2.6: Treatment of Compliance Issues (Toronto: Independent Electricity System Operator, 2012).
[17] Independent Electricity System Operator, Market Rules – Chapter 6 Wholesale Metering (Toronto: Independent Electricity System Operator, 2013).
[18] Independent Electricity System Operator, Market Rules – Chapter 6 Wholesale Metering – Appendices (Toronto: Independent Electricity System Operator, 2012.) ["Market Rules- Chapter 6 Wholesale Metering – Appendices"]
[19] For instance, Section 2 sets out the metering installation requirements. Section 3 of Chapter 6 sets out the obligation to participate in the real-time administered IESO market as a metered market participant. Section 4 sets out the meter installation standards for both main and alternate meters. In addition, the Chapter 6 Appendices set forth the obligations of metered market participants and metering service providers in respect of metering. Finally, Market Manual 2: Market Administration Part 2.6 MDP_PRO_0022: Treatment of Compliance Issues, provides the steps required for the treatment of compliance issues by both Market Participants and the IESO.

It should be noted that, in addition to ensuring that Toronto Hydro remains in compliance with the regulations, this project will also improve the accuracy of billing information for every customer within Toronto Hydro's jurisdiction.

E5.1.4 Timing & Pacing of the Program

The timeline for the Metering Program's initiatives and projects is primarily driven by regulatory obligations and compliance requirements with respect to the IESO and the OEB. Planned spending for the period 2015 to 2019 is outlined in Table 13.

TABLE 13: PROPOSED SPENDING FOR METERING PROGRAM

	Historical Spending					Future Spending				
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	$28.4	$22.1	$12.1	$12.2	$14.0	$24.7	$16.6	$14.7	$11.7	$13.7

/C

Please note that during the period 2010-2013, Toronto Hydro did not sample test residential and small C&I meters, as conventional meters were all re-verified under the Smart Meter Conversion project impacting the historical metering program spending. Toronto Hydro converted approximately 71,000 meters to smart meters in 2010 and 2011.

There are three programs expected to commence in 2015 that are one-time programs (not included in any of the historical spending years). The one-time programs include:

- Interval metering MDM software and hardware system upgrades,
- SmartSynch Interval Meters Replacement, and
- IESO MDM/R integration project.

In addition to these one-time program costs, the number of new suite meter installations is expected to be 12,000 units in 2015 based on current contracts, which is 30% higher than the average future expected number of new suite meters (9,250 units per year) from 2016-2019 and 33% higher than the historical average of 9,012 units. The higher number of suite meters increases the investment for this program in 2015 by approximately $2 million. In total, one-time programs and higher suite meter installations represent $12.9 million of the $24.7 million forecasted investment in 2015. /C

In general, there are several factors contributing to the year over year variances in investment. The most significant factors are the following:

(1) Smart Meter installations – In years 2010, 2011 and 2012, Toronto Hydro needed to access conventional meters with expiring seal periods, which required certain customers to be disconnected so that Toronto Hydro could obtain access to change meters. Some of these meters also had asbestos backer-boards that led to higher meter replacement costs. Historical spending between 2010 and 2011 is proportional to the conversion of approximately 43,000 conventional meters to smart meters in 2010, compared to approximately 28,000 meters in 2011 when the program was essentially completed. Historical spending further declined in 2012 with only approximately 4,500 conventional meters that were converted to smart meters.

(2) With the conversion of conventional meters, only one reading is needed per billing period to calculate consumption. With smart meters, automated remote readings of 15 or 60 minute interval data for TOU or HOEP are used for billing. This large volume of data requires system upgrades for processing, validating and estimating data. These upgrades are captured in years 2015, 2016 and 2019 and were not captured in the historical spend.

(3) Wholesale Revenue meter changes are to be completed depending on HONI's schedule. The number of wholesale meter points and full metering upgrades can vary drastically each year, causing a variance in spending of $4 to $6 million per year.

(4) Meter system upgrades were not included in past filings.

E5.1.4.1 Ranking & Prioritization

All of the projects in the Metering Program are driven by regulatory compliance requirements. Initiatives that address meters with seals expiring in a program year were given the highest priority in that particular year so that work will be completed before the seals expire. Similarly, if meters in a sampling group fail accuracy testing, the replacement of the sampling group's seals will be given high priority. The remaining projects making up the Metering Program are prioritized based on their relative time criticality. These additional prioritization considerations are further detailed below.

Toronto Hydro plans to install smart meters with remote connect/disconnect switches when a service needs to be disconnected due to bill payment delinquency. This will enable the service to be remotely reconnected, saving the cost of dispatching a field crew to reconnect the service and

reducing the inconvenience to the customers concerned. The meters removed may be reused at other services if there is significant seal life left.

While the upgrade of the interval metering system is not mandated to be completed in a specific year, the initiative should be carried out as soon as possible given that the system is obsolete and is relied on to support billing for $2.23 million of annual revenue. System replacement is therefore scheduled for 2015 and will continue into 2016.

8,500 SmartSynch meters use Rogers' GPRS or 2G network to wireless communicate to Toronto Hydro's back-end data collection systems. As previously mentioned, Rogers has advised Toronto Hydro that this network is being phased out by 2018. The life expectancy of SmartSynch meters is 15 years. Meters will be scheduled to be replaced to ensure that the years in-service, as well as the second seal period will equal the expected 15 year life expectancy of the meters.

Given the projected number of suite meters that will be in use going forward, towards the end of the 2015-2019 period, the existing suite metering system, Primeread, will not be able to collect and process meter data in time for it to be accessible to customers as per regulatory requirements. The need for a system upgrade is dependent on the projected growth in the number of suites requiring suite metering. This growth projection will be closely monitored and the upgrade of the system is scheduled for 2019.

The installation of suite meters is driven by the timing of the condominium construction development projects. Toronto Hydro will need to have the resources available, whether internal or by contract with a qualified service provider, to meet the suite meter installation requirements as requested.

The provincial MDM/R integration initiative is planned for 2015 to 2017. The extended implementation period is necessary to allow all required testing to be performed, both for the system changes and for the changes to business processes. MDM and billing will both be impacted by the MDM/R integration, and both are critical business functions of Toronto Hydro.

Toronto Hydro has committed to a long-term plan with the IESO to complete full meter upgrades at all applicable delivery points by 2021. The timing of the work will be dependent on HONI's schedule, as their resources are required in connection with the work to be completed by Toronto Hydro. The schedule for 2015 to 2019 as shown in Table 8 has been determined with HONI's input, but the precise timing of which work is completed within a given year will ultimately be determined in collaboratively with HONI.

E5.1.5 Program Execution

The projects within the Metering Program will either replace meters or upgrade systems that support metering. Meters to be addressed are distributed across the City of Toronto. In certain instances, meters in certain locations are of similar age since they were installed at a similar time during Toronto Hydro's Smart Meter mass deployment. See Figure 2 below.

Toronto Hydro's Smart Meter deployment began with east crews working from the east border moving west to the city core and west crews starting from the west border moving east to the city core in 2006. Once the east and west regions were completed, Toronto Hydro moved from the north end and moved south. The City of Toronto core was left until the very end. Toronto Hydro's sampling program will work along the same principle since the first seal expiring meters will be located in the east and west regions.



FIGURE 2: MAP OF STRATEGIC DEPLOYMENT STRATEGY BY GEOGRAPHICAL LOCATION AND YEAR.

Work planning will take advantage of geographical concentration wherever possible.

Based on regulatory compliance requirements and the urgency to address the risks associated with system obsolescence, Toronto Hydro expects to execute the initiatives and projects within

the Metering program according to the timeline provided in Table 14. The specifics for each project related to the project scope, work planning and execution are described in Section 5.1.8.

TABLE 14: METERING PROGRAM PROJECTS & SCHEDULE

Project Name	Start Date	In-service Date
Revenue Meter Replacement		
Compliance Sampling and Reverification	Jan 2015	Dec 2019
Large User C&I Reverification with Enhanced Meter Functionality	Jan 2015	Dec 2019
Interval Metering System Upgrade	Jan 2015	Jul 2016
SmartSynch Interval Meters Upgrade	Jan 2015	Dec 2017
Suite Metering System Upgrade	Jan 2019	Dec 2019
Suite Meter Installations	Jan 2015	Dec 2019
Provincial MDM/R Integration	Jan 2015	Sep 2017
Wholesale Metering Equipment Replacement	Jan 2015	Dec 2019

(i) Revenue Meter Replacement

There are three initiatives under revenue meter replacement:

- Meter Compliance Sampling and Re-verification,
- Meter Compliance Sampling Program, and
- Meter Re-verification for Large User Class.

Each initiative is an ongoing operation, and will be planned and executed as follows.

Meter Compliance Sampling and Re-verification

At the beginning of each year within the 2015 to 2019 timeframe, Toronto Hydro plans to create a detailed plan for the sampling and re-verification program for the meters expiring that year. The plan is expected to include all of the work for the entire year with geographical locations for all meters, addresses, customer contact information meter type and service type.

Meter Compliance Sampling Program

Within the compliance sampling program, meter groups that are due for sample testing are identified. To allow an efficient sampling program, meters will be selected by geographical area.

Figure 3 is a map used to form meter groups (also referred to as Meter Test Groups) of homogeneous meters, based on the Geo Code areas. For the year 2015, three Meter Test Groups have been created from which sample meters will be selected using the random number generator and sample selection algorithms from the Toronto Hydro CC&B system. These test groups are only for R1S-single phase, with meter seal year 2006 (expiring 2016). Sample size is determined by Measurement Canada S-S-06, Sampling Plans for the Inspection of Isolated Lots of Meters in Service, Annex C, Table 2, Limiting Quality 3.15.

An example of three Meter Test Groups that have been created for meters with seals expiring in 2016 are shown in Table 15 below.

TABLE 15: EXAMPLE OF THREE METER TEST GROUPS

Meter Group Number	Meter Group Population	Sample Size
9101	14,825	315
9102	15,497	315
9103	16,834	315

From each meter group, the specified random number generator is used to create a sample list. Field activity orders are issued for Toronto Hydro field crews to remove the meters and return them to Toronto Hydro's Accredited Service Provider for compliance sample-testing. Test results are forwarded to Toronto Hydro for record updating and action based on the test results. A pass will result in an update to the meter records only. If meters pass the accuracy tests, the level of the accuracy will determine the seal extension period. For smart meters with a ten-year initial seal period that receive a passing grade, the seals will be extended for eight years. If the sample meters fail the statistical accuracy test, Measurement Canada allows for a second sample of randomly selected meters to be tested. If the second sample passes, the seals for all of the remaining meters will be extended for a period less than eight years depending on the overall statistical accuracy results. If the second sample of meters also fails, the meters in the entire meter group will have to be replaced before the end of the seal expiry year.

Work within the 2015 to 2019 timeframe will be planned and executed as outlined above. Table 2 shows the number of sample meters to be tested during the five years.

FIGURE 3: GEOGRAPHICAL AREA OF THE THREE SAMPLE TEST GROUPS

Revenue meters that do not belong in the compliance sampling program must be removed from service and tested (re-verified) by the accredited meter shop service provider before the seal period expires. Meters with seal periods expiring in the 2015 to 2019 period are identified and printed out in a re-verification list at the beginning of each year for the meters with seals expiring in that year. Field activity work orders are issued from the CC&B system for the field crews to replace the meters. Field work is organized based on the geographical locations of these meters for efficiency purposes.

Meter Re-verification – for Large User Class

Meter removal/installation work for the large C&I customers over 1 MW requires special arrangements with the customers in order to minimize negative impacts to their business operations. Toronto Hydro plans to prepare a list of meters with seals expiring in a given year that are due for re-verification. The Meter Department will then coordinate with the customers concerned to schedule access to their utility room for the metering work. Every effort will be made to accommodate the customers' needs when scheduling work.

Table 2 shows the number of meters expected to be replaced within the 2015 to 2019 period.

(ii) Interval Metering System Upgrade

The interval metering system upgrade is scheduled to begin in January 2015 and be completed by July 2016. The extended project timeline is necessary due to the complexity of the system and business requirements involved. This system is required to aggregate multiple metering points each meter may have a different configuration which needs to be accounted for and managed by the system. For example, each meter within an aggregation calculation may have a specific loss factor, various interval lengths (five minute, 15 minute and 60 minute intervals), various interval channels (some meters have two channels while other meters have as many as 10 channels of interval data) into a summed hourly interval value for each measurement.

Toronto Hydro plans on forming an implementation team at the beginning of 2015 with a Meter Department staff member, who is familiar with the interval metering data collection and data management requirements, serving as team lead. The team will include a representative from Billing, and an Information Technology Systems Consultant, who will enlist other Information Technology resources as and when necessary.

The implementation team will prepare a document that will specify in detail the required functions and technical capabilities of the system for a RFP, and will then work with Procurement to select a suitable vendor through the RFP process. The selected vendor's proposal will include a detailed system implementation plan acceptable to Toronto Hydro. It is vital that the implementation plan include a parallel run stage to ensure the new system performs satisfactorily before the old system is decommissioned.

(iii) SmartSynch Interval Meters Replacement

The 8,500 SmartSynch meters will be upgraded by 2018 through planned staging. This will involve obtaining 100 new SmartSynch meters with a 3G module that will be purchased at the beginning of 2015 to start the staging process. The first 100 SmartSynch meters in the field will be replaced with the new SmartSynch meters. The obsolete 2G SmartSynch meters are returned to the meter shop where they will have their 2G module replaced with a 3G module. These upgraded meters are then used to replace the next 100 2G SmartSynch meters in the field. By recycling batches of 100 meters at a time and upgrading their software, Toronto Hydro can use a lower cost retrofit kit versus purchasing 8,500 new meters. This process is repeated until all the 2G SmartSynch meters have been upgraded. The very last 100 3G SmartSynch meters (upgraded 2G from the field) left over in the end will be warehoused for future use, either to meter new customers or to replace the defective meters in service.

(iv) Suite Metering System Upgrade

Suite metering system upgrades are scheduled to be completed in 2019. Toronto Hydro plans on forming an implementation team at the beginning of 2019 with a Meter Department staff member who is familiar with suite metering data collection and data management requirements serving as team lead. The team will include a representative from Billing, and an Information Technology Systems Consultant, who will enlist other Information Technology resources as and when necessary.

The implementation team will prepare a document that will specify in detail the required functions and technical capabilities of the system for a RFP, and will then work with procurement to select a suitable vendor through the RFP process. The selected vendor's proposal will include a detailed system implementation plan acceptable to Toronto Hydro. It is vital that the implementation plan include a parallel run stage to ensure the new system performs satisfactorily before the old system is decommissioned.

(v) Suite Meter Installation

Toronto Hydro's suite meter installation schedule will be based on the condominium construction schedule submitted by the developers and will be adjusted according to actual construction progress.

(vi) Provincial MDM/R Integration

The Provincial MDM/R integration project is a major undertaking due to its complexity and its potential impact on Toronto Hydro's core business operation. Business-to-Business (B2B) integration of this nature requires changes not just to systems, but also to associated business processes and business practices. Careful planning, implementation and thorough testing at every stage and for all levels will be critical for the success of the integration. Close coordination with the SME throughout the project is also vital.

Since 2013, Toronto Hydro has been working with the SME to plan Toronto Hydro's transition to the provincial MDM/R. In 2013, the two parties undertook a pilot project to explore ways in which they could leverage the existing VEE services and address Toronto Hydro's needs through configuration rather than customization of the MDM/R. Toronto Hydro plans on using the experience and information from this pilot project and the joint workshops that has been

conducted with the SME to assess the gaps in Toronto Hydro's systems to initiate system change design and planning.

Toronto Hydro plans on developing a project plan based on the MDM/R integration technical, business and testing requirements. The SME resource should be engaged from the outset to ensure proper understanding of the SME MDM/R requirements with respect to the interface protocol and specifications. Toronto Hydro plans on holding regular meetings to help ensure that projects progress and to resolve project issues, whether they are system or business process related. Contingency measures will be built into the project plan to ensure billing operation continuity in the event of system problems.

It is critical that test cases be designed to include all situations that can be anticipated, including with respect to data transmission, data processing, meter data uploading and actual billing. Toronto Hydro expects that the implemented solution, including system changes and business process changes, will only be signed off by the business clients after a thorough user acceptance test.

(vii) Wholesale Metering and Transformer Replacement

In order to undertake wholesale metering and transformer replacement successfully, close coordination with HONI is critical since Toronto Hydro personnel will have to work with HONI personnel to carry out the metering equipment upgrade work. At the beginning of each year in the 2015 to 2019 period, Toronto Hydro's Meter Department is expected to meet with HONI to review the work plan and to schedule the resources needed. Toronto Hydro will make every effort to accommodate the resource constraints of HONI.

The actual metering upgrade involves de-registering the existing wholesale revenue metering points, preparing the site for new fully-compliant IESO wholesale metering installations and carrying out the installation work, as indicated in Table 16.

TABLE 16: WHOLESALE METERING REPLACEMENT LOCATIONS

Windsor TS	253 Wellington Street West, Toronto, Ontario
The site is a 115/13.8 kV transformer station supplying local loads. Over multiple years the A5-A6-A9-A10, A3-A4-A7-A8 and A11-A12 feeders, which are in a ring bus configuration, will be subject to a revenue metering upgrade.	
Wiltshire TS (A5,6)	13-19 Wiltshire Avenue, Toronto, Ontario
The site is a 115/13.8 kV transformer station supplying local loads. The A5-A6 is the subject of this revenue metering upgrade.	
Strachan TS (A5,6)	6 Strachan Avenue, Toronto, Ontario,

The switchyard site is a 115/13.8 kV, 60 Hz TS supplying local loads. There are two power transformers (T13 and T15) providing step down transformation from the 115 kV system to the 13.8 kV system.	
Duplex TS (A1,2)	400 Duplex Street, Toronto, Ontario
The site is a 115/13.8 kV transformer station supplying local loads. The A1-A2 is the subject of this revenue metering upgrade.	
Carlaw TS (A4,5)	369 Carlaw Avenue, Toronto, Ontario
The site is a 115/13.8 kV transformer station supplying local loads. The A4-A5 is the subject of this revenue metering upgrade.	

E5.1.5.1 Program Risks

Table 17 illustrates the major program risks that may occur while executing the Metering program.

TABLE 17: PROGRAM RISKS

Initiative/Project	Risk	Impact	Risk Probability	Mitigation
Compliance Sampling Program	Meter group fails sample testing.	Sample sizes would need to be increased or entire sample lot would need replacement. High cost implications.	Low – Meters are relatively new at 10 years old, and accuracy testing in other jurisdictions has been successful.	The risk of sample test failure cannot be reduced. If the initial sample fails, Toronto Hydro will conduct secondary sampling as permitted. If it fails again, Toronto Hydro will schedule the replacement of the meter group concerned within the systematic meter replacement initiative.
Upgrade Smart Synch Interval Meters due to 2G wireless network obsolescence	Conversion kit availability.	Meters would require manual reading if the communication network is unavailable. The cost associated with manual meter reading is high.	Low - vendor is currently already working on a suitable conversion.	Ensure effective and continual communication with vendor to maintain high priority for the project.
Wholesale Metering and Transformer	HONI projects are delayed.	Compliance with IESO Market	Medium – projects are complicated	Work closely with HONI to schedule work and to allocate resources.

Initiative/Project	Risk	Impact	Risk Probability	Mitigation
Replacements		Settlement rules is delayed.	and subject to equipment delays and resource availability.	

E5.1.5.2 External Constraints

The external constraints of the Metering Program are noted below.

- Toronto Hydro will be working closely with HONI resources to carry out the wholesale metering equipment upgrade. HONI resources might be unavailable when required due to other projects that it is working on. To mitigate the risk, Toronto Hydro plans on providing generous advanced notice to HONI and schedule the work accordingly.

- Measurement Canada may change calculation methods related to the metrological parameters, particularly for interval meter data. However, Measurement Canada generally provides sufficient lead time to the LDCs to make the necessary adjustments to their systems.

- Site access to the metering equipment for the Large User Class meter change-out will require coordination with the customers concerned. Toronto Hydro plans on scheduling the work by taking into consideration the customers' business operation if power interruption is needed.

- The provincial MDM/R integration with Toronto Hydro's systems will require IESO's resources, system capacity and performance capability for the large amount of data that will be transferred daily. Integration issues and network interfaces between Toronto Hydro's systems will impact the project timelines and costs. Toronto Hydro plans on working closely with the IESO to mitigate these risks.

E5.1.5.3 Standard & Regulation Adherence

Metering is a fundamental component of the operation of an electric utility and is regulated by federal and provincial regulations, either directly or via regulatory bodies. In addition, metering requires compliance with ANSI standards for communications security. All of Toronto Hydro's meters toned to comply with ANSI standards and have been audited. The Metering Program is

expected to improve meter security encryption for the delivery of data to Toronto Hydro. The Metering program should also enhance customer access and security features for their data. The relevant standards and regulations are identified in Table 18.

TABLE 18: STANDARDS AND REGULATIONS FOR METERING

Revenue Meter Re-verification and Sampling Program	ƒ Weights and Measures Act ƒ Electricity and Gas Inspection Act ƒ Measurement Canada Bulletin S-02 ƒ Measurement Canada's Bulletin S-06
Wholesale Metering and Transformer Replacements	ƒ Meter ANSI standard C12.20 (0.2% accuracy class) ƒ Meter transformers ANSI standard C12.20 (0.3% accuracy class) ƒ IESO Wholesale Revenue Metering Standard IESO Market Rules Chapter 6 Wholesale Metering ƒ IESO Market Rules for the Ontario Electricity Market
Upgrading Smart Synch Interval Meters to 3G Wireless Standard	ƒ Communication standard HSPCA
Remote Disconnect Meters	ƒ Meter ANSI standard C12.20 (0.5% accuracy class)
Upgrade Metering at Large User Buildings (over 1 MW)	ƒ Weights and Measures Act ƒ Electricity and Gas Inspection Act ƒ Measurement Canada Bulletin S-02 ƒ Measurement Canada's Bulletin S-06
Interval Metering, MDM Software and Hardware Upgrade	ƒ Toronto Hydro IT Standards ƒ Sections 3.2.1, 3.2.1A, and 3.2.2 of the Standard Supply Service Code (Appendix C)
Suite Metering, MDM Software and Hardware Upgrade	ƒ Toronto Hydro IT Standards ƒ IESO "Functional Specifications for an advanced Metering Infrastructure" ƒ Sections 3.2.1, 3.2.1A, and 3.2.2 of the Standard Supply Service Code (Appendix C)

E5.1.6 Evaluation of Alternatives

Due to the regulatory obligations for Metering, there are no alternatives other than willfully contravening the rules and governing laws.

E5.1.6.1 Quantification/ Evaluation of Options

(1) Re-verification and Sampling – no alternatives.

(2) IESO Wholesale Settlement – no alternatives.

(3) Large C&I customers AMI – no alternatives.

(4) Suite Meter AMI System Upgrade – no alternatives.

(5) SmartSynch – no alternatives.

(6) Large C&I meters – no alternative.

(7) Remote disconnect – cost of manual R/D based on percent of re-offenders Toronto Hydro standards.

(8) Suite meter installations – no alternative

(9) Provincial MDM/R Integration – no alternative – provincial legislation requires integration with Smart Meter Entity.

(10) Upgrade Smart Synch Interval Meters - reverting to a manual reading process would require immense resources; therefore upgrading the metering to maintain system viability is the only option.

(i) Status Quo

Due to the regulatory obligations surrounding Metering, there are no alternatives to the proposed Metering Program. If Toronto Hydro does not undertake the Metering Program, it may be in violation of the rules governing the operation of an LDC. For example, if the progress of the upgrades does not meet the satisfaction of the IESO, Toronto Hydro may be found to be in breach of the Market Rules.

(ii) Replacement with Standard Equipment

The Replacement with Standard Equipment within the Metering program should allow Toronto Hydro to meet the Mandated Service Obligations and adhere to various regulations as detailed in Status Quo above. This program should also Toronto Hydro to improve the visibility customers have on their electricity use and ensure the accurate billing, providing significant value to the customer. Therefore, this is the preferred alternative.

E5.1.7 2015 Project Details

Table 19 lists all projects that will be partially or completely executed as part of the 2015 work program. In addition to the projects initiated in 2015, Toronto Hydro also forecasts $704 K in carryover costs related to the 2014 wireless collector project, which was originally filed as part of the OEB approved Metering segment in Phase 2 of the utility's 2012-2014 IRM/ICM rate filing. Collectors retrieve hourly data from the utility's 680,000 smart meters and provide an access point to backhaul this data for Time of Use billing. The collectors are also used to process power outage notification, disconnection and reconnection status, meter events and alerts.

Note that the table shows total costs for each project.

TABLE 19: 2015 PROJECTS

Project Number	Project Name	Total Project Cost ($000)	Start Date
30963	Revenue Meter Replacement		
	x Meter Compliance Sampling and Reverification	$12,144	2015
	x Installing Remote Disconnect Meters	$4,833	2015
	x Meter Reverification for Large User Class	$6,019	2015
30965	Interval Metering System Upgrade - MDM Software and Hardware Upgrade for Large Commercial and Industrial Customers	$5,277	2015
30963	SmartSynch Interval Meters Replacement	$5,267	2015
30964	Wholesale Metering and Transformer Replacement	$1,251	2015
31674	Suite Meter Installations	$35,606	2015
31675	Provincial MDM/R Integration	$8,083	2015
31360	Pole Mounted Collector project 2014 carryover[20]	$4,300	2014

/C

/C

[20] Note: $704K of the total $4.3M Pole Mounted Collector project cost is forecasted as carry-over into the 2015 CapEx budget.

E5.2 Customer Connections

TORONTO HYDRO CREW RESPONDING TO AN ELECTRICAL SERVICE REQUEST

E5.2.1 Summary

Program Description

Expenditures in the Customer Connections program account for the system investments and modifications required to provide customers with access to electricity services via Toronto Hydro's distribution lines. The program also includes any additional expansions or enhancements to the system for connections where Toronto Hydro is required to make an Offer to Connect (OTC).

The work executed in this program delivers customer value by serving new customers with timely, cost-efficient and reliable connections to the distribution system. Energizing new residences, businesses and institutions is necessary for the City of Toronto's economic and cultural expansion and development. The following table summarizes the expected benefits of this program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Providing connection to the distribution system to residents and businesses ƒ Providing and maintaining reliable and cost efficient service to customers
Reliability	ƒ Reliability to existing customers is maintained or improved through new connections

Safety	ƒ Helps ensure safe connection to the distribution system for all customers, as stated in Toronto Hydro's Conditions of Service.
Efficiency	ƒ Future capital projects and customer expansion are coordinated where possible for cost-efficiencies and to minimize the number of future construction projects.

Program Drivers

The Customer Connections program is driven primarily by the number of customer service requests that Toronto Hydro receives annually. Supporting information such as development and economic forecasts are additional factors that are included in the baseline forecast. According to Economic Indicators data provided by the City of Toronto Economic Development Division, an upward trend in economic growth is reflected in the number of developments being applied for through City zoning applications and building permits. In addition to the baseline amounts, a number of major projects with multi-year construction schedules are considered in the spending forecasts, including the West Don Lands work for the Pan Am Village, the TTC expansion at Leslie and Lakeshore, and several major Metrolinx projects including the Eglinton Light Rail Transit (ELRT) line. The following table is a summary of this program's trigger and secondary drivers.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Customer Service Request	ƒ Obligated to complete new customer connections and/or modifications to existing customer connections. ƒ Required to perform necessary expansions for customer connections or property development in order to provide service.
Secondary Driver	**Reasoning**
Mandated Service Obligations	ƒ As per Conditions of Service and the Distribution System Code, obligated to connect, or make an Offer to Connect to any customer that lies along the distribution system.

Preferred Alternative

As discussed above, Toronto Hydro is obligated to connect customers to its distribution system, where safe to do so, by the Electricity Act, 1998,[2] Distribution System Code and its own Conditions of Service. As such, there are no alternatives to this program.

Timing and Pacing

The proposed timing and pacing of this program is based on several factors. Historical spending amounts and trends inform the baseline forecast for the program, which covers the typical or basic connection work that occurs for customer connections. Development and economic forecasts are additional factors that are included in the baseline forecast to determine projected growth above the baseline in future years, as well as known major projects such as the ELRT.

TABLE C: HISTORICAL AND FORECASTED EXPENDITURES

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gross ($M)	39.29	58.12	50.11	77.05	65.62	53.90	66.14	77.98	71.73	62.66
Customer Contributions ($M)	(24.05)	(26.93)	(19.11)	(23.62)	(13.48)	(14.60)	(12.36)	(13.09)	(14.83)	(16.10)
Ratio (%)	61.21	46.34	38.14	30.66	20.54	27.09	18.69	16.79	20.67	25.69
Net ($M)	15.25	31.19	31.01	53.43	52.13	39.30	53.78	64.89	56.90	46.56

[2] R.O. 1998, C. 15, Sched. A. ["Electricity Act"]

E5.2.2 Program Description

Toronto Hydro distributes electricity to residential, commercial, and industrial customers via overhead and underground infrastructure. As the owner and operator of this distribution system in the City of Toronto, Toronto Hydro is obligated by section 28 the Electricity Act to connect a building to its distribution system if:

(a) the building lies along any of the lines of the distributor's distribution system; and

(b) the owner, occupant or other person in charge of the building requests the connection in writing.

Expenditures in the Customer Connections program account for the system investments and modifications required to provide customers with access to electricity services via Toronto Hydro's distribution lines. This includes the installation of connection assets such as overhead or underground supply lines from Toronto Hydro overhead service poles or cable chambers, any connections at the customer service mast or meter base, installation of required overhead or padmount transformers, installation and connection of commercial meters, and other basic connection tasks as required by any customer service requests.

The program also includes any additional expansions or enhancements to the system for connections where Toronto Hydro is required to make an Offer to Connect (OTC). Toronto Hydro requires OTCs when the building requesting service cannot be connected to the Toronto Hydro distribution system without an expansion. Expansion work is typically needed for larger industrial or commercial connections, or requests in areas of the city that are capacity constrained. Expansion work involves the installation or upgrade of distribution assets such as new circuits or civil infrastructure that is required to accommodate new customer loading. Without this work, the existing distribution system could not accommodate the customer.

In total, Toronto Hydro forecasts $261 million in net capital expenditures from 2015 to 2019, with an additional $70 million of capital contributions from customers requesting connection. Figure 1 shows the locations of all proposed and approved building development projects in Toronto Hydro's service area as of December 2013. These projects are in various stages of completion, ranging from the pre-construction/zoning approval stage, to under construction, to complete. As illustrated, there are new developments across the Toronto Hydro distribution system, and the investments made through the Customer Connection program will impact Toronto Hydro's entire service area.

FIGURE 1: DEVELOPMENTS IN PLANNING OR CONSTRUCTION STAGE IN TORONTO HYDRO SERVICE AREA

The following table summarizes the expected benefits of the Customer Connections program.

TABLE 1: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Providing connection to the distribution system to residents and businesses ƒ Furthering the economic and cultural expansion of the City of Toronto ƒ Providing and maintaining reliable and cost efficient service to customers
Reliability	ƒ Reliability to existing customers is maintained or improved through new connections
Safety	ƒ Ensures safe connection to the distribution system for all customers, as stated in Toronto Hydro's COS.
Efficiency	ƒ Future capital projects and customer expansion are coordinated where possible for cost-efficiencies and to minimize the number of future construction projects.

The work executed in this program delivers customer value by serving new customers while maintaining reliable and cost efficient service to existing customers. With timely, cost-efficient and reliable connections to the distribution system, residents and businesses are able to maintain a high standard of living and can generate income and value for the City of Toronto. Energizing

new residences, businesses and institutions is necessary for the City of Toronto's economic and cultural expansion and development.

E5.2.3 Why the Program is Needed

As explained previously, Toronto Hydro is obligated to connect new customers in its service area. Upon receipt of a customer service request and after consultation with the customer, Toronto Hydro will make every reasonable effort to connect the customer or, if necessary, issue an OTC to the customer.

In any given year, Toronto Hydro receives over 10,000 connection requests. As highlighted in Figure 1, many development projects are forecasted for the City of Toronto, the majority of which will require new or upgraded service connections. As has been well documented in the media, Toronto led North America in the number of high rise buildings under construction over 2012 and 2013, as shown in Figure 2. As of November 2013, Toronto ranked ahead of major North American cities such as New York and Mexico in high rise construction according to data from construction and commercial real estate firm Emporis.

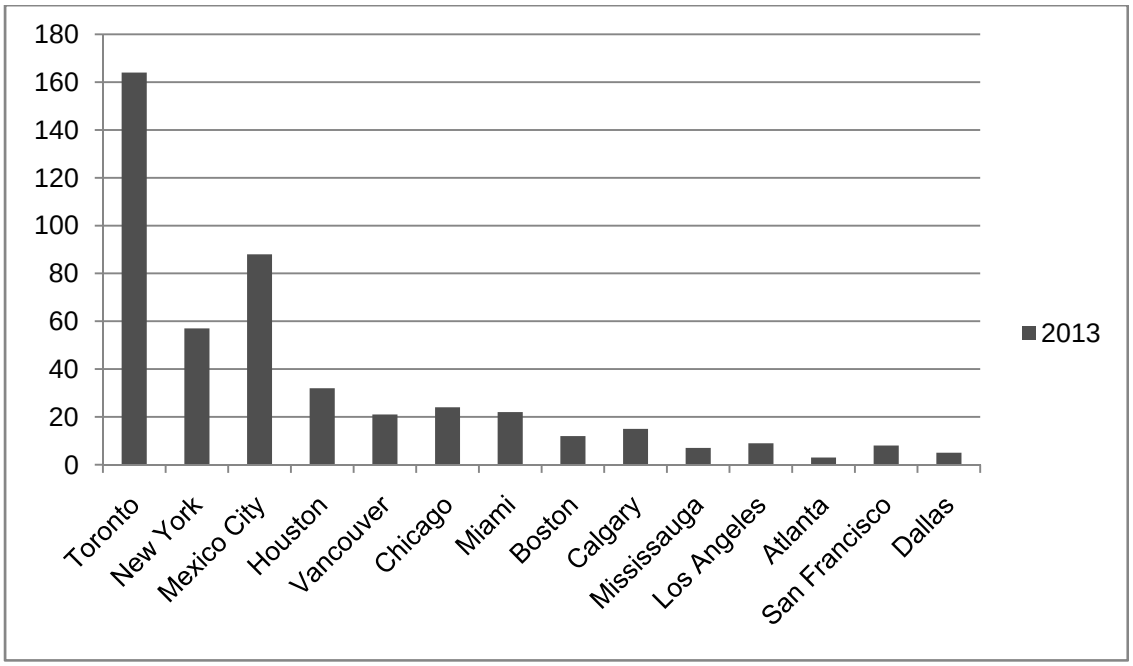


FIGURE 2: HIGH RISE BUILDINGS UNDER CONSTRUCTION AS OF NOV 2013 [7]

[7] Emporis, New High-Rises, online: Emporis<http://www.emporis.com/continent/northamerica>.

In addition to the large number of current developments, economic forecasts indicate that Toronto's economy will experience growth over the 2015-2019 period. According to The Conference Board of Canada, the City of Toronto's Gross Domestic Product (GDP) is forecasted to grow by 3.3% in 2015, 2.9% in 2016 and 2.4% in 2017.

E5.2.3.1 Program Drivers

Table 2 presents the trigger and secondary drivers for the Customer Connections program. The program is a System Access initiative because the trigger driver is customer service requests.

TABLE 2: PROGRAM DRIVERS

Trigger Driver	Reasoning
Customer Service Request	ƒ Obligated to complete new customer connections and/or modifications to existing customer connections. ƒ Required to perform necessary expansions for customer connections or property development in order to provide service. ƒ Maintain service obligations to provide reliable and efficient connection to the distribution system, thereby delivering customer value.
Secondary Driver	**Reasoning**
Mandated Service Obligations	ƒ As per Conditions of Service and the Distribution System Code, obligated to connect, or make an Offer to Connect to any customer that lies along the distribution system.

E5.2.4 Timing & Pacing of the Program

Expenditures in the Customer Connections program are driven primarily by the number of customer service requests that Toronto Hydro receives annually. Toronto Hydro is required to make every reasonable effort to consult and work with the customer within the mandated timelines set out in the Electricity Act and the utility's own Conditions of Service (COS) . The COS require that Toronto Hydro respond to a customer's written request for connection within 15 calendar days of receipt and make an OTC, if required, within 60 calendar days of receipt of the written request, unless other necessary information is required from the customer before the offer can be made. Table 3 shows the historical and future spending for the Customer Connections program.

TABLE 3: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gross ($M)	39.29	58.12	50.11	77.05	65.62	53.90	66.14	77.98	71.73	62.66
Customer Contributions ($M)	(24.05)	(26.93)	(19.11)	(23.62)	(13.48)	(14.60)	(12.36)	(13.09)	(14.83)	(16.10)
Ratio (%)	61.21	46.34	38.14	30.66	20.54	27.09	18.69	16.79	20.67	25.69
Net ($M)	15.25	31.19	31.01	53.43	52.13	39.30	53.78	64.89	56.90	46.56

The proposed timing and pacing of this program is based on several factors. Historical spending amounts and trends inform the baseline forecast for the program. These baseline amounts cover the typical or basic connection work that occurs for customer connections, such as the activities described in Section E5.2., which include installing a padmount transformer or connecting commercial meters.

Development and economic forecasts are additional factors that are included in the baseline forecast. According to Economic Indicators data provided by the City of Toronto Economic Development Division, retail sales data has shown year over year increases since 2010[8]. This upward trend in economic growth is also reflected in the number of developments being proposed and applied for through City zoning applications and building permits. The same Economic Indicators data referenced earlier shows that the total number of building permits each year has been increasing since 2011, and according to the January 10, 2014, Economic Development Committee Dashboard Report for the City of Toronto, the total value of building permits issued in November 2013 increased by over 120% as compared to the same month in 2012[9]. Given this data and using a similar growth trend, Toronto Hydro anticipates that the number of customer service requests and the size of the customers requesting connection will continue to trend upwards. This is reflected in the projected spending over the 2015-2019 period where Toronto Hydro has taken into account the number of new building permit applications and the forecasted development numbers from the city and commercial developers. The slight depression in 2015 is due to the anticipated slowing in construction projects as a result of the Pan Am Games being hosted in Toronto during the main construction season.

[8] City of Toronto Economic Development and Culture, Economic Indicators Database, online: City of Toronto <www1.toronto.ca/City%20Of%20Toronto/Information%20&%20Technology/Open%20Data/Data%20Sets/Assets/Files/economic_indicators_database.xlsx>.
[9] City of Toronto Economic Development and Culture, Economic Dashboard Report, (Toronto: City of Toronto, 2014) at page 5.

In addition to the baseline amounts, a number of major projects with multi-year construction schedules are considered in the spending forecasts. These projects are considered to be extensive customer connections that require planning and work beyond the typical basic connection and typically have a defined scope of work entering each budget year. Examples include the West Don Lands work for the Pan Am Village, the TTC expansion at Leslie and Lakeshore or several major Metrolinx projects which are described in more detail below. These major projects will typically require an OTC to be signed with expansion work needed to connect the customer.

The higher number of large customer service requests has also required Toronto Hydro to issue an increasing number of OTCs to address situations where the requested service cannot be provided without completing expansion work. Expansion work can have a significant impact on the pacing of the program because it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a large customer. The resulting expansion projects are usually large scale and complex, and thus require weeks or months to complete.

As mentioned above, Metrolinx's light rail transit projects are examples of the sort of large scale customer service requests that will have a substantial impact on the timing and pacing of the Customer Connections program during the planning horizon. Specifically, the Eglinton Light Rail Transit (ELRT) line requires several connection points to the Toronto Hydro system. Approximately 30 new LRT stations are proposed for this line, with a total demand of approximately 90 MVA. Connecting this many stations with such a large load will require significant expansion work over the 2015-2019 time frame and is the primary basis for the substantial net spend in 2017 and 2018. Current timelines and schedules for the ELRT project require the majority of expansion and connection work to be executed in 2017 and 2018 as Metrolinx underground tunneling work is scheduled to be complete in the summer of 2017. Following the completion of the ELRT work, Toronto Hydro anticipates a return to 2014 levels of spending in 2019.

Typically, large customer requests, such as the Metrolinx work described above, not only have a significant impact on Toronto Hydro's capital work program, but also on its capital expenditures. Capital contributions from customers with large connected load are minimal because the forecasted revenues used in the Economic Evaluation are often equal to or greater than the projected expansion and connection costs needed to serve them. As a result, these projects typically produce a positive Net Present Value. The result of the increasing number of these large

requests in recent years and in that projected for the future is a lower ratio of customer contributions to gross capital expenditures.

E5.2.4.1 Ranking & Prioritization

Toronto Hydro ranks and prioritizes jobs in the Customer Connections program in accordance with the schedules and timelines of individual customers and service requests. For customers requiring basic connection, prioritization is on a first come, first served basis, taking into account the in-service date requested by the customer. This prioritization applies where Toronto Hydro has sufficient physical electricity supply, such as overhead or underground lines, to make the connection as well as adequate capacity on the relevant distribution feeder cable and station bus. If either of physical supply or capacity are lacking, the connection will occur once the situation is remedied.

For connections that cannot be completed without an expansion, prioritization of the work is determined in accordance with the timelines and requirements stated in the OTC.

E5.2.5 Program Execution

The Customer Offers group manages the work required under the Customer Connections program for Toronto Hydro. As outlined in Section 2 of the Conditions of Service, the customer or customer representative is required to consult with Toronto Hydro concerning the availability of supply, the supply voltage, service location, metering, and any other details necessary to establish service.

The customer or its authorized representative is required to apply for new or upgraded electricity services and temporary power services in writing. The customer also is required to provide Toronto Hydro with sufficient lead-time to ensure the timely provision of electricity supply to the building or the availability of adequate capacity for additional loads to be connected to the system.

During the consultation and design phase of a customer's request, if it is determined that the connection requires expansion and a subsequent OTC, Toronto Hydro attempts to realize potential cost-efficiencies by grouping other needed investments with the connection project. Primary considerations include future investment plans and forecasted load growth for the project area.

If Toronto Hydro anticipates that load growth will require additional infrastructure upgrades beyond what is required under the expansion work in the OTC, engineers or planners will include the additional distribution work, which can range from installing larger circuits to rebuilding cable chambers, as a part of the project. This coordinated approach is more cost-efficient than returning and performing additional upgrades in the same area at a later date.

An example of this approach to gaining efficiencies can be found along Toronto's Waterfront, where the required civil work to connect new condominiums and developments was augmented to include the additional infrastructure necessary to accommodate the Waterfront's future demands and system requirements.

If during the design and consultation phase of reviewing the customer request Toronto Hydro determines that connection to the distribution system would cause unsafe conditions to the public, workers, or the system, Toronto Hydro reserves the right to deny the request. This is highlighted in Section 2.1.3 of Toronto Hydro's COS:

"…Toronto Hydro is not obligated to connect a Customer within its service area if the connection would result in any of the following...

- Adverse affect on the reliability or safety of Toronto Hydro's distribution system
- Public safety reasons or imposition of an unsafe work situation beyond normal risks inherent in the operation of Toronto Hydro's distribution system

To abide by the section and ensure safe connection to the system, a load analysis is performed for each customer request. This analysis ensures that the requested connection would not overload any Toronto Hydro assets above their rated capacity. Operating assets over rated capacity increases their risk of failure, and could also create potential safety risks. For large connections, this analysis also includes protection and coordination studies to ensure the proper protection is in place so that if a fault occurs, it is cleared in timely manner so that the fault ceases to be fed, which could cause damage to equipment and create potential safety risks.

In addition, while customer connections projects are not intended to result in improved system performance, as part of the connection process, the load analysis also ensures that the load being added not negatively affect reliability. Toronto Hydro provides new customers with connections that are designed to deliver, at a minimum, the level of reliability currently experienced by the customers currently being fed by that feeder or station. If a connection could potentially worsen the reliability of the feeder or station, expansion work is undertaken to increase

capacity or transfer load so that the current level of reliability is maintained. As described previously, this expansion work is charged to the customer through the OTC process.

Once design and consultation with the customer is complete, the resulting work is to be carried out by Toronto Hydro resources unless otherwise stated or agreed upon in the OTC. This work includes the installation of connection assets, such as overhead or underground service lines from Toronto Hydro overhead service poles or cable chambers, any connections at the customer service mast or meter base, installation of required overhead or padmount transformers, installation and connection of commercial meters. Customer charges or allowances associated with the work are pursuant to the OEB's Distribution System Code and Toronto Hydro's COS. One set of charges or allowances are Basic Connection Fees. As contained in Revision 13 of the COS, Toronto Hydro's Basic Connection Fees include:

TABLE 4: BASIC CONNECTION FEES (AS OF MAY 1, 2014)

Customer Class	Basic Connection Fee
Class 1 - Residential	$1,396
Class 2 – General Service (<50kW)	$1.396
Class 3A/3B/3C – General Service (50 kW – 999kW)	$1,396
Class 4 & 5 – General Service (1000kW and Up)	$1,396
Unmetered – Overhead Supply (excluding street lighting)	$446 or $1,011
Street Lighting	$533 or $574

These fees are reviewed annually and updated with notice to customers when Toronto Hydro's COS is revised.

E5.2.5.1 Program Risks

The following are risks to program completion that Toronto Hydro considers when planning and executing the Customer Connections program.

(i) Capacity Upgrade Requirements

Due to the increasing quantity and size of customer service requests, Toronto Hydro anticipates that many future connections will require expansion work to deal with capacity constraints. This could include the installation of new feeders, which would require the preparation of existing feeder positions on the switchgear and possibly even the installation of new assets such as breakers at the station switchgear. These types of upgrades have long lead times that could cause Toronto Hydro to fail to meet the customer's required timelines for connection.

This issue is being addressed through long term forecasting, which includes analysis of city area and development plans in order to plan for the expected increase in demand. Toronto Hydro's load forecast then in turn drives the proactive upgrade or installation of new station assets as required.

(ii) Customer Timelines and Requirements

Due to the nature of the work in the Customer Connections program, customer consultation and involvement is often required. Customer timelines and requirements can therefore present a risk to the project timeline. Changing requirements or increase/decrease in service demand as well as delays in the signing of OTCs can impact the schedule and timeliness of completion.

The Customer Offers group attempts to identify and mitigate these risks during the design and consultation phase with the customer and by adhering to the guidelines in Toronto Hydro's COS to respond to a customer's written request for connection within 15 calendar days of receipt of the written request and will make an OTC if required within 60 calendar days of receipt of the written request.

E5.2.5.2 Standard & Regulation Adherence

Toronto Hydro's COS describes the operating practices and connection policies to connect to the distribution system as required by Section 2.4 of the Distribution System Code. The COS also indicates how Toronto Hydro complies with its obligations under section 28 of the Electricity Act.

E5.2.6 Evaluation of Alternatives

As discussed above, Toronto Hydro is obligated to connect customers to its distribution system, where safe to do so, by the Electricity Act, Distribution System Code and its own COS. As such, there are no alternatives to this program.

E5.3 Externally-Initiated Plant Relocation and Expansion

WORKS AT TORONTO'S UNION STATION

E5.3.1 Summary

Program Description

Expenditures in the Externally Initiated Plant Relocation and Expansion program account for the relocation of Toronto Hydro's assets to accommodate construction by governmental and other agencies.

In general, when relocations are required, Toronto Hydro replaces the existing facilities on a like-for-like basis. This approach is, in most instances, the preferable alternative because it represents the minimum investment that allows Toronto Hydro to continue providing safe and reliable electricity distribution service. However, sometimes the nature of the project is such that like-for-like replacement is not the most efficient or desirable option. In some instances there is an opportunity for Toronto Hydro to maximize construction efficiencies and increase the existing capacity at the same time a relocation project is completed. This often offers a more prudent and cost-effective solution for ratepayers than conducting this expansion work later.

The following table summarizes the expected benefits of this program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Opportunistic expansion work reduces the frequency and duration of construction disruptions for local area residents over time
Efficiency	ƒ Reduction in capital costs during the installation of infrastructure through cost sharing agreements, as well as shared construction efforts between Toronto Hydro and other organizations.
Reliability	ƒ Externally initiated relocation and expansion projects are not driven by reliability. However, where Toronto Hydro relocates or expands existing infrastructure, the new infrastructure is installed at current standards, which typically increases reliability.
Safety	ƒ Facilities the establishment of safe work sites that do not have high voltage electrical infrastructure on them. This minimizes safety risks to third parties who request the relocation work.
Other	ƒ Coordination with sponsor agencies provides a benefit to the economic well being of the City. This benefit is realized by Toronto Hydro relocating infrastructure, allowing sponsor agencies to complete their capital work plans, including transit expansions, bridge rehabilitations, and external utility upgrades.

Program Drivers

The following table summarizes the trigger driver for this program.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Customer Service Requests	ƒ Projects are driven by operational decisions of third parties that are beyond Toronto Hydro's control. ƒ Responding to such requests is part of Toronto Hydro's mandated service obligations, including those set out in the Distribution System Code and the Public Service Works on Highways Act, 1990, which requires Toronto Hydro to work with road authorities to complete relocations when requested ƒ Construction work carried out by third parties can provide an opportunity to expand the distribution system in a manner that minimizes disruption to customers and is more cost-effective for ratepayers.

Preferred Alternative

As discussed above, responding to these requests is part of Toronto Hydro's mandated service obligations. As such, there are no alternatives to executing this work.

Timing and Pacing

The timing and pacing of Externally Initiated Plant Relocation and Expansion is primarily determined by the project timelines set by sponsor agencies. Due to the uncertain nature of this work, some projects are delivered on short-notice. Toronto Hydro's projected spending in this program is based on historical expenditures and known or anticipated capital plans from other agencies.

TABLE C: HISTORICAL AND PROJECTED SPENDING FOR RELOCATION PROJECTS

	Historical Spending ($ Millions)					Future Spending ($ Millions)				
Year	2010[1]	2011[2]	2012	2013	2014	2015	2016	2017	2018	2019
Total Project Cost	3.3	7.8	10.7	19.6	12.2	22.3	43.6	52.6	42.8	43.3
Customer Contribution	2.6	2.8	0.9	1.1	3.4	8.7	23.5	24.1	15.0	14.5
Toronto Hydro Costs	0.7	5.0	9.8	18.6	8.8	13.6	20.1	28.5	27.8	28.8

Spending in this program is largely outside of Toronto Hydro's control. Due to the often high cost and significant volatility around the externally-initiated projects, Toronto Hydro has only included a portion the forecast program costs in its funding requirements. Although the utility forecasts that this program will cost approximately $119 million between 2015 and 2019, it has included only one-sixth of this amount (approximately $20 million) in its revenue requirement, or approximately $4.0 million of net Toronto Hydro costs per year. This sub-forecast amount represents a base level of spending that will be required over this term.

Toronto Hydro proposes to seek rates funding only for this sub-forecast base amount, with a variance account to record differences from this amount. Since the current projections for costs over the 2015-19 period are significantly higher than the amount included in Toronto Hydro's

[1] Prior to 2012, relocation projects were grouped together with Capital Projects, and were not tracked as a separate set of projects. The data only reflects the costs of projects within the capital work plan that Toronto Hydro could confirm were relocation projects, and as such, the actual numbers are expected to be higher.
[2] See footnote 1.

funding requirements, the utility is requesting the establishment of a variance account to capture annual differences from this base amount. Further details on the request for this account are in Exhibit 9, Tab 1, Schedule 1. The utility's expectation is that this approach will allow it to fund necessary, non-discretionary work while, at the same time, holding ratepayers harmless from the potential that a material amount of the forecast third party work does not materialize, due to the unpredictable nature, costs, and timing of such projects.

E5.3.2 Program Description

Construction projects initiated by the agencies includes work to maintain, upgrade, expand and improve existing public infrastructure such as roads, bridges, highways, and rail crossings. Among the entities initiating this work are Waterfront Toronto, the City of Toronto, the Ontario Ministry of Transportation, and Metrolinx (GO Transit). Legislation such as the Public Service Works on Highways Act, 1990,[4] mandates that Toronto Hydro work with public entities to facilitate their projects in a timely manner to promote the maintenance and improvement of public infrastructure.

When requested to relocate its infrastructure, Toronto Hydro works with the agencies initiating the work to find an efficient solution to accommodate the project in question. In general, when relocations are required, Toronto Hydro replaces the existing facilities on a like-for-like basis. This approach is in most instances, the preferable alternative because it represents the minimum investment that allows Toronto Hydro to continue providing safe and reliable electricity distribution service. However, sometimes the nature of the project is such that like-for-like replacement is not the most efficient or desirable option. In some instances there is an opportunity for Toronto Hydro to maximize construction efficiencies and increase the existing capacity at the same time a relocation project is completed. In these cases, Toronto Hydro reviews the relocation in conjunction with its future plans before, and works with the sponsor agency to complete system expansion work in conjunction with the required relocation. When Toronto Hydro increases the capacity of its infrastructure during an externally initiated project, this is known as expansion for the purposes of this narrative.

Broadly speaking, the projects within this program can be divided into requests from road authorities, which are governed by the Public Service Works on Highways Act, and those that are not governed by the Act.

(i) Requests from Road Authorities

The Public Service Works on Highways Act defines the obligations of utilities (Operating Corporations, such as Toronto Hydro) with facilities in road allowances and those that have responsibility to operate and maintain road allowances (Road Authority) during the course of construction. When a Road Authority has a project within the road right of way, the Act obligates a utility, such as Toronto Hydro, to relocate these facilities in cooperation with the Road Authority.

[4] R.S.O. 1990, C. P-49. ["Public Service Works on Highways Act"]

Within the City of Toronto, a Road Authority includes the City of Toronto or the Ontario Ministry of Transportation. A typical relocation project for a Road Authority could involve relocation of Toronto Hydro infrastructure due to a City-initiated modification in the road alignment. The new road alignments often require Toronto Hydro poles to be relocated to enable the road realignment.

The Public Service Works on Highways Act provides a mechanism for negotiating the apportionment of labour costs of relocations required by Road Authorities as between the Road Authority and the Operating Corporation. The Act includes a default provision that labour costs must be apportioned equally between the Road Authority and the Operating Corporation, while all other costs of the work shall be borne by the Operating Corporation (i.e. Toronto Hydro). Finally, the Act provides for a mechanism to appeal unfair or unjust cost allocations to the Ontario Municipal Board for a final determination. Road Authorities are also responsible to governmental and regulatory bodies, and thus are also aiming to minimize costs. As such, projects are typically completed with the default provision for labour and equipment costs. Consistent with past experience, Toronto Hydro estimates that it will be able to recover approximately 30% of the total job costs associated with projects from a Road Authority.

For projects that are initiated by a Road Authority, but are not explicitly covered under the Act, such as streetscape improvement projects, Toronto Hydro negotiates cost sharing agreements with the Road Authority on a case by case basis.

(ii) Requests from Other Agencies

Projects initiated by an organization other than a Road Authority are not covered under the Public Service Works on Highways Act. The Act requires Toronto Hydro to work with Road Authorities to complete relocations when requested on public road allowances, and although not mandated to complete relocations for other agencies, should deal with requests in a fair and reasonable manner. The sponsor agency typically funds 100% of the relocation costs of projects where distribution assets are located on the public road right of way, while Toronto Hydro is responsible for the entirety of any expansion work conducted in concert with the relocation. An example of this type of project is the Metrolinx Light Rail Transit (LRT) expansion. This project includes significant work already underway along Eglinton Avenue for the Eglinton LRT, as well as proposed works for the Finch LRT, Sheppard LRT and Scarborough Rapid Transit replacement. The locations of the Metrolinx LRT projects are shown in Figure 1. In total there are over 60 kilometers of light rail planned throughout the City of Toronto to be completed by 2020. The

Eglinton Crosstown line is the only LRT line currently under design, and is expected to run 19 kilometers from Kennedy Station to Jane Street along Eglinton.

Within these corridors, Toronto Hydro is expanding its existing infrastructure in preparation for load growth expected along the LRT lines. The expansions are based on City plans for the area, and projected density increases.

FIGURE 1: MAP OF METROLINX LRT PROJECTS PLANNED FOR COMPLETION BY 2020

Where Toronto Hydro infrastructure is on private property, or right of ways held by other organizations, individual agreements and cost responsibility are typically reviewed on a case by case basis. This was the case with GO Transit's Georgetown South Service Expansion, where Toronto Hydro infrastructure crossed the GO rail right of way. Table 1 outlines various benefits realized through this program.

TABLE 1: PROGRAM BENEFITS

Customer Value	ƒ Opportunistic expansion work reduces the frequency and duration of construction disruptions for local area residents over time
Efficiency	ƒ Reduction in capital costs during the installation of infrastructure through cost sharing agreements, as well as shared construction efforts between Toronto Hydro and other organizations.
Reliability	ƒ Externally initiated relocation and expansion projects are not driven by reliability. However, where Toronto Hydro relocates or expands existing infrastructure, the new infrastructure is installed at current standards, which typically increases reliability.
Safety	ƒ Facilities the establishment of safe work sites that do not have high voltage electrical infrastructure on them. This minimizes safety risks to third parties who request the relocation work.
Other	ƒ Coordination with sponsor agencies provides a benefit to the economic well being of the City. This benefit is realized by Toronto Hydro relocating infrastructure, allowing sponsor agencies to complete their capital work plans, including transit expansions, bridge rehabilitations, and external utility upgrades.

E5.3.3 Why the Program is Needed

Toronto Hydro undertakes the externally initiated relocations and expansions projects solely in response to the capital work initiated by sponsor agencies. Toronto Hydro is required to undertake this work by the applicable legislation and requests from the other agencies. Any expansion work carried out within the program is needed to meet anticipated future load growth, to allow Toronto Hydro to coordinate projects with construction work being carried on by third parties, to minimize disruption for customers, and to realize efficiencies and cost-effective solutions for ratepayers.

E5.3.3.1 Program Drivers

Toronto Hydro's Externally Initiated Plant Relocation and Expansion program is driven by third party requests, requirements under the Public Service Works on Highways Act and other requests from sponsor agencies.

TABLE 2: PROGRAM DRIVERS

Trigger Driver	Reasoning
Third Party Requests	ƒ Projects are driven by operational decisions of third parties that are beyond Toronto Hydro's control. ƒ Responding to such requests is part of Toronto Hydro's mandated service obligations, including those set out in the Distribution System Code and the Public Service Works on Highways Act, which requires Toronto Hydro to work with road authorities to complete relocations when requested ƒ Construction work carried out by third parties can provide an opportunity to expand the distribution system in a manner that minimizes disruption to customers and is more cost-effective for ratepayers.

E5.3.4 Timing & Pacing of the Program

The timing and pacing of Externally Initiated Plant Relocation and Expansion is primarily determined by the project timelines set by sponsor agencies. Toronto Hydro works with sponsor agencies to schedule the work in a manner that meets the requirements of the agencies and the company. Due to the uncertain nature of this work, some projects are delivered on short-notice.

Toronto Hydro's projected spending in this program is based on historical expenditures as well as known or anticipated capital plans from other agencies. Toronto Hydro gathers this information through a number of means, including direct consultation with external agencies, the Toronto Public Utilities Coordinating Committee (TPUCC), project plan publications such as the MTO Southern Highways Program and the Metrolinx Big Move documentation. At this time, the forecast projects, as well as timing for those projects, are based on the most current information available from the sponsor agencies. Toronto Hydro relocation projects are directly related to a capital project from the sponsor agency. Capital plans from sponsor agencies are subject to change based on their business cycles, funding requirements, and changing business demands. Any modification to the sponsor agency's capital plan could impact Toronto Hydro relocation and expansion projects.

The Public Service Works on Highways Act requires Toronto Hydro to work with Road Authorities to complete relocations when requested on public road allowances, and to deal with requests from other agencies in a fair and reasonable manner.

Expansion work is also governed by road work moratoriums that are imposed after road resurfacing is completed. If Toronto Hydro does not complete expansion work in conjunction with capital programs of external agencies, there may not be another opportunity to install required infrastructure in the area for a minimum of five years. The infrastructure requirements are based on predicted growth, future projects, and the reliability of the system.

TABLE 3: HISTORICAL AND PROJECTED SPENDING FOR RELOCATION PROJECTS

	Historical Spending ($ Millions)					Future Spending ($ Millions)				
Year	2010[6]	2011[7]	2012	2013	2014	2015	2016	2017	2018	2019
Total Project Cost	3.3	7.8	10. 7	19.6	12.2	22.3	43.6	52.6	42.8	43.3
Customer Contribution	2.6	2. 8	0.9	1.1	3.4	8.7	23.5	24.1	15.0	14.5
Toronto Hydro Costs	0.7	5.0	9 .8	18.6	8.8	13.6	20.1	28.5	27.8	28.8

[6] Prior to 2012, relocation projects were grouped together with Capital Projects, and were not tracked as a separate set of projects. The data only reflects the costs of projects within the capital work plan that Toronto Hydro could confirm were relocation projects, and as such, the actual numbers are expected to be higher.
[7] See footnote 1.

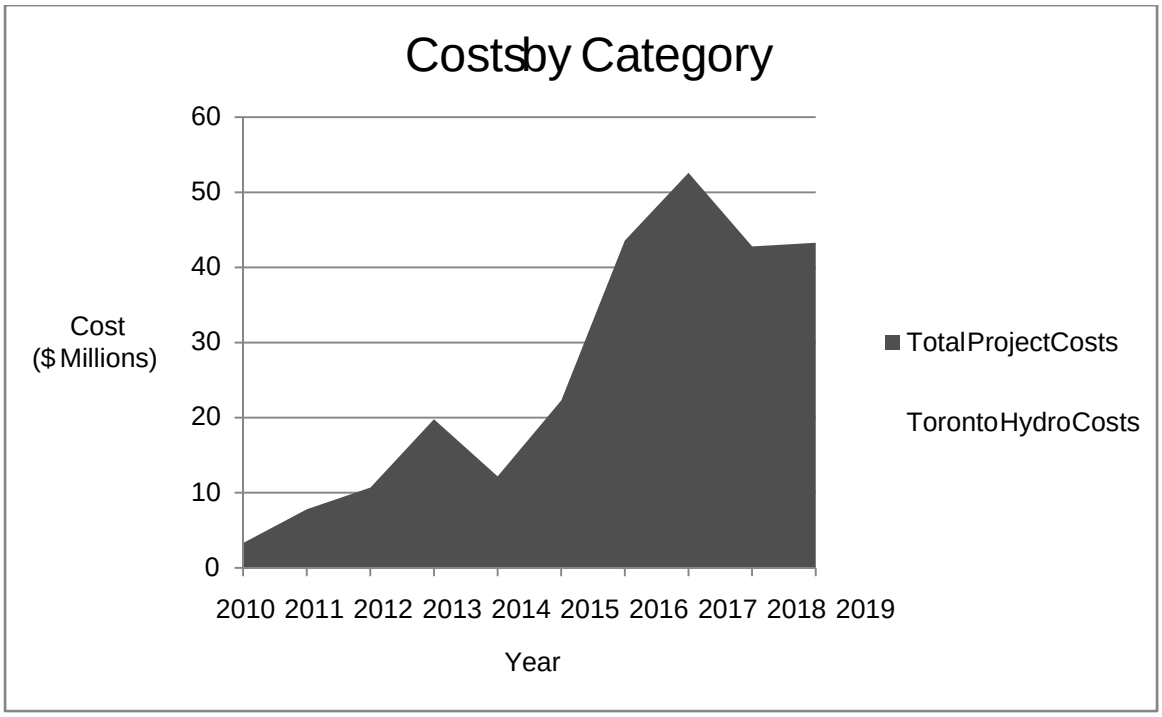


FIGURE 2: HISTORICAL AND PROJECTED SPENDING FOR EXTERNALLY INITIATED RELOCATION AND EXPANSION PROJECTS

Prior to 2012, relocation projects were grouped together with Capital Projects, and were not tracked as a separate set of projects. The data only reflects the costs of projects within the capital work plan that Toronto Hydro could confirm were relocation projects, and as such, the actual numbers are expected to be higher. Since 2012, after Toronto Hydro implemented a new tracking system for relocation projects, a general upward trend of Toronto Hydro costs associated with the externally initiated relocation and expansion program can be seen as a whole.

A large number of City work projects, driven by the Pan Am Games in 2015, had increased the spending required on utility relocations in 2013. These works were focused in 2013 in order to allow the City time to construct the capital projects required for the Pan Am Games in 2014 and early 2015. This is why the number of projects, as well as the overall spending, is predicted to decrease in 2014. While costs are expected to drop in 2014, work associated with the Metrolinx light rail transit projects are expected to significantly increase costs over the 2015-19 period. Design and some construction is expected in 2015, and significant construction investment beginning in 2016, and continuing through construction completion in 2020. Additionally,

electrification of the GO rail service between Pearson airport and Union Station may require significant investments, currently forecast to total $24 million over three years from 2015-2017. These projects, along with other known large projects, are expected to cause the upward trend in relocation and expansion costs to continue. Some of the projects that make a notable contribution to the expected costs are outlined below.

(i) MTO Bridge Rehabilitation Program

The MTO is responsible for the safety and operations of the provincial highways and bridges. This project is driven by the Southern Highways Program of MTO. This program mentions new highway and bridges to be constructed as well as existing highway and bridges to be rehabilitated. Toronto Hydro has identified four locations where there are known conflicts with bridges to be rehabilitated.

(ii) GO Transit Electrification – Union Pearson Express

One of the improvements proposed as part of the Big Move is to electrify the GO Transit network, which will allow the operation of electric motor trains. This is beneficial as these trains are able to run at a higher speed than the current models, and will also mitigate the localized greenhouse gas emissions that result from diesel trains. Although there are long term plans to electrify the entire network, the corridor for the Union Pearson Express will be electrified first, with an estimated construction completion date of 2017. The first 22 km of the line is within the existing GO Transit Rail right-of-way, while a new three km spur is being constructed to connect to the airport. The system that Metrolinx has proposed for the electrification consists of an overhead catenary system that will operate at 25 kV line to ground. Along the portion that is shared with the existing rail corridor, the system will consist of two conductors both at 25 kV at a 180^{o} phase shift, resulting in a line to line voltage of 50 kV, while the three km spur to the airport will only consist of a single conductor at 25 kV line to ground. Figure 3 outlines the route GO Transit plans to follow for the Union Pearson Electrification Project.

At present, Toronto Hydro has identified 24 overhead crossings along the route as conflicts with the proposed overhead catenary system. To mitigate the conflicts, Toronto Hydro's overhead conductors will likely have to be buried under the rail tracks using tunnelling technology. Historically, similar projects have cost between one and two million dollars per crossing. Therefore Toronto Hydro estimates that, if Metrolinx proceeds with the electrification project during 2015-2019, the utility may be required to spend approximately $24 million over that period. However, this project is subject to government direction, and has not been fully approved.

Metrolinx has undertaken preliminary planning milestones, however, technical details are still under review and to be refined by Metrolinx.

FIGURE 3: UNION PEARSON ELECTRIFICATION ROUTE

(iii) Eglinton Light Rail Transit Project

As part of the province-wide push to improve the transportation infrastructure, Metrolinx is constructing a 19km light rail transit (LRT) line along Eglinton Avenue, which will provide the City of Toronto with a second east-west rail transit route. To minimize the impact to vehicular traffic, the central portion of the LRT between Keele Street and Laird Drive will run underground, while the outskirts in the west between Black Creek Drive and Keele Street and in the east between Laird Drive and Kennedy Road will run at-grade. The LRT will be constructed to facilitate connection to other transit systems such as the GO Transit system and the Union Pearson Express at Mount Dennis station, the Spadina Subway at Eglinton West and Allen Road, the Yonge Subway at Yonge-Eglinton Interchange station, and the Bloor-Danforth Line at Kennedy Station. In the future, there is also the possibility that it will connect into an improved Scarborough SRT line. Currently, the construction of the LRT is projected to be completed and in operation by 2020.

A variety of relocations are currently in progress for this project to facilitate the passage of the tunnel boring machines as well as the construction of the station headwalls. The scope of the relocation works, whether overhead, underground, or a combination of both, vary depending on its location. Going forward, the scope of the relocations will likely increase in central Toronto due to the increased road disruption caused by the open cut construction required to build the underground stations. In the areas where the LRT will be at-grade, the relocations required will be to maintain standard overhead clearances between the LRT's catenary system and Toronto Hydro's distribution conductors, as well as underground clearances between the rail tracks and Toronto Hydro's civil infrastructure. In addition to the LRT work, the City of Toronto is expecting significant growth and development to take place along this corridor. To accommodate the proposed development, Toronto Hydro will install additional ducts beyond what is currently required to facilitate the connection of the future development to the distribution network.

(iv) Other Metrolinx Transit Projects

In addition to the Eglinton LRT, Metrolinx is proposing to build two other LRTs along Finch Avenue West and Sheppard Avenue East. The Finch West LRT is proposed to be approximately 11 km in length, and would connect the new Finch West station on the Spadina Subway extension in the east and Humber College, located just east of Highway 27. The Sheppard LRT is expected to be approximately 15 km in length, and would extend from Don Mills station on the Sheppard Subway line in the west, to Morningside Avenue in the east. Both LRTs are proposed to be at-grade on a dedicated right-of-way in the middle of the road. Similar to the Eglinton LRT, the relocations that are required for these LRTs would be to mitigate the conflict with the overhead catenary system for the LRT and Toronto Hydro's overhead distribution lines, as well as to maintain clearances between the LRT rail tracks and Toronto Hydro's underground civil infrastructure. Both LRTs have currently been put on hold, with construction slated to recommence between 2015 and 2017, with completion around 2021.

Figure 4 shows the number and average cost of historical and projected projects. From 2015-2019, the number of projects is expected to increase significantly, as well as the cost per project. This is due largely to the addition of Metrolinx LRT projects. The average number of non-Metrolinx projects per year from 2012-2014 was 34, and it is estimated that this average will continue through 2015-2019. These projects include typical requests seen historically, which include requests from the City of Toronto for road widening, utility installations, the MTO bridge reconstruction program, the Union Pearson Electrification projects. In addition to the typical projects expected to continue through 2015-2019, there is estimated to be an additional 28

Metrolinx projects added per year. The scopes of the Metrolinx projects are typically larger than the standard projects seen in past years, which increases the average cost per project. The additional Metrolinx projects are spread across four LRT lines including Eglinton, Sheppard, Finch, and the Scarborough transit line.

Traditional projects may involve the relocation of a small number of poles, or isolated sections of underground infrastructure, whereas typically Metrolinx projects involve hundreds of meters of infrastructure at a time. This also offers a significant opportunity for Toronto Hydro to install additional infrastructure at this time, given the large areas of improvement. In the case of the Metrolinx LRT projects, the typical station area affect is 100-300 meters. This amount of area allows Toronto Hydro to install sufficient infrastructure to support future growth in the area, including duct runs and cable chambers. This approach often offers a more prudent and cost-effective solution for ratepayers than conducting this expansion work later, including a reduced number of disruptions for local area residents and enhanced benefits from existing road cuts.

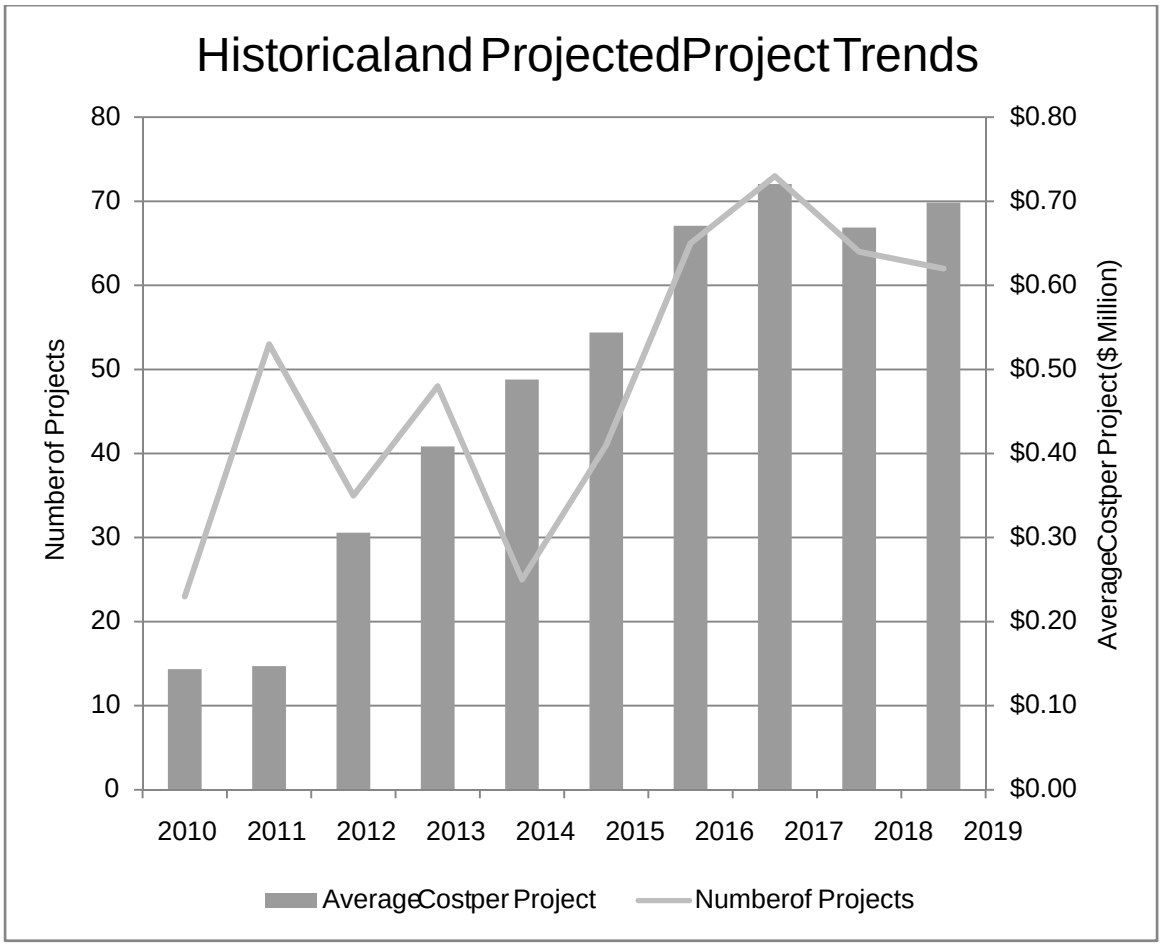


FIGURE 4: HISTORICAL AND PROJECTED PROJECT TRENDS

As noted above, Toronto Hydro has only included a portion of its forecasted costs in its funding requirements. The utility has included approximately $20 million over the five years covered by this application, or approximately $4 million of net Toronto Hydro costs per year. This sub-forecast amount represents a base amount of spending that will be required over this term. As shown in Figure 2 forecasts show that significantly more work is likely to be required over that period.

Toronto Hydro is requesting significant less funding than is forecast to be required. Due to the often high cost and significant volatility around externally-initiated projects and the work's non-discretionary nature, and since the current projections for costs over the 2015-19 period are significantly higher than the amount included in Toronto Hydro's funding requirements, Toronto

Hydro is requesting the establishment of a variance account to capture annual differences from this base amount.

Toronto Hydro's expectation is that this approach will allow it to fund necessary, non-discretionary work while, at the same time, holding ratepayers harmless from the potential that a portion of the forecasted third party work does not materialize, due to the unpredictable nature, costs, and timing of such projects. Please see Exhibit 9, Tab 1, Schedule 1 for further detail regarding the variance account requested for spending in excess of the sub-forecast baseline amount for which Toronto Hydro is seeking rate funding.

E5.3.4.1 Ranking & Prioritization

Externally-Initiated Plant Relocations and Expansions are driven by the schedules and timing of sponsor agencies. Project sequencing is largely dictated by the completion date proposed by the sponsor agency, so Toronto Hydro works with sponsor agencies to coordinate projects in order to increase efficiency. Approximately 75% of externally driven relocation and expansion projects have a requested completion date within 12 months.

E5.3.5 Program Execution

Toronto Hydro completes the majority of the design and construction work for externally-driven relocation and expansion projects using internal resources. For certain projects, typically where detailed work sequencing is required, Toronto Hydro works with sponsor agencies to have Toronto Hydro relocations and expansions completed by approved Toronto Hydro contractors under the agency's general contractor. Toronto Hydro still maintains control of the scope of work and scope changes. An example of this is with Metrolinx for the tunnelling contracts with the Eglinton LRT. Toronto Hydro and Metrolinx entered an agreement to allow Metrolinx to directly engage a Toronto Hydro-approved contractor. Metrolinx was able to dictate the schedule for design and construction, with input and review from Toronto Hydro. Toronto Hydro works closely with sponsor agencies completing the coordinated work on behalf of Toronto Hydro to ensure the scope and costs of the project are controlled. When the project is executed by sponsor agencies, Toronto Hydro has specific control points where review of the scope, cost, design, materials, and construction progress is required.

For all projects, once a project is initiated, coordination takes place between the sponsor agency and Toronto Hydro to determine the scope of relocation work required, a preliminary estimate, and agreed upon cost sharing arrangement. At this point in the process, Toronto Hydro reviews

the system requirements in the area, and determines if any capital upgrades are prudent to install in conjunction with the requested relocation work. The project then proceeds to the Program Management team to arrange for design and construction. Toronto Hydro maintains communication with the sponsor agency throughout the process.

E5.3.5.1 Program Risks

Since the program is based solely on forecast requests from external parties, Toronto Hydro's projected costs are based on historical amounts, ongoing discussions with external agencies, and available information on anticipated large projects. There is a possibility that the forecasted projects will not materialize from the sponsor agency, which would impact the relocation and expansion portfolio within Toronto Hydro. Conversely, projects previously unidentified may be requested, which would add relocation projects required by Toronto Hydro. The proposed variance account will ensure the ratepayers will not be held responsible for any more or less of the relocation work than actually occurs.

E5.3.5.2 External Constraints

The scope, timing and cost of Toronto Hydro's relocation and expansion work are determined in part by the schedule and plans of the sponsor agencies. The sponsor agencies often face their own constraints with respect to execution plans and completion timelines of their projects, requiring Toronto Hydro to work in consideration of these constraints.

E5.3.5.3 Standard & Regulation Adherence

Toronto Hydro complies with the Public Service Works on Highways Act, which requires utilities to work with Road Authorities when there is other work to be completed within the road right of way. All relocated infrastructure must be built to current Toronto Hydro construction standards.

E5.4.6 Evaluation of Alternatives

E5.4.6.1 Quantification/ Evaluation of Options

As indicated previously, Toronto Hydro is obligated to facilitate external agency capital work projects. In general, when relocations are required Toronto Hydro replaces the pre-existing facilities on a like-for-like basis. In most instances this approach constitutes the preferred alternative because it represents the minimum investment on the part of Toronto Hydro to continue providing safe and reliable electricity distribution service.

Sometimes the nature of the project is such that like-for-like replacement is not the most efficient, or otherwise desirable option. In these cases, Toronto Hydro reviews its obligations and options in light of its future plans before it undertakes any plant relocation and/or expansion. As an example, Toronto Hydro has to work with the MTO to facilitate the relocation of existing Toronto Hydro infrastructure off of various bridges throughout the City. Toronto Hydro develops preliminary plans to relocate the existing infrastructure, and then reviews internal plans for upgrades, as well as predicted load growth in the area. To complete the relocation, specialized tunnelling equipment is required to tunnel under the highway. As the equipment is already on site and is being used for the relocation construction, it is more efficient to install additional capacity at this time. Moreover, the analysis indicated that the additional capacity would be required in the area, so it has become prudent to maximize efficiencies and install additional capacity while relocating off of the MTO bridges over Highway 427.

Another example of how expansion and relocations may be combined to maximize efficiencies is the Eglinton LRT project. To accommodate the LRT line on Eglinton, Toronto Hydro reviewed two options. The first option was simply to undertake the relocation necessary to facilitate the Metrolinx project without constructing any additional civil infrastructure to accommodate Toronto Hydro's anticipated demand growth. The second, and preferred, option was to construct civil infrastructure sufficient to accommodate both the relocation and Toronto Hydro's anticipated demand growth and other system requirements. To predict the system capacity that will be required in the future, the Planning teams have been using reports published by the City regarding planned usages for Eglinton Avenue, as well as looking at other examples of similar transit stations and the demand required in those areas. Eglinton Avenue, on average, is currently lacking 25% of the Toronto Hydro infrastructure available, compared to similar areas along transit lines within Toronto.

The second option is the preferable approach for three reasons

(1) The new LRT line will encourage future growth in the LRT corridor, which should in turn increase the electrical load. The existing civil infrastructure is forecast to be insufficient to serve this load growth between 2020 and 2030. It will be less expensive to construct new civil infrastructure to support this load growth simultaneously with relocation work required by the LRT construction.

(2) Toronto Hydro needs to coordinate its expansion work with work of other impacted utilities (i.e., telecommunications, natural gas, sewer, and water in addition to electricity)

to ensure there is sufficient real estate for Toronto Hydro needs. Failure to do so may mean the corridor through the road right of way will be unavailable to Toronto Hydro and sub-optimal alternatives to serve load would be required.

(3) The City of Toronto imposes a five-year moratorium on road cuts in the area once the LRT work is completed, preventing THESL from installing the additional civil infrastructure when required.[9] This could lead to THESL having to install more costly and less optimally located facilities to connect any emerging load.

As noted in section E.5.4.1, the OEB affirmed Toronto Hydro's approach to the execution of prudent work in conjunction with other, non-discretionary work. As a practical matter of cost-effectiveness, it is prudent and cost-effective for the utility to complete other important associated work when carrying out non-discretionary capital projects.[10]

[9] Such moratoriums are part of the Municipal Consent Requirements for the Installation of Plant Within City of Toronto Streets, which states:
To ensure the long-term sustainability of the City's infrastructure, the General Manager enforces a moratorium on all newly improved streets. The moratorium ensures that the integrity of the pavement structure is protected and also serves to minimise the disruptions and inconvenience to the public resulting from repeated construction activity.
[10] EB-2012-0064, Phase 1 Partial Decision and Order (April 2, 2013), at page 17.

E5.4.7 Program Projects

Table 4 illustrates a listing of projected programs for 2015, which are planned for completion as a part of the 2015-2019 Program. Projects carried over from 2014 to 2015 are flagged

TABLE 4: PROGRAM PROJECTS

Project Name	Expansion Potential	Agency	Estimated Project Timelines (Subject to modification by the sponsor agency)	Estimated Project Cost in 2015 ($ Millions)
North West PATH Phase 2 (2014 Carry-over)	Yes	City of Toronto	Q4 2014-Q4 2015	$1.2
427 and Bloor Bridge Rehabilitation	Yes	MTO	Q1 2015 – Q3 2016	$2.2
427 and Burnhamthorpe Bridge Rehabilitation	Yes	MTO	Q1 2015 – Q3 2016	$1.9
427 and Rathburn Bridge Rehabilitation	Yes	MTO	Q1 2015 – Q3 2016	$2.2
Eglinton LRT	Yes	Metrolinx	Q1 2015 – Q4 2019	$4.9
Dupont Subway Station	No	TTC	Q1 2015	$0.4
Six Points Intersection	Yes	City of Toronto	Q2-Q3 2015	$2.2
Union Pearson Express Electrification	Yes	GO Transit / Metrolinx	Q2 2015 – Q4 2017	$4.8
Subtotal of Scoped Projects				$19.8
Additional Projected and Unscoped 2015 Projects		Various	Q1 – Q4 2015	$2.5
Total 2015 Estimated Costs				$22.3

E5.3.7.1 North West PATH Addition Phase 2

This project is initiated by the City of Toronto and is planned to be completed with cost sharing under the Public Service Works on Highways Act. There is opportunity for Toronto Hydro to expand its existing infrastructure in the area in conjunction with this relocation project.

The North West PATH is a new underground extension to the City of Toronto underground PATH network from Union Station to Wellington Street via York Street. This expansion will provide additional capacity to accommodate the growing numbers of pedestrians accessing Union Station from the downtown core. The City of Toronto has requested that THESL relocates its

infrastructure that is in conflict with proposed work from the intersection of York Street and Front Street to York Street and Wellington Street. Phase 1 involved relocating the infrastructure at the intersection of Front and York to the area in front of the Royal York Hotel, on York Street. Phase 2 involves the relocation of Toronto Hydro infrastructure along York Street from the area in front of the Royal York Hotel, to the intersection of Wellington Street and York Street. Phase 2 consists of approximately 300 meters of duct and 11 cable chambers. Design of Phase 2 is scheduled by the City to begin in 2014, with construction taking place in 2015. The City project experienced significant delays from the original estimated completion date, which caused delay to the Toronto Hydro relocation work.

E5.3.7.2 Highway 427 and Bl oor Bridge Rehabilitation

This project is initiated by the MTO and is planned to be be completed with cost sharing under the Public Service Works on Highways Act. There is opportunity for Toronto Hydro to expand its existing infrastructure in the area in conjunction with this relocation project.

This project is being done due to the rehabilitation of the Bloor Street Bridge over Highway 427. MTO has stated that no utilities are permitted within the bridge structure after rehabilitation, so Toronto Hydro is relocating its assets of the bridge to under Highway 427. To accomplish this, there is a tunnel being constructed under Highway 427, large enough to accommodate sixteen 100mm ducts. The tunnel design should conform to MTO requirements as stipulated within the Guidelines for Foundation Engineering-Tunnelling Specialty for Corridor Encroachment permit Application document. This project consists of approximately 300m of duct and four cable chambers.

E5.3.7.3 Highway 427 and Burnha mthorpe Bridge Rehabilitation

This project is initiated by the MTO and is expected to be completed with cost sharing under the Act. There is opportunity for Toronto Hydro to expand its existing infrastructure in the area in conjunction with this relocation project.

This project is being done due to the rehabilitation of the Burnhamthorpe Street Bridge over Highway 427. MTO has stated that no utilities are permitted within the bridge structure after rehabilitation, so THESL is relocating its assets of the bridge to under Highway 427. To accomplish this, there is a tunnel being constructed under Highway 427, large enough to accommodate sixteen 100mm ducts. The tunnel design should conform to MTO requirements as stipulated within the Guidelines for Foundation Engineering-Tunnelling Specialty for Corridor

Encroachment permit Application document. This project consists of approximately 280m of duct and four cable chambers.

E5.3.7.4 Highway 427 and Rathburn Bridge Rehabilitation

This project is initiated by the MTO and is expected to be completed with cost sharing under the Public Service Works on Highways Act. There is opportunity for Toronto Hydro to expand its existing infrastructure in the area in conjunction with this relocation project.

This project is being done due to the rehabilitation of the Rathburn Street Bridge over Highway 427. MTO has stated that no utilities are permitted within the bridge structure after rehabilitation, so THESL is relocating its assets of the bridge to under Highway 427. To accomplish this, there is a tunnel being constructed under Highway 427, large enough to accommodate sixteen 100mm ducts. The tunnel design should conform to MTO requirements as stipulated within the Guidelines for Foundation Engineering-Tunnelling Specialty for Corridor Encroachment permit Application document. This project consists of approximately 250m of duct and four cable chambers.

E5.3.7.5 Eglinton LRT

This project is initiated by Metrolinx and will be recoverable from Metrolinx. There is an opportunity for Toronto Hydro to expand its existing infrastructure in the area in conjunction with this relocation project.

The Eglinton LRT is a major transit expansion project proposed by Metrolinx as part of their Regional Transportation Plan called the Big Move. The LRT will run between Black Creek Drive in the west to Kennedy Road in the east, with the central portion between Keele Street and Laird Drive being underground and the rest at grade. It will provide a second east-west rail transit route within the City of Toronto, and will connect to other rail transit systems such as the GO Transit system and the Union Pearson Express at Mount Dennis station, the Spadina Subway at Eglinton West and Allen Road, the Yonge Subway at Yonge-Eglinton Interchange station, and the Bloor-Danforth Line at Kennedy Station. To facilitate the construction of the tunnels and headwalls, construction is already underway in various locations along the route. Most of the relocation work required going forward will be to assist the construction of the underground stations and the surface routes. The relocation work required for the underground stations will minimize the conflicts with Toronto Hydro assets within the construction area, while the relocations required for the surface routes will be to maintain standard overhead clearances between the LRT's catenary system and Toronto Hydro's distribution conductors, as well as underground clearances between

the rail tracks and Toronto Hydro's civil infrastructure. During the construction process, additional Toronto Hydro ducts required to accommodate the projected future loads will be installed.

E5.3.7.6 Dupont Subway Station

This project is initiated by the TTC and will be recoverable from the TTC. Toronto Hydro has no requirements to expand its infrastructure in the area in conjunction with this relocation project.

The TTC's Easier Access Initiative proposes to upgrade their subway and SRT stations to be fully accessible by 2025. As part of this program, the TTC will be installing three elevators at Dupont Station on the Bloor-Danforth Line. Two elevators will connect the concourse to track level, while one elevator will connect the concourse to ground level. To facilitate the installation of the elevators, the duct bank feeding the TTC traction power substation will be relocated to avoid the proposed elevator location, and the overhead feeders in the area will be relocated during the construction, and be reinstated to their original alignment upon completion. This project requires coordination between the TTC's General Contractor and Toronto Hydro construction crews to work through the two phases of installing the elevators.

E5.3.7.7 Six Points Intersection

This project is initiated by the City of Toronto and will be recoverable from the City of Toronto as it is an overhead to underground streetscape improvement project. There is opportunity for Toronto Hydro to expand its existing infrastructure in the area in conjunction with this streetscape improvement project.

The City of Toronto is planning to redesign the three-way intersection of Bloor Street West, Kipling Avenue, and Dundas Street West to eliminate the multiple overpasses and build an at-grade intersection. In conjunction, a significant amount of land development and streetscape work will be undertaken. The City of Toronto has requested that Toronto Hydro bury its overhead assets along Bloor Street West, as well as to install any underground civil infrastructure required to connect the proposed development to the distribution grid. In addition, the reconstruction of the area will provide Toronto Hydro with the opportunity to expand the distribution system in the area. Toronto Hydro has historically avoided crossing through this intersection due to the complexity of the road configuration, which previously included multiple overpasses. The additional infrastructure will allow Toronto Hydro to have a significant north south duct run through the area for future use.

E5.3.7.8 Union Pearson Electrification

This project is initiated by the GO Transit and the cost sharing agreements for each affected crossing are currently under review. Standard relocation agreements across the GO rail corridor indicate that Toronto Hydro is responsible for all relocation costs. There is opportunity for Toronto Hydro to expand its existing infrastructure in the area in conjunction with this relocation project.

As part of the Big Move, one of the enhancements proposed to the existing GO Transit network is to electrify the tracks, thereby improving the speed of the trains in their fleet and mitigating the local greenhouse gas emissions that results from the use of diesel trains. The infrastructure proposed by Metrolinx consists of an overhead catenary system operating at 25 kV line to ground. In the instances where Toronto Hydro has overhead assets crossing over the rail corridor, the conductors for Toronto Hydro's distribution network and the overhead catenary system will cause a conflict. It is anticipated that 24 crossings will need conflict mitigation by burying the cables underground using tunnelling technology. During this process, the underground crossings can be built such that they can accommodate extra conductors to allow for future system expansion.

E5.4 Load Demand

ACCOMMODATING FOR CITY OF TORONTO'S EXPANDING DOWNTOWN CORE

E5.4.1 Summary

Program Description

The Load Demand program addresses overloads at the bus and feeder level for the 27.6 kV and 13.8 kV systems through load transfers and investing in feeder and equipment upgrades. Through this program, Toronto Hydro plans to make room for new load additions on the distribution system and to alleviate operational constraints that could restrict the utility's ability to execute the most cost-effective system renewal program possible over the five year planning horizon.

Investments in the Load Demand program will deliver customer value by maintaining Toronto Hydro's ability to promptly address customer service requests, while also maintaining operational flexibility and system efficiency. These benefits are summarized in the following table.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Toronto Hydro is able to connect new customers to the distribution system without extensive delays or adverse impacts to existing customers. ƒ Avoid service quality issues caused by summer peak loads.
Reliability	ƒ Restoration capabilities during outages are maintained with the introduction of spare capacity on existing feeders through load transfers,

	cable upgrades, and equipment upgrades.
Safety	ƒ The risk of failure for overloaded equipment is mitigated. Toronto Hydro workers and members of the public will be less exposed to overloaded infrastructure. ƒ Rebuilding existing civil infrastructure will remove old assets and those in poor condition from pedestrian sidewalks and roadways.
Efficiency	ƒ The additional capacity introduced in this program is expected to give the control room the ability to operate the system with necessary flexibility, especially during the summer peak period. ƒ Currently, operational constraints exist that restrict highly loaded feeders from being removed from service for capital or maintenance work.

Program Drivers

The drivers of this program are summarized in the table below.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Customer Service Requests	ƒ Further load growth due to development in specific areas is expected to limit Toronto Hydro's ability to connect new customers quickly and economically. ƒ Toronto Hydro's obligations per the Distribution System Code Section 3.3.1: "A distributor shall continue to plan and build the distribution system for reasonable forecast load growth. A distributor may perform enhancements to its distribution system for purposes of improving system operating characteristics or for relieving system capacity constraints. "
Secondary Driver	**Reasoning**
Mandated Service Obligations	ƒ Toronto Hydro's system is designed for single contingency conditions. In some cases, equipment is overloaded such that under single contingency, customers cannot be transferred to their standby supplies due to capacity constraints. ƒ Under the Distribution System Code, Toronto Hydro is obligated to connect new customers while not adversely affecting the quality of distribution services received, which is becoming more difficult as the system grows in load without an equal increase in capacity.
Reliability	ƒ A lack of capacity between adjacent feeders can greatly increase the number of customers at risk of facing lengthy interruptions. ƒ Increasing the capacity of the feeder trunk cable can also decrease the likelihood of lengthy outages. ƒ Toronto Hydro's must meet the obligations set out in Section 4.4.1 of the Distribution System Code: "A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."

System Efficiency	ƒ Restrictions are placed on the system during peak load conditions so that certain feeders cannot be taken out of service. This constrains Toronto Hydro's ability to implement new customer connections and hinders its ability to plan and execute other capital maintenance work in a timely and efficient manner.

Preferred Alternative

The Load Demand program analyzed and evaluated the following options

(1) Maintain the status quo by postponing the upgrades in heavily loaded areas with projected influx of new development.

(2) Add station capacity through expansion of existing stations or construction of new stations in the heavily loaded areas with projected influx of new development.

(3) Upgrade equipment and infrastructure in high load and congested areas of the system and in areas of proposed high load developments with a focus on relieving overloads under first contingency basis.

Option III is preferable as it provides capacity for increased loading in already heavily loaded areas, enables first contingency load transfer in these areas and thereby reduces the risk of widespread, long duration outages for customers.

Evaluating the first year of activities within the Load Demand program produces an estimated net present value (NPV) of $12.25 million. This value accounts for reduction in risk, including the costs of customer interruptions for both asset-related as well as non-asset related interruptions, as well as any additional benefits associated with the program that are realized through the execution of the first year of activities.

Timing and Pacing

The timing and pacing of the Load Demand program is driven by the timing and pattern of development in specific areas of the city, load and customer growth forecasts, as well as known road moratoriums and other external constraints. Deferral of this work could expose the system to operational constraints within the 2015 to 2019 period that could severely impact the reliability of power supply for new and existing customers, and could hinder the ability of Toronto Hydro to efficiently carry-out other planned renewal work during the forecast period.

TABLE C: HISTORICAL AND FORECAST SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.00	0.00	0.29	2.40	1.11	11.96	13.93	14.05	15.70	19.23

The City of Toronto has introduced restrictions, related to the Pan Am Games, on Toronto Hydro that will limit the amount of Load Demand work that it can complete in 2015. Accordingly, in 2015, Toronto Hydro plans to complete the load transfers to Copeland TS in the Windsor TS area. Work at George and Duke MS must also be completed in 2015 in order to avoid a scheduled road moratorium that will prevent work from occurring in the area for a five year period.

In 2016, Toronto Hydro plans to rebuild and expand the civil infrastructure in the Windsor TS area to service the entertainment district customer base. In the next year, planned capacity increases at Carlaw TS will oblige Toronto Hydro to make infrastructure upgrades between Gerrard TS and Carlaw TS. Spending in 2018 and 2019 is dictated by the load transfers required in order to control loading at the bus level for certain stations. The required load transfers must occur in a timely manner to avoid necessary load shedding during the summer peak period.

E5.4.2 Program Description

The Load Demand program addresses overloads at the bus and feeder level. Through this program, Toronto Hydro plans to make room for new load additions on the distribution system and will alleviate operational constraints that could restrict the utility's ability to execute the most cost-effective system renewal program possible over the five year planning horizon. This program impacts the 27.6 kV and 13.8 kV overhead, underground and network systems, and includes the following three activities:

(1) load transfers,

(2) feeder upgrades,

(3) equipment upgrades.

Toronto Hydro plans to spend an estimated $63.14 million on these activities between 2015 and 2019. Each of the activities is explained in detail in the following subsections.

E5.4.2.1 Load Transfers

Toronto Hydro plans to execute targeted load transfer projects on the 27.6 kV overhead and underground systems and the 13.8 kV dual radial distribution system. The load transfer activities in this program focus on transmission stations under pressure from ongoing and anticipated load growth in their respective locales. These load transfers are required to provide load relief and prevent the overloading of existing assets.

FIGURE 1: INCREMENTAL KVA OF PROPOSED LOAD

Figure 1 shows a snapshot of proposed customer loads and illustrates the density of ongoing and future developments anticipated in Toronto. These developments range from new office towers and condominium buildings to commercial sites and data centres. As the figure indicates, the majority of anticipated growth is situated around the downtown core and around major avenues in the former suburbs, i.e. the "Horseshoe" distribution area.

Table 1 below lists the station buses that are addressed by this program in order to provide load relief and prevent the overloading of existing assets in these stations. Forecasts indicate that several buses are trending towards being overloaded in the 2015 to 2019 planning period. While all of the projects under the program are designed to mitigate these load issues, the work to be conducted will depend on the precise circumstances of each station bus and the revised load forecast.

If the required work is not completed, connecting new customers to these stations will likely not be possible. Each new customer request will require load to be transferred to another part of the system; under tight timeline requirements from the customer, non-optimal system configurations may be necessary. These customer connections will likely be more costly and require a longer connection time to complete the work.

TABLE 1: STATION BUSES THAT REQUIRE LOAD TRANSFERS

Station	Bus	Capacity (MVA)	Load Relief Required		
			Year	Projected Load (MVA)	% Loading
BASIN (115KV/13.8KV) TS	A5-6	49	2018	47	96%
BRIDGMAN (115KV/13.8KV) TS	A1-2B	40	2016	38	95%
	A1-2H	66	2020	63	95%
	A7-8H	66	2021	64	97%
CARLAW (115KV/13.8KV) TS	A8-9	41	2015	39	95%
CECIL (115KV/13.8KV) TS	A3-4	47	2019	45	96%
	A5-6	72	2022	68	94%
	A7-8	72	2017	68	94%
CHARLES (115KV/13.8KV) TS	A1-2	45	2020	43	86%
	A3-4	45	2020	43	96%
DUFFERIN (115KV/13.8KV) TS	A5-6	48	2022	46	96%
	A7-8	48	2016	46	96%
ESPLANADE (115KV/13.8KV) TS	A1-2GD	69	2016	66	96%
	A3-4GD	69	2021	66	96%
FAIRBANK (115KV/27.6KV) TS	B & Q	95	2017	96	101%
GERRARD (115KV/13.8KV) TS	A1-2	39	2017	37	95%
HORNER (230KV/27.6KV) TS	B & Y	192	2017	193	101%
LESLIE (230KV/27.6 & 13.8KV) TS	B & Y	101	2015	110	109%
MAIN (115KV/13.8KV) TS	A3-4MN	42	2019	40	95%
MANBY (230KV/27.6KV) TS	Q & Z	63	2017	63	100%
	V & F	112	2019	113	101%
RUNNYMEDE (115KV/27.6KV) TS	B & Y	117	2015	130	111%
SHEPPARD (230KV/27.6KV) TS	B & Y	115	2021	115	100%
STRACHAN (115KV/13.8KV) TS	A1-2	56	2017	53	95%
	A7-8	40	2021	38	95%
TERAULEY (115KV/13.8KV) TS	A3-4	60	2017	57	95%
	A5-6	60	2015	57	95%
WINDSOR (115KV/13.8KV) TS	A13-14	41	2017	39	95%
	A15-16	69	2015	73	106%
	A17-18	49	2016	50	102%

In order to transfer load from one station to another, Toronto Hydro often needs to install and pull new feeders and cable from stations with spare capacity. These stations can either be existing

stations with switchgear that have available capacity and feeder positions, or they can be new stations into which switchgear will be installed in order to create additional capacity. Additional civil infrastructure may also be required to implement a load transfer because existing egress chambers can be congested or require rebuilds. Afterwards, extensive cable pulling and splices are involved to transfer customers from existing feeders to new feeders.

Extending existing feeders is another method of transferring load to feeders with excess capacity. As well, with respect to the Horseshoe distribution area, another alternative that can facilitate the shifting of load is the installation of new switches or the relocation of existing switches.

E5.4.2.2 Feeder Upgrades

Feeder upgrades are another key component of the Load Demand program. In order to meet the growing demand of new customers, Toronto Hydro plans to target portions of feeders within the 27.6 kV distribution system and the 13.8 kV distribution system for upgrades.

(i) 27.6 kV System Feeder Upgrades

The 27.6 kV system is setup as a looped configuration, with feeders tied via switches so that loading can be transferred from one feeder to an adjacent feeder during contingency scenarios (i.e. when a feeder is interrupted). Over time, growth can cause the load to exceed feeder capacity, which constrains system operational effectiveness under both normal and contingency scenarios. In addition, capacity for load transfers is required in order to maintain consistent service during planned maintenance and construction activities. To manage the load growth, Toronto Hydro plans to perform cable upgrades.

Some of Toronto Hydro's feeder trunks contain underground and overhead cables that are smaller than the current standard. These cables can possess less capacity than what station circuit breakers offer. In order to address emerging load capacity requirements, Toronto Hydro plans to upgrade undersized segments of underground cables and overhead conductors and will utilize stranded station circuit breaker capacity in order to provide additional capacity.

(ii) 13.8 kV System Feeder Upgrades

The majority of the underground 13.8 kV system in downtown Toronto is configured as a dual radial scheme. Customers are supplied by two feeders: one that provides their normal supply and the other that operates as standby supply. In some areas that have experienced load growth, customers now have an overloaded standby supply. To address this issue, Toronto Hydro plans

to upgrade primary cables or install new feeders so that load can be transferred to these newly established feeders.

Some 13.8 kV primary feeders may have undersized portions of cable that act as bottlenecks to feeder capacity. Toronto Hydro plans to upgrade undersized trunk cable to the current standard to utilize previously stranded capacity. Figure 2 below depicts non-standard segments of cable along the trunk of feeder A51WR. For underground cable upgrade projects, it is typical that a rebuild or expansion of existing civil plant will be required. The civil plant located downtown is fairly congested and in some cases nearing end-of-life. Replacing cables usually involves installing the new cable prior to removing the existing one. However, existing civil plant may not be able to accommodate additional or upgraded cables in this manner. Therefore, Toronto Hydro also plans to complete upgrades or rebuilds of the existing civil plant to accommodate the cable upgrades.

FIGURE 2: A51WR - EXAMPLE FEEDER - UNDERSIZED CABLE SEGMENTS HIGHLIGHTED

E5.4.2.3 Equipment Upgrades

The network system's transformers are fed from various feeders that are paralleled on the secondary side of the transformer in order to provide a redundant supply to customers. This

configuration helps reduce the risk of customers experiencing momentary interruptions during single contingency events. In order to prevent the overloading of equipment during these events, Toronto Hydro has established that load being supplied by these network vaults should not exceed 50% for two unit vaults, 66% for three unit vaults, etc. This loading requirement ensures that equipment does not get overloaded if one of the primary supply feeders is taken out of service. Overloading is likely to lead to premature deterioration and failure of the network equipment.

Network equipment that is at or over capacity must be upgraded in order to facilitate operating the network system without overloading. Toronto Hydro plans to upgrade network units if they are not already the largest size available. Network equipment comes in three sizes for low voltage distribution (120/208 V) and three sizes for high voltage distribution (240/416 V). For low voltage transformers, the sizes are 500 kVA, 750 kVA and 1,000 kVA, and for high voltage the transformer sizes are 1,000 kVA, 1,500 kVA and 2,000 kVA. An additional benefit of replacing existing overloaded network equipment is the introduction of a more robust submersible design that is capable of operating underwater.

In locations where an upgrade is not possible, an additional transformer may be installed or additional secondary cables will be added between vaults to support highly loaded vaults.

FIGURE 3: 500KVA NETWORK UNIT

E5.4.2.3 Civil Upgrades

Expanding civil infrastructure is an important component of the Load Demand program. As additional customer and loads have been added to Toronto Hydro's system, the civil infrastructure located immediately outside transformer stations has, in certain cases, become progressively more congested. This congestion occasionally limits the ability of planners to optimally allocate and route feeders to supply load. In addition, congestion and a lack of civil infrastructure immediately outside the transformer station can directly impact the ability to fully utilize all capacity on remaining buses.

A similar situation can occur within Toronto Hydro's feeder duct infrastructure as various cables are assigned to new load and routed through available paths. Those paths become congested and as overall loading continues to increase in certain parts of the system, bottlenecks are created. Investing in additional duct bank infrastructure allows Toronto Hydro to reduce the distance between connected loads and supply points, and ensure that all available capacity is made available for allocation in the most optimal way. The following map shows the areas of investment planned for 2015 as a part of this program.

FIGURE 4: MAP

Toronto Hydro anticipates that the investments in the Load Demand program will deliver customer value by increasing Toronto Hydro's ability to promptly address customer service requests, while also adding operational flexibility to improve system efficiency. In addition, the utility expects to realize reliability and safety benefits. These benefits are summarized in the following table.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	x Toronto Hydro is able to connect new customers to the distribution system without extensive delays or adverse impacts to existing customers. x Avoid service quality issues caused by summer peak loads. x The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $24.2 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E5.4.7). x Accounting for capital program costs, the first year's activities deliver a positive NPV of $12.3 million, confirming the economic prudence of the investments (see Section E5.4.7).
Reliability	ƒ Restoration capabilities during outages are maintained with the introduction of spare capacity on existing feeders through load transfers, cable upgrades, and equipment upgrades.
Safety	ƒ The risk of failure for overloaded equipment is mitigated. Toronto Hydro workers and members of the public will be less exposed to overloaded infrastructure. ƒ Rebuilding existing civil infrastructure will remove old assets and those in poor condition from pedestrian sidewalks and roadways.
Efficiency	ƒ The additional capacity introduced in this program will give the control room the ability to operate the system with necessary flexibility, especially during the summer peak period. ƒ Currently, operational constraints exist that restrict highly loaded feeders from being removed from service for capital or maintenance work.

E5.4.3 Why the Program is Needed

The Load Demand program is needed to address customer load growth that is already straining parts of Toronto Hydro's distribution system. Toronto Hydro anticipates that additional development will exacerbate the situation. The existing distribution system was built with a fixed amount of capacity to connect new customers. Surplus capacity on all levels of the system has already been utilized to connect nearby customers; this has led to significant loading of some station buses, feeders, and transformers. In addition, the civil infrastructure that houses electrical

infrastructure is not sufficient to accommodate the additional electrical infrastructure that will be required.

E5.4.3.1 Program Drivers

The drivers of this program are outlined in the chart below and further detailed throughout this section.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Customer Service Requests	ƒ Growth in certain areas of Toronto has led to the distribution system becoming strained. Surplus capacity on all levels of the system has been utilized to connect nearby customers; this has led to the overloading of some station buses, feeders, and transformers. ƒ Further load growth due to development will limit Toronto Hydro's ability to connect new customers quickly and economically. ƒ Toronto Hydro's obligations per the Distribution System Code Section 3.3.1: "A distributor shall continue to plan and build the distribution system for reasonable forecast load growth. A distributor may perform enhancements to its distribution system for purposes of improving system operating characteristics or for relieving system capacity constraints. "
Secondary Driver	**Reasoning**
Mandated Service Obligations	ƒ Toronto Hydro's system is designed for single contingency conditions. In some cases, equipment is loaded such that under single contingency, customers cannot be transferred to their standby supplies due to capacity constraints. ƒ Under the Distribution System Code, Toronto Hydro is obligated to connect new customers while not adversely affecting the quality of distribution services received, which is becoming more difficult as the system grows in load without an equal increase in capacity.
Reliability	ƒ A lack of capacity between adjacent feeders can greatly increase the number of customers at risk of facing lengthy interruptions. ƒ Increasing the capacity of the feeder trunk cable can also decrease the likelihood of lengthy outages. ƒ Toronto Hydro's must meet the obligations set out in Section 4.4.1 of the Distribution System Code: "A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."
System Efficiency	ƒ Restrictions are placed on the system during peak load conditions so that certain feeders cannot be taken out of service. This constrains Toronto Hydro's ability to implement new customer connections and hinders its ability to plan and execute other capital maintenance work in a timely and efficient manner.

Customer Service Requests

In the last five years, the City of Toronto has experienced robust growth in building developments. City of Toronto data shows that between 2008 and 2012, 1,645 development projects comprised of 148,200 residential units and almost 4.25M m^2 of non-residential Gross Floor Area (GFA) were submitted to the city's Planning Division for review and approval (Table 5). Of the proposed developments, 41% of all residential units and 39% of the non-residential GFA are located in the downtown and central waterfront areas of the City of Toronto, putting significant strain on Toronto Hydro's system.

TABLE 4: PROPOSED DEVELOPMENTS IN THE CITY OF TORONTO (2008 - 2012)

Developments generally move through three stages: submitted (not approved), approved (no permits issued) and permits issued. Of all proposed developments submitted from 2008 to 2012, 47% do not yet have permits issued. Projects without permits represent 79% of all residential units and 60% of all non-residential GFA proposed. The average time that a development takes to reach completion is 4.3 years; therefore, Toronto Hydro expects a large number of the aforementioned developments to be completed between 2015 and 2019. This Load Demand program is required to ensure proper loading on the electrical infrastructure within the system can be maintained during the 2015-2019 period and shortly beyond. The number of proposed projects that are awaiting approval and permits is a clear indication that the City of Toronto will continue to experience construction and development activity going forward, necessitating that Toronto Hydro increase capacity to be able to manage the growth.

(i) Customer Service Requests: Downtown Area

Figure 5 below shows a map of the Entertainment District in the downtown core of the City of Toronto, with the location of Windsor TS and Copeland TS highlighted. Over the last three to four years, many vacant lots have been developed as condominiums. As shown on the map, of the 44 developments listed, 18 are under construction while 21 development projects are proposed or approved. These developments will add significant load onto existing electrical infrastructure that has already seen an addition of 80 developments, or about 100 MVA of load, between Cecil TS and Windsor TS since 2008.

While Toronto Hydro has been able to connect each customer promptly, the development has put a strain on the feeders and station buses from Windsor TS. Some of the activities in the Load Demand program are designed to offload feeders and the station buses at Windsor TS to the soon to be completed Copeland TS so that Windsor TS will be able to continue servicing new customers in the local distribution area.

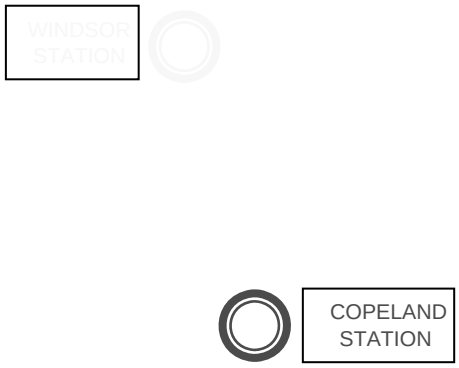


FIGURE 5: MAP OF ENTERTAINMENT DISTRICT, TORONTO (FROM BIA WEBSITE, HTTP://TORONTOED.COM/FILES/DEVELOPMENT_TRACKING_NOV2013.PDF)

As shown in Figure 3, Cecil, Terauley, Windsor and Esplanade are nearing their respective capacities and require load transfers to be able to accommodate the additional load added to the downtown core (of which the Entertainment District is a subset) in recent years. Cecil station is located just north of the area shown in Figure 5, Terauley station is located just east of the area in Figure 5 and Esplanade is located south west of the area in Figure 5.

On a more localized level, customer load growth in certain parts of the downtown core has necessitated the upgrade of secondary network infrastructure. These capacity upgrades will enable the connection of future customers, while also maintaining the reliable operation of the system during contingency events. In Figure 6 there is a comparison of loading on Vault LOC4442 between 1998 and 2012. During this 14-year period, the load grew 24%, or almost 2% annually. This load build-up is not captured in any new customer requests and is attributed to growth in load demand of existing customers over time. As a result, the system in this neighbourhood may have trouble operating under contingency events during the summer peak period. Investments are required to upgrade the equipment in this vault.

1998 Total Load on Network Location 4442: 542kVA	2012 Total Load on Network Location 4442: 714kVA

FIGURE 6: VAULT LOC 4442 (QUEEN ST W AND SOHO ST)

The load on secondary network equipment may be within operating limits during normal operation; however, during single contingency events, loads are shifted, which may result in overloading on network units. In order to prevent accelerated degradation of these assets due to overloading, certain feeders are restricted from being taken out of service. In the above example, the load connected to LOC4442 has risen above 50% loading, which means that Toronto Hydro will likely be unable to take either of the primary feeders out of service for work during peak load periods over the summer months.

(ii) Customer Service Requests: Horseshoe Area

In the Horseshoe distribution area, centers of major development have been planned by the city. As shown in Figures 7 and 8, the major areas of development are Etobicoke Centre, North York Centre, Scarborough Centre and Yonge-Eglinton Centre. 36 proposed projects are located in these four areas of development, which translates into 9% of proposed residential units and 150,000 m^2 of non-residential GFA.

FIGURE 7: MAJOR DEVELOPMENTS MAP - CITY OF TORONTO

FIGURE 8: FOUR MAJOR DEVELOPMENT CENTERS IN THE HORSESHOE

Load growth in these development centers necessitates an upgrade to the electrical infrastructure. Since 2008, Toronto Hydro has received about 60 new requests for these development centres, totalling 80 MVA of new loads added to the existing infrastructure in the area. There is a need to immediately shift load from the existing infrastructure to nearby station and feeders and upgrade existing infrastructure to the latest standards in order to accommodate the continued growth of these areas. Removing the bottlenecks caused by undersized cable on trunk sections will allow Toronto Hydro to maximize the capacity of existing feeders.

Mandated Service Obligations

Utility practices require Toronto Hydro to ensure that its assets are not overloaded (i.e. loaded above rated capacity under normal operating conditions) and that it operates a reliable system that can accommodate future development as per the Distribution System Code. If no action is taken, critical parts of Toronto Hydro's system will be at risk of being overloaded and load

shedding may be required during the summer peak period. The risk of not meeting service obligations is a relatively new risk that is attributable to the rapid influx of new dense load in the downtown core. This trend has caused bus loading to increase to rated capacity and will require offloading in the near term. Operating assets like station switchgear and distribution feeders above their rated capacity over extended periods of time under normal conditions is not an acceptable operating practice for utilities, as doing so could result in a reduction in the useful lives of existing assets, a failure of assets, and/or loss of supply to customers. As such, this program is required to maintain existing reliability and operational flexibility in areas experiencing load growth.

Reliability

The Load Demand program is also required to address the constant overloading of equipment, especially during the summer months, which can lead to the premature failure of undersized primary conductor and cable, impairing system reliability. These undersized legacy assets were installed at least 25 years ago, a period in which the standard trunk cables were smaller than today's and had a lower ampacity rating (i.e. lower current capacity).

The overloading conductors and cables cause their operating temperature to increase. An increase in operating temperate in overhead conductor can reduce the conductor's tensile strength. After a 10% loss of the rated tensile strength, significant sagging occurs, which generally triggers a necessary replacement of the conductor. For underground cables used in the 13.8 kV system (XLPE), conductors will soften as the temperature increases. The cable can deform at high operating temperatures and in areas where the insulation is under mechanical stress (bends in the route). The deformation of the cable can lead to electrical stresses and electrical failures.

The increase of load in the system has led to undersized trunk cable no longer being adequate to supply customers and to backup adjacent feeders. The failure of assets targeted by the Load Demand program could lead to outages that can last over an hour, as crews switch customers to standby supplies until the failure can be isolated and fixed. Failures that require assets to operate as standby supplies can lead to longer outage events. If feeder capacity is constrained, the number of customers able to use these feeders as a standby supply may be limited.

System Efficiency

The Load Demand program is also expected to mitigate current operational constraints that are expected to worsen during peak load periods, impacting system efficiency. In contingency scenarios (i.e. when a feeder is experiencing an interruption), the Toronto Hydro's system is designed to continue operating at or below rated capacity in order to facilitate the transfer of load from feeders under a faulted condition to adjacent feeders, allowing for the restoration of power to affected customers while repairs are conducted. When the load on a faulted feeder exceeds the available rated capacity of adjacent feeders, restoration of power to affected customers is not possible until repairs are completed.

An asset failure occurred on September 10, 2013 that led to the subsequent loss of an entire feeder supplying 4,362 customers from Richview TS. This outage required over 85 minutes of extensive systemic load shifting to restore power to 3,027 customers. 1,335 customers were left stranded without power until repairs were completed 47 minutes later, as there was no available adjacent feeder with capacity.

In addition to being a reliability concern, the operational constraints placed on the system by overloading can impede the efficient and timely execution of planned capital and maintenance work.

E5.4.4 Timing & Pacing of the Program

The timing and pacing of the Load Demand program is dictated by several system pressures and external constraints, including:

(1) the timing and pattern of ongoing and anticipated development in specific areas of the city;

(2) load and customer growth forecasts; and

(3) known road moratoriums and other external constraints on project scheduling in the 2015 to 2019 period.

The spending forecasts presented in Table 6 are based on Toronto Hydro's assessment of how best to prioritize the required load demand work within the 2015 to 2019 period given the aforementioned pressures and constraints. Deferral of this work could expose the system to operational constraints within the 2015 to 2019 period that could severely impact the reliability of

power supply for new and existing customers, and could hinder the ability of Toronto Hydro to efficiently carry-out other planned renewal work during the forecast period.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.00	0.00	0.29	2.40	1.11	11.96	13.93	14.05	15.70	19.23

Investments between 2010 and 2014 alleviated loading problems at Dufferin TS, Strachan TS and Windsor TS. To address loading concerns at Dufferin TS, load was transferred within the station to a lesser loaded bus, and some load was also transferred to Wiltshire TS. Work was completed at Strachan TS to increase the civil capacity to supply new customers, with some of this work expected to continue into 2015 as described in E5.4.7.7. Finally, work was completed at Cecil TS, located just north of the Windsor TS distribution area, in order to accommodate the increased load in the Entertainment District BIA.

Section E5.4.7 provides additional details for projects planned for execution in 2015. These projects are indicative of the type of work that will be planned and executed over the course of the 2016-2019 program. The 2015 projects are generally reflective of the urgent need to free-up capacity in dense areas where additional customer requests are anticipated. For example, a number of projects will aim to move a significant amount of load from the Entertainment District to nearby Copeland TS. These projects are planned to alleviate operational constraints on these feeders during the summer peak period in order to safely and prudently maintain operation of all equipment within rated capacity. Failure to complete these projects in a timely manner could leave Windsor TS buses at full capacity and unable to take on new area customers in the short term. Cost-inefficient projects may be required to connect future new customers in a timely manner, and these projects may result in system configurations that are not optimized for system efficiency and reliability.

The City of Toronto has introduced restrictions, related to the Pan Am Games, on Toronto Hydro that will limit the amount of work that it can complete in 2015. Accordingly, in 2015, Toronto Hydro will complete the load transfers to Copeland TS in the Windsor TS area. Work at George and Duke MS must also be completed in 2015 in order to avoid a scheduled road moratorium that will prevent work from occurring in the area for a five year period.

In 2016, Toronto Hydro plans to rebuild and expand the civil infrastructure in the Windsor TS area to service the entertainment district customer base, as outlined in Section E5.4.3.1(i). In the next year, planned capacity increases at Carlaw TS will oblige Toronto Hydro to make infrastructure upgrades between Gerrard TS and Carlaw TS. The new infrastructure will allow additional cables to be installed and the eventual replacement of the existing cables. Spending in 2018 and 2019 is dictated by the load transfers required in order to control loading at the bus level for certain stations. Each load transfer project is generated from Toronto Hydro's load forecast, which takes into account new customer requests and the timeline of their connection (details of the methodology behind the load forecast can be found in Section D2.3 of the Distribution System Plan). The required load transfers must occur in a timely manner to avoid necessary load shedding during the summer peak period.

E5.4.4.1 Ranking & Prioritization

Toronto Hydro considers several factors when prioritizing projects within the Load Demand program, including:

- Capacity to connect new customers – The primary driver for the program is the need to address areas of the system that are at capacity and that require significant investments in order to connect new customers. The lack of forecasted capacity in the short-term is what ultimately triggers projects within this program.
- Single contingency operation – Currently there are limitations placed on the system to prevent overloading during contingency operations. Projects that introduce additional capacity to allow the operators to remove these limitations will receive a higher priority.
- Reliability – For load transfer projects, sections of cable that require upgrading and that are on feeders with poor reliability or adjacent feeders will be given higher priority in order to improve future outage restoration times.

E5.4.5 Program Execution

The Load Demand program involves a number of load transfers, feeder upgrades and network unit upgrades. The program targets equipment that is overloaded under single contingency and, as a result, it is necessary to conduct most of this work outside of the summer months.

In terms of load transfer work, either new cables are required to be connected to new station feeder positions or existing feeders need to be extended to the desired area. If an existing feeder

is being extended, a feeder outage is required in order to splice together the new feeder. Certain areas may require rebuild or expansion of civil infrastructure in order to accommodate the additional electrical infrastructure.

For feeder upgrade work, new standard cable will be installed prior to de-energizing existing cable. The customers on the feeder will be transferred to standby supplies so that the feeder work can be carried out. Customers will not experience a service interruption; however, the standby supplies will operate under contingency. This work is planned to be carried out outside the summer months to avoid additional stress on existing cables at their peak load. Again, additional or rebuilt civil infrastructure may be required in order to install new cables prior to decommissioning existing cables.

Equipment upgrades require existing equipment to be de-energized prior to the larger capacity equipment being installed. Again to avoid additional strain on existing equipment, completing this work outside of the peak load time during the year would be required.

In order to address loading issues in the Horseshoe distribution area, an interim solution that Toronto Hydro plans to use involves switching load to parts of the system with excess capacity. The operating states of some existing switches will be converted from being “Normally Open” to “Normally Closed” and vice versa in order to shift load between more heavily and lighter loaded feeders. The rearrangements are done to provide alternative paths in the distribution grid to improve the reliability of supply to heavily loaded areas.

Also, in the Horseshoe distribution area, Toronto Hydro plans to construct new feeders from stations with surplus capacity to densely loaded areas; these new feeders will pickup load from existing overloaded feeders. A constraint that may be encountered during the execution of the Horseshoe distribution area load transfer projects is the need to cross major highways, rivers and railways. Toronto Hydro plans to address these issues by creating ducts under highways and railways. Special submarine ducts are being considered for paths across the rivers. Since major load transfers in the Horseshoe distribution adrea are done at 27.6 kV, large areas with primarily 4 kV distribution constraining the desired load transfer paths will be converted to 27.6kV.

Care has been taken to schedule the program’s projects so that they are completed before the next peak demand period (typically taking place in the summer months) in order to avoid rolling blackouts, which could result if multiple feeders are overloaded during such periods.

E5.4.5.1 Proposed Work Plan

The majority of work to be completed in 2015 and 2016 addresses the increased load in downtown Toronto, and specifically in the "Entertainment district". Loads will be transferred to Copeland TS in order to offload Windsor TS and the egress for Windsor TS will be expanded to accommodate the additional capacity added during the Windsor bus replacement.

In 2017, Toronto Hydro plans to upgrade the infrastructure in the Gerrard area to accommodate the replacement of the station bus at Gerrard and the additional cables required for the higher capacity bus. As for 2018 and 2019, details have yet to be confirmed, but Toronto Hydro plans on addressing the need to offload Strachan TS and Esplanade TS.

TABLE 6: 2015-2019 LONG TERM PLAN

Year	Station
2015	Windsor TS to Copeland TS
2015	Esplanade TS to Copeland TS
2015	Terauley TS to Copeland TS
2015	George and Duke Egress
2016	Windsor TS Egress
2016	Fairbank TS
2017	Gerrard/Carlaw TS Egress
2017	Main TS
2017	Manby TS
2018	Dufferin TS
2018	Strachan TS
2019	Leslie TS
2019	Esplanade TS

E5.4.5.2 Program Risks

Several issues can arise that present risks to the Load Demand program. These issues include inaccurate or unforeseen load additions or subtractions, addition of loads or redevelopment of an area with old or a lack of civil infrastructure, road moratoriums and difficulties coordinating with third party utilities.

Inaccurate and incomplete customer data could lead to potential investments made in the wrong areas. This change would require additional investments to ensure infrastructure is then built in the needed areas. The additional infrastructure would require additional planning and construction which would add additional work and costs to the connection of new customers.

In order to complete load transfers, new or existing feeders may need to travel long distances, utilizing several cable chambers and duct banks along the route. Typically this requires a rebuilding or expansion of civil infrastructure. Projects within the Load Demand program may be delayed as a result of this civil infrastructure work since it requires considerable coordination with external parties and other utilities. In addition, city imposed road moratoriums may require Toronto Hydro to create alternate plans before performing infrastructure work.

E5.4.6 Evaluation of Alternatives

Three options were evaluated during the formulation of the Load Demand Program.

E5.4.6.1 Quantification/Evaluation of Options

(i) Status Quo

Maintain the status quo would entail postponing the load transfers, feeder and network upgrades in the heavily loaded areas with projected influx of new development.

Benefits of this option are:

- Deferred capital spending to upgrade assets.

Drawbacks of this option are:

- Increased loading stress to existing electrical infrastructure in heavily loaded areas under first contingency load transfers, which can shorten the operational life time of the electrical infrastructure.
- Rolling blackouts may be required during the summer to ensure that the peak loading remains under the capacity for the system.
- Areas of heavy loading continue to experience increased loading, with the capacity to transfer loads under contingency decreasing.
- Impaired ability to expedite upgrades to relieve heavy loading effectively and efficiently.
- The addition of new high load customers in identified heavily loaded areas may exceed first contingency capacity, making system upgrades increasingly difficult and lengthy.

- The exposure risk to customers in high load areas to lengthy outages due to equipment failures or storms will be higher because contingency load transfers will not be possible due to loads exceeding capacity constraints.

Toronto Hydro does not recommend this option given the drawbacks listed.

(ii) Upgrade Stations Capacity

Under this option, Toronto Hydro would add station capacity through expansion of existing stations or construction of new stations in the heavily loaded areas with projected influx of new development.

Benefits of this option are:

- Builds more capacity into the system.

Drawbacks of this option are:

- Requires a large capital outlay spread over multiple years.
- Requires detailed studies for optimal location, environmental assessments, drawn-out construction times plus additional work for system expansion with new exigent feeders to distribute the newly created surplus around the grid.
- Could take eight to ten years to complete which will be too late based on current load growth forecast. This timeline would expose customers in existing high load growth areas to potential lengthy outages. These outages would result from equipment failures or storms because contingency load transfers would not be possible since loads would be exceeding capacity constraints.
- Does not make use of existing stranded station capacity that could be transferred.

Toronto Hydro determined that this option is not feasible given the drawbacks listed.

(iii) Upgrade Equipment & Infrastructure as per Load Demand Program

The preferred option is to upgrade equipment and infrastructure in high load and congested areas of the system and in areas of proposed high load developments with a focus on relieving overloads under first contingency basis.

Benefits of this option are:

- Provides capacity for increased loading in heavily loaded areas that are already at maximum capacity.
- Enables first contingency load transfers in areas of heavy loading that show trending of load increase, which would otherwise exceed present capacity to transfer loads under contingency.
- Provides capacity to expedite future upgrades and balance system loading.
- By providing adequate contingency load transfer capacity, the program reduces exposure risk and outage durations for customers in identified high load areas resulting from equipment failures or storms.

Drawbacks of this option are:

- Requires capital investment to upgrade existing or install new assets.
- Upgrading of assets can subject customers to the risk of prolonged outages if asset failure occurs when feeders are operated in contingency condition to facilitate construction.

The cost of ownership (COO) and program net benefit (NPV) associated with the Load Demand program is further detailed in Table 9. The cost of ownership is established for both the existing state (COO_E), based on the first year of activities in the program, as well as the new state (COO_N) proposed within this program. The COO of a state reflects the risk of asset failure including both direct and indirect costs, including the costs of customer interruptions, emergency repairs, and asset replacements associated with that design. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first of activities, the Load Demand produces a NPV value of $12.25M, as shown in Table 7 and Table 8.

TABLE 7: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	$ 26.83
Non Asset Risk [NAR_E]	$0
Maintenance Cost [MC_E]	$0
Additional Quantifiable Benefits [AQB_E]	$0
Cost of Ownership of Existing Assets [COO_E]	$ 26.83

TABLE 8: LOAD DEMAND BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 2: Conversion to Standardized 13.8kV Feeders (N)	
Asset Risk [AR_N]	$ 2.61
Non Asset Risk [NAR_N]	$0
Maintenance Cost [MC_N]	$0
Additional Quantifiable Benefits [AQB_N]	$0
Cost of Ownership of New Assets (Conversion to 13.8kV) [COO_N]	$ 2.61
Option 2: Project Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\Delta COO_1 = (COO_E - COO_N)$]	$ 24.22
Program Cost [PC_1]	$ 11.96
Program Net Benefit [$NPV_1 = (\Delta COO_1 - PC_1)$]	$ 12.25

E5.4.7 2015 Project Details

Table 9 lists all projects that Toronto Hydro plans to partially or completely execute as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015.

TABLE 9: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Project Type (ICM or CIR)
E14011	E14011 Rebuild UG Trunk NT63M12 M8 Brimley - Electrical	$ 0.87 M	CIR
E14026	E14026 Rebuild UG Trunk 502M21-28 Warden - Electrical	$ 0.82 M	CIR

Project Number	Project Name	Total Project Cost	Project Type (ICM or CIR)
E14442	E14442 Wallsend OH to UG extension Horgan Plant 47M16 SCNT47M7	$ 0.47 M	CIR
E14679	E14679 Leaside load transfer to Bermondsey NY53M6	$ 0.15 M	CIR
S13462	S13462 Dufferin A7-8 load transfer to A5-6W Wiltshire TS 2013	$ 0.08 M	ICM
S13464	S13464 Dufferin A5-6 load transfer to A5-6W Wiltshire TS 2013	$ 0.05 M	ICM
X12638	X12638 Pirandello St Rail Crossing Tunnel	$ 0.98 M	ICM
X13470	X13470 -P18 Transfer A256DN from A5-6DN to A5-6W	$ 0.58 M	ICM
X14683	X14638 Electrical Ph 1 Feeder Transfer A273DN and A310DN to Wiltshire	$ 0.65 M	ICM
X14697	X14697 - LOC4673 TTC switch replacement w/ Network	$ 0.68 M	CIR
X15158	P19 Load Transfer A8-9E bus to A6-7E bus Elec Carlaw TS	$ 0.42 M	CIR
X15308	LOAD TRANSFER ESPLANADE TS TO COPELAND TS	$ 2.27 M	CIR
X15320	Charles Feeder Upgrade A52CS and A54CS Phase 1: Civil	$ 1.35 M	CIR
X15323	LOAD TRANSFER TERAULEY TS TO COPELAND TS	$ 0.89 M	CIR
X15436	George and Duke new civil egress PH 1	$ 1.26 M	CIR
X15583	Queen St W New Switch and B2DF Load Transfer	$ 0.06 M	CIR
X16009	LOAD TRANSFER WINDSOR TS TO COPELAND TS	$ 0.40 M	CIR

E5.4.7.1 E14011 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: Rebuild UG Trunk NT63M12 M8 Brimley - Electrical

Project Number: E14011

Project Year: 2015

Estimated Cost: $ 865,527

(i) Objective

The objective of this project is to upgrade existing cable to the current standard.

(ii) Scope of Work

TABLE 10: E14011 SCOPE OF WORK DETAILS

District Neighbourhood	BRIMLEY RD & STEELES AVE
Station(s)	AGINCOURT TS
Feeder(s)	63M12, 63M8

TABLE 11: E14011 ASSETS REPLACED

Assets (Units)	2015
1000 kcmil TRXLPE CL	3020 M
SF6 PMH 9 Switch	4
SCADAmate Switch	4

(iii) Justification & Benefits

This project will introduce additional capacity for the feeder, allowing it to accommodate more customers. As well, the feeder will be available during contingency situations to backup adjacent feeders.

E5.4.7.2 E14026 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: Rebuild UG Trunk 502M21-28 Warden -Electrical

Project Number: E14026

Project Year: 2015

Estimated Cost: $ 824,147

(i) Objective

The objective of this project is to upgrade existing cable to the current standard.

(ii) Scope of Work

TABLE 12: E14026 SCOPE OF WORK DETAILS

District Neighbourhood	WARDEN AVE & STEELES AVE
Station(s)	CAVANAGH TS
Feeder(s)	NA502M21, NA502M28

TABLE 13: E14026 ASSETS REPLACED

Assets (Units)	2015
1000 kcmil TRXLPE CABLE	3020M
SCADAmate Switch	4

(iii) Justification & Benefits

This project will introduce additional capacity for the feeder, allowing it to accommodate more customers. As well, the feeder will be able to be utilized during contingency situations to backup adjacent feeders.

E5.4.7.3 E14442 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: Wallsend OH to UG extension Horgan Plant 47M16 SCNT47M7

Project Number: E14442

Project Year: 2015

Estimated Cost: $ 473,175

(i) Objective

The objective of this project is to transfer existing customers by extending existing feeders into the distribution area.

(ii) Scope of Work

TABLE 14: E14442 SCOPE OF WORK DETAILS

District Neighbourhood	CHEMICAL COURT & MANSE ROAD
Station(s)	SHEPPARD DS
Feeder(s)	NT47M7, NY47M16

TABLE 15: E14442 ASSETS REPLACED

Assets (Units)	2015
1000 kcmil TRXLPE CABLE	1000 M
PHM 11 Switch	1
SCADAmate Switch	1

(iii) Justification & Benefits

This project will introduce additional capacity into a distribution area. Loads will then be shifted so that new customers can be added to the existing feeder.

E5.4.7.4 E14679 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: Leaside Load Transfer to Bermondsey NY53M6

Project Number: E14679

Project Year: 2015

Estimated Cost: $ 146,961

(i) Objective

The objective of this project is to transfer load from Leaside TS to Bermondsey TS

(ii) Scope of Work

TABLE 16: E14679 SCOPE OF WORK DETAILS

District Neighbourhood	
Station(s)	LEASIDE TS & BERMONDSEY TS
Feeder(s)	53M6, 53M25, 53M27

TABLE 17: E14679 ASSETS REPLACED

Assets (Units)	2015
SCADA-mate Switch	1
556.5 kcmil ASC	200m

(iii) Justification & Benefits

This project will transfer load from Leaside TS to Bermondsey TS. This project will free up capacity at Leaside TS to connect new/additional customers.

E5.4.7.5 S13462 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: STATION SUPPORT FOR X13470 TO PREPARE STATION CELL

Project Number: X13462

Project Year: 2015

Estimated Cost: $ 80,798

(i) Objective

The objective of this scope is preparing the station cells at Wiltshire TS to accept new feeders that will be used in a project to transfer load from Dufferin TS and decommission a 4dkV transformer at Junction MS.

(ii) Scope of Work

TABLE 18: E14697 SCOPE OF WORK DETAILS

District Neighbourhood	DUFFERIN TS & WILTSHIRE TS
Station(s)	WILTSHIRE TS, JUNCTION MS
Feeder(s)	A273DN, A310DN, A271DN

TABLE 19: E14697 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1
MS Transformer	1

(iii) Justification & Benefits

This is a station support project that supports X13470. For Justification and Benefits please see E5.4.7.8.

E5.4.7.6 S13464 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: STATION SUPPORT FOR X14683 TO PREPARE STATION CELL

Project Number: X13464

Project Year: 2015

Estimated Cost: $ 46,170

(i) Objective

The objective of this scope is preparing the station cells at Wiltshire TS to accept new feeders that will be used in a project to transfer load from Dufferin TS and decommission a 4kV transformer at Dupont MS.

(ii) Scope of Work

TABLE 20: E14697 SCOPE OF WORK DETAILS

District Neighbourhood	DUFFERIN TS & WILTSHIRE TS
Station(s)	WILTSHIRE TS/DUPONT MS
Feeder(s)	A273DN, A310DN, A271DN

TABLE 21: E14697 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1
MS Transformer	1

(iii) Justification & Benefits

This is a station support project that supports X14683. For Justification and Benefits please see E5.4.7.9.

E5.4.7.7 X12638 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: Pirandello St Rail Crossing Tunnel

Project Number: X12638

Project Year: 2015

Estimated Cost: $ 981,120

(i) Objective

Construct a new tunnel rail crossing beneath the CN tracks to connect existing civil infrastructure for the west egress at Strachan TS to the existing civil infrastructure at East Liberty St and Pirandello St.

(ii) Scope of Work

TABLE 22: E14697 SCOPE OF WORK DETAILS

District Neighbourhood	LIBERTY VILLAGE
Station(s)	STRACHAN TS
Feeder(s)	N/A

TABLE 23: E14697 ASSETS REPLACED

Assets (Units)	2015
6x4 Duct Bank (m)	200

(iii) Justification & Benefits

The current east egress at Strachan TS leads directly into the south rail crossing along Strachan Ave. This tunnel crossing is extremely deep and the chambers which access the tunnel are old and represent a potential safety risk. In addition, several ducts within the rail crossing have collapsed making cable removal impossible. Under contingency, if the cable could not be removed and new cable cannot be installed there is the risk of an extended outage.

This project entails building a new rail crossing point that would allow for the relocation of all feeders from the unsafe tunnel crossing so that it can be abandoned and/or rebuilt.

E5.4.7.8 X13470 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: LOAD TRANSFER A256DN FROM A5-6DN TO A5-6W

Project Number: X13470

Project Year: 2015

Estimated Cost: $ 577,129

(i) Objective

The objective of this project is to transfer A256DN from A5-6DN bus at Dufferin TS to A5-6W bus at Wiltshire TS in order to reduce load on A5-6DN and maintain loading within firm capacity.

(ii) Scope of Work

TABLE 24: X13470 SCOPE OF WORK DETAILS

District Neighbourhood	DUFFERIN ST & DAVENPORT ST
Station(s)	DUFFERIN TS & WILTSHIRE TS
Feeder(s)	A256DN, A291W

TABLE 25: X13470 ASSETS REPLACED

Assets (Units)	2015
500 KCMIL TRXLPE CABLE	550 M

(iii) Justification & Benefits

Based on 2013 load forecast, loading on A5-6DN will continue to exceed firm capacity in the years to come. This project is necessary in order to contain loading and provide capacity for conversion of 4kV Dupont feeders.

E5.4.7.9 X14683 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: LOAD TRANSFER A273DN, A310DN from DUFFERIN to WILTSHIRE

Project Number: X14683

Project Year: 2015

Estimated Cost: $ 647,804

(i) Objective

The objective of this project is to transfer A273DN and A310DN from A7-8DN bus at Dufferin TS to A5-6W bus at Wiltshire TS in order to reduce load on A7-8DN and maintain loading within firm capacity.

(ii) Scope of Work

TABLE 26: X13470 SCOPE OF WORK DETAILS

District Neighbourhood	WILTSHIRE AVE & DUPONT AVE
Station(s)	DUFFERIN TS & WILTSHIRE TS
Feeder(s)	A273DN, A310DN

Table 27: X13470 Assets Replaced	Assets (Units)	2015
500 KCMIL TRXLPE CABLE		650 M

(iii) Justification & Benefits

Based on 2013 load forecast, loading on A7-8DN will continue to increase and eventually exceed the firm capacity in 2015-2016. This project is necessary in order to contain loading and provide capacity for conversion of 4kV Dupont feeders.

E5.4.7.10 X14697 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: LOC4673 TTC switch replacement w/ Network

Project Number: X14697

Project Year: 2015

Estimated Cost: $ 682,084

(i) Objective

Install new network equipment in LOC 4673 and tie to LOC4691 to relieve capacity constraints in area.

(ii) Scope of Work

TABLE 28: E14697 SCOPE OF WORK DETAILS

District Neighbourhood	RUNNYMEDE-BLOOR & BLOOR-WEST
Station(s)	DUFFERIN TS
Feeder(s)	A33DN, A36DN

TABLE 29: FIGURE 29: E14697 ASSETS REPLACED

Assets (Units)	2015
1000kVA Network Units	2

(iii) Justification & Benefits

During the summer switching restrictions list creation, LOC 4691 was identified as a highly loaded 2-unit vault. Both feeders feeding that vault, A33DN and A36DN, could not be switched out over during the summer period (with a 24 degree restriction) as it would result in an overload of a network unit. LOC 4673, was identified just north of the existing vault as a TTC-style vault that could be converted to a network configuration and be tied to LOC 4691. This would alleviate the overload under contingency issue, allow for summer switching, and provide higher reliability to the existing customer fed via LOC 4673.

E5.4.7.11 X15158 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: Load Transfer A8-9E bus to A6-7E bus Elec Carlaw TS

Project Number: X15158

Project Year: 2015

Estimated Cost: $ 417,732

(i) Objective

The objective of this project is to transfer 3MVA of load from A8-9E bus to A6-7E bus to prevent bus overloading at Carlaw TS A8-9E and to accommodate future load growth. According to the latest load forecast from Capacity Planning, A8-9E bus from Carlaw TS is forecast to reach 100% capacity in the near future.

(ii) Scope of Work

TABLE 30: X15158 SCOPE OF WORK DETAILS

District Neighbourhood	GREENWOOD-CARLAW AVE
Station(s)	CARLAW TS
Feeder(s)	A64E, A31E, A77E, A33E, A78E, A12E, A11E

TABLE 31: X15158 ASSETS REPLACED

Assets (Units)	2015
500 kcmil TRXLPE (m)	1,650

(iii) Justification & Benefits

This project aims to transfer load from one station bus to another at Carlaw TS.

E5.4.7.12 X15308 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: LOAD TRANSFER ESPLANADE TS TO COPELAND TS

Project Number: X15308

Project Year: 2015

Estimated Cost: $ 2,266,374

(i) Objective

The objective of this project is to transfer five feeders of load from Esplanade TS (A1-2X) to Copeland TS (A3-4CL) bus to accommodate future load growth. According to the latest load forecast from Capacity Planning, A1-2X bus from Esplanade TS is forecast to reach 100% capacity in the near future.

(ii) Scope of Work

TABLE 32: X15308 SCOPE OF WORK DETAILS

District Neighbourhood	YONGE ST & FRONT ST
Station(s)	ESPLANADE TS, COPELAND DS
Feeder(s)	A30X, A31X, A32X, A40X and A41X

TABLE 33: X15308 ASSETS REPLACED

Assets (Units)	2015
500 kcmil TRXLPE	

(iii) Justification & Benefits

This project aims to transfer load from one station bus to another at Copeland TS. The bus that will be freed up at Esplanade TS will supply new customer loads coming online in the Queens Quay area.

E5.4.7.13 X15320 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: CHARLES FEEDER UPGRADES A52CS, A54CS

Project Number: X15320

Project Year: 2015

Estimated Cost: $ 1,349,649

(i) Objective

The objective of this project is to upgrade and rebuild the civil route for A52CS and A54CS to ensure that the chambers are safe and large enough and have sufficient duct space to accommodate the feeder upgrades.

(ii) Scope of Work

TABLE 34: X15320 SCOPE OF WORK DETAILS

District Neighbourhood	SHERBOURNE & BLOOR STE
Station(s)	CHARLES TS
Feeder(s)	A52CS, A54CS

TABLE 35: X15320 ASSETS REPLACED

Assets (Units)	2015
6x4 Duct Bank (m)	450
Cable Chambers	3

(iii) Justification & Benefits

This project allows Toronto Hydro to replace undersized cable.

E5.4.7.14 X15323 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: LOAD TRANSFER TERAULEY TS TO COPELAND TS

Project Number: X15323

Project Year: 2015

Estimated Cost: $ 890,117

(i) Objective

The objective of this project is to transfer 4 feeders from Terauley TS to Copeland TS to accommodate future load growth. According to the latest load forecast from Capacity Planning, Terauley TS is forecast to reach 100% capacity in the near future.

(ii) Scope of Work

TABLE 36: X15323 SCOPE OF WORK DETAILS

District Neighbourhood	BREMNER BLVD & YORK ST
Station(s)	TERAULEY TS, COPELAND DS
Feeder(s)	A31A, A33A, A55A, A56A

TABLE 37: X15320 ASSETS REPLACED

Assets (Units)	2015
500 KCMIL TRXLPE CABLE	500 M

(iii) Justification & Benefits

This project aims to transfer load from one station bus to another at Copeland TS. This load transfer aims to free up capacity at Terauley TS, this gives planners and operators flexibility to connect new customers to Terauley TS and operate the system with less restrictions.

E5.4.7.15 X15436 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: GEORGE AND DUKE CIVIL EGRESS PHASE 1

Project Number: X15436

Project Year: 2015

Estimated Cost: $ 1,255,794

(i) Objective

The objective of this project is to construct new civil infrastructure to improve present and future feeder egress at George and Duke TS.

(ii) Scope of Work

TABLE 38: X15436 SCOPE OF WORK DETAILS

District Neighbourhood	ADELAIDE STE & JARVIS ST
Station(s)	GEORGE AND DUKE TS
Feeder(s)	A28/29/45/23/27/35/47/44/46/48/49/40/42/43GD

TABLE 39: X15436 SCOPE OF WORK DETAILS

Assets (Units)	2015
500 KCMIL TRXLPE CABLE	2,000M
Cable chambers	3
3x5 Duct bank	250M
6x4 Duct bank	50 M

(iii) Justificat ion & Benefits

The new egress would allow for new cable chambers to be constructed for improved and proper cable pulling and racking, ability to install new cable for George and Duke feeders, upgrade and remove old clay tile ducts.

E5.4.7.16 X15583 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: B2DF LOAD TRANSFER

Project Number: X15383

Project Year: 2015

Estimated Cost: $ 56,665

(i) Objective

The objective of this project is to transfer load from B2DF to B11T to accommodate future load growth. A total of 1125kVA will be transferred from B2DF to B11T.

(ii) Scope of Work

TABLE 40: X15583 SCOPE OF WORK DETAILS

District Neighbourhood	MANNING AVE & QUEEN ST W
Station(s)	DAFOE MS & STRACHAN MS
Feeder(s)	B2DF, B11T

TABLE 41: X15583 ASSETS REPLACED

Assets (Units)	2015
Manually Operated Load Interrupting Switch	2 Units

(iii) Justification & Benefits

Current loading on Dafoe MS is projected to exceed firm capacity during the summer peak. This project is necessary in order to contain loading and provide capacity for the addition of new customers in the King West neighbourhood.

E5.4.7.17 X16009 Project Description

Investment Category: System Access

Program: Load Demand

Project Title: LOAD TRANSFER 2 FROM WINDSOR TS TO COPELAND TS

Project Number: X16009

Project Year: 2015

Estimated Cost: $ 402,740

(i) Objective

The objective of this project is to transfer load from Windsor TS to Copeland TS to prevent buses at Windsor TS from overloading.

(ii) Scope of Work

TABLE 42: X15583 SCOPE OF WORK DETAILS

District Neighbourhood	SPADINA AVE & WELLINGTON ST W
Station(s)	WINDSOR TS, COPELAND DS
Feeder(s)	A46WR, A47WR, A19WR, A21WR, A73WR, A79WR

TABLE 43: X15583 ASSETS REPLACED

Assets (Units)	2015
500 KCMIL TRXLPE CABLE	1000 M

(iii) Justification & Benefits

This project aims to transfer load from one station bus to another at Copeland TS. This will help free up capacity at Windsor TS to accommodate the upgrade of A5-6WR bus which will ultimately increase the capacity available at Windsor TS.

E5.5 Generation Protection, Monitoring and Control

DG INSTALLATION AT GROCERY STORE

E5.5.1 Summary

Program Description

The Generation Protection, Monitoring and Control (GPMC) program is required so that Toronto Hydro can continue to fulfill its obligations to connect the growing number of DG projects to the distribution system. This program captures the majority of Toronto Hydro's forecasted "renewable enabling improvements" (as defined in section 3.3.2 of the Distribution System Code (DSC)) for the 2015-2019 forecast period.

DG connections are expected to more than triple in total capacity by 2019, reaching over 625 MW. To (1) alleviate existing connection capacity constraints that currently prevent the expansion of DG in a number of areas and (2) provide Toronto Hydro system controllers with necessary capabilities to monitor and control DG connections, the utility plans to make the following investments over the 2015-2019 period:

(1) install advanced protection systems at three stations with short-circuit capacity constraints;

(2) install a bus-tie reactor at Richview TS to alleviate short-circuit capacity constraints; and

(3) install required monitoring and control systems at all DG facilities.

The anticipated benefits of the GPMC program are as follows:

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Advanced protection systems, upgrades, and monitoring and control will enable the connection of additional DG – including renewable energy generation (REG) – to Toronto Hydro's distribution system.
Reliability	ƒ Advanced protection systems and monitoring and control provide greater reliability for new and existing customers by ensuring that the operation of the distribution system is within allowable limits.
Safety	ƒ Monitoring and control systems help Toronto Hydro avoid backfeed situations by automatically issuing an electronic trip/shutdown command to isolate DG. A backfeed situation can energize a circuit after the utility source has ceased to energize the circuit. This could potentially go undetected by field crews working on the circuit.
Efficiency	ƒ Monitoring and control will provide power system controllers with situational awareness into the operating conditions of all DG connected to the distribution system at the station/bus/feeder when required for planned or emergency load transfers.
Public Policy Responsiveness	ƒ This program aligns to public policy objectives with respect to green energy and the green economy by enabling additional REG connections during the 2015-2019 period and by providing system planning engineers with a level of precision in DG capacity monitoring that is expected to facilitate the maximization of REG and DG penetration at any given time.
Environment	ƒ The program will help realize environmental benefits from connecting renewable DG sources to the grid.

Program Drivers

The GPMC program is driven by OEB guidelines to provide DG access to the distribution system. Forecasted growth in DG connections during the five-year planning horizon stems from the public policy objectives established in the GEGEA regarding the expansion of REG capacity in Ontario.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Mandated Service Obligations	ƒ The DSC obligates Toronto Hydro to make all reasonable efforts to connect a generation facility in a timely manner. ƒ Capacity to connect DG is currently limited, with certain areas of the system currently unable to facilitate any additional DG in 2015 and beyond. ƒ Investments are required to overcome short-circuit capacity constraints and to facilitate integration of DG into the distribution grid with bi-directional flow capability. ƒ Without these investments, Toronto Hydro may not be able to respond to public policy objectives with respect to the expansion of renewable energy generation sources in the province of Ontario.
Secondary Drivers	Reasoning

Drivers	
Safety	ƒ Ensure safe connection and operation of DG. ƒ Provide power system controllers tools to remotely disconnect DG as part of the Work Protection Code procedures to safeguard linepersons from unexpected start-up of generator, preventing backfeed into the local distribution grid area while field crews are present.
Reliability	ƒ Prevent backfeed situations from causing voltage fluctuations and equipment failures. ƒ Monitoring to ensure bi-directional flows are within distribution system design parameters including thermal and short circuit capability. ƒ Provide power system controllers real-time customer generation data to determine load flow and switching procedures during planned and unplanned work. ƒ Integrate real-time customer generation data into distribution planning and generation planning work including the determination of generation to load ratios required to correlate and assess the depth of penetration and system impact.

Preferred Alternative

The GPMC program analyzed and evaluated the following options

(1) Major Asset Upgrades, Monitoring and Control (MAUMC)

(2) Generation Protection, Monitoring and Control (GPMC)

Option II is the preferred option as it is the most cost-effective and timely option for facilitating the continued integration of DG connected to the Toronto Hydro distribution system.

Timing and Pacing

The timing and pacing of the GPMC program is driven by customer requests to connect DG to the distribution system. Toronto Hydro plans to install monitoring and control equipment for existing DG sites between 2015 and 2016, while the remainder will be installed in 2017.

TABLE C: HISTORICAL AND FORECAST SPENDING

	Historical Spending					Future Spending				
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	-	-	-	-	-	$6.12	$5.19	$3.26	$2.10	$2.02

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E5.5.2 Program Description

The Green Energy and Green Economy Act, 2009 [2] encourages new generation sources, including solar photovoltaic (PV), biogas and wind power generation to connect to the distribution system as distributed generation (DG). DG allows for the generation of electricity from many small decentralized sources located in close proximity to the distribution loads that they serve. This type of generation requires bidirectional flow of electricity. The load and generation levels at the customer point of connection are dynamic and may increase or decrease depending on site conditions. For example, during light load periods, the power from local generation is exported to the distribution grid; during peak load periods, the customer site imports power from the distribution grid. This method of generation contrasts with the traditional approach where large, often distant, generating stations are linked by transmission systems to local distribution systems to supply local loads unidirectionally.

Since the passage of the GEGEA in 2009, Toronto Hydro has made over 890 DG connections with 114 MW of capacity. Figure 1 shows the current distribution of DG connections within Toronto Hydro's distribution system.

FIGURE 1: TORONTO HYDRO DG CONNECTIONS (AS OF MAY 31ST, 2014)

[2] S.O. 2009, C.12. ["GEGEA"]

The GPMC program is required so that Toronto Hydro can continue to fulfill its obligations to connect the growing number of DG projects to the distribution system. This program captures the majority of Toronto Hydro's forecasted "renewable enabling improvements" (as defined in section 3.3.2 of the Distribution System Code (DSC)) and any other necessary DG connection enabling improvements for the 2015-2019 forecast period.

As of June 2014, Toronto Hydro has responded to over 3,000 inquiries from customers and developers through the Feed-in-Tariff Program (FIT) pre-assessments. A wide range of proponents have submitted project applications, including many schools, housing, large grocery stores and department stores. Toronto Hydro's present rate of inquiry for individual FIT customers is estimated at 7.5 MW per month for 50 inquiries. Schools have received over 300 pending offers to connect renewable generation from the Ontario Power Authority (OPA) with over 40 MW of capacity. DG connections are expected to more than triple in total capacity by 2019, reaching over 625 MW. This represents an additional 450 MW over the five year planning period on top of the 114 MW of existing DG and 62 MW of DG planned for connection by the end of 2014.

Toronto Hydro's DG connection forecast is based on historical DG connections from 2009 onwards. It takes into account the historical connection trends with respect to various DG programs, and uses a linear approximation to forecast the anticipated amount of connections and total generation from 2015 through 2019. Please refer to Table 1 and Figure 2 for a year-by-year breakdown of the DG connection forecast.

TABLE 1: BREAKDOWN OF DG CONNECTION FORECAST (BY MW) PER PROGRAM TYPE (2015-2019)

Program	Existing (Includes 2014 Planned)	2015	2016	2017	2018	2019	Total (MW)
FIT 1.0 - 2.0	53.9	31.2	0.0	0.0	0.0	0.0	85.0
FIT 3.0 - 7.0	0.0	10.7	23.9	25.8	27.7	29.7	117.8
Combined Heat and Power (CHP)	59.6	35.5	28.2	27.3	24.0	104.0	278.6
Other DG	62.7	32.9	18.0	8.0	15.0	8.0	144.6
Total	176.2	110.3	70.1	61.1	66.7	141.7	626.0

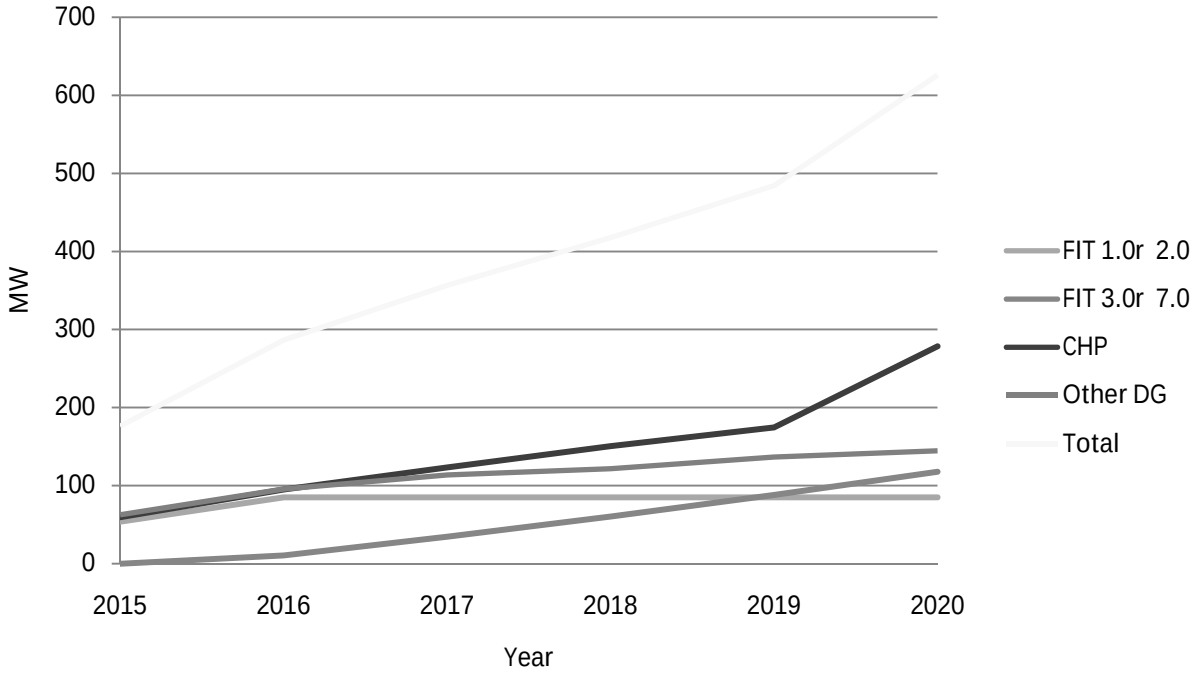


FIGURE 2: GRAPH OF DG CONNECTION FORECAST PER PROGRAM TYPE (2015-2019)

The following protection, monitoring and control equipment is required to facilitate the increasing volume of DG in the Toronto Hydro distribution system:

- advanced protection systems,
- bus-tie reactors installed on the station bus, and
- monitoring and control systems.

Sections E5.5.2.1 to E5.5.2.3 provide detailed information regarding work to be carried out as part of the program. Toronto Hydro forecasts that the selected activities and methods of enabling DG facilities described in detail below will cost an estimated $18.69 million during the 2015 to 2019 period. /C

E5.5.2.1 Advanced Protection Systems

Some of Toronto Hydro's existing and proposed generation customers operate DG projects that connect to the distribution system with an inverter-type interface. These interfaces, which are commonly found on PV generation facilities, can potentially increase short-circuit levels on the

distribution system. Short circuits on power systems require that protection devices such as feeder breakers operate to interrupt current in the order of thousands of amps. Short circuits involve high levels of energy which typically last up to 160 milliseconds. In this transient period, the interaction of DG sources with the grid is quite complex and it is crucial that the various interconnected sources decouple (i.e. disconnect) from the grid within the timeframe of the system designed ratings. If system design fault levels are exceeded, failures and safety hazards can occur. The resulting failures could expose Toronto Hydro equipment to prolonged outages and costly restoration work. A discussion of these safety hazards and the importance of mitigating these risks is provided in Section 5.6.3.1.

In situations where short circuit capacity limitations exist, Toronto Hydro prohibits the connection of DG customers to ensure that unsafe conditions, such as equipment failures, do not arise and to maintain continuity of service to customers. Leslie TS, Wiltshire TS and Basin TS at this time have short circuit constraints on several station buses. To cost-effectively enable the connection of DG at these locations in a timely manner, a high-speed advanced protection scheme must be implemented on buses with short circuit constraints that currently prevent inverter based connections. This technology leverages fibre optic technology with the fast operating time of inverter based devices. Installing this protection system will enable generation customers to connect to the grid where they presently cannot and is expected to mitigate the risks to the distribution system caused by an increasing number of connections.

The advanced protection system uses a high speed communication network with the associated protective equipment to enable the isolation of the generator from the distribution system before the main circuit breakers operate. As a result, the distribution system and customer high voltage equipment is less likely to be damaged during a fault. Inverters inherently have a fast isolation time for inverter gating and are integrated with the communication grid for coordinated isolation (example provide below). Figure 3 below provides an overview of the advanced protection and monitoring scheme. With such a system, the short circuit duration is decreased significantly due to the speed of the electronics as compared to the operating time of mechanical devices.

FIGURE 3: ADVANCED PROTECTION AND MONITORING SCHEME

The microprocessor-based feeder relay protection at the station breakers uses a protocol compliant with National Institute of Standards and Technology (NIST) and Electric Power Research Institute (EPRI) endorsement. The network with self-healing provides a normal and redundant path to feeder customers. All inverter-based generators will cease power production well before the station breaker begins to open, thereby mitigating the short circuit impact. This solution allows the distribution system to operate as designed and well within station-available short circuit capacity limits.

For instance, during a cable fault on the distribution feeder, the transmission supply and all DG sources will feed into the fault. The utility feeder protection will detect the over-current condition and send an open command to the main breaker and simultaneously to all DG sources. The inverter-based DG sources will receive the open command and cease energy production in a short period of time, estimated at 15 milliseconds. The main breaker will open sometime later (in the order of 120 milliseconds). As a result, the DG in-feed will cease much faster than the breaker mechanism, which avoids adverse affects on distribution equipment.

Industry experience indicates that microprocessor-based protection and control devices have a lifecycle of 15-20 years. These devices operate maintenance free for this period of time. Good utility practice requires replacement of this equipment at the end of its lifecycle. Fibre optic cable typically lasts for 25 years, and is also maintenance free unless the cable is cut. In this scenario the entire fibre strand would need to be replaced. Table 2 below outlines the total units of equipment to be installed as part of this portion of the Generation Planning, Monitoring and Control program.

TABLE 2: ADVANCED PROTECTION SYSTEM ASSETS TO BE INSTALLED

Assets (Units)	2015	2016	2017	2018	2019	Total (Units)
Protection and Control Devices(by feeder)	8	7	7	6	3	31
Fibre Optic Interface cable (km)	10	10	10	10	10	50

E5.5.2.2 Bus-Tie Reactor

Richview TS at this time has a short circuit constraint on several feeders. A bus-tie reactor scheme has been proposed to address this limitation.

To facilitate DG connections, bus-tie reactors are installed on the bus to mitigate high fault current levels. Bus-tie reactors lower the short circuit current on the station bus and distribution system by inserting impedance at the bus-tie point. This limits the fault contribution of the two transformer windings in a typical Dual Element Spot Network (DESN) type station arrangement. A reactor of 0.5 ohms could allow up to an additional 15 MW of DG capacity. This method of fault mitigation has been successfully applied by PowerStream and Hydro One Networks Inc. (HONI).

To facilitate Toronto Hydro DG customer connections, exploratory meetings are underway with HONI to install such bus-tie systems. Toronto Hydro plans to work with HONI to install a bus-tie reactor at Richview TS on the BY bus to eliminate the existing fault current constraint. This constraint is generated from the high fault levels at the station due to the low impedance transformers in-service. At present, all proposed connections on the Richview BY bus and any future DG applicants cannot proceed with connection due to the existing constraint. The bus-tie reactor solution will provide relief for this constraint and enable the connection of DG to the system.

A bus-tie reactor has a useful life of 30 years, and requires maintenance every five years. Table 3 below outlines the total units of equipment to be installed as part of this portion of the Generation Planning, Monitoring and Control program.

TABLE 3: BUS TIE REACTOR ASSETS TO BE INSTALLED

Assets (Units)	2015	2016	2017	2018	2019	Total (Units)
Bus Tie Reactor (per station)	0	1	0	0	0	1

E5.5.2.3 Monitoring and Control Systems

Due to the volumes of forecasted DG connections from 2015 through to 2019, Toronto Hydro requires real-time monitoring and control via utility communication networks and the supervisory control and data acquisition (SCADA) system in order to ensure distribution system safety and the adequate management of bi-directional distribution grid flows from DG connections. Real-time monitoring and control is required for existing and future DG sites, 50 kW and above. Toronto Hydro is mandated to connect DG sites to the distribution system, as per Section 6.2.4 of the DSC. With monitoring and control, Toronto Hydro expects to be able to connect the forecasted amount of DG sites to the distribution system while meeting the mandated requirements of the DSC.

Monitoring and control provides situational awareness into the operating conditions of all DG connected to the distribution system, which will give Toronto Hydro the ability to collect data for planning purposes to connect additional DG sites to the distribution system. This will have additional long-term value with respect to planning for future DG connections. Currently, system planning engineers assess the potential to connect a DG site to the distribution system based on estimated thermal loading values. This approach assumes that a DG site will continuously generate 100% of its rated capacity. This inherently limits the number of DG sites that can be connected to the system, because the estimated value assumes that the thermal loading of the DG site is greater than it likely is at any given time. Monitoring and control will provide actual performance data from in-service connections for thermal loading values, which will give Toronto Hydro a more precise view of existing conditions, which in turn will help enable the connection additional DG sites to the distribution system.

Monitoring and control also enables greater real-time visibility into the operating conditions of DG sites located in Toronto Hydro's service territory. Power system controllers need to know the aggregate generation connected to the system during planned or emergency load transfers. A

power system controller must account for all DG during a load transfer, because the increase in generation connected to the alternate feeder may exceed its short circuit capacity. The ability to remotely and automatically disconnect all DG sites on a feeder during planned or emergency load transfers is expected to simplify these operations as it would allow power system controllers to focus on restoration of customers, rather than each individual DG site connected to a feeder.

Toronto Hydro's requirement for monitoring and control is modeled after requirements developed by the Independent Electricity System Operator (IESO). The IESO has developed DG monitoring and control guidelines with a focus on visibility, dispatch and forecasting capabilities for DG sites over 5 MW. At present, the aggregate installed capacity of DG on Toronto Hydro's distribution system is over 110 MW. Because of the volume and capacity of DG sites in Toronto Hydro's service territory, monitoring and control is required to connect additional DG projects and for grid management. This approach to implement monitoring and control is also consistent with the requirements of other LDCs, including PowerStream and Horizon Utilities.

Toronto Hydro's current monitoring and control process allows for the connection of DG sites through a Toronto Hydro communication interface as shown in Figure 4 below. Figures 5 to 7 show customer installations which adhere to the standards developed by Toronto Hydro.

FIGURE 4: MONITORING AND CONTROL INTERFACE TO TORONTO HYDRO SCADA SYSTEM

FIGURE 5: COMMUNICATION GATEWAY INSTALLED AT CUSTOMER DG SITE

FIGURE 6: TORONTO HYDRO COMMUNICATION STANDARD FOR DG CONNECTIONS

FIGURE 7: TORONTO HYDRO COMMUNICATION ANTENNA SETUP AT A CUSTOMER DG SITE

Monitoring and control equipment has a useful life of 15 years and requires maintenance every four years for battery replacement. Table 4 below outlines the total units of equipment to be installed as part of this portion of the Generation Planning, Monitoring and Control program.

TABLE 4: MONITORING AND CONTROL SYSTEM ASSETS TO BE INSTALLED

Assets (Units)	2015	2016	2017	2018	2019	Total (Units)
Monitoring and Control Equipment (per generator)	280	195	201	140	152	968

The GPMC program is instrumental in enabling DG connections within Toronto Hydro's distribution system. This program is fundamentally customer-driven, as the proposed work will allow Toronto Hydro to connect additional customer DG projects to the distribution system, now and in the future.

The planned investments are also critical renewable enabling improvements that Toronto Hydro must carry-out in order to safely and reliably facilitate the continuing proliferation of REG facilities across the City of Toronto. By addressing short-circuit limitations on the system and installing needed monitoring and control capabilities, Toronto Hydro plans to continue to deliver an efficient and timely DG connections program that is responsive to the Ontario Government's public policy goals during the 2015-2019 period and beyond.

Reliability is also expected to be positively affected by the addition of monitoring and control, since these systems give Toronto Hydro visibility into active power generation and system load flows. At this time, the amount of DG penetration has surpassed the one-third level on nineteen feeders; this level of penetration presents the risk of islanding, described further in section 5.5.3.1. Furthermore, a rising number of Toronto Hydro circuits have DG penetration levels in the 25% to 30% range. Toronto Hydro must gain active monitoring and control of DG sites prior to penetration levels growing further.

Power restoration during emergency situations will require DG monitoring and control in addition to the current SCADA telemetry of system/feeder load. For system planning engineers, monitoring and control data provides the means for improving system reliability going forward. Toronto Hydro expects that stations and distribution feeder planning will be increasingly impacted by the depth of DG penetration, and will need to consider DG performance data in order to forecast station load growth as well as new customer connection assessments (for both load and generation proponents).

Figures 8 and 9 demonstrate typical DG installations taking place on the Toronto Hydro distribution system, as enabled by investments in this program.

FIGURE 8: RESIDENTIAL DG INSTALLATION

FIGURE 9: DG INSTALLATION AT A GROCERY STORE

Table 5 provides an overview of the anticipated benefits associated with the GPMC program.

TABLE 5: PROGRAM BENEFITS

Customer Value	ƒ Advanced protection systems, upgrades, and monitoring and control will enable the connection of additional DG to Toronto Hydro's distribution system.
Reliability	ƒ Advanced protection systems and monitoring and control provide greater reliability for new and existing customers by ensuring that the operation of the distribution system is within allowable limits.
Safety	ƒ Monitoring and control systems help Toronto Hydro avoid backfeed situations by automatically issuing an electronic trip/shutdown command to isolate DG. Backfeed results in energizing a circuit after the utility source ceases to energize the circuit.
Efficiency	ƒ Monitoring and control will provide power system controllers with situational awareness into the operating conditions of all DG connected to the distribution system at the station/bus/feeder when required for planned or emergency load transfers.
Public Policy Responsiveness	ƒ This program aligns to public policy objectives with respect to green energy and the green economy by enabling additional REG connections during the 2015-2019 period and by providing system planning engineers with a level of precision in DG capacity monitoring that will facilitate the maximization of REG and DG penetration at any given time.
Environment	ƒ The program will help realize environmental benefits from connecting renewable DG sources to the grid.

E5.5.3 Why the Program is Needed

The GPMC program is required to provide system access to the existing and forecasted levels of DG in Toronto Hydro's distribution system. At the present time, the ability to connect new DG is limited by constraints within the Toronto Hydro system. As DG connection requests increase, Toronto Hydro will face several issues that could inhibit the ability to connect the forecasted DG projects. As per Section 6.2.4 of the DSC, Toronto Hydro is mandated to connect DG to the distribution system:

> "Subject to all applicable laws, a distributor shall make all reasonable efforts in accordance with the provisions of section 6.2 to promptly connect to its distribution system a generation facility which is the subject of an application for connection."

E5.5.3.1 Program Drivers

Toronto Hydro anticipates that the GPMC program will provide additional DG access to the distribution system in accordance with OEB guidelines, DSC requirements, and the legal framework and policies established in the GEGEA. Table 6 presents the trigger and secondary drivers for the program.

TABLE 6: GENERATION PROTECTION, MONITORING AND CONTROL PROGRAM DRIVERS

Trigger Driver	Reasoning
Mandated Service Obligations	ƒ The DSC obligates Toronto Hydro to make all reasonable efforts to connect a generation facility in a timely manner. ƒ Capacity to connect DG is currently limited, with certain areas of the system currently unable to facilitate any additional DG in 2015 and beyond. ƒ Investments are required to overcome short-circuit capacity constraints and to facilitate integration of DG into the distribution grid with bi-directional flow capability. ƒ Without these investments, Toronto Hydro may not be able to respond to public policy objectives with respect to the expansion of renewable energy generation sources in the province of Ontario.
Secondary Drivers	**Reasoning**
Safety	ƒ Ensure safe connection and operation of DG. ƒ Provide power system controllers tools to remotely disconnect DG as part of the Work Protection Code procedures to safeguard linepersons from unexpected start-up of generator, preventing backfeed into the local distribution grid area while field crews are present.
Reliability	ƒ Prevent backfeed situations from causing voltage fluctuations and equipment failures. ƒ Maintain and enhance system reliability by providing monitoring and control. ƒ Monitoring to ensure bi-directional flows are within distribution system design parameters including thermal and short circuit capability. ƒ Provide power system controllers real-time customer generation data to determine load flow and switching procedures during planned and unplanned work. ƒ Integrate real-time customer generation data into distribution planning and generation planning work including the determination of generation to load ratios required to correlate and assess the depth of penetration and system impact.

Toronto Hydro has a dedicated generation planning group that supports connecting DG to the distribution system, which is consistent with the DSC and direction from HONI and the OPA.

Toronto Hydro has identified a number of constraints within its system that have an impact on DG connections and on interconnection-related decisions. The issues that limit Toronto Hydro's ability to connect DG include short-circuit capacity, risk of islanding, thermal limits and the lack of ability to transfer loads between feeders during planned work and emergency situations. Asset failure can occur when distribution equipment exceeds system short circuit levels, equipment thermal ratings and nominal voltage ratings. Asset failures due to distribution system stresses from DG sources can cause transformer equipment failure, surge arrester failure, nuisance outages from sympathetic tripping and other similar effects. Introducing increased levels of bi-directional flows from DG will require protection, monitoring and control to prevent such occurrences during normal operation, planned work and emergency situations.

Short Circuit Capacity Limitations

In situations where short circuit capacity limitations exist, Toronto Hydro prohibits the connection of DG customers to ensure that unsafe conditions do not arise and to maintain continuity of service to customers.

Short-circuit capacity constraints can be both transmission based and distribution based. Transmission based constraints involve the power equipment used for the bulk transfer of electrical energy from large generating plants to transformer stations in an LDC territory. (The transmission system within the City of Toronto operates at 115 kV or 230 kV.) Distribution based constraints involve limitations in the equipment used to distribute electricity to many customers. The distribution system in the City of Toronto operates at a nominal voltage of 27.6 kV or less.) The GPMC program addresses distribution based constraints.

Transmission-Based Constraints

HONI is implementing its own program to relieve transmission based short-circuit capacity constraints encountered by the proliferation of DG. These transmission-based short-circuit constraints currently pose a DG connection challenge to a significant portion of Toronto. Upgrades are underway to alleviate these capacity issues by the end of 2014.

In HONI's 2011 and 2012 transmission revenue requirement filing, transmission constraints at both Manby and Leaside Transformer Stations (TS) were identified,[3] each of which has limited

[3] EB-2010-0002, Application and Evidence (May 19, 2010), at Exhibit A, Tab 11, Schedule 4.

Toronto Hydro's ability to approve requests for DG interconnection. HONI's identified system constraints include the following:

- short circuit capacity constraints per Transmission System Code (TSC) limits;
- thermal capacity on station transformers that limits reverse power flow;
- minimum bus load requirements to limit reverse power flow; and,
- short circuit capacity constraints due to transmission breaker capacity.

The short-circuit capacity and reverse power flow constraints are necessary to ensure the proper operation of both the transmission and distribution systems. These constraints reflect the technical limits of transformer stations and the equipment therein, such as circuit breakers and transformers. Figure 10 illustrates the extent of short-circuit capacity constraints prior to the execution of HONI's planned investments.

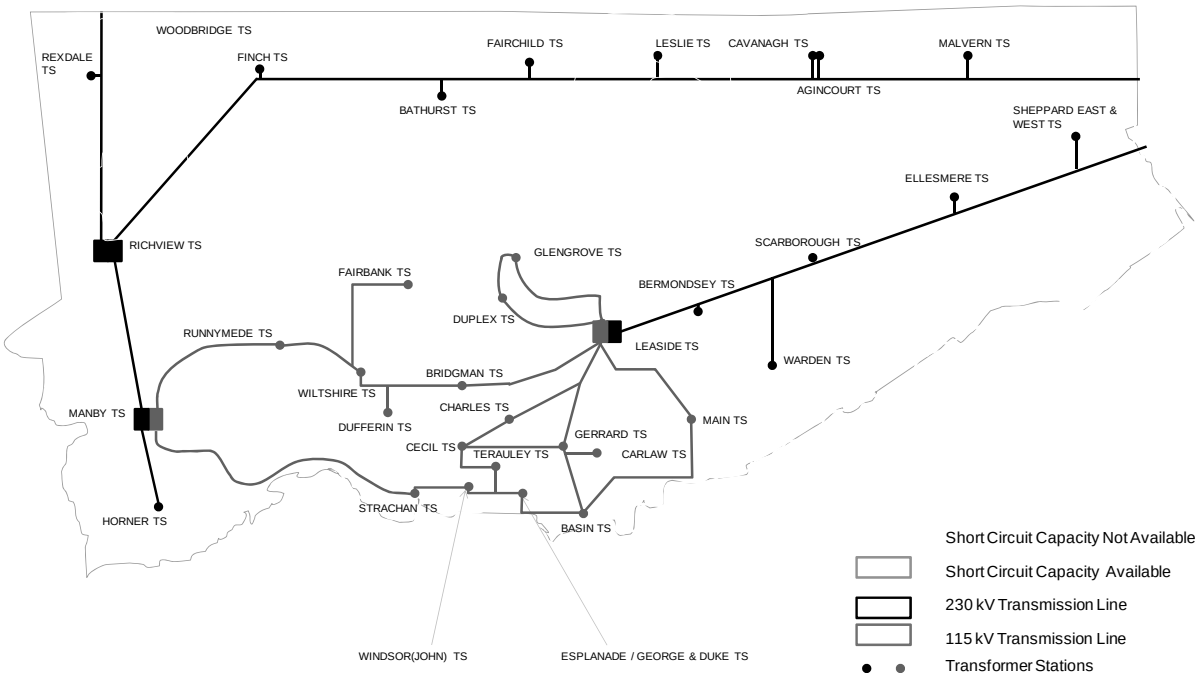


FIGURE 10: SHORT CIRCUIT CONSTRAINTS – PRE-HONI LEASIDE/MANBY/HEARN UPGRADES

Planned HONI upgrades on the downtown Toronto 115 kV transmission system should resolve Leaside TS issues by the end of 2014. Completion of this project along with upgrades to the

Scarborough East 230 kV transmission system should address most of Toronto Hydro's current short circuit and thermal capacity issues. When this work is completed, Toronto Hydro anticipates that it will remove the upper layer of DG connection constraints as imposed by the transmission system.

Distribution Based Constraints

In addition to the transmission based constraints being addressed by HONI, Toronto Hydro must address distribution based short-circuit capacity constraints in specific locations throughout the system. Figure 11 shows areas within Toronto which are presently constrained due to short circuit limits at individual stations. These stations are supplied by HONI transformers and directly connect to Toronto Hydro feeders. The distribution based constraints will remain even after HONI has addressed the transmission constraints at the 230 kV and 115 kV level.

FIGURE 11: DISTRIBUTION SYSTEM SHORT CIRCUIT CAPACITY CONSTRAINTS MAP

The advanced protection system and bus-tie reactor investments proposed within this program will address these short circuit capacity limits, and help ensure that Toronto Hydro has the capacity to connect DG customers.

Downstream distribution system enhancements are necessary to realize the benefits of significant transmission system investments and upgrades presently in the final stages. The transmitter, HONI, has undertaken to replace equipment that alleviates capacity constraints on the transmission system. An additional effort is required by the distributor Toronto Hydro to alleviate capacity constraints on the distribution system.

Anti-Islanding Condition for Distributed Generators

Islanding occurs when a DG source continues to power a portion of the grid even after the main utility supply source has disconnected or is no longer available. This situation must be avoided, as it can interfere with grid protection systems and may potentially be dangerous to Toronto Hydro crews.

The connection of photovoltaic solar inverters and other DG sources must be accomplished in a manner that ensures that unintentional islanding of DG sources cannot take place. Toronto Hydro plans to deploy real-time monitoring and control investments proposed within this program at every DG site to provide the needed ability to address anti-islanding concerns.

One of the anti-islanding measures in the IEEE 1547 Standard for Interconnecting Distributed Resources (DR) with Electric Power Systems, section 4.4.1, requires that "DR aggregate capacity is less than one-third of the minimum load of the Local Electric Power System (EPS)." Some other utilities such as HONI have adopted the one-third rule to ensure unintentional islanding does not occur. With the proliferation of DG in Toronto in recent years, several feeder circuits have already surpassed the generation to minimum load ratio of one-third. A total of nineteen distribution feeders have ratios ranging from 0.34 to 2.86 (refer to Table 7 below). These feeders currently present an increased risk to the distribution system of unintentional islanding conditions.

TABLE 7: FEEDERS WITH GENERATION TO LOAD RATIO GREATER THAN ONE-THIRD

Feeder Name	TS Station Name	TS Bus	TOTAL DG Connected & In Progress (MW)	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
A-35-T	Strachan	A7A8	1.00	0.35	2.86
85-M7	Bathurst	Y	6.01	2.96	2.03
51-M4	Leslie	Y	6.20	3.73	1.66
A-21-CE	Cecil	A1A2	6.00	5.16	1.16
85-M30	Bathurst	J	5.05	4.59	1.10
85-M6	Bathurst	B	4.34	4.94	0.88

Feeder Name	TS Station Name	TS Bus	TOTAL DG Connected & In Progress (MW)	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
R30-M1	Horner	B	2.30	3.28	0.70
A-34-T	Strachan	A7A8	0.43	0.64	0.66
80-M23	Fairchild	J	0.90	1.43	0.63
R30-M10	Horner	Y	4.28	6.88	0.62
55-M2	Finch	Y	5.30	9.47	0.56
53-M3	Bermondsey	B	0.66	1.34	0.50
80-M10	Fairchild	Y	1.30	2.66	0.49
R30-M2	Horner	Y	4.71	10.20	0.46
51-M25	Leslie	J	1.27	3.04	0.42
51-M23	Leslie	J	2.10	5.10	0.41
R29-M34	Rexdale	Q	0.50	1.43	0.35
35-M8	Fairbank	Z	1.32	3.86	0.34
35-M7	Fairbank	Y	1.35	3.98	0.34

DG penetration is growing rapidly, as an additional ten feeders are approaching the one-third limit (as shown in Table 8). These numbers do include the forecasted 626 MW of additional DG capacity anticipated by the year 2019. This four-fold increase in DG penetration will further exacerbate the existing islanding risks. This will adversely affect Toronto Hydro's ability to safely and reliably connect additional DG to the distribution system and could ultimately lead to an increase in declined applications for connections if not addressed by proactive investments into control and monitoring capabilities.

TABLE 8: FEEDERS WITH GENERATION TO LOAD RATIO APPROACHING THE ONE-THIRD REQUIREMENT

Feeder Name	TS Station Name	TS Bus	TOTAL DG Connected & In Progress (MW)	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
A-14-BN	Basin	A5A6	0.29	1.00	0.29
38-M4	Manby	F	0.35	1.31	0.27
85-M4	Bathurst	B	1.00	3.89	0.26
63-M6	Agincourt	Y	1.59	6.79	0.23
55-M23	Finch	J	0.99	4.49	0.22
63-M4	Agincourt	Y	0.72	3.25	0.22
53-M11	Bermondsey	B	0.38	1.72	0.22

Feeder Name	TS Station Name	TS Bus	TOTAL DG Connected & In Progress (MW)	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
35-M23	Fairbank	B	0.47	2.25	0.21
53-M5	Bermondsey	B	0.68	3.35	0.20
11-M1	Runnymede	Y	0.55	2.71	0.20

System Thermal Limits and Load Transfer Capability

Protection, monitoring and control upgrades also provide the ability to connect additional DG by ensuring system thermal thresholds are satisfied. Exceeding system thermal limits sacrifices the life of distribution equipment and can cause immediate equipment failure.

For large generation or aggregated generation connections, an important operating condition is the limit of a feeder's continuous load thermal ratings. Feeder planning and operation considers the system impact when the generator is up and running as well as when the units go off-line. These thermal levels come into play with such factors as the variability of various generation sources, system load growth and the occurrence of contingencies. The ability to provide monitoring and control allows Toronto Hydro to monitor and mitigate the thermal levels issue.

Toronto Hydro's existing SCADA system has been configured to allow for the basic monitoring and control of DG sites in Toronto Hydro's distribution system. However, the current backend system was not intended to accommodate the volume of existing and forecasted DG sites. Without system upgrades, Toronto Hydro could lack the necessary situational awareness to safely and efficiently manage DG across the system. To avoid this situation, it is vital to enable the remote monitoring and control of DG sites.

In Toronto Hydro's experience, load displaced by DG has been increasing over the past five years and, as previously discussed, is forecasted to continue increasing at a relative rapid pace. In order to stay abreast of this increase, the GPMC program will provide Toronto Hydro's power system controllers with real-time information concerning DG status and output. Toronto Hydro power system controllers are on duty 24/7 to monitor the distribution system and take immediate corrective actions when emergencies occur. Specifically, they need to have both real-time information on the status and output of DG sites as well as the load connected to any specific distribution feeder.

In case of a distribution system emergency, such as an interruption, occurring on a feeder that has multiple DG sites connected to it, power system controllers need to know the extent of the affected load in order to safely direct the load restoration to the affected customers. Currently, if an emergency occurs on a feeder, power system controllers rely on the feeder loading information provided by the SCADA system to determine the restoration procedure and feeder configuration. With the proliferation of DG, it will likely be necessary to shut down, or transfer, the DG for safety or technical reasons. In addition to the system loads, power system controllers will need to take the aggregate DG capacity into considered in the decision making process for assessing options to restore the interrupted load through other available feeders.

By way of an example, prior to an outage, the net feeder load on a given feeder was 5 MW because the aggregate connected DG was serving 5 MW of the total customer load of 10 MW. The standby feeder requirement for restoring the load in case of an interruption would therefore be 5 MW, as this represents the net load. Following an outage, however, the generation disconnected for a period of time, causing the net load to surge up to 10 MW; the load then settled back down as the generator sources began to reconnect. Identifying spare feeder capacity and restoring a net load of 5 MW can be more readily achieved as compared to the gross load value of 10 MW. The range of power flows will need to be clearly understood and visible to power system controllers to provide the necessary feedback on the state of the system.

The hurdles and pressures that Toronto Hydro faces for integrating DG system wide can be effectively mitigated through monitoring and control. Monitoring and control can alleviate the risks associated with DG for the public and Toronto Hydro field personnel. The Electrical Safety Authority (ESA) Bulletin DSB-07/11, dated August 17th, 2011, outlines a real-world situation where an inverter failed to disconnect and started to back feed into the local distribution system.

> "The Ontario Electrical Safety Code (OESC) rule 84-008 requires a distributed generation system to automatically disconnect electric power production sources when there is a loss of power from the supply authority. In the case of this near miss incident, the solar inverter's "anti-islanding" feature failed to fully disconnect the energy produced from the PV system."

This situation poses a serious potential safety risk to the public, Toronto Hydro workers, and the system in general. If the anti-islanding feature of a DG were to fail, as it did in this situation, the DG would backfeed into the local distribution system, which could potentially pose a safety risk to the public and Toronto Hydro field personnel. Active monitoring and control systems help Toronto

Hydro avoid this situation by automatically issuing an electronic trip/shutdown command when the feeder breaker is opened.

Toronto Hydro takes its responsibility to minimize the level of risk associated with work very seriously. Field personnel wear Personal Protective Equipment (PPE), such as safety gloves, glasses, and boots, but these items represent the last stage of worker protection. In addition to physical disconnection, remote tripping is an additional level of protection for Toronto Hydro field personnel. Automated and remote tripping will add an additional level of protection making it safer to perform work by eliminating the hazard. Refer to Figure 12 outlining the effectiveness of work barriers.

FIGURE 12: EFFECTIVENESS OF WORK BARRIERS

Power system controllers will have the status and state of all DG, either reporting in to the control room or forecasted, and use this information to help the decision making process during planned work and emergency situations.

The real-time monitoring and control investments proposed within this program will be deployed at every DG site to address system thermal limits and load transfer capabilities.

Table 9 provides a summary of the proposed GMPC program and the respective issues addressed. Toronto Hydro anticipates that successful implementation of the GPMC program, in

addition to the successful completion of HONI capacity upgrade investments, will allow for system-wide capacity availability for DG connection, as depicted in Figure 13 below.

TABLE 9: SUMMARY OF GPMC PROGRAM ISSUES ADDRESSED

Technology	Issue(s) Addressed	Result	Location(s)
Advanced Protection System	x Short Circuit Capacity x Anti-Islanding Condition for Distributed Generators x System Thermal Limits and Load Transfer Capability	› Ability to connect inverter based DG within constrained area	x Leslie TS x Basin TS x Wiltshire TS
Bus Tie Reactor	x Short Circuit Capacity	› Ability to connect DG within constrained area	x Richview TS
Monitoring & Control System	x Anti-Islanding Condition for Distributed Generators x System Thermal Limits and Load Transfer Capability	› Ability to connect additional DG in the distribution system	x Distribution system-wide

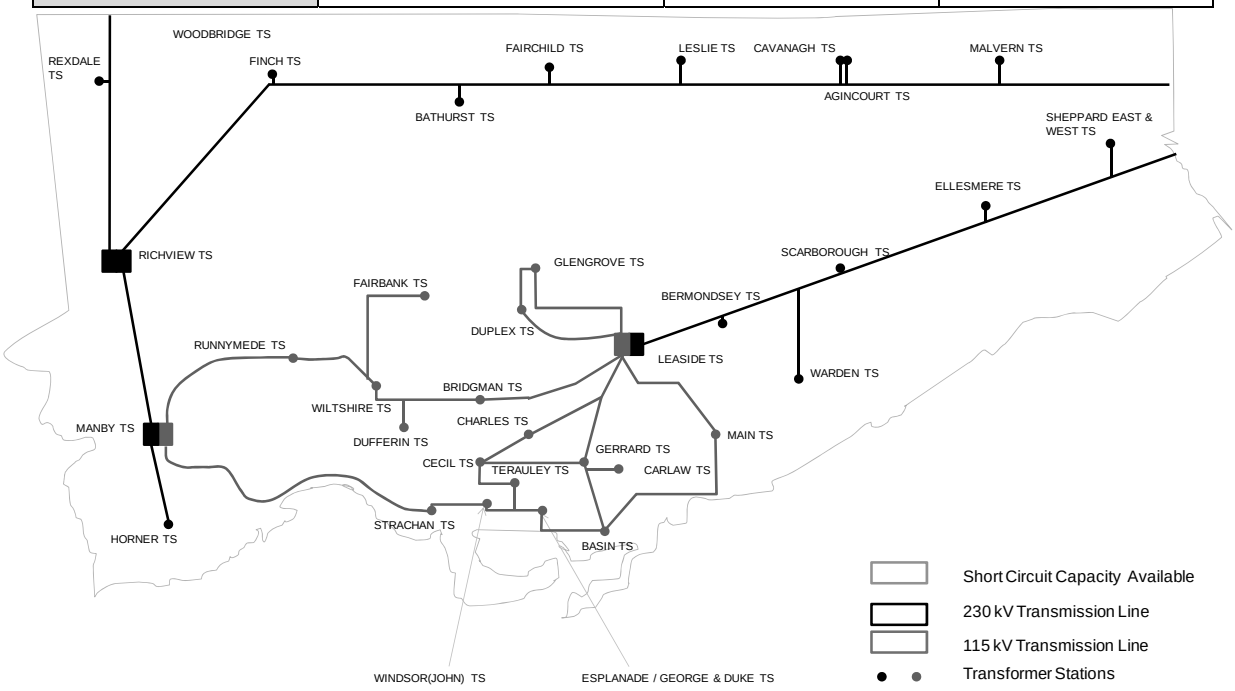


FIGURE 13: DISTRIBUTION SYSTEM AVAILABLE CAPACITY MAP FOR AFTER GPMC PROGRAM

E5.5.4 Timing & Pacing of the Program

The GPMC program is projected to cost $18.69 million over the 2015 to 2019 period. In order to prevent the rejection of DG connections, the installation of advanced protection systems, a bus-tie reactor at Richview TS, and monitoring and control equipment will commence in 2015. As it stands today, Toronto Hydro would not be able to connect customers at Basin TS, Leslie TS, Wiltshire TS, and Richview TS without the advanced protection systems and the bus-tie reactor. In addition, the absence of monitoring and control for DG sites will prevent Toronto Hydro from having real-time situational awareness of the operating conditions of DG sites in the distribution system. This information is vital in ensuring that the forecasted DG connections do not approach or exceed the minimum load, capacity limit, or short circuit constraint. If any portion of the program is delayed or denied, Toronto Hydro's ability to connect customer DG projects could be constrained, which could ultimately lead to an increase in the rejection of DG connections. /C

Toronto Hydro plans to install monitoring and control equipment for existing DG sites from 2015 to 2016 at a rate of 75 units per year. Toronto Hydro plans to install the remaining 73 units in 2017. In parallel, monitoring and control equipment for the new DG sites are planned for installation at a rate of 205,120,128,140 and 152 units per year until 2019 (based on the DG Connections Forecast from Section E5.5.1). Finally, work required for the backend infrastructure necessary to accommodate the remote management of DG sites is planned to be initiated in 2015 and conclude in 2016. Vendor support and maintenance for the backend system is planned to begin in 2016 through to 2019. A yearly breakdown of these costs is provided in Table 10 below. /C

TABLE 10: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	-	-	-	-	-	$6.12	$5.19	$3.26	$2.10	$2.02

/C

E5.5.4.1 Ranking & Prioritization

In 2015, Toronto Hydro plans to initiate work involving advance protection systems at Leslie, Basin and Wiltshire TS and a bus tie reactor at Richview TS. These locations have been identified as priorities due to their limited short circuit capacity. Without completing this work, Toronto Hydro will not be able to connect DG sites to these stations. These projects address the immediate need for capacity and short circuit relief to enable the connection of DG sites.

Between 2015 and 2017, Toronto Hydro plans to retrofit 223 existing DG sites that presently do not have monitoring and control. These DG sites have already been commissioned and are active on the distribution system, which allows for immediate scheduling into the work program. As these sites are already operational, it is imperative to have the monitoring and control equipment installed as Toronto Hydro does not have any situational awareness into the operating conditions of these DG sites. The recent proliferation of DG and the rising penetration levels and continues to exacerbate the present situation. The proposed work is planned to be completed at a pace of 75 units per year and will begin with the DG sites that have the largest nameplate value. This is due in part to labour resource availability and the connection of new DG sites. As mentioned in Section E5.5.5.3, Toronto Hydro is dependent on the DG project/site owner to co-ordinate resources for the installation and commissioning of monitoring and control equipment, which complicates work program scheduling. Due to the dependency on DG project/site owners, Toronto Hydro plans to complete the work on an ad-hoc basis. Toronto Hydro expects to connect approximately 745 new DG projects per year from 2015 through 2019 according to the DG connection forecast from Section E5.4.1. /C

E5.5.5 Program Execution

Projects are listed in Section E5.5.8 and outline the work required in order to install advanced protection systems at Leslie, Basin and Wiltshire TS and install the bus-tie reactors at Richview TS. Projects will be created for the installation and commissioning of monitoring and control equipment at DG sites, once the customer/site owner has informed Toronto Hydro that the project is ready for commissioning. Due to the unique nature of each project, the timelines to complete work will vary from site-to-site. This would not apply for sites that require retrofitting for monitoring and control, as they have already been commissioned. Finally, work related to the backend infrastructure necessary to accommodate the remote management of DG sites is planned to occur in parallel with the field work mentioned above.

E5.5.5.1 Proposed Work Plan

Table 11 outlines the entire proposed work plan from 2015 through to 2019.

TABLE 11: 2015-2019 LONG TERM PLAN

Year	Project	Station
2015	Advance Protection System – Basin TS	Basin TS
2015	Advance Protection System – Leslie TS	Leslie TS
2015	Advance Protection System – Wiltshire TS	Wiltshire TS
2015	Bus Tie Reactor - Richview TS	Richview TS

Year	Project	Station
2016 – 18	Advance Protection System – Basin TS	Basin TS
2016 – 17	Advance Protection System – Leslie TS	Leslie TS
2016 - 19	Advance Protection System – Wiltshire TS	Wiltshire TS
2016 - 17	Bus Tie Reactor - Richview TS	Richview TS
2015	Monitoring &Control Retrofit DG Sites – Phase 1	Entire distribution system
2015	Monitoring &Control New DG Sites – Phase 1	Entire distribution system
2016	Monitoring &Control Retrofit DG Sites – Phase 2	Entire distribution system
2016	Monitoring &Control New DG Sites DG – Phase 2	Entire distribution system
2017	Monitoring &Control Retrofit DG Sites – Phase 3	Entire distribution system
2017	Monitoring &Control New DG Sites – Phase 3	Entire distribution system
2018	Monitoring &Control New DG Sites – Phase 4	Entire distribution system
2019	Monitoring &Control New DG Sites – Phase 5	Entire distribution system

E5.5.5.2 Program Risks

The risks associated with the installation and commissioning of bus tie reactors and upgrades to TS protection systems include:

- Limited technical labour resources to install both systems,
- Conflicting timing and inability to coordinate with other capital projects and planned maintenance work of station assets, and
- Transferring existing customer loads to standby feeders.

Advance planning between relevant Toronto Hydro departments will help address issues and constraints related to labour availability and general capacity. Planning this work during off-peak periods will mitigate potential impacts to standby feeders.

E5.5.5.3 External Constraints

Toronto Hydro station upgrades focus on areas with short circuit constrained stations and buses. Resolving the issues will depend on the co-ordination between HONI and Toronto Hydro, to ensure any planned work will not interfere with current or planned capital work initiated by each party. Toronto Hydro must also rely on the DG project/site owner to co-ordinate resources for installation and commissioning activities. Due to the unique nature of every project, the timelines to complete work will vary from site-to-site. To address this variability Toronto Hydro plans to

inform project/site owners, at the beginning of each project, and to provide notice of any work related to commissioning.

E5.5.5.4 Standard & Regulation Adherence

The proposed program will incorporate Toronto Hydro Conditions of Service, Distributed Generation Requirements, and Distribution System Planning Guidelines. These requirements adhere to industry standards such as IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems, CSA C22.3 No. 9 Interconnection of distributed resources and electricity supply systems and CSA C22.2 No. 257 Interconnecting inverter-based micro-distributed resources to distribution systems.

Integrating customer owned DG in accordance with Toronto Hydro requirements should ensure that system needs are satisfied including protection criteria as well as monitoring and control standards as posted on Toronto Hydro website. The interconnecting DG sources must adhere to Toronto Hydro's standards and regulations to ensure integrity of the distribution grid.

E5.5.5.5 Renewable Energy Generation

As of June 2014, Toronto Hydro's customers have enquired about connecting over 600 MW of inverter-based PV systems and synchronous generation through pre-assessments. As a result of current restrictions, however, applicants may not be approaching Toronto Hydro in areas where project developers know that system constraints preclude connections. Toronto Hydro therefore anticipates that future applications may increase markedly once existing constraints have been addressed and lifted. As such, Toronto Hydro anticipates over 626 MW of distributed generation interconnections on the distribution system.

E5.5.6 Evaluation of Alternatives

E5.5.6.1 Quantification/Evaluation of Options

As mentioned earlier, Toronto Hydro is mandated by Section 6.2.4 of the DSC to connect DG to the distribution system. In order to comply with section 6.2.4, Toronto Hydro evaluated two alternatives for addressing the system constraints that currently limit the utility's ability to connect the growing amount of DG on the system and safely and reliably manage DG connected to the distribution system. These options are explained in detail below.

(i) Major Asset Upgrades, Monitoring and Control (MAUMC)

Rather than execute the GPMC program as described throughout this program narrative, Toronto Hydro could choose to perform major asset upgrades at Leslie, Wiltshire, and Basin TS. Assets to be upgraded include power transformers and switchgear. Monitoring and control equipment would also be installed as part of this option. The work associated with this option would allow for the continued integration, expanded visibility, and automated monitoring and control of DG connected to the Toronto Hydro distribution system beginning in 2017 through 2019 and beyond. The major assets associated with this program have 1-2 year material lead-times, on top of the 1 year required for installation. The entire process may take up to five years. Since Toronto Hydro does not own any of the major assets, it would have to request that HONI perform the upgrades. Because these upgrades would be outside of HONI's planning cycle, Toronto Hydro would have to pay for the upgrades instead of letting HONI replace the assets when required at no cost. This option would help alleviate the issues related to connecting DG to the distribution system, as mentioned in Section E5.5.2; however Toronto Hydro estimates the total cost for this option would be approximately $54.09 million to ratepayers over the 2015 to 2019 period, compared to an estimated $18.69 million for the option outlined in this program narrative. The estimated net present value (NPV_1) of this option is -$47.08 million. /C /C

(ii) Generation Protection, Monitoring and Control (GPMC)

The planned GPMC program would allow for the continued integration, expanded visibility, and monitoring and control of DG connected to the Toronto Hydro distribution system beginning in 2015 through 2019 and beyond. In addition to enabling the integration of DG sites and providing expanded visibility, Toronto Hydro expects that it would have the ability to predict the amount of generation produced by DG connected to the distribution system. This program would help alleviate the issues related to connecting DG to the distribution system, mentioned in Section E5.5.2. The overall cost of this option is $18.69 million over the 2015 to 2019 period.

The cost of ownership of each option is established for both the existing state (COO_E) and the proposed new state (COO_{N2}) based on the planned activities within this program, as shown in Tables 12 to 14. The cost of ownership (COO_{N2}) of a state reflects the risk of asset failure including both direct and indirect costs. These costs include customer interruptions, emergency repairs, and asset replacements associated with a given design. All of these factors combine to form the COO_{N2} for each option. For further details on the COO_{N2} approach, please refer to Section D3.3. The options considered are modeled over a 5-year period due to the fact that both

upgrading the power transformer in option 1 and the installation of bus-tie reactors as part of the proposed program in option 2 will require multiple years for implementation. In addition, the benefits of these options can only be realized once the total work has been completed. As such, the evaluation of the benefits must also be carried over the five year period as opposed to the first year of execution as in the traditional methodology explained in Section D3. When the difference in cost of ownership (ûCOO$_2$) is compared to the associated program costs (PC$_2$), the preferred GPMC program produces an NPV$_2$ of -$18.11 million.

Options (i) and (ii) are the only feasible options for Toronto Hydro to continue accommodating additional DG connections during the 2015-2019 period. When comparing the NPV's of each option, both account for the installation of new assets in order to mitigate the risk of not being able to connect DG customers to our system. Toronto Hydro's inability to connect new DG would violate the DSC's specifications that the utility make a reasonable effort to connect all DG customers and would result in a lack of responsiveness to public policy regarding the expansion of distributed generation in Ontario. Neither of these risks could be translated into a quantifiable metric within this business case exercise, and therefore both options have negative net benefits. In this instance, Toronto Hydro plans to proceed with the least negative option, which is also the most cost-efficient option and the option that will deliver the most value to customers in Toronto and province-wide.

TABLE 12: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR$_E$]	$7.17
Non Asset Risk [NAR$_E$]	
Maintenance Cost [MC$_E$]	
Additional Quantifiable Benefits [AQB$_E$]	
Cost of Ownership of Existing Assets [COO$_E$]	$7.17

1 **TABLE 13: MAUMC BUSINESS CASE EVALUATION (BCE)**

Business Case Element	Cost (in Millions)
Option 1: Major Asset Upgrades, Monitoring and Control (N1)	
Asset Risk [AR_{N1}]	$0.16
Non Asset Risk [NAR_{N1}]	
Maintenance Cost [MC_{N1}]	
Additional Quantifiable Benefits [AQB_{N1}]	
Cost of Ownership of New Assets [COO_{N1}]	$0.16
Option 1: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_{N1})$]	$7.00
Program Cost [PC_1]	$54.09
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	$-47.08

/C
/C

2 **TABLE 14: PMC BUSINESS CASE EVALUATION (BCE)**

Business Case Element	Cost (in Millions)
Option 2: Generation Planning, Monitoring and Control (N2)	
Asset Risk [AR_{N2}]	$9.88
Non Asset Risk [NAR_{N2}]	
Maintenance Cost [MC_{N2}]	
Additional Quantifiable Benefits [AQB_{N2}]	
Cost of Ownership of New Assets [COO_{N2}]	$9.88
Option 2: Program Net Benefit (NPV_2)	
Difference in Cost of Ownership [$\hat{u}COO_2 = (COO_E - COO_{N2})$]	-$2.71
Program Cost [PC_2]	$18.69
Program Net Benefit [$NPV_2 = (\hat{u}COO_2 - PC_2)$]	-$21.40

/C
/C

E5.5.7 2015 Projects

Table 15 lists all projects that Toronto Hydro Plans to partially or completely execute as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015.

TABLE 15: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date	
E31556	Basin TS A7A8 Bus	$159,457	2015	/C
E31558	Leslie BY Bus	$212,609	2015	/C
E31559	Wiltshire A3A4 Bus	$382,696	2015	/C
E31560	Richview BY Bus	$31,891	2015	/C
E31561	M&C DG Retrofit – Phase 1	$1,071,548	2015	/C

E5.5.7.1 E31556 Project Description

Investment Category: System Access

Program: Generation Protection, Monitoring & Control

Project Title: Basin TS A7A8 Bus

Project Number: E31556

Project Year: 2015

Estimated Cost: $159,457 /C

(i) Objective

To enable inverter based renewable energy connections to connect onto the distribution grid.

(ii) Project of Work

The scope of work involves the interfacing and commissioning of gateway devices to microprocessor-based feeder protection relays for all station breakers on the Basin TS A7A8 bus. The protection relays will be interconnected through a gateway network system that will interface with the customer DG system. It will serve the purpose of providing transfer trip protection as well as monitoring and control functionality.

TABLE 16: E12345 PROJECT OF WORK DETAILS

District Neighbourhood	CENTRAL & DOWNTOWN TORONTO
Station(s)	BASIN TS
Feeder(s)	A17BN, A19BN, A25BN, A27BN, A29BN

TABLE 17: E12345 ASSETS REPLACED

Assets (Units)	2015
Fibre Optic cable	4 km
Gateway Interface	5 units

(iii) Justification & Benefits

With the presently proposed DG connections there will be no further capacity available to connect renewable energy generation. The anticipated benefits include integration of a proposed 10MW biogas plant as well as future opportunities of solar PV connections.

E5.5.7.2 E31558 Project Description

Investment Category: System Access

Program: Generation Protection, Monitoring & Control

Project Title: Leslie BY Bus

Project Number: E31558

Project Year: 2015

Estimated Cost: $212,609 /C

(i) Objective

To enable inverter based renewable energy connections to connect onto the distribution grid.

(ii) Project of Work

The scope of work involves the installation and commissioning of microprocessor-based feeder protection relays at all station breakers on the Leslie TS BY bus. The protection relays will be interconnected through gateway network system that will interface with customer DG systems. It will serve the purpose of providing transfer trip protection as well as monitoring and control functionality.

TABLE 18: E31558 PROJECT OF WORK DETAILS

District Neighbourhood	UPTOWN
Station(s)	LESLIE TS
Feeder(s)	51M5, 51M7

TABLE 19: E31558 ASSETS REPLACED ASSETS (UNITS)

Assets (Units)	2015
Feeder Protection Relays	2 units
Fibre Optic cable	5 km
Gateway Interface	2 units

(iii) Justification & Benefits

With future DG connections there will be no further capacity available to connect renewable energy generation. The benefits include integration of solar PV connections.

E5.5.7.3 E31559 Project Description

Investment Category: System Access

Program: Generation Protection, Monitoring & Control

Project Title: Wiltshire A3A4 Bus

Project Number: E31559

Project Year: 2015

Estimated Cost: $382,696

/C

(i) Objective

To enable inverter based renewable energy connections to connect onto the distribution grid.

(ii) Project of Work

The scope of work involves interfacing and commissioning of gateway devices to microprocessor-based feeder protection relays for all station breakers on the Wiltshire TS A3A4 bus. The protection relays will be interconnected through a gateway network system that will interface with the customer DG system. It will serve the purpose of providing transfer trip protection as well as monitoring and control functionality.

TABLE 20: E31559 PROJECT OF WORK DETAILS

District Neighbourhood	CENTRAL & DOWNTOWN TORONTO
Station(s)	WILTSHIRE TS
Feeder(s)	A25W, A26W, A27W, A36W, A37W, A38W, A39W,A42W, A43W

TABLE 21: E31559 ASSETS REPLACED

Assets (Units)	**2015**
Fibre Optic cable	6 km
Gateway Interface	9 units

(iii) Justification & Benefits

With future DG connections there will be no further capacity available to connect renewable energy generation. The benefits include interconnection protection monitoring and control of solar PV connections.

E5.5.7.4 E31560 Project Description

Investment Category: System Access

Program: Generation Protection, Monitoring & Control

Project Title: Richview BY Bus

Project Number: E31560

Project Year: 2015

Estimated Cost: $31,891

/C

(i) Objective

To enable inverter based renewable energy connections to connect onto the distribution grid.

(ii) Project of Work

The scope work involves working with HONI to design and implement and bus-tie reactor suitable to lower the bus fault levels such that DG will be enabled to connect.

TABLE 22: E31560 PROJECT OF WORK DETAILS

District Neighbourhood	UPTOWN TORONTO
Station(s)	RICHVIEW TS BY BUS
Feeder(s)	88M1, 88M3, 88M8

TABLE 23: E31560 ASSETS REPLACED

Assets (Units)	**2015**
Bus Tie Reactor Design	1 unit
Isolation switches	2 units

(iii) Justification & Benefits

With future DG connections there will be no further capacity available to connect renewable energy generation. The benefits include enabling DG interconnections. There have been projects proposed for solar PV interconnection which had to be turned down due to no available short circuit capacity.

E5.5.7.5 E31561 Project Description

Investment Category: System Access

Program: Generation Protection, Monitoring & Control

Project Title: M&C DG Retrofit – Phase 1

Project Number: E31561

Project Year: 2015

Estimated Cost: $1,071,548

/C

(i) Objective

Phase one deals with the retrofit of 75 existing DG sites with monitoring and control equipment.

(ii) Project of Work

The scope of work involves the installation and commissioning of monitoring and control equipment and existing DG sites. The DG site will interface with Toronto Hydro's Control room via a private communication network and existing Toronto Hydro SCADA system. It will serve the purpose of providing monitoring and control functionality.

TABLE 24: E31561 PROJECT OF WORK DETAILS

District Neighbourhood	THROUGHOUT TORONTO HYDRO'S SERVICE TERRITORY
Station(s)	VARIOUS
Feeder(s)	VARIOUS

TABLE 25: E31561 ASSETS REPLACED

Assets (Units)	**2015**
Monitoring and Control Equipment	75

(iii) Justification & Benefits

There are 223 existing DG sites that do not have monitoring and control capabilities. This makes it more difficult for Toronto Hydro to safely and effectively manage the DG connected to the distribution system. In addition, this can prevent Toronto Hydro from connected additional DG to the distribution system. The addition of monitoring and control equipment to existing DG sites will

enable power system controllers to have situational awareness into the operating conditions of DG in the distribution system.

This project represents the first phase deals with the completion of 50 DG sites for 2015.

The System Renewal investment programs detailed within this section serve to target and replace these worst-of-the-worst overhead, underground, secondary network and stations assets. Table 1 describes the primary drivers for capital investments in this category.

TABLE 1: TRIGGER DRIVERS FOR SYSTEM RENEWAL CATEGORY

Driver	Description
Failure Risk	ƒ There is the imminent risk of asset failure due to age or condition deterioration
Functional Obsolescence	ƒ The asset/asset installation is no longer aligned to Toronto Hydro processes and practices such that it can no longer be maintained (e.g., lack of spare parts, lack of accessibility or operational constraints) or utilized as intended in the distribution system
Failure	ƒ Failures have already taken place that Toronto Hydro must reactively respond to as part of capital investment activities.

Table 2 provides a brief description for each investment program within the System Renewal narrative along with total expenditures for each program from 2015 onwards to 2019. Individual section numbers for each investment program are also provided in this table.

TABLE 2: BRIEF DESCRIPTION OF SYSTEM ACCESS INVESTMENT PROGRAMS

Program Index and Name		Brief Description	Total (5 years)
E6.1	Underground Circuit Renewal	Replace end-of-life and obsolete underground assets with new ones on a "like-for-like" basis. The assets include switches, transformers, and cables. Replacing the assets will help improve system reliability and efficiency.	$459 M
E6.2	Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers	Program will address two issues related to underground PILC cable. PILC cables are aging and a number have developed cracks and pinholes and will either be replaced or repaired. The program will also increase cable length to address unsafe congested areas and allow the cables to be safely and properly routed.	$7 M
E6.3	Underground Legacy Infrastructure	Targets non-standardized equipment that is at or near end-of-life and poses a failure risk. Many of these assets are now obsolete and will be replaced with standardized equipment, helping to improve safety and system reliability.	$27 M

Program Index and Name		Brief Description	Total (5 years)
E6.4	Overhead Circuit Renewal	Focuses on replacing poles, switches, transformers, overhead accessories and street lighting assets that are either aged, in poor condition, or functionally obsolete on a "like-for-life" basis. Toronto Hydro expects the program to mitigate significant sources of outages that negatively impact service reliability to customers and may pose potential safety risks for employees and the general public.	$147 M
E6.5	Overhead Infrastructure Relocation	Provide a modern and efficient configuration to replace feeders that are past end-of-life and functionally obsolete from a design perspective to mitigate the number of system outages. Feeders will be relocated to eliminate difficult-to-access overhead plant, overhead egress plant and overhead plant crossing highways.	$10 M
E6.6	Rear Lot Conversion	This program replaces the existing, end-of-life rear lot distribution service configuration with an underground front lot access system to eliminate challenges in performing maintenance activities and to mitigate the increased risk of long duration outages inherent in the existing plant design. The conversion eliminates operational constraints and reduces the safety and reliability risks associated with this obsolete connection configuration.	$59. M
E6.7	Box Construction Conversion	This program transitions customers from functionally obsolete 4.16 kV box construction feeders to the current standard 13.8 kV or 27.6 kV overhead infrastructure. By eliminating box construction feeders, Toronto Hydro anticipates that the program will reduce safety concerns for crew members dealing with restricted working spaces, improve restoration times and mitigate costs related to load capacity constraint when connecting new customers in the downtown area.	$103 M
E6.8	SCADA-MATE R1 Replacement	This program replaces malfunctioning switches. Moisture has caused internal switch components to corrode. The corrosion poses significant potential safety hazards for the public and Toronto Hydro employees due to misrepresentation of the switch state, preventing core functions of the switch from being used. The new R2 design will improve remote functionality and reliability of the switch, thereby reducing prolonged outages and failure risk for customers.	$13 M

Program Index and Name		Brief Description	Total (5 years)
E6.9	Network Vault Rebuild Program	Rehabilitation of vaults that were identified to be high-risk to protect the assets that are housed within and to eliminate potential safety hazards for crews, pedestrians and emergency response crews in busy downtown areas. Rehabilitation options include decommissioning the vaults, rebuilding the vault roofs, or rebuilding the entire vault.	$45 M
E6.10	Network Unit Renewal Program	Replacement of obsolete and poor condition Network Units that are at risk of failure with new submersible Network Units. Toronto Hydro anticipates that this program is expected to increase service reliability, improve employee safety and reduce environmental concerns by mitigated oil leaks.	$34 M
E6.11	Legacy Network Equipment Replacement (ATS & RPB)	Replacement of automatic transfer switches (ATSs) and reverse power breakers (RPBs) with manual secondary switches, stand alone network protectors (SANPs), or network units. The ATSs and RPBs are no longer supported by their original manufacturer, making it difficult to comply with prudent maintenance practices and policies. These assets are also not submersible by design and are subject to a high risk of equipment failure.	$5 M
E6.12	Network Circuit Reconfiguration	Reconfiguration of the functionally obsolete network system by splitting a large secondary grid into enhanced mini grids. Increasing grid flexibility will enhance its ability to supply new classes of customers, to operate under different contingency events and decrease the necessity to drop the entire network during failure.	$9 M
E6.13	Stations Switchgear Renewal	Replacement of existing switchgears that have become functionally obsolete and that have passed the end of their useful lives. The existing non-arc resistant switchgear at municipal stations and transformer stations will be replaced with type C, arc resistant switchgear with vacuum circuit breakers.	$106 M
E6.14	Stations Power Transformer Renewal	Replacement of power transformers located at municipal stations across the city to mitigate the failure risk of prolonged outages due to assets at the end of their useful lives. This program will directly benefit customers connected to the transformers identified for replacement by reducing outage risk and increasing system reliability in their respective areas.	$12 M

Program Index and Name		Brief Description	Total (5 years)
E6.15	Stations Circuit Breaker Renewal	Replacement of obsolete oil circuit breakers, which are no longer supported by manufacturers, with stand-alone vacuum circuit breakers. Vacuum circuit breakers are cheaper to maintain and are less likely to fail catastrophically.	$9 M
E6.16	Stations Control & Monitoring	This program aims to replace aging and obsolete remote terminal units (RTUs) and install SCADA systems at substations with no SCADA capabilities. Existing RTUs and radio communications networks at Etobicoke MS and downtown Toronto TS will be replaced while modern SCADA systems at Scarborough MS will be installed.	$5 M
E6.17	Stations Ancillary Systems	Replacement of end-of-life and outdated ancillary systems (air compressors, station service power supply systems, fire alarm systems, and fire barriers) that are at risk of failure and functionally obsolete with more reliable modern technologies.	$2 M
E6.18	Stations Buildings	This program focuses primarily on the structural integrity of eleven TS and MS buildings in which electrical stations assets are housed. The program takes a proactive approach to improve existing station buildings to extend their serviceable lives. Toronto Hydro anticipates that this will help ensure uninterrupted service, protect the safety of crews and the public, and ensure the integrity of nearby customer property.	$11 M
E6.19	Stations DC Battery Replacement	Replacement of end-of-life DC batteries and chargers systems with new ones at various stations locations to mitigate battery failure risk and ensure faults are isolated to the local feeder. These batteries are used to provide the necessary power supply to operate the associated circuit breaker assets if the main power supply to the entire station is lost.	$3 M
E6.20	Reactive Capital	Accounts for unplanned, non-discretionary capital expenditures required to repair or replace assets. With proper budgeting and resource allocation, timely reactive work improves safety, reduces the backlog of assets to be maintained, avoids depriving other capital programs of planned resources and reduces strain on the distribution system.	$166 M

Program Index and Name		Brief Description	Total (5 years)
E6.21	Worst Performing Feeder	This program analyses the performance of feeders that are at risk of seven or more outages in a year and determines the root cause of the outage trend. Condition of the equipment will be assessed during feeder patrols and appropriate mitigation work will be performed to alleviate outages caused by design or environmental disturbances. The program improves the reliability of feeders, minimizes power outages for customers experiencing especially poor service, and mitigates the risk of additional asset failures.	$8 M
E6.22	Distribution System Communication Infrastructure	This program renews and improves the telecommunications system by identifying gaps in the communication service platform, updating the obsolete SONET technology and SCADA infrastructure. An updated telecommunication system reduces failure risk an provides safe, efficient and reliable supply of electricity to customers.	$16 M

The following Sections E6.1 though to E6.23 contain the details and justification for each capital investment program within the System Renewal investment category.

E6.1 Underground Circuit Renewal

INSTALLING NEW SUBMERSIBLE BUILDING VAULT SF6-INSULATED SWITCH

E6.1.1 Summary

Program Description

The Underground Circuit Renewal program replaces end-of-life and obsolete assets that contribute to the deterioration of system reliability. The program is a continuation of activities previously described in the OEB approved Underground Infrastructure segment as part of Toronto Hydro's 2012-2014 IRM/ICM rate application.

The Underground Circuit Renewal program replaces three assets types: underground switches, transformers and cables. These assets are primary components of an underground distribution system, and degrade due to age and exposure to harsh field environments. Proactive renewal is needed to ensure that reliability, safety and environmental risks are properly mitigated.

The anticipated benefits of the Underground Circuit Renewal program are as follows:

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Installing newer assets allows for reduced customer disruption in the event of an outage ƒ Improved neighborhood aesthetics depending on the age and condition of existing assets
Reliability	Proactively replacing assets with a high risk of failure is expected to: ƒ Reduce customers interruptions ƒ Mitigate safety risks to employees ƒ Minimize reactive repair costs
Safety	ƒ Minimize safety related issues due to flashovers (seen with pad-mounted and submersible switches and non-switchable submersible transformers). ƒ Minimize the risk associated with dig-ins of direct buried cables and cables in direct buried PVC ducts.
Efficiency	ƒ Improved restoration time by replacing older and unreliable assets with modern equipment capable of remote sensing and operation (i.e. switchgear). ƒ Improved isolation of transformers without affecting power supply to customers on the rest of the distribution system. ƒ Faster cable replacement of underground cables due to the concrete encased duct infrastructure.
Other	ƒ Elimination of routine CO_2 washing used to maintain air insulated pad-mounted switches.

Program Drivers

The trigger and secondary drivers for the Underground Circuit Renewal program are:

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	Various combinations of external factors, including, but not limited to, dirt, salt, dust, moisture and humidity affect: ƒ all switch types, thereby accelerating the degradation to both the enclosure and internal components of the switch which in-turn increases their failure risk as the equipment ages in the field. ƒ all transformers, leading to cumulative corrosion on the enclosure, seals and gaskets resulting in compromised enclosure and oil integrity and inevitable failure of the unit. ƒ insulation integrity of XLPE cables; resulting in failure of underground cables regardless of their method of installation (direct buried or in duct for this particular cable type).
Secondary Drivers	Reasoning

Safety	The main safety concerns with the assets in the program include: ƒ arcing and flashover due to switches and transformers (and the harm it poses to field crews and the public) ƒ dig-ins due to unprotected direct buried cable and cable in direct buried duct. ƒ environmental safety concern includes SF6 gas leakage into the atmosphere due to vintage URD switches.
Functional Obsolescence	The inherent design flaws of the various assets targeted for replacement through this program include: ƒ live-front and open louver design of air-insulated switches (pad-mounted or building vault). ƒ live-front design of non-switchable submersible transformers. ƒ poor quality assurance and manufacturing standards of earlier generations of XLPE cable.

Preferred Alternative

Toronto Hydro evaluated the following options for the assets addressed in this program:

(1) Do nothing and replace on a reactive basis only

(2) Proactively replace these aged assets with new, standard equipment

Option II is the preferred option as it will best mitigate the risks associated with failure of the current, end-of-life assets.

The replacement of underground switches, transformers and cable in the first year of the program will result in an avoided risk cost (ARC) of $102.93 million, as detailed in Table 8. This value represents the avoided cost of executing the first year of activities as scheduled as opposed to deferring these activities until 2020. These avoided costs include quantified risks, taking into account the probability of failure of the assets and multiplying this figure by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement. Further details on the ARC approach is provided in Section D3.

Timing and Pacing

Table C provides a summary of the five year historical spending in the Underground Circuit Renewal program (or its equivalent) as well as projected spending from 2015 to 2019.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	108.4	90.3	53.8	68.8	108.1	96.0	80.1	84.0	99.7	99.5

Given that a high population of assets will be approaching the end of their useful lives in 2015, Toronto Hydro expects to maintain a level of investment similar to the forecasted 2014 magnitude throughout the 2015-2019 period. Minor fluctuations in the pacing of investment over the forecast period (e.g. the drop in spending in 2016 and 2017) will likely be required to facilitate other high-priority renewal and service investments in the underground system using similar resources. The proposed rate of investment in the Underground Circuit Renewal program will allow Toronto Hydro to prudently and proactively manage the significant backlog of end-of-life and poor condition underground assets, maintaining system reliability performance while enhancing customer value with the installation of more robust and reliable underground construction.

E6.1.2 Program Description

The Underground Circuit Renewal program replaces end-of-life and obsolete assets that contribute to the deterioration of system reliability. The program is a continuation of activities previously described in the OEB approved Underground Infrastructure segment as part of Toronto Hydro's 2012-2014 ICM application[1].

The program consists of three major underground asset classes: switches, transformers and cable. Each asset class is discussed in further detail in this section. These assets are primary components of an underground distribution system, and degrade due to age and exposure to harsh field environments. Over time, equipment will reach a point where failure risk accelerates and proactive renewal is needed to ensure that reliability, safety and environmental risks are properly mitigated. Reliability and environmental risks are discussed further in section E6.1.3.1 and safety risks are discussed further in section E6.1.3.2.

The estimated total capital budget for this program is $459.2 million for the 2015-2019 forecast period.

E6.1.2.1 Replacement of Underground Switches

Figure 1 shows a breakdown of the various types of switches used in Toronto Hydro's underground distribution system.

FIGURE 1: TORONTO HYDRO'S UNDERGROUND SWITCH BREAKDOWN

The switching assets targeted for replacement in this program are:

[1] EB-2012-0064.

- pad-mounted, air-insulated switches (referred to as "pad-mounted" for the remainder of the document),
- submersible oil-insulated switches (referred to as "oil-insulated" for the remainder of the document),
- submersible[2] vintage SF_6-insulated switches used only in the underground residential distribution (URD) system in downtown Toronto (referred to as "vintage URD" for the remainder of the document), and
- building vault, mini-rupter switches (referred to as "mini-rupter" for the remainder of the document).

Pad-mounted switches are prone to premature failure due to the louvers that allow ingress of air borne moisture and contaminants inside the switch cabinet. This is similar to the degradation process that affects mini-rupter switches. Corrosion and oil leakage cause oil-insulated switches to fail, resulting in a potentially catastrophic[3] failure (discussed further E6.1.3.1). As well, vintage URD switches are dated and known to have a gas leakage problem inherent to the former design of the bolted viewing window.

Given the failure risks associated with all switch types; and functional obsolescence of submersible switch types, all switches will be replaced with the new generation of SF_6–insulated switches. The new generation of switches has a stainless steel enclosure to prevent premature rusting and degradation of the cabinet. The unit consists of welded viewing windows that mitigate SF_6 gas leakage into the environment. As well, programmable relays are used instead of fuses for downstream circuit protection. This eliminates the need for on-site switch re-fusing after a fault on the branch circuit. The units also have internal grounding provisions making grounding easier and safer for crews in comparison to the external grounding elbows on the existing switches.

[2] "Submersible switch" will be used as a general term to refer to both oil insulated and vintage URD throughout this document.

[3] The terms 'catastrophic failure', 'fail catastrophically', and related forms, are used throughout the DSP programs presented in this Application. These terms refer to a mode of failure of an electrical distribution component in which incidental damage to other equipment and/or injury to a person occur or could occur, in addition to the loss of the electrical distribution function of the component itself. Arc flashes, fires, falling debris, and structural collapse are examples of catastrophic failure. Catastrophic failure is distinguished from failure by design and simple failure modes in which a component, such as a fuse, performs according to design to interrupt the flow of electricity.

The SF_6-insulated switches replacing the existing submersible (both oil-insulated and vintage URD) and building vault switches typically use a single, top operable switch positioned just below ground level. Due to the switches' construction, the vaults can be dry or subject to flooding. Figure 2 provides an example of the new pad-mounted SF_6-insulated switch that is used in Toronto Hydro's distribution system. Figure 3 provides an example of a typical SF6-insulated switch suitable for either submersible or above ground vaults.

FIGURE 2: NEW PAD-MOUNTED SF6-INSULATED SWITCH

FIGURE 3: NEW SUBMERSIBLE AND/OR BUILDING VAULT SF6-INSULATED SWITCH

It should be noted that the SCADA capability for remote sensing offered by the new SF_6 switches offers increased system efficiency. This improves restoration time in the event of a power failure while saving the cost associated with crews physically operating the switch on site.

Another advantage of pad-mounted SF_6-insulated switches is that it has the same circuit configuration and footprint as the existing pad-mounted units, thereby avoiding additional cable and civil construction work. As well, all external components of the SF_6-insulated switch are sealed. Therefore it is a low-maintenance asset and does not require costly, routine CO_2 washing to remove accumulated contaminants on the switch components which is commonly required for the existing pad-mounted switches.

E6.1.2.2 Replacement of Underground Transformers

Three types of transformers are used in Toronto Hydro's underground distribution system: below-grade submersible, pad-mounted and building vault.

Submersible transformers are installed in underground vaults that experience degradation mainly due to internal and external factors (details of which are discussed in section E6.1.3). Pad-mounted transformers installed outdoors experience degradation primarily due to external factors (i.e., dirt, water and ice). Vault transformers are installed in an indoor environment and experience degradation caused by contaminants trapped inside the building they are housed in (i.e. dust and moisture/humidity). Given the failure risk associated with each of the existing transformers in the field, they will all be replaced with units best suited for their existing applications.

Non-switchable submersible transformers will be replaced with new switchable submersible transformers that allow for isolation of the individual transformer vault without affecting power supply to customers on the rest of the distribution loop. All related transformer ancillary equipment (i.e. elbows and terminations) will be replaced with the non-switchable, submersible transformer to ensure compliance with Toronto Hydro's current transformer installation standard.

Replacing non-switchable submersible transformers with switchable submersible transformers allows for isolation of the individual transformer without affecting power supply to customers on the rest of the distribution loop (discussed in greater detail in E6.1.3).

As well, depending on the age and condition of pad-mounted and building vault transformers, they will be replaced with new transformers of like size, except where loading necessitates a larger size transformer. Where prudent and feasible, all related ancillary (i.e., cable and terminations) and building vault switches (i.e., mini-rupters) will be replaced at the same time. Figure 4 provides an example of the new below-grade submersible, pad-mounted and build vault transformers that will be installed through this program.

FIGURE 4: NEW BELOW-GRADE SWITCHABLE SUBMERSIBLE, PAD-MOUNTED AND BUILDING VAULT TRANSFORMER

E6.1.2.3 Replacement of Underground Cables

Two main types of cables exist in Toronto Hydro's underground distribution system: cross-linked polyethylene (XLPE) and tree-retardant, cross-linked polyethylene (TR-XLPE).

Almost all remaining XLPE cable, either direct buried or in duct has reached and/or passed its useful service life. This cable type was installed in the system before 1990 and was fabricated using dated manufacturing processes (as detailed in section E6.1.3). Due to the failure risk presented by this cable type and its functional obsolescence, Toronto Hydro plans on replacing the remaining XLPE cable in the system with TR-XLPE cables in concrete-encased ducts. This is

a continuation of renewal activities previously described in the OEB approved Underground Infrastructure segment of Toronto Hydro's 2012-2014 rate filing[4].

TR-XLPE cables use improved materials and are fabricated using a triple extruded, dry cure process that reduces impurities and moisture penetration into the cable insulation. The incorporation of a Poly Vinyl Chloride (PVC) or Polyethylene (PE) jacket, metal foil barriers and other water migration controls further reduces moisture penetration into the insulation. As a result, these cables can maintain their original insulation integrity for a longer period of time, improving performance in wet underground operations. As well, new TR-XLPE cables allow for the option of "strand-blocked" conductors. This further mitigates the risk of longitudinal penetration of water along the cable.

Aged XLPE cable either direct buried or in duct will be replaced with new TR-XLPE cable in concrete encased duct. Concrete encased ducts provide physical protection for cables due to ground shifts, vehicular weight, and dig-ins. Once the civil infrastructure for a concrete encased duct bank has been installed, it can last for several decades. This has been demonstrated with the concrete encased duct banks used in downtown Toronto where many are over 60 years. Although cables inevitably age and outages may occur due to faulty equipment or natural causes, having the appropriate civil infrastructure (concrete encased ducts) in place simplifies the cable replacement job. With concrete encased ducts, the entire cable segment between two cable chambers is removed and a new cable pulled through the ducts. The latter advantage means that power may be restored more quickly to customers in case of an unplanned outage and that the cable life cycle is renewed. An example of the problems related to direct buried cables is illustrated in Figure 5. (In this particular case, the customer had to be notified in the middle of the night to move their vehicle so that the faulted cable under their driveway could be repaired and power restored.)

[4] EB-2012-0064, Tab 4, Schedule B1.

FIGURE 5: DISTURBANCE TO CUSTOMER IN THE MIDDLE OF THE NIGHT TO REPAIR CABLES AND RESTORE SERVICE

Figure 6 illustrates the new TR-XLPE cable, concrete encased duct bank and duct bank schematic used by Toronto Hydro for underground distribution purposes. Details regarding how assets were prioritized will be discussed in section E6.1.4.1.

FIGURE 6: NEW TR-XLPE CABLE USED FOR UNDERGROUND DISTRIBUTION

In addition to XLPE cables, conductors between street lighting poles are also approaching the end of their useful service life. Many of these conductors are not only aged but also direct buried and face similar degradation problems seen in direct buried XLPE cables. Since the underground

conductor running between the poles is considered to be a distribution asset, it falls under the responsibility of Toronto Hydro. As such, based on age and historical reliability, these conductors will be replaced as part of this program. The City of Toronto will fund the replacement of all unregulated street lighting poles, luminaries and conductors in the pole, up to the lamp. Therefore, replacement of street lighting poles will be coordinated with the replacement of the conductors between the poles. In doing so, all existing infrastructure is planned to be brought up to Toronto Hydro's standard and placed within concrete encased ducts.

An overview of underground assets to be replaced in 2015 is given in Figure 6. Table 1 provides a snapshot of the assets which will be replaced during the 2015 test year and the four consecutive years which follow (2016-2019). As well, a summary of the program benefits is given in Table 3.

FIGURE 7: OVERVIEW OF UNDERGROUND ASSETS TO BE REPLACED IN 2015

1 **TABLE 1: UNDERGROUND CIRCUIT RENEWAL PROGRAM ASSET REPLACEMENT UNITS**

Assets (Units)	2015	2016	2017	2018	2019	Total
Underground Switches	84	71	74	88	88	405
Underground Transformer	348	291	305	362	361	1,667
Underground Cable (circuit km)	149	125	131	155	155	715

/C

2 **TABLE 2: SUMMARY PROGRAM BENEFITS**

Customer Value	***f*** Installing newer assets allows for reduced customer disruption in the event of an outage (i.e. quicker restoration due to SCADA switches and no digging for cable replacement). *f* Improved neighborhood aesthetics depending on the age and condition of existing assets (i.e. heavily rusted transformers and switches). *f* The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $102 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.1.7).
Reliability	Proactively replacing assets with a high risk of failure will: *f* Reduce customers interruptions *f* Mitigate safety risks to employees *f* Minimize reactive repair costs
Safety	*f* Minimize safety related issues due to flashovers (seen with pad-mounted and submersible switches and non-switchable submersible transformers). *f* Minimize the risk associated with dig-ins of direct buried cables and cables in direct buried PVC ducts.
Efficiency	*f* Improved restoration time by replacing older and unreliable assets with modern equipment capable of remote sensing and operation (i.e. switch). *f* Improved isolation of transformers without affecting power supply to customers on the rest of the distribution system. *f* Faster cable replacement of underground cables due to the concrete encased duct infrastructure.
Other (flashovers, dig-ins)	***f*** Elimination of routine CO_2 washing used to maintain pad-mounted switches. *f* Complete removal of cables in duct when a feeder is abandoned rather than dead-ending the cables and leaving it in the ground where removal of direct buried cables is not economically feasible.

E6.1.3 Why the Program is Needed

Assets addressed in the Underground Circuit Renewal program are aged, in poor condition and/or have inherent design flaws. The program targets three types of assets for proactive intervention: switches, transformers and cables.

E6.1.3.1 Program Drivers

Table 3 summarizes the trigger and secondary drivers for the Underground Circuit Renewal program.

TABLE 3: UNDERGROUND CIRCUIT RENEWAL PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	Various combinations of external factors, including, but not limited to, dirt, salt, dust, moisture and humidity affect: • all switch types, thereby accelerating the degradation to both the enclosure and internal components of the switch which in-turn increases their failure risk as the equipment ages in the field. • all transformers, leading to cumulative corrosion on the enclosure, seals and gaskets resulting in compromised enclosure and oil integrity and inevitable failure of the unit. • insulation integrity of XLPE cables; resulting in failure of underground cables regardless of their method of installation (direct buried or in duct for this particular cable type).
Secondary Drivers	**Reasoning**
Safety	The main safety concerns with the assets in the program include: • arcing and flashover due to switches and transformers (and the harm it poses to field crews and the public) • dig-ins due to unprotected direct buried cable and cable in direct buried duct. • environmental safety concern includes SF6 gas leakage into the atmosphere due to vintage URD switches.
Functional Obsolescence	The inherent design flaws of the various assets targeted for replacement through this program include: • live-front and open louver design of air-insulated switches (pad-mounted or building vault). • live-front design of non-switchable submersible transformers. • poor quality assurance and manufacturing standards of earlier generations of XLPE cable.

It can be seen in Table 3 that the trigger driver for all three asset types targeted for replacement in the Underground Circuit Renewal program is Failure Risk. Among the various external and

internal elements affecting these assets, moisture is the common culprit which accelerates both the aging and degradation process. This leads to catastrophic failures (i.e., arc-flashes, internal short circuits), which are a safety risk to both Toronto Hydro field crews and the public. The reliability and safety risks associated with these assets will be discussed in greater detail in this section. Lastly, functional obsolescence of certain asset types (i.e., oil-insulated switches, non-switchable submersible transformers and XLPE cables) means that standards for replacement are no longer available. Therefore, during an unplanned outage, these items would not be stocked and will need to be replaced with standard equipment. Customers would face unnecessary lengthy outages until a solution can be implemented. The following sub-sections provide more specific details on the drivers to replace these assets. These factors ultimately drive the decision to replace these assets over the 2015 to 2019 period.

(i) Underground Switches

In recent years, Toronto Hydro has had to replace pad-mounted switches well in advance of the end of their useful service lives. As well, there has been an increase in the need to replace oil-insulated switches in the field. This is mainly due to the safety hazard these units pose to field crews and the public once they start to become contaminated and begin to age. Section E6.1.3.2(ii) discusses catastrophic failures which have occurred due to both oil-insulated and pad-mounted switches as well as the impacts these failures have on the system.

Pad-mounted switches are designed to be vented naturally through louvers under the hood of the enclosure. This provides a route for airborne particles, such as dust and road salt, to enter the switching compartments. These contaminants land and accumulate along the barriers separating the different phases of the switches and other components contained within the asset. Scheduled preventive maintenance (i.e., CO_2 washing) is effective in removing the excessive buildup of contaminants; however, it is only effective for a limited time as contaminants will build up again. More importantly, CO_2 washing causes microscopic damage to the coating on the insulator within the switch. Over time, this will result in degradation to the insulation strength of the switch and lead to premature failure. Therefore, although prudent, routine maintenance does not extend the useful service life of the switch. Instead, it perpetuates the potential for catastrophic failure, since the uneven surface is now an ideal platform for partial discharge activity which will inevitably lead to a flashover.

Other sources of contamination include the concrete foundation, upon which the pad-mounted switch rests, where primary cables attach to the fusing and switching compartments. These

cables may be tightly packed within the enclosure, creating an environment with tight clearances and an increased potential for moisture formation. As the ambient temperature changes, the trapped moisture condenses into water, dampening the dirt and other contaminants that are already present on the insulation surface. The surface then becomes conductive and eventually creates a carbonized track between the live terminal and ground. This "tracking" and increased leakage current eventually results in a flashover. A flashover may also result from partial electrical discharge in the air, known as corona, due to contaminants and moisture.

The result of a flashover is a near simultaneous ignition of all combustible material within the compartment. The flashover also releases an ionized gas that travels to other compartments in the enclosure. This ionized gas is conductive and can result in a discharge of electrical energy within the other compartments of the switch. This ultimately results in additional flashovers and combustion that leads to the total failure of the unit.

Toronto Hydro engineers suspect that this breakdown process is affecting pad-mounted switches. This aligns with the increasing frequency of reports by crews of corona activity within this asset type. Figure 8 provides an illustration of how contaminants build up on a typical pad-mounted switch leading to a potential flashover.

FIGURE 8: PENETRATION OF CONTAMINANTS ONTO LIVE-FRONT COMPONENTS OF PAD-MOUNTED SWITCHES

There are two types of submersible switches covered by this program: oil-insulated and vintage URD.

Oil-insulated switches are installed in below grade vaults, exposed to dirt, salt and other contaminants that degrade the physical integrity of the unit. This degradation can cause the non-stainless steel enclosure to corrode, leading to oil leakage and eventually the failure of the oil-insulated switch. Oil-insulated switches can fail catastrophically, resulting in a fire. These units must be replaced to ensure reliability and mitigate potential safety risks to the public, field crews and the environment. An example of a catastrophic oil-insulated switch failure, which took place on April 25, 2013, is discussed in section E6.1.3.2 (ii).

Vintage URD switches were installed in Toronto Hydro's underground residential distribution system in the late 1980s and early 1990s. A large portion of these switches do not have stainless steel enclosures. Therefore, many have been damaged by corrosion from moisture present in the underground vault environment.

Due to the inherent design flaw, which includes bolted viewing windows; these units have higher gas leakage rates and are now exhibiting "low gas" conditions. This has resulted in operational constraints to field crews because switches with low gas cannot be operated due to the safety risk they present (i.e., potential for flashover). This prevents Toronto Hydro from safely executing normal system operations, leading to longer outage times for customers. An incident was documented on October 7, 2006, where a Toronto Hydro protection and control crew member suffered facial burns while performing a routine inspection of an air-insulated pad-mounted switch. While opening a compartment door, debris from the environment initiated a flashover event which resulted in facial burns to the employee. Figure 9 shows an example of existing SF_6-insulated switches used in Toronto Hydro's URD system.

FIGURE 9: EXISTING SUBMERSIBLE VINTAGE URD SWITCH

Mini-rupters are switches typically used in building vaults. Although reliable, they are a type of air-insulated switch, exhibiting safety risks similar to those of pad-mounted switches. A complete discussion of the risks associated with pad-mounted (air-insulated) switches is located earlier in this section. The full extent of the discussion and associated risks and concerns applies to these switches as well.

A snapshot of the ten-year reliability of the underground switches discussed in this program is shown in Figures 10, 11 and 12. In these figures it can be seen that proactive switch replacement has started to result in system improvements beginning around 2009. The total number of failures and customer interruptions pertaining to switches has started to decline. However, the number of switches remaining in the field is aging at a rate faster than replacements can be executed. If Toronto Hydro does not maintain the current renewal pace, the utility expects that the benefits seen in the figure will not be sustained and failure rates will start to increase. Therefore it is important to continue proactive replacement of the remaining switches to help ensure the system reliability is maintained.

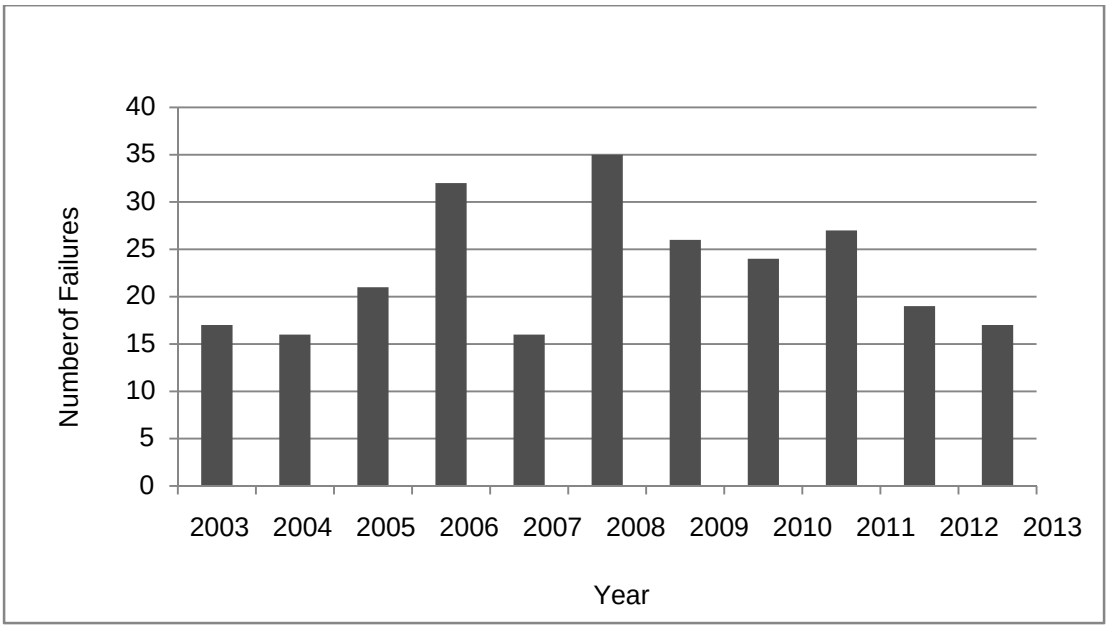


FIGURE 10: TEN-YEAR SNAPSHOT OF OUTAGES DUE TO UNDERGROUND SWITCH FAILURES

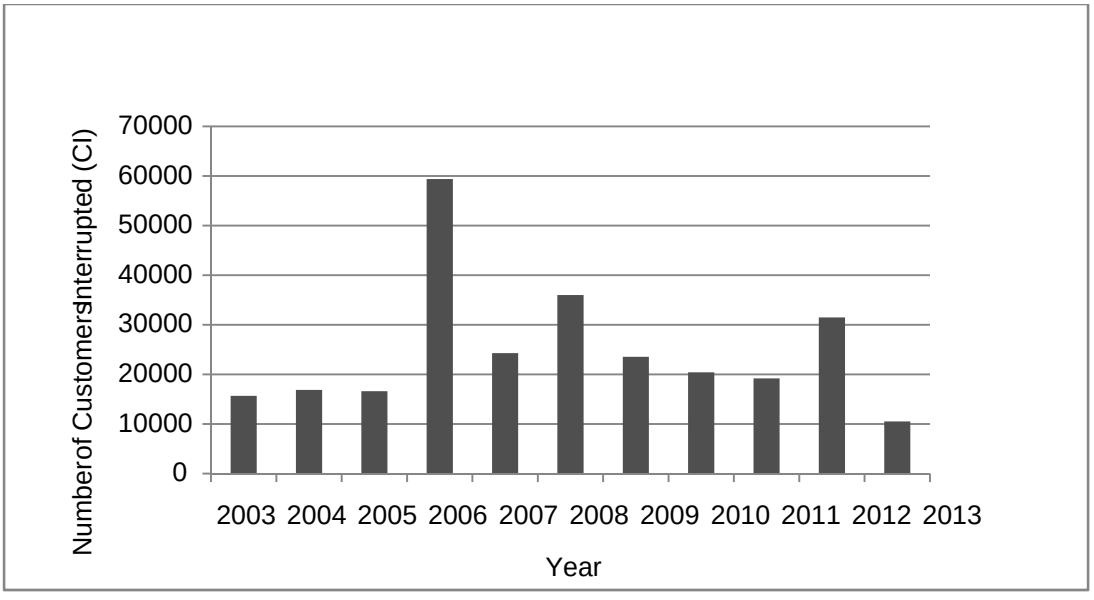


FIGURE 11: TEN-YEAR SNAPSHOT OF TOTAL CUSTOMERS INTERRUPTED (CI) DUE TO UNDERGROUND SWITCHES

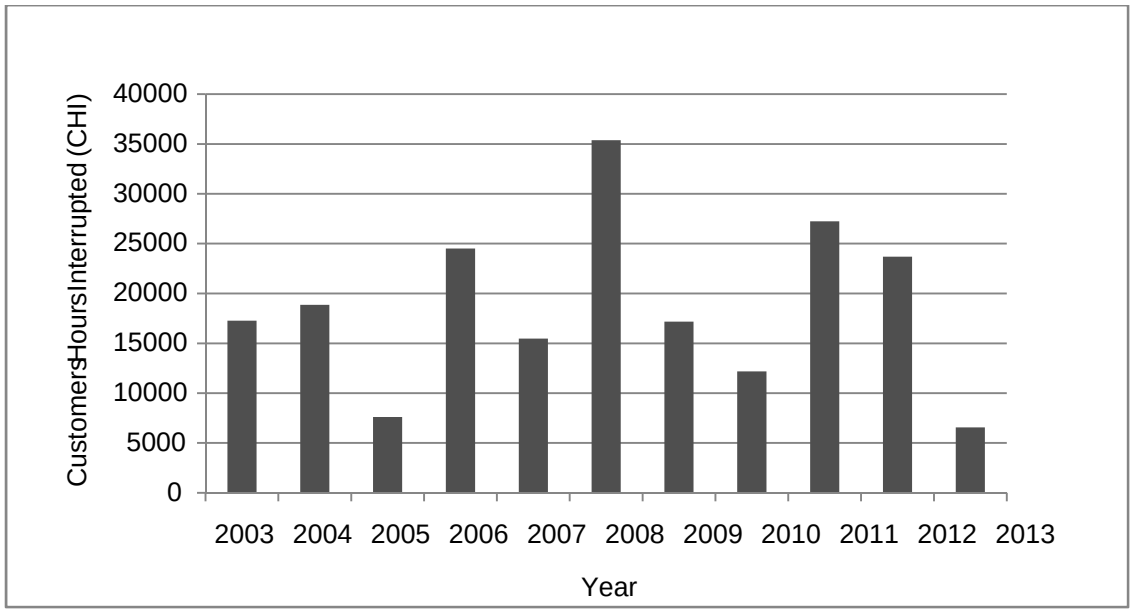


FIGURE 12: TEN-YEAR SNAPSHOT OF CUSTOMER HOURS INTERRUPTED (CHI) DUE TO UNDERGROUND SWITCHES

(ii) Underground Transformer

Transformer degradation is caused by both external and internal elements. Among the various degradation factors (i.e., dirt, aging etc.), moisture is the single most destructive element that affects transformers both externally and internally. External sources of moisture are seasonal precipitation and humidity. Moisture is present internally due to penetration through bushings, aged/poorly fitted gaskets or naturally as a result of the decomposition of the paper insulation (which produces CO_2 and H_2O).

The most destructive effect moisture has on a transformer is the loss of the oil's insulating ability, which may occur either:

- during periods of high load - water can boil off the conductor surfaces and the vapor bubbles can lead to dielectric failures as they rise to the top; or
- during periods of cool down after high load - during cool down, the water molecules combine with the oil vapor molecules, resulting in oxidation.

Once the oil has started to oxidize, it is be able to absorb more water (referred to as "water-saturated-decay-molecule"). This molecule is polar and naturally attracted to areas of high stress (i.e., conducting surfaces), which leads to arcing.

Therefore, external degradation due to moisture leads to corrosion and oil leakage into the environment. The secondary effect of this leakage is a reduction of the oil within the transformer that will cause the paper insulation to dry, and when paired with the heat created within the unit due to loading, will inevitably result in arcing and potentially catastrophic failure of the unit.

Whereas internal degradation due to moisture leads to a reduction in the oils insulation integrity, damage to the paper insulation and arcing along the conducting surfaces within the transformer. Figure 13 illustrates the difference between new and aged paper insulation within a transformer.

In both cases the damage is harmful to the public and field crews. It is imperative to replace aging transformers in the field to ensure safety and system reliability.

Damage due to moisture in aging transformers have been the leading cause in an increase seen in oil spills since 2012. The Environmental Health and Safety department at Toronto Hydro has seen a spike in transformer related oil spills linked directly to aged and corroded transformers. In 2013, there were a total of 107 transformer related oils spills, 25 of which were reportable to government agencies. This represents a 92% increase when compared to 2012 which totaled 15 spills two of which were reportable to government agencies. To date, there have been a total of 13 transformer related oil spills, five of which were reportable to government agencies in 2014. Based on this information, over 80% of the spills are due to aged and corroded transformers.

As well, there is a documented incident of a catastrophic transformer failure which took place on May 17, 2011. Figure 14 is a report published in the Toronto Star of a Toronto Hydro-owned transformer which failed. This was an older style transformer that had started to leak, the oil leakage eventually led to the catastrophic failure of the unit, causing a fire. Figure 15 is a photo taken by a bystander at the time of the incident.

FIGURE 13: MICROSCOPIC SCALE, DIFFERENCE BE TWEEN FIBERS IN NEW AND AGED TRANSFORMER PAPER INSULATION DUE TO MOISTURE DAMAGE

"News/GTA
Agincourt Mall evacuated after fire in transformer

By: Christine Dobby Staff Reporter, Published on Thursday May 17, 2011.

A blown hydro transformer forced the evacuation of the Agincourt Mall at Sheppard Ave. E. and Kennedy Rd. on Thursday.

The mall, which is home to both a Wal-Mart and a No Frills grocery store, was without power after a fire started in a hydro transformer about 15 to 20 feet from the building shortly after 6 p.m., said Toronto police Staff Sgt. Karl Heilimo.

Shoppers were evacuated due to smoke but there were no injuries reported and the power outage was limited to the mall, Heilimo said.

The cause of the fire or when the mall would reopen was not known."

FIGURE 14: TORONTO STAR ARTICLE - AGINCOURT MALL FIRE DUE TO TRANSFORMER FAILURE

FIGURE 15: PHOTO OF AGINCOURT MALL FIRE TAKEN BY BYSTANDER

A snapshot of the 10-year reliability of the underground transformers discussed in this program is shown in Figure 16, and Figure 18. In these figures it can be seen that proactive transformer replacement has started to show system improvements beginning around 2009. The total number of failures and customer interruptions pertaining to transformers has started to decline. However, similar to the switches discussed previously, the number of transformers remaining in the field is aging at a rate faster than replacements can be executed. If Toronto Hydro does not maintain the current renewal pace, it expects that the benefits seen in the figure will not be sustainable and failure rates will start to increase. Therefore it is important to continue proactive replacement of the remaining transformers to ensure the system reliability is maintained.

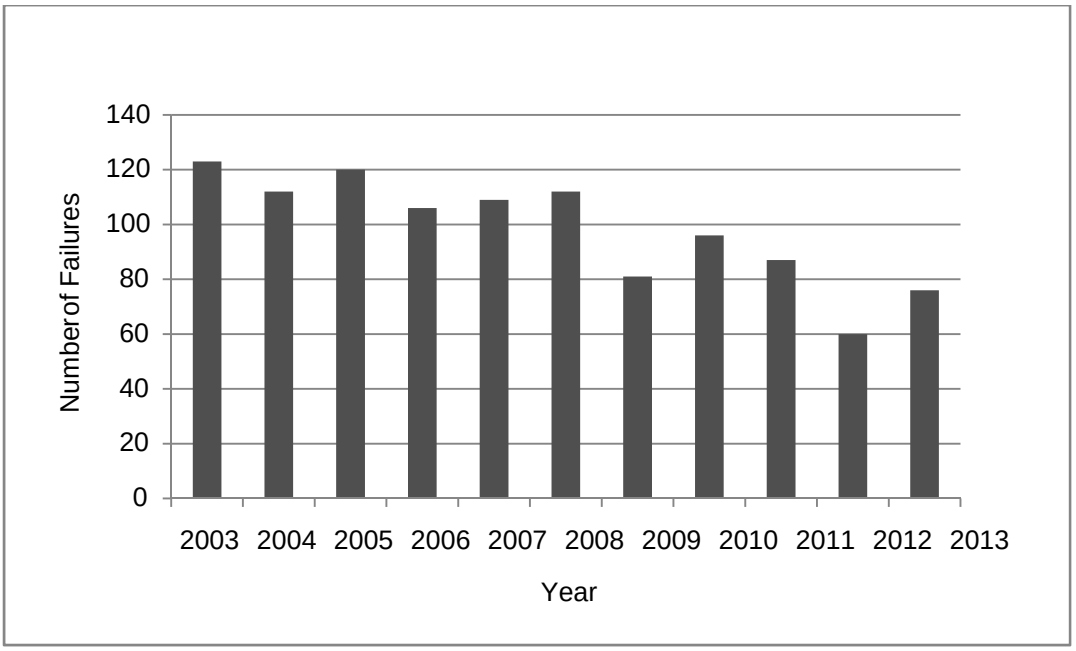


FIGURE 16: TEN-YEAR SNAPSHOT OF OUTAGES DUE TO UNDERGROUND TRANSFORMER FAILURES

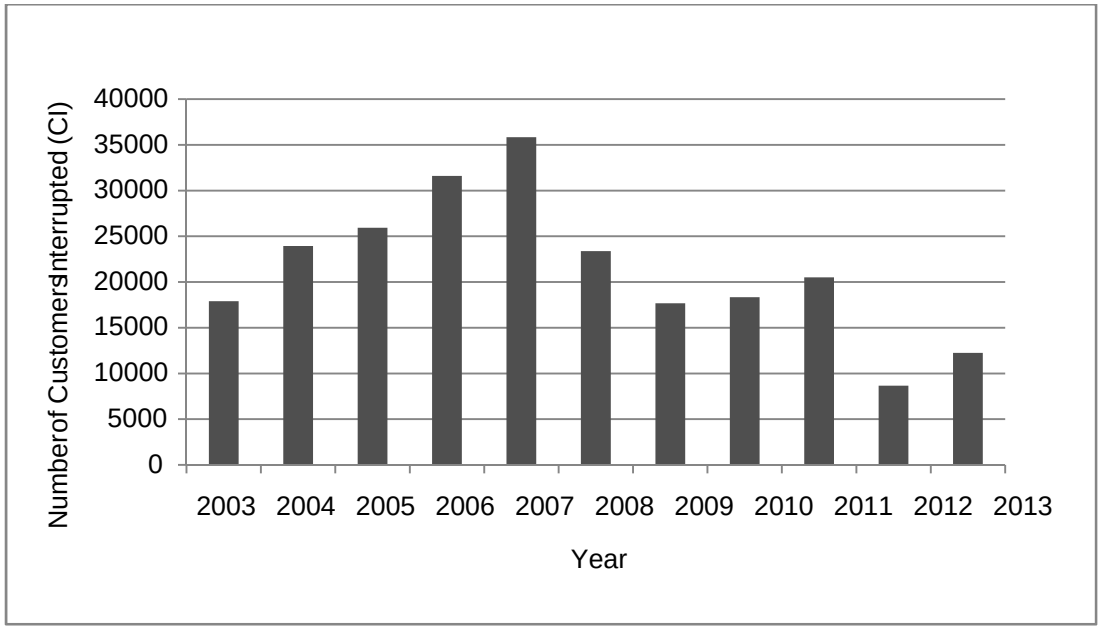


FIGURE 17: TEN-YEAR SNAPSHOT OF TOTAL CUSTOMERS INTERRUPTED (CI) DUE TO UNDERGROUND TRANSFORMERS

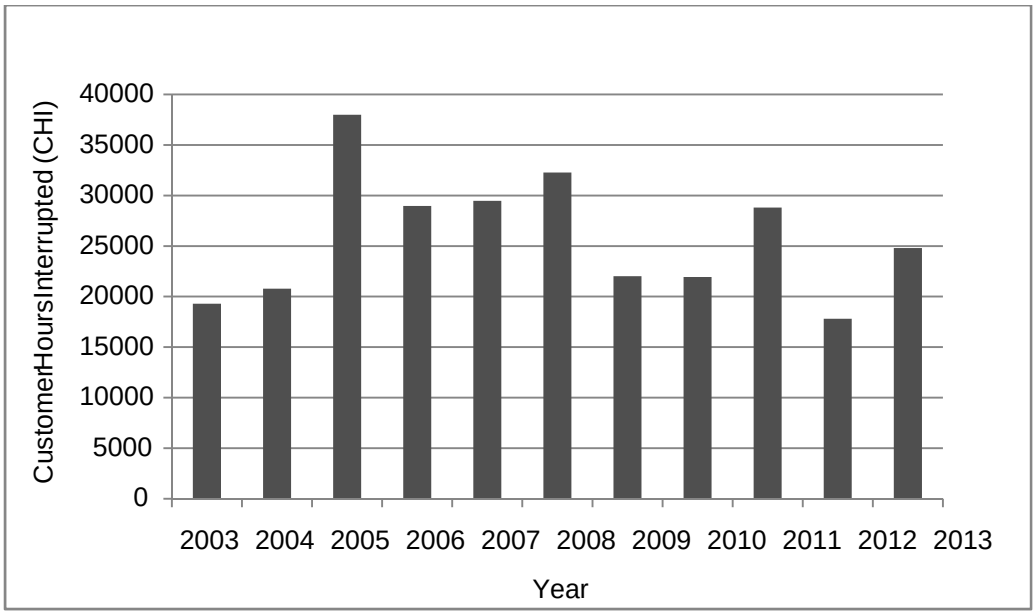


FIGURE 18: TEN-YEAR SNAPSHOT OF CUSTOMER HOURS INTERRUPTED (CHI) DUE TO UNDERGROUND TRANSFORMERS

(iii) Underground Cable

The most significant degradation process for vintage cross-linked polyethylene (XLPE) cable is "water treeing." Water treeing starts with moisture penetration into the cable insulation in the presence of an AC electric field. These trees are microscopic tears within the dielectric. In the early stages of water treeing, the path between the conductor and neutral remains intact. However, over time, continuous seepage of moisture into the insulation combined with electrical stress allows ions from the conductor to start migrating into the microscopic tears. These tears then become carbonized and form electrical trees. Once this final stage of treeing is reached, the cable quickly fails due to internal short circuits that occur between the primary conductor and the neutral shield on the outside of the cable insulation.

Figure 19 depicts the internal short circuit that occurs once electrical trees are formed in the dielectric insulation. Figure 20 provides field and laboratory samples of microscopic voids (bubbles) and damage (water and electrical trees) to the insulation. There is an immediate need to address the issues associated with XLPE type cables which were installed either direct buried or in ducts in an effort to increase system reliability.

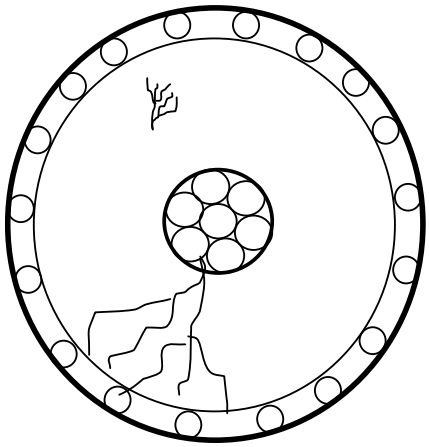


FIGURE 19: SHORT CIRCUIT BETWEEN PRIMARY CONDUCTOR AND NEUTRAL SHIELD DUE TO ELECTRICAL TREEING

FIGURE 20: FIELD AND LABORATORY SAMPLES OF MICROSCOPIC VOIDS (BUBBLES) AND DAMAGE (WATER AND ELECTRICAL TREES) TO EXTRUDED DIELECTRIC INSULATION

Underground street lighting conductors (the conductors running between two poles) provide power to street lights mounted on a pole. Most of these conductors are direct-buried. Constant exposure to moisture and soil contamination has caused deterioration of the conductors' insulation, which leads to eventual failure. Depending on the location of failure, it may cause loss of power to a number of street lights, which can lead to customer complaints and potential public safety risks. Toronto Hydro believes it is prudent to replace the conductors at the same time as the street lighting poles to ensure more reliable service to residents of the City of Toronto.

A snapshot of the ten-year reliability of the underground cables discussed in this program is shown in Figure 21, Figure 22 and Figure 23. In these figures it can be seen that proactive XLPE cable replacement has started to show system improvements since around 2007. The total number of failures and customer interruptions pertaining to XLPE cables has started to decline. However, the XLPE cable remaining in the field is aging at a rate faster than rebuilds can be executed. If Toronto Hydro does not maintain the current renewal pace, it expects that the benefits seen in the figure will not be sustainable and failure rates will start to increase. Therefore it is important to continue proactive replacement of the remaining XLPE cable to ensure the system reliability is maintained.

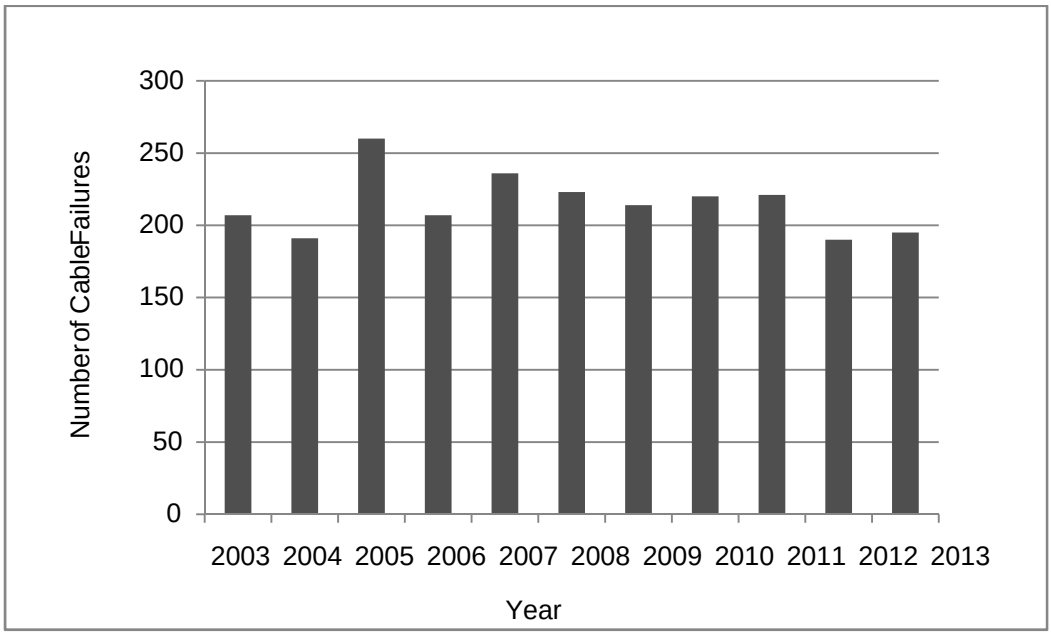


FIGURE 21: TEN-YEAR SNAPSHOT OF OUTAGES DUE TO UNDERGROUND PRIMARY CABLE FAILURES

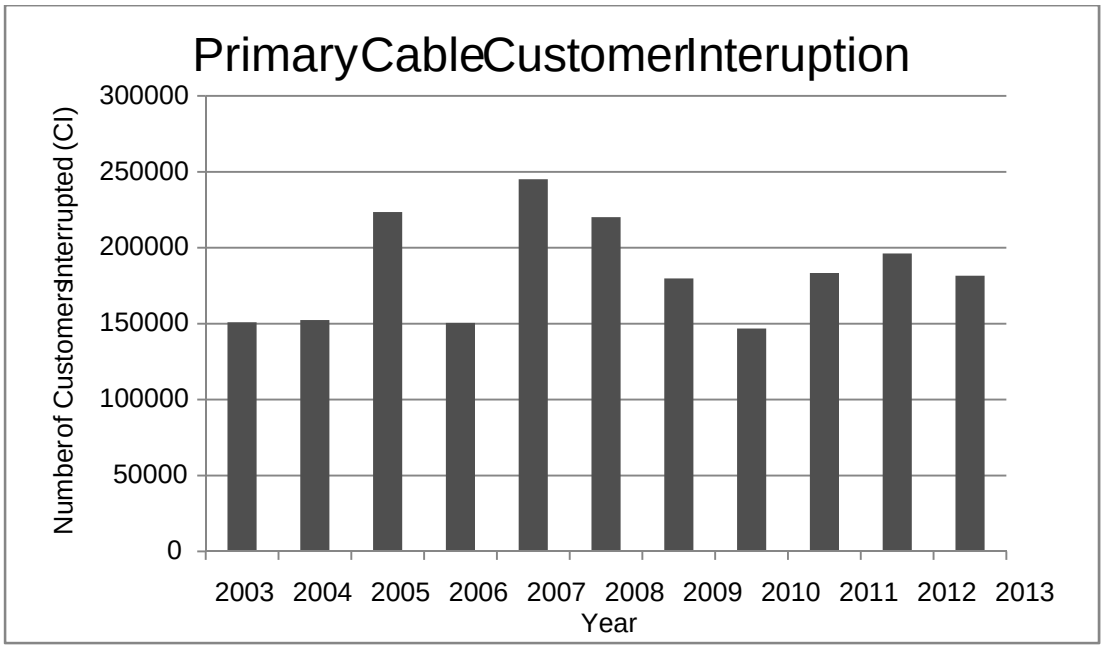


FIGURE 22: TEN-YEAR SNAPSHOT OF TOTAL CUSTOMERS INTERRUPTED (CI) DUE TO UNDERGROUND PRIMARY CABLES

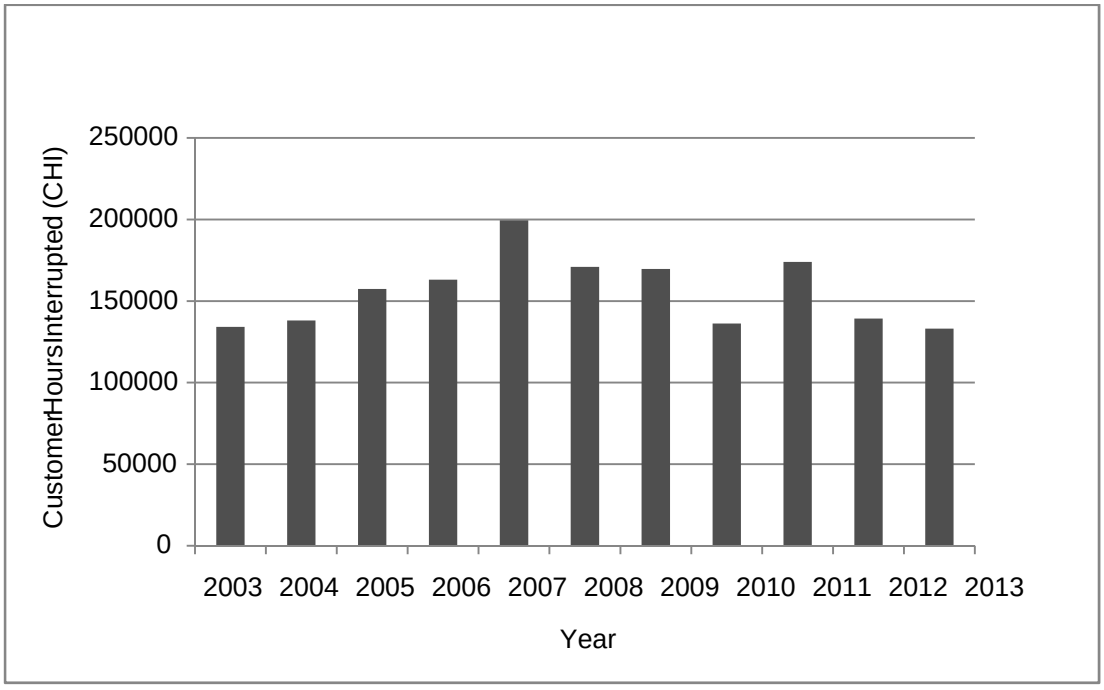


FIGURE 23: TEN-YEAR SNAPSHOT OF CUSTOMER HOURS INTERRUPTED (CHI) DUE TO UNDERGROUND PRIMARY CABLES

E6.1.3.2 Asset Details

In this section, the lifecycle and failure impacts of switchgear, transformers and cables that will be replaced through this program are discussed in greater detail.

(i) Asset Lifecycle

Table 4 provides an overview of the average useful service life of the various assets suggested for replacement through this program. Although the assets have varying useful service lives, based on the discussion in section E6.1.3.1, moisture is the common factor affecting all underground assets. Therefore, the extent of external damage limits the actual service life of assets compared to their expected useful service life.

As described above, moisture corrodes the enclosures of switches and transformers leading to oil leakage and tracking which can result in arc-flashes and potentially catastrophic failures, potentially posing safety risks to the public and field crews (further discussed in E6.1.3.2 (ii)). As well, moisture seeps into the cable insulation and leads to water-treeing which eventually turns to electrical trees that result in internal short circuits leading to cable failures.

TABLE 4: UNDERGROUND ASSET – TYPICAL USEFUL SERVICE LIFE

<table>
<tr><th colspan="2">Switch</th><th colspan="2">Transformer</th><th colspan="2">Cable</th></tr>
<tr><th>Type</th><th>Average Useful Life</th><th>Type</th><th>Average Useful Life</th><th colspan="2">Type</th><th>Average Useful Life</th></tr>
<tr><td rowspan="2">Pad-mounted</td><td rowspan="2">30</td><td rowspan="2">Submersible</td><td rowspan="2">33</td><td rowspan="2">Direct buried</td><td>Jacketed</td><td>40</td></tr>
<tr><td>Un-jacketed</td><td>23</td></tr>
<tr><td>Vintage URD</td><td>40</td><td>Pad-mounted</td><td>35</td><td colspan="2" rowspan="2">Cable in duct (Jacketed/Un-jacketed)</td><td rowspan="2">50</td></tr>
<tr><td>Mini-rupter</td><td>40</td><td>Building vault</td><td>35</td></tr>
</table>

Switches are an essential component of the distribution system. They are used for feeder load switching, isolation and emergency power restoration procedures. The average service life of pad-mounted switches is 30 years while vintage URD and mini-rupter switches are 40 years each. A detailed discussion of the various factors affecting the degradation of switches has been given in section E6.1.3.1 (i).

Transformers are key components used to step voltage down and supply commercial and residential customers with electricity via underground cables. Submersible transformers have an average service life of 33 years while pad-mounted and building vault transformers have an

average useful service life of 35 each. Direct buried cables have an average service life of 23 and 40 years for un-jacketed and jacketed types respectively while ducted cables have an average service life of 50 years.

However, the service life of both transformers and cables are significantly impacted by the presence of moisture in the atmosphere and underground environment into which they are installed. Due to this, they show signs of aging and start to fail sooner than expected. A detailed discussion of the various factors affecting the degradation of transformers and cables has been given in section E6.1.3.1 (ii) and E6.1.3.1 (iii) respectively.

Figure 24 illustrates the remaining life of all assets targeted for replacement through the Underground Circuit Renewal program. From this population of underground assets that are targeted for replacement in this program, 1,349 switches, 7,504 transformers and 692 kilometers of cable are currently operating beyond their useful service lives. This indicates that by 2015, the majority of the underground assets in the program will need to be replaced. However, due to operational constraints and limited resources, it is not prudent or feasible to replace all of these assets at once, and the work has been spread over the 2015-2019 period. Section E6.1.4 provides a detailed discussion on the timing and pacing of the program.

FIGURE 24: REMAINING USEFUL LIFE OF ALL ASSETS ADDRESSED IN THE UNDERGROUND CIRCUIT RENEWAL PROGRAM

(ii) Asset Failure Impacts

The switches, transformers and cable targeted for replacement in the Underground Circuit Renewal program are aged, in poor condition or have inherent design flaws. In this section the failure impacts of these assets to the system will be looked at in further detail.

Failure Causing Secondary/Local Outage

The failure mode that would impact the least number of customers would be an outage that only affected customers downstream of a distribution transformer or on a segment of a feeder. This is referred to as a secondary or localized outage. While the system is designed to handle first contingency, a contingency plan does not always exist at this level due to the relatively small number of customers impacted. As such, restoration requires the equipment to be replaced by some other form of resupply.

The impact of this type of failure varies depending on the type of asset and how it is connected in the circuit. For example, pad-mounted switches are designed to feed up to six single phase distribution (residential) loops. In the event of an unplanned outage, up to 1,200 customers could experience an outage.

Due to functional obsolescence, non-submersible transformers in particular, pose a risk to the system independent of the degradation factors discussed in section E6.3.1. According to Toronto Hydro outage information, 12,242 customer interruptions (CI) in 2013 were due to transformer failures alone. Each customer experienced interruptions lasting an average of two hours (customer hours interrupted or CHI).

The majority of existing submersible transformers in the field are non-switchable. These units have been in the field for many years and, over time, transformer elbows may have seized due to corrosion. This makes it difficult for field crews to operate the elbow to isolate the faulty unit without risking personal injury. As a result, failure of any non-switchable submersible transformer in a loop will require the entire loop to be de-energized to enable safe isolation of the unit by field crews. In the event of an unplanned non-switchable transformer outage, up to 1,200 customers can experience a short term outage while crews isolate the feeder at the switchgear. Once the feeder is isolated, up to 200 customers in the loop of the failed transformer will experience a sustained outage lasting six to eight hours.

Additionally, these transformers do not have a built in current limiting fuse (CLF). In the 1980's, after experiencing a number of submersible transformer failures, Fault Fiter fuses were installed upstream of these units. This fuse is a current-limiting device inside a PMH-4 pad-mounted switch and is installed at the beginning of a loop to protect downstream transformers from excessive high fault current. However, the standard for submersible transformers was recently harmonized so that each new submersible transformer is of a switchable type and contains an internal CLF. When an existing non-switchable submersible transformer in the field fails, it is replaced with a new switchable submersible transformer. Given that the former relied on the CLF of the PMH and the latter has an internal CLF, this leads to what is called 'protection mis-coordination' as shown in Figure 25. This may result in a partially operated Fault Fiter fuse after the internal CLF in a submersible transformer has cleared the fault current. The Fault Fiter fuse may operate prematurely upon re-energization, causing the customers in the loop to experience a secondary outage. This time the PMH will need to be replaced and the secondary outage can result in up to 1200 customers losing power.

FIGURE 25: ILLUSTRATION OF PROTECTION MIS-COORDINATION OF NON-SWITCHABLE AND SWITCHABLE TRANSFORMER IN ONE LOOP

Historical failures due to extreme low gas and direct buried cables related to the secondary/local outage scenario for switches and cables include the following:

- A "low gas" event took place in March 2013; feeders A5L, A10L and A6L were connected to a submersible SF_6 switch which failed catastrophically due to low levels of SF_6 gas. This outage is also described in detail in the Underground Legacy Infrastructure (section E6.4) program in terms of how not having standard replacement parts available impacted the outage duration. In this case, the low gas pressure inside the switches caused an internal fault to ground which resulted in failure of all three incoming feeders. This outage initially affected 70 customers, including many large apartment buildings.

- On April 25, 2013 there was a catastrophic failure related to an oil-insulated switch on feeder 51-M28 which left 421 customers without power. In this case, the external contamination buildup on the unit degraded the physical integrity of the unit. This in turn caused the enclosure to corrode and oil to leak igniting a fire which led to the unit failing catastrophically. The failure caused traffic congestion along Sheppard Ave East (where the unit was located) and potential transformer oil seepage into the environment.

- On August 1, 2013, a failure on feeder A320CE left a total of 3,133 customers without power due to low gas failure of SF_6 switches. Had the switches functioned as intended, only 1,298 customers would have been without power during this event. In this case, the breaker supplying the primary feeder had failed. Once it had been determined that there was no cable damage, the crew needed to close the normally open point on the standby feeder using a 600A submersible SF_6 switch. However, the switch was low on gas and could not be operated. Therefore, the controller had to open the breaker on the standby feeder, causing an outage to all customers normally supplied by the standby feeder. Once the standby feeder was out, the proper switching could occur to isolate the failed feeder; then the controller was able to reclose the breaker on the standby feeder. As a result 1,835 additional customers were affected by the outage.

- As well, a direct buried cable example can be seen in the Bridletowne area. Since 2011, this area has experienced many repetitive outages, five of which were specifically related to direct buried cables. Due to these five outages, 10,484 customers in the Bridletowne area have been without power for a total of 6,524 outage hours over the past three years (2011 to 2013). Figure 26 is a map of the Bridletowne neighborhood. It should be noted that the majority of projects issued for the 2015 rate filing are designed to deal with many of the problems associated with the 502-M22 feeder, including upgrades to Bridletowne circle.

FIGURE 26: MAP OF BRIDLETOWNE FED BY 502-M22

Failure Causing a First Contingency Feeder Outage

A failure mode which would have a severe impact to customers is an outage that takes out an entire primary feeder, referred to as a first contingency feeder outage. The system is designed to handle a first contingency, so while customers on a feeder will still be interrupted by a failure, they can restored before the source of the failure is complete resolved. Outage restoration time will depend on the number of customers on the feeder.

An example of this can be seen with pad-mounted switches connected to the trunk portion of a feeder. Pad-mounted switches are commonly connected to the trunk portion of a feeder for load distribution and feeder switching. When load is transferred from one feeder to another, individual switches are closed or opened so that power can be diverted from one feeder to another. These actions cannot occur when a pad-mounted switch fails, leading to a significant impact on system reliability. According to Toronto Hydro outage information, 10,525 CIs in 2013 were due to switch failures alone. Each customer experienced interruptions lasting an average of 0.63 hours (customer hours interrupted or CHI).

The catastrophic failure of a pad-mounted switch may also present a potential safety risk to the public. As these units are installed on city sidewalks, anyone in the vicinity of the pad-mounted switch could be injured if the switch door or other exposed parts were to dislodge during an explosive failure. An example of a contaminated air-insulated switch that failed can be seen in Figure 27.



FIGURE 27: FAILED AIR-INSULATED PAD-MOUNTED SWITCH (TAKEN NOVEMBER 19, 2008)

Failure Causing a Second/Multiple Contingency Feeder Outage

The failure mode that would have the most severe impact on customers is an outage that takes out multiple primary feeders. This is referred to as a second (or multiple) contingency feeder outage. The system is not designed to handle a multiple contingency, so there may be customers on the interrupted feeders that cannot be restored before the source of the failure is in some way resolved. Outage restoration will depend on the severity of the damage to each feeder.

An example of this can be seen during a cable outage, depending on where the cable has failed. According to Toronto Hydro outage information, 181,577 CIs in 2013 were due to primary cable failures alone. Each customer experienced interruptions lasting an average of 0.73 CHI. Installing new TR-XLPE cable in concrete-encased duct helps to reduce the lengthy repair process associated with repairing/replacing direct buried cable as described in (a) to (g) below and shown in Figures 28 to 30.

Repair Process

Identify the faulted cable segment (50-100m length) based on visual inspection of the interrupted devices

(a) Install fault-locating equipment (thumper) to determine the fault location[5]

(b) Dig a splice-pit in the identified location (see Figure 28)

(c) If the device erred in the location of the fault, repeat thumping and step (c)

(d) Cut and remove the faulted section of cable (see Figure 29)

(e) Install a new section of cable and connect via splices (see Figure 30)

(f) Back-fill pit

FIGURE 28: FIELD PERSONNEL WITHIN A SPLICE- PIT PREPARING TO SPLICE A FAULTED CABLE TO RESTORE SERVICE TO AREA

[5] Thumping itself weakens an already aged, stressed cable due to the repeated short term high voltage (up to 30kV) DC pulses transmitted to locate the fault, http://www.abb.com/cawp/seitp202/003a3146d08e8aedc12578380056f1f3.aspx

FIGURE 29: FIELD PERSONNEL WITHIN SPLICE-PIT, REMOVING FAULTED CABLE SEGMENT

FIGURE 30: FIELD PERSONNEL COMPLETED SPLICING THE CABLE. NOTICE TWO SPLICES REQUIRED FOR EACH FAULTED CABLE SEGMENT

In addition to direct buried cables, Toronto Hydro also has cables in ducts. There are two types of ducts installed in the underground distribution system: direct buried PVC and concrete encased. Ducts minimize many problems associated with direct buried cables, including: replacement of an entire faulted cable segment (rather than splicing); reduced residential disturbance (no trenching/splice pits required for cable repair); and added mechanical protection against dig-ins and environmental contaminants.

Direct buried ducts are installed in two ways: open-trench and micro-tunneling. Open-trench provides some flexibility as to how the ducts are laid and allows for the ducts to be installed flush between two cable chambers or transformer vaults. Micro-tunneling allows for minimal disturbance above ground by avoiding long length trenches. In this case, a clearance is required to set up the micro-tunneling bore head, prohibiting ducts from running flush between cable chambers or transformer vaults. Instead, a portion of the cable on either end must be direct buried. In the event of an unplanned outage on a cable installed in the latter scenario, two splice pits are required to expose the direct buried cable portions before the new cable can be pulled through the ducts. Unplanned repairs in this case are as difficult and intrusive as repairs made to direct buried cables. However, in the case of the former duct installation, cables can be pulled directly from the cable chamber or building vault transformer with minimal disruption to customer property. Thus, where prudent, the direct buried ducts will be replaced with concrete encased ducts as per Toronto Hydro's standard. An example of both types of direct buried duct installation is given in Figure 31.

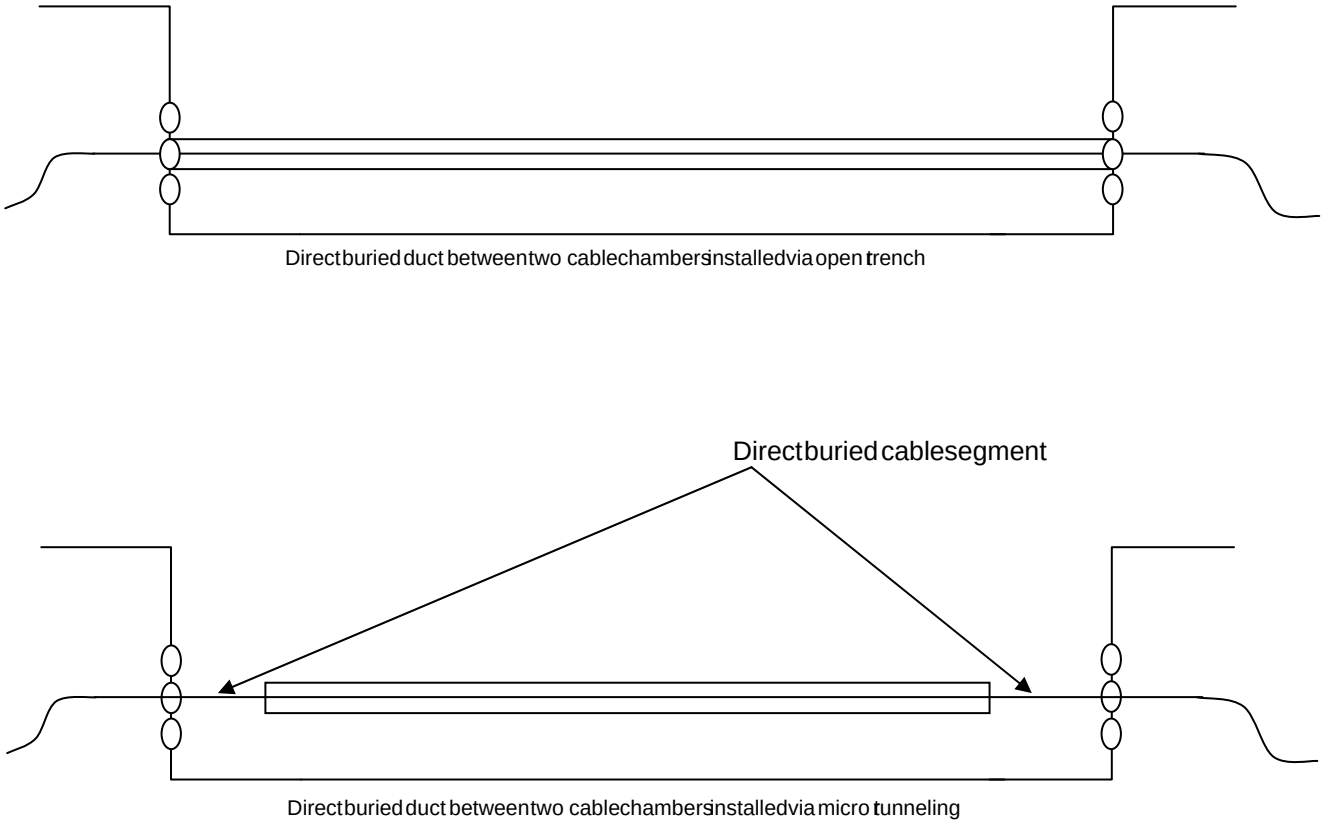


FIGURE 31: OPEN-TRENCH AND MICRO-TUNNEL DIRECT BURIED DUCT CONFIGURATIONS

Failures Causing System Operating Constraints

A final failure mode that would impact customers is a failure causing an operating constraint. This refers to the situation when equipment can no longer be operated as intended. When this occurs, forced feeder outages may be required to operate the system. This impact of the outage varies based on the equipment involved and could affect multiple primary feeders. Most outages incurred due to operating constraints would be momentary outages.

An example of this type of failure on the system can be seen when a vintage URD switch indicates “low-gas” levels. In this case, the switch is considered a failed switch. A detailed discussion of the failure impacts of this type of switch has been given in the Underground Legacy Infrastructure program (section E6.4). A summary of the reliability impact of this failure has been discussed earlier in this section (E6.1.3.2 (ii) – Failures Causing Secondary/Local Outage).

E6.1.4 Timing & Pacing of the Program

Assets planned for replacement in this program are aged, unreliable and in some cases contain critical design flaws. These factors pose failure and safety risks to the system, customers and field crews. This program proposes to proactively replace these assets over the next five years to mitigate system reliability risk as well as to enhance customer and crew safety. Table 5 provides a summary of the five year historical spend on the Underground Circuit Renewal program or its equivalent as well as projected spending from 2015 to 2019.

TABLE 5: SUMMARY OF FIVE YEAR UNDERGROUND RENEWAL PROGRAM SPEND

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	108.4	90.3	53.8	68.8	108.1	96.0	80.1	84.0	99.7	99.5

The drop in spending from 2011 to 2012 was related to the timing of the regulatory decisions with respect to Toronto Hydro's previous Cost of Service filing and the subsequent 2012-2014 ICM filing.

Given that a high population of assets will be approaching the end of their useful lives in 2015, Toronto Hydro expects to maintain a level of investment similar to the forecasted 2014 magnitude throughout the 2015-2019 period. Minor fluctuations in the pacing of investment over the forecast period (e.g. the drop in spending in 2016 and 2017) will likely be required to facilitate other high-priority renewal and service investments in the underground system using similar resources. These types of investments (e.g., Feeder Automation (E7.3), Design Enhancement (E7.2), Underground Legacy Infrastructure (E6.3)) address similar or related underground assets and are expected to deliver complimentary reliability, safety and system efficiency benefits for customers on the underground system.

The proposed rate of investment in the Underground Circuit Renewal program will allow Toronto Hydro to prudently and proactively manage the significant backlog of end-of-life and poor condition underground assets, maintaining system reliability performance while enhancing customer value with the installation of more robust and reliable underground construction. Toronto Hydro expects that a slower pace of investment would increase the backlog of end-of-life underground assets, making it increasingly difficult to efficiently mitigate deteriorating system reliability performance in the future.

E6.1.4.1 Ranking & Prioritization

Switch and transformer replacements are generally prioritized to coordinate with cable replacements. However, switches and transformers that are in need of replacement but are not connected to cable that is in need of replacement will be prioritized by historical feeder reliability, asset condition, the number of customers that would be affected by a failure and the duration of such an outage. This approach is intended to ensure switches and transformers on feeders that suffer the highest number of outages or long outage durations are refreshed as soon as possible.

Cable replacement is prioritized based on factors such as the number of failures experienced by the cable segment as well as the number of underground cable failures experienced by the feeder. Replacement of cable in duct is mainly prioritized based on suggested optimal year of intervention derived from Toronto Hydro's Feeder Investment Model (FIM). A detailed discussion of the FIM model is given in Section D3.

Capital replacement for street lighting assets is prioritized on the basis of the age and condition of the street lighting pole and luminary as well as historical underground conductor failure rate. Replacing conductors supplying power to street lights will be prioritized based on the condition of the pole it is connected to and will be coordinated with the City of Toronto.

E6.1.5 Program Execution

This program consists of three major underground asset classes: switches, transformers and cables. The program proposes to replace:

- Pad-mounted, oil-insulated, vintage URD and mini-rupter switches which are approaching end-of-life with new SF_6-insulated switches.
- Non-switchable, submersible transformers will be replaced with switchable submersible transformers and pad-mounted and building vault transformers with similar units.
- Direct buried XLPE cable and cable in direct buried duct will be replaced with new TR-XLPE cable in concrete encased duct.

Detailed discussions of these assets have been given in Section E6.1.2.

The intent of the underground renewal program is to replace assets that will pose a higher failure risk, are functionally obsolete or pose a safety risk to field crews and the public with newer, standard assets.

It can be seen in section E6.1.3.2 (ii) that the majority of assets considered in this program are due for replacement in 2015. The underground replacement initiative taken since 2007 has produced significant reliability improvements in terms of CIs and CHIs as discussed in section E6.1.3.1. Although it would benefit the distribution system to replace all assets approaching end-of-life in 2015, it is neither practically feasible nor prudent to do so. Therefore, in an effort to maintain the reliability improvements and ensure a prudent approach to asset upgrades, the assets are expected to be replaced from 2015 to 2019. By replacing the assets proposed for the first year of the program, the ARC to the distribution system is $102.93 million.

E6.1.5.1 Proposed Work Plan

The Underground Circuit Renewal projects will primarily be performed on feeders emanating from 27.6 kV transformer stations (TS), because the majority of feeders supplying residential customers in the North York and York area are designed as 27.6 kV underground distribution circuits whereas the circuits supplying Toronto, Scarborough and Etobicoke use 13.8 kV or 4.16 kV overhead distribution. Given that this program addresses underground circuit renewal, the bulk of the work will be along 27.6 kV circuits and, where applicable, underground 13.8 kV and 4.16 kV circuits.

E6.1.5.2 Program Risks

The risks associated with the Underground Circuit Renewal program include, but are not limited to:

- Unforeseen (i.e., emergency) updates and changes to existing road moratoriums by the City of Toronto.
- In this case, Toronto Hydro will monitor the road moratorium list and delay or accelerate individual projects within the 2015 to 2019 program accordingly.
- Unforeseen weather conditions that may affect either the summer heat restriction list (i.e., more feeders added to the list due to extended periods of unanticipated heat/humidity) or construction in the fall/winter (i.e., hurricanes or ice storms).

In this case, depending on the level of the emergency, resources will be limited and as a result, projects may be shifted to the following year. Because of such scenarios, program management has prioritized projects to be High, Medium and Low. In a case where natural events push a project to the following year, low priority projects may be deferred. This will allow major projects to be completed while maintaining system reliability in the event of an emergency.

E6.1.6 Evaluation of Alternatives

E6.1.6.1 Quantification/Evaluation of Options

(i) Status Quo

By maintaining the status quo, all assets that have been discussed in the Underground Circuit Renewal program will remain in the distribution system until eventual failure, at which point the assets will be replaced on a like-for-like basis with similar assets. Doing so is expected to perpetuate the safety and reliability problems discussed in section E6.1.3.

(ii) Replacement with Standard Equipment

All assets that have been discussed will be replaced with newer, standard assets. This will allow the distribution system to benefit from these assets as discussed in section E6.1.2. Table 7 summarizes the existing assets in the field and their proposed replacement options.

TABLE 6: SUMMARY OF EXISTING AND PROPOSED REPLACEMENT ASSETS

Asset Class	Existing Type	Proposed Replacement Asset [6]
Switches	Pad-mounted	SCADA operated, SF_6-insulated switches
	Oil-insulated	
	Vintage URD	
	Mini-rupter	
Transformer	Non-switchable submersible	Switchable, submersible
	Pad-mounted	Pad-mounted
	Building vault	Building vault
Cable	Direct buried XLPE	TR-XLPE cable in new concrete encased duct
	XLPE in direct buried duct	
	End-of-life TR-XLPE in duct [7]	

The replacement of underground switches, transformers and cable in the first year of the program will result in an ARC of $102.93 million, as detailed in Table 8. This value represents the avoided cost of executing the first year of activities as scheduled as opposed to deferring these activities until 2020. These avoided costs include quantified risks, taking into account the assets' probability of failure and multiplying this figure by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement. Further details on the ARC approach is provided in Section D3.3.

[6] Based on Toronto Hydro's standard design practice
[7] In this case only the end of life "cable" is replaced. The existing duct structure will be re-used.

TABLE 7: AVOIDED RISK COST BUSINESS CASE EVALUATION

Business Case Element	Cost (in Millions)
Asset Renewal	
Present Value of Net Cost in 2020 **[PV(NET_COST(2020)]**	$192.56
Net Cost for the First Year of Activity **[NET_COST(First Year of Activity)]**	$96.00
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - (NET_COST(First Year of Activity))]	$102.93

E6.1.7 2015 Project Details

Table 9 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

(a) previously filed projects that appeared as jobs in the OEB approved Underground Infrastructure segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 8: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	**CIR Projects**
18.6	77.3

IC

Table 10 lists all projects that will be partially or completely executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 9: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
E11628	E11628 Morningview UG Rebuild Phase 1 - Elec (47M3)	$344,403	2014	ICM
E11629	E11629 Morningview UG Rebuild Phase 2 - Elec (47M3)	$574,005	2014	ICM
E11803	E11803 Rebuild feeder egress H9M32 and M26 Ellesmere-Civil	$770,354	2015	CIR
E12128	E12128 Morningview UG Rebuild Phase 3 -Civil(47M3)	$1,607,213	2014	ICM
E12210	E12210 - Venture Drive UG SCNT47M1 - Civ / Elec	$1,838,314	2015	ICM
E12213	E12213 - Morningside Casebridge SCNT47M1 - Elec	$1,963,487	2015	ICM
E12217	E12217 Windfield Bayview Area Rebuild (51M21, NYSS27F1)	$172,201	2014	ICM
E12243	E12243 Durnford-Rylander-Tideswell Rebuild ph2 Electrical (47M17)	$57,400	2014	ICM
E12244	E12244 Tallpine Rebuild Phase Electrical (47M17)	$688,805	2014	ICM
E12251	E12251 Scenic Millway Rebuild SS27 - Electrical	$1,722,014	2014	ICM
E12267	E12267 Clappison Rebuild Electrical (47M17)	$229,602	2014	ICM
E12278	E12278 Nashdene-Tiffield UG Rebuild - Elec (NAR26M22) (DESIGN ONLY)	$3,628,734	2015	CIR
E12302	E12302 McNicoll Maybrook SCNAR26M32 UG Rebuild – Civil	$1,378,994	2015	CIR
E12310	E12310 Scunthorpe Invergordon UG Rebuild Ph A - Civil H9M26 SCNAH9M26	$1,273,978	2015	CIR
E12311	E12311 Scunthorpe Invergordon UG Rebuild Ph A - Electrical H9M26 SCNAH9M26	$739,958	2015	CIR
E12324	E12324 Dynamic Dr/McNicoll - Electrical (NAR26M32)	$919,012	2015	CIR
E12331	E12331 Civil Works for Rebuild of NYSS38F2 off Bunty Lane NYSS38F2	$51,856	2015	CIR
E12346	E12346 Bluffwood Saddletree Electrical NY51M3	$124,286	2015	ICM
E12380	E12380 Rebuild of NY51M4 Consumers Rd & Victoria Park Areas - Electrical NY51M4	$1,540,160	2015	CIR
E12385	E12385 Don Mills / Eglinton Rebuild - Civil (53M1)	$131,366	2015	ICM

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
E12386	E12386 Don Mills / Eglinton Rebuild - Electrical (53M1)	$285,129	2015	ICM
E12400	E12400 Cass Ave UG VC NHF3 to 502M22 - Civil SCNHF3	$2,247,023	2015	CIR
E12406	E12406 Palmdale Dr UG VC NHF3 to 502M22 - Civil SCNHF3	$1,203,205	2015	CIR
E12409	E12409 Thimble Berryway Aspenwood UG Rebuiild Electrical NY51M3	$206,194	2015	ICM
E12428	E12428 Rebuild of NY51M4 Consumers Rd & Victoria Park Areas - Civil NY51M4	$342,386	2015	CIR
E12430	E12430 Cherrystone Aspenwood - Electrical (51M27)	$166,171	2015	ICM
E12477	E12477 Middlefield Passmore StateCrown Civil SCNAR26M21	$1,403,077	2015	CIR
E12487	E12487 Middlefield Industrial UG 63M6 Rebuild-Civil SCNT63M6	$859,191	2015	CIR
E13041	E13041 Ironside Crescent UG Rebuild Civil SCNAR26M21	$953,041	2015	ICM
E13046	E13046 NY53M26 UG Rebuild in Curlew and Victoria Park areas – Civil	$348,912	2015	CIR
E13065	Rebuild of SCNAE5-1M25 by Brimley Rd and Skagway Avenue – Electrical	$392,239	2015	ICM
E13069	E13069 NY51M24 UG Rebuild North of Finch	$430,208	2014	ICM
E13194	E13194 off Don Mills/Graydon Hall UG Reh (NY51M29)	$2,066,416	2014	ICM
E13212	E13212 Teesdale Place UG Reb Civil (SCNAR43M27)	$240,432	2015	CIR
E13240	E13240 51M22, 51M4 UG rehab off Sheppard & Victoria Park Intersection-Civil	$633,781	2015	CIR
E13621	Brandy Court PandC Civil Elec NY53M24	$113,533	2015	CIR
E13673	E13673 FESI mitigation 47M13 submersible transformer SCNA47M13	$75,664	2015	CIR
E14008	E14008 Rebuild Trunk 502M1 M22 Birchmount – Electrical	$362,801	2015	CIR
E14035	E14035 Teesdale Place UG Rebuild Electrical SCNAR43M27	$360,264	2015	CIR
E14116	E14116 DB Cable Replacements on SS63F1-Cummer & Maxome area-Civil	$262,347	2015	CIR
E14141	E14141 UG Rebuild 502M32 Eastwood SD- Civil	$1,442,504	2015	CIR
E14160	E14160 UG Cable Replacement 53M25 Cassandra 3Ph	$408,725	2015	CIR

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
E14177	E14177 UG Rebuild 502M29 Carabob Crt - Civil	$415,952	2015	CIR
E14179	E14179 UG Rebuild 502M29 Bonis King Henrys- Civil	$936,238	2015	CIR
E14191	E14191 UG Rebuild H9M30 Kingston Mason -Electrical	$623,791	2015	CIR
E14230	E14230 Manse Road 209-245 UG Rebuild Civil	$744,400	2015	CIR
E14234	E14234 Grenoble Gateway UG Rebuild Civl NY53M9	$297,997	2015	CIR
E14236	E14236 185 Galloway UG Rebuild SCNAH9M29 - Civil	$457,867	2015	CIR
E14281	E14281 UG Rebuild VC 64F2 to 51M5 Argonne Simeon- Civil	$1,175,981	2015	CIR
E14322	E14322 Establish Neilson Tapscott R26M34 Main – Electrical	$737,921	2015	ICM
E14411	E14411 Crow Tr Remaining UG Rebuild Civ and Elect R26M34 SCNAR26M34	$473,989	2015	CIR
E14432	E14432 P01 47M1 Mammoth Hall UG Rebuild Ph3 (Electrical) SCNT47M1	$855,398	2015	ICM
E15024	E15024 P01 Sheppard UGDB Cable Reb Ele	$429,796	2015	CIR
E15193	E15193 Leslie-Clovercrest-UG Renewal-Civil & Elec-51M6 NY51M6	$540,298	2015	CIR
E15195	E15195 Morningside Ave UG trunk-Civil NT47M3 SCNT47M3	$431,057	2015	CIR
E15197	E15197 P01-Finch-Sheppard-Replacement 51M22 trunk-Elec-51M22-Leslie Ts	$539,483	2015	CIR
E15198	E15198 Finch-Sheppard-trunk cable repl.-Elec- 51M28 NY51M28	$476,680	2015	CIR
E15231	E15231 Leslie/Finch Replace UG cable 51M23 NY51M23	$137,417	2015	CIR
E15232	E15232 Leslie/Finch Replace UG trunk cable 51M7 NY51M7	$123,896	2015	CIR
E15233	E15233 Woody Vineway & Curly Vineway UG renewal 51M6 NY51M6	$290,478	2015	CIR
E15267	E15267 -P162 Bermondsey Trunk UG Renewal Elec 53M2, M12, M27, M28 NY	$1,687,487	2015	CIR
E15270	E15270 Victoria Park Gordon Baker UG renewal Phase II Civil 51M32 NY51M3	$1,456,519	2015	CIR
E15273	E15273 Wynford Heights Crescent UG Renewal Elec NY53M2	$378,823	2015	CIR
E15306	E15306 Leslie Francine Gideon Conversion Civil SS68-F10 to 51M3	$2,695,018	2015	CIR

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
	NYSS68F1			
E15307	E15307 Bridgeport UG Rebuild Ph1 - Civil 47M13 SCNA47M13	$1,896,861	2015	CIR
E15316	E15316 Leslie Threadneedle Clansman Conversion SS68F10 to 51M3 NYSS68F10	$501,360	2015	CIR
E15317	E15317 Bridgeport UG Rebuild Ph2 - Civil 47M13 SCNA47M13	$1,853,593	2015	CIR
E15318	E15318 Bridgeport UG Rebuild Ph3 - Civil 47M13 SCNA47M13	$1,943,271	2015	CIR
E15324	E15324 Paul Markway Conversion Civil SS68-F10 to 51M27 NYSS68F10	$559,217	2015	CIR
E15325	E15325 Paul Markway Conversion Elec SS68-F10 to 51M27 NYSS68F10	$123,755	2015	CIR
E15328	E15328 McNicoll Leslie Conversion Civil SS68F10 to 51M3 NYSS68F10	$2,933,082	2015	CIR
E15332	E15332 Guildpark Pathway UG Rebuild - Civil H9M30 SCNAH9M30	$401,734	2015	CIR
E15342	E15342 Tahoe Court UG Rebuild Civil NY53M24	$243,928	2015	CIR
E15350	E15350 Confederation Angora UG Rebuild - Civil H9M30 SCNAH9M30	$2,007,342	2015	CIR
E15353	E15353 Brahms Clansman Don Mills Conversion Civil SS68-F1 to 51M27	$569,495	2015	CIR
E15355	E15355 Gracemount UG Rebuild - Civil H9M30 SCNAH9M30	$975,476	2015	CIR
E15356	E15356 Gracemount UG Rebuild - Electrical H9M30 SCNAH9M30	$340,470	2015	CIR
E15379	E15379 Victoria Park York Mills UG cable replacement 51M25 NY51M25	$817,406	2015	CIR
E15390	E15390 Scunthorpe Invergordon UG Rebuild Ph B - Civil H9M26 SCNAH9M26	$1,466,283	2015	CIR
E15392	E15392 Scunthorpe Invergordon UG Rebuold Ph D - Civil H9M26 SCNAH9M26	$1,737,054	2015	CIR
E15393	E15393 Scunthorpe Invergordon UG Rebuild Ph E - Civil H9M26 SCNAH9M26	$761,102	2015	CIR
E15395	E15395 Consumers Rd Sheppard UG Renewal 51M28 NY51M28	$929,773	2015	CIR
E15397	E15397 Scunthorpe Invergordon UG Rebuild Ph G- Civil H9M26 SCNAH9M26	$900,235	2015	CIR
E15429	E15429 Bridletowne-Warden 1-Ph UG	$1,738,101	2015	CIR

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
	Rehab Civ SCNA502M22			
E15442	E15442 McGrisken Rd UG Rebuild - Electrical H9M23 SCNAH9M23	$180,272	2015	CIR
E15445	E15445 Cromwell Senator UG Rebuild - Civil 47M14 SCNA47M14	$1,594,380	2015	CIR
E15476	E15476 45 Birchmount Road UG Rebuild Civil SCNAR43M24	$88,288	2015	CIR
E15477	E15477 45 Birchmount UG Rebuild Elec SCNAR43M24	$97,275	2015	CIR
E15558	E15558 Bridletown-Warden 3-Ph UG Rehab Civ SCNA502M22	$97,275	2015	CIR
E15587	1123 Leslie St at Eglinton UG cable replacement 34M5	$32,837	2015	CIR
E16071	E16071 Morningside Ave UG trunk Electrical NT47M3 SCNT47M3	$409,540	2015	CIR
E16110	E16110 Guildpark Pathway UG Rebuild - Electrical H9M30 SCNAH9M30	$318,278	2015	CIR
E16131	E16131 Scunthorpe Invergordon UG Rebuild Ph D - Electrical H9M26 SCNAH9M26	$556,505	2015	CIR
W11156	35M10, M2, M4 & M9 Fairbank TS PILC Cable Replacmnt (Revised)	$826,754	2015	CIR
W11161	W11161 35M9 Fairbank TS PILC Cable Replacmnt	$74,025	2015	CIR
W11170	W11170 35M4 Fairbank TS PILC Cable Replacmnt	$215,957	2015	CIR
W11287	W11287 FESI - NY55M22 - Lateral Cable Replacmnt - Rowntree (ph4)	$718,430	2015	CIR
W11288	W11288 FESI 55M22 LATERAL CABLE REPLACEMENT-ISLINGTON	$332,907	2015	CIR
W12077	Hoggs Hollow PH4	$1,722,014	2013	ICM
W12308	W12308 FESI Clubhouse Crt and Brookwell Dr Rebuild	$1,290,728	2015	CIR
W12480	W12480 Primary Trunk Cable Replacement-The East Mall	$585,421	2015	CIR
W13114	W13114 Trunk Cable Replacement-The East Mall-ETHL-F2/F4	$597,047	2015	CIR
W13284	W13284 UG Lateral Repalcement Phase 1	$1,509,954	2015	CIR
W13287	W13287 UG Lateral Repalcement Phase 2	$1,951,438	2015	CIR
W14130	Rebuild Russfax & Twin Circle Crt	$439,236	2015	CIR
W14217	UG Lateral Cable Replacement - Signet/Kenhar 55M1	$1,063,379	2015	CIR

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
W14274	UG Lateral Cable Replacement - Fenmar/Ormout 55M1	$1,055,354	2015	CIR
W14653	W14653-P01-Richview Feeder Egress Via Kelfield Rd	$1,341,461	2015	ICM
W14730	W14730-P01-Cable Upgrade to Increase Capacity on 88M46	$116,478	2015	CIR
W15268	W15268 - P01 - Red Robinway & Arnott UG Direct-Buried Cable Renewal CIVIL	$507,205	2015	CIR
W15269	W15269 - P01 - Red Robinway & Arnott UG Direct-Buried Cable renewal ELEC	$578,936	2015	CIR
W15278	W15278 The East Mall area UG Voltage Conversion Civil LDF1, LDF2 and LDF3 LDF1	$622,916	2015	CIR
W15279	W15279 - Dundas/Shaver area UG VC Civil QCF1, QCF2 and QCF3	$617,408	2015	CIR
W15298	W15298 West of Kipling Avenue, UG Voltage Conversion AHF2, AHF5	$573,753	2015	CIR
W15357	W15357 270 The Kingsway, Upgrade PT44103 Humbertown Plaza, 38M7 38-M7	$208,386	2015	CIR
W15363	W15363 150 Berry Rd VC of Tx/Sw at loc PT7257 to feeder 38M29 T-F1	$386,009	2015	CIR
W15462	W15462 Alcester Crt Underground Rebuild 35M7	$304,772	2015	CIR
W16076	W16076 - P01 Mayall Avenue Underground Rebuild 55M26	$564,185	2015	CIR
X12138	X12138 Larksong Crt Feeder DB Cable Replace (53M8) (DESIGN ONLY)	$240,187	2015	CIR
X12497	X12497 - Lotherton Parkway UG reconfiguration NY35M12	$880,289	2015	CIR
X15590	Electrical Work for the Replacement of A60CS and A61CS	$72,565	2015	CIR

The following subsections provide project details for all 2015 projects.

E11628, E11629, E12128 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Morningview UG Rebuild Phases 1 & 2 - Elec and Phase 3 – Civil (47M3)

Project Number: E11628, E11629, E12128

Project Year: 2015

Estimated Cost: $2,525,621.00

(i) Objective

Rebuild the UG distribution system of the Morningview area under consideration. The civil portion of Phase 1 and 2 has been completed. E11628 and E11629 will complete the electrical portion. E12128 will complete the civil portion of Phase 3. All projects appeared in the ICM approved segment.

(ii) Scope of Work

TABLE 10: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Sheppard TS (27.6kV)
Feeder(s):	SCNT47M3

TABLE 11: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	6,350.28m + 5,568.91m
Underground Transformers	35 + 33
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

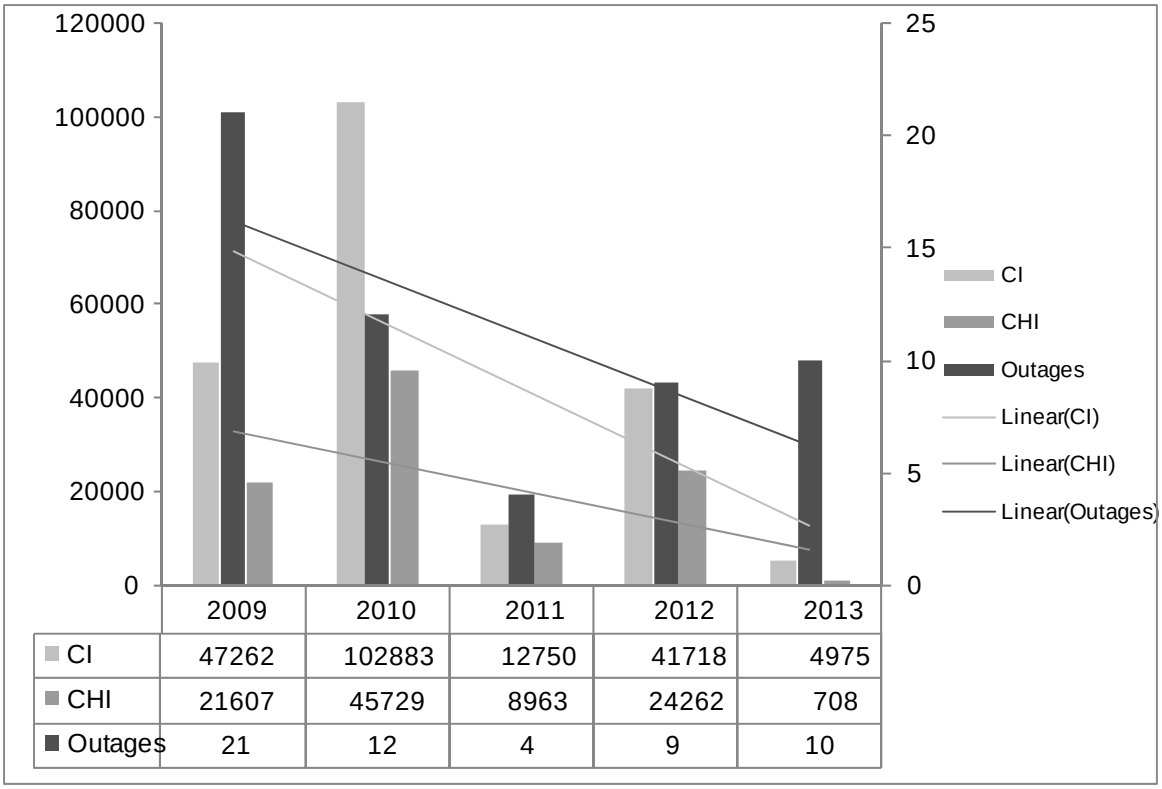
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 12: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1984 (30 years old)
Reliability	ƒ The feeder was the Worst Performing Feeder (WPF) from 2005 to 2012 ƒ Reliability improvements seen due to recent rebuilds, however feeder is still ranks second in the WPF list with 10 sustained outages in 2013 alone
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 32.



	2009	2010	2011	2012	2013
CI	47262	102883	12750	41718	4975
CHI	21607	45729	8963	24262	708
Outages	21	12	4	9	10

FIGURE 32: HISTORICAL RELIABILITY DETAILS FOR SCNT47M3

E11803 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E11803 Rebuild feeder egress H9M32 and M26 Ellesmere-Civil

Project Number: E11803

Project Year: 2015

Estimated Cost: $770,354

(i) Objective

Replace the old and partially direct buried cables for the egress of feeder H9M32 and H9M26 from Ellesmere TS station. E11803 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 13: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Centre
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCH-A9M32, SCH-A9M26

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

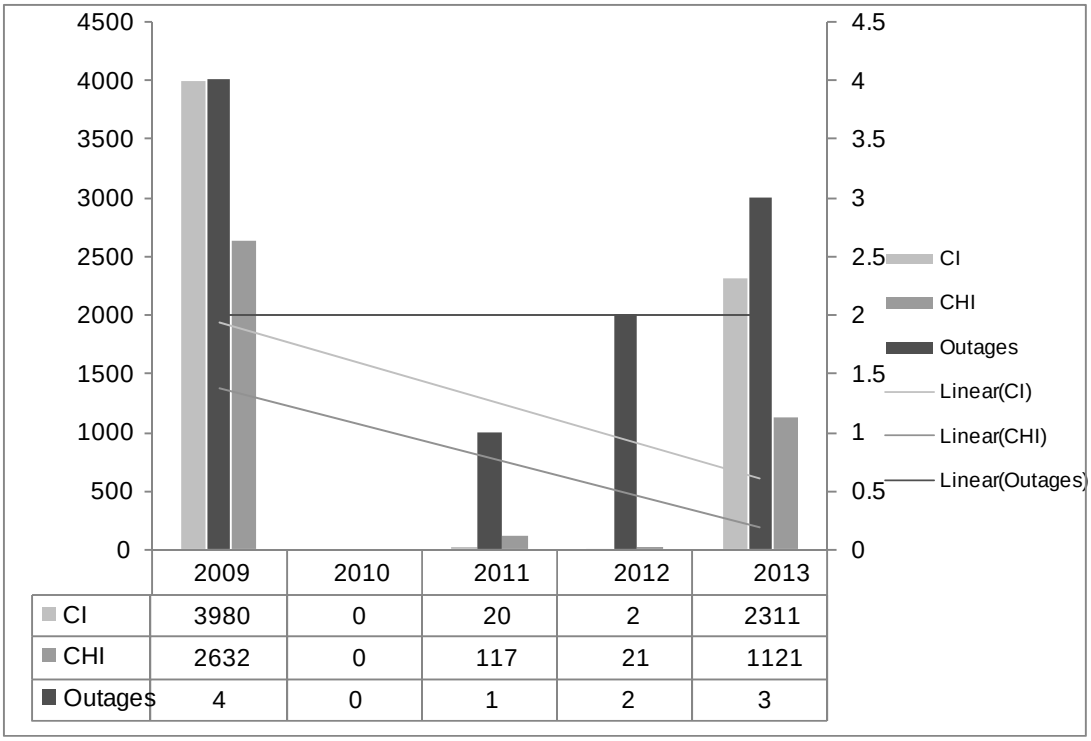
TABLE 14: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1979 (35 years old)
Reliability	ƒ Increasing number of outages from 2011 to 2013, not including momentary outages
Other (i.e. road	ƒ N/A

Supplemental Details	Description
moratoriums, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 33 and 34.

FIGURE 33: HISTORICAL RELIABILITY DETAILS FOR SCNAH 9M32



	2009	2010	2011	2012	2013
CI	3980	0	20	2	2311
CHI	2632	0	117	21	1121
Outages	4	0	1	2	3

FIGURE 34: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M26

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E12210 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12210 - Venture Drive UG SCNT47M1 - Elec

Project Number: E12210

Project Year: 2015

Estimated Cost: $1,838,314

(i) Objective

Rebuild a portion of SCNT47M1 out of Sheppard TS to improve reliability and service to customers. The civil portion has been completed. E12210 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 15: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Sheppard TS
Feeder(s):	SCNT47M1

TABLE 16: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	3,490.06 m
Underground Transformers	0
Underground Switchgear	1
Poles	0
Overhead Transformer	0
Overhead Switch	1

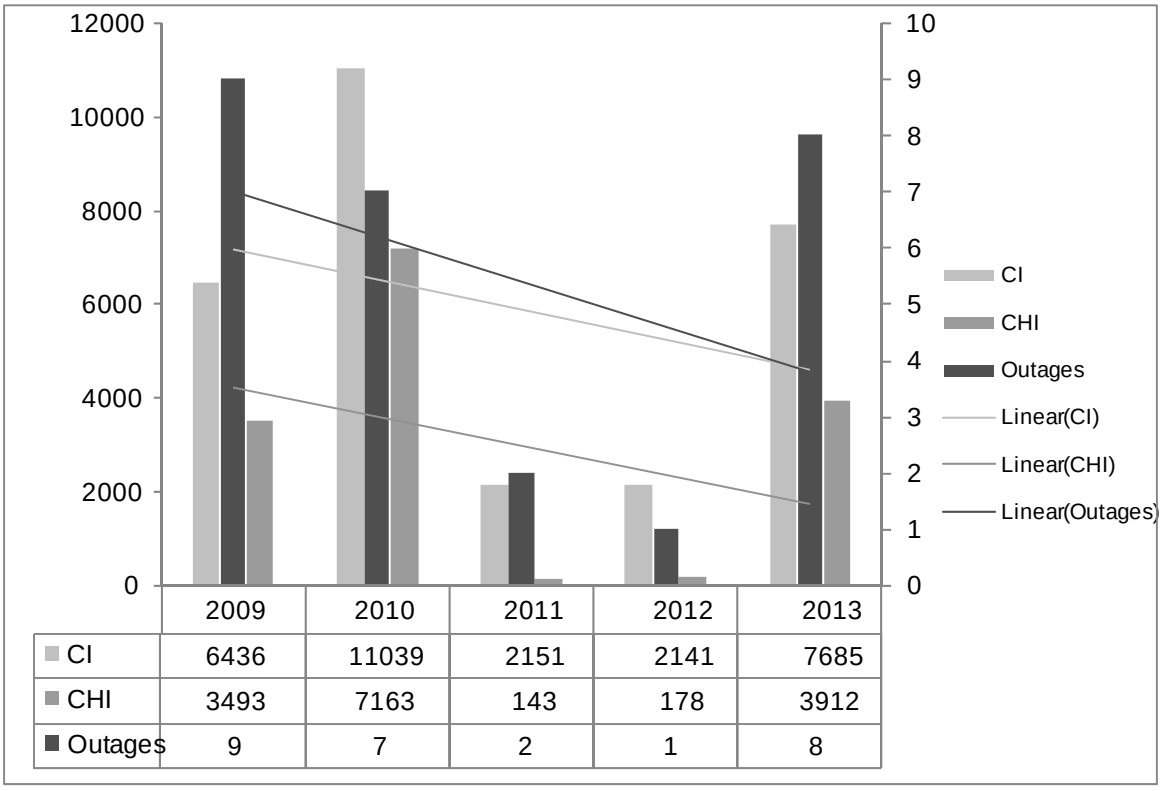
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 17: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1983 (31 years old)
Reliability	ƒ Reliability improvements seen up until 2012 ƒ Reliability weakened in 2013, with the feeder experiencing 8 sustained outages in 2013 alone
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 35.



	2009	2010	2011	2012	2013
CI	6436	11039	2151	2141	7685
CHI	3493	7163	143	178	3912
Outages	9	7	2	1	8

FIGURE 35: HISTORICAL RELIABILITY DETAILS FOR SCNT47M1

E12213 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12213 - Morningside Casebridge SCNT47M1 - Elec

Project Number: E12213

Project Year: 2015

Estimated Cost: $1,963,487

(i) Objective

Rebuild a portion of SCNT47M1 out of Sheppard TS to improve reliability and service to customers. The civil portion has been completed. E12210 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 18: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Sheppard TS
Feeder(s):	SCNT47M1

TABLE 19: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	3,018.14 m
Underground Transformers	0
Underground Switchgear	1
Poles	0
Overhead Transformer	0
Overhead Switch	0

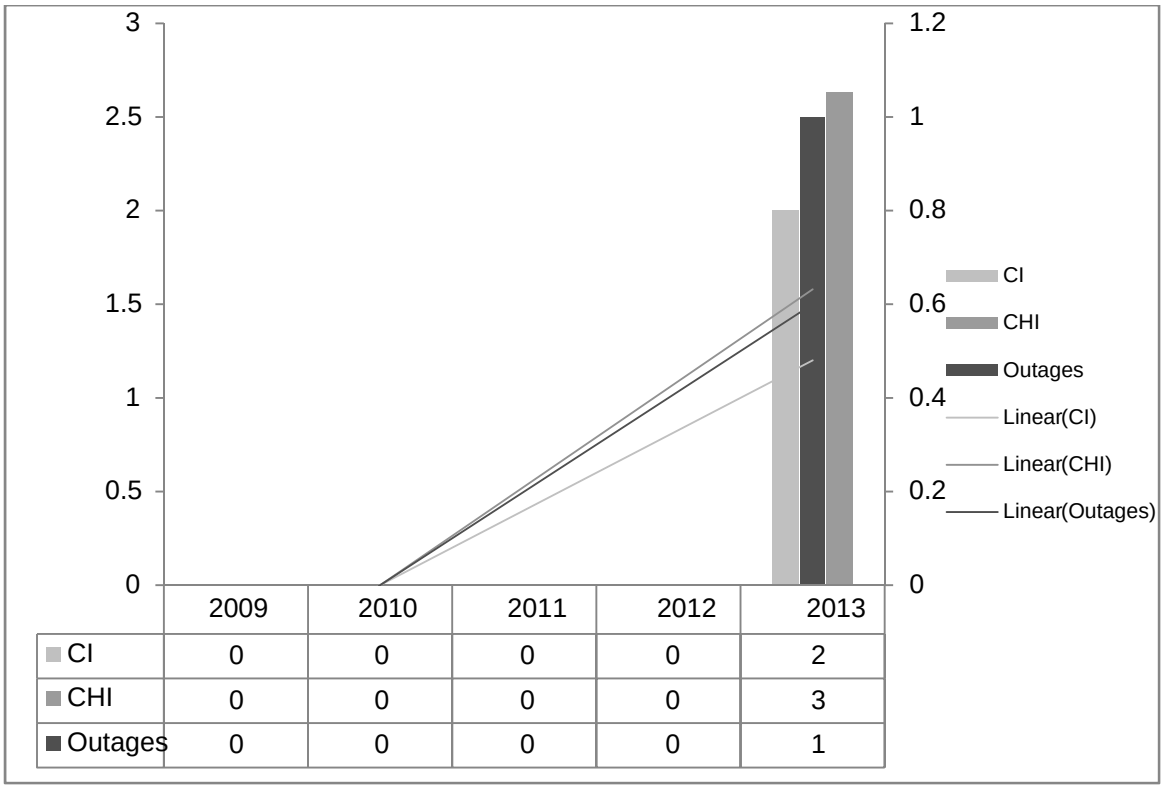
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 20: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1983 (31 years old)
Reliability	ƒ Reliability improvements seen up until 2012 ƒ Reliability weakened in 2013, with the feeder experiencing 8 sustained outages in 2013 alone
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 36.



	2009	2010	2011	2012	2013
CI	0	0	0	0	2
CHI	0	0	0	0	3
Outages	0	0	0	0	1

FIGURE 36: HISTORICAL RELIABILITY DETAILS FOR SCNT47M1

E12217 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12217 Windfield Bayview Area Rebuild (51M21, NYSS27F1)

Project Number: E12217

Project Year: 2015

Estimated Cost: $172,201

(i) Objective

Rebuild 4.16kV primary distribution system fed by Windfield MS (SS27) by converting to 27.6kV system. Most of the load from this station will be connected to NY51M21. To increase efficiency, this project combines OH and UG work that is needed to complete the conversion. E12217 is ICM approved.

(ii) Scope of Work

TABLE 21: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Windfield MS (4.16kV)
Feeder(s):	NYSS27F1, NYSS27F2, NYSS27F3

TABLE 22: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	278.34m
Underground Transformers	1
Underground Switchgear	0
Poles	52
Overhead Transformer	27
Overhead Switch	0

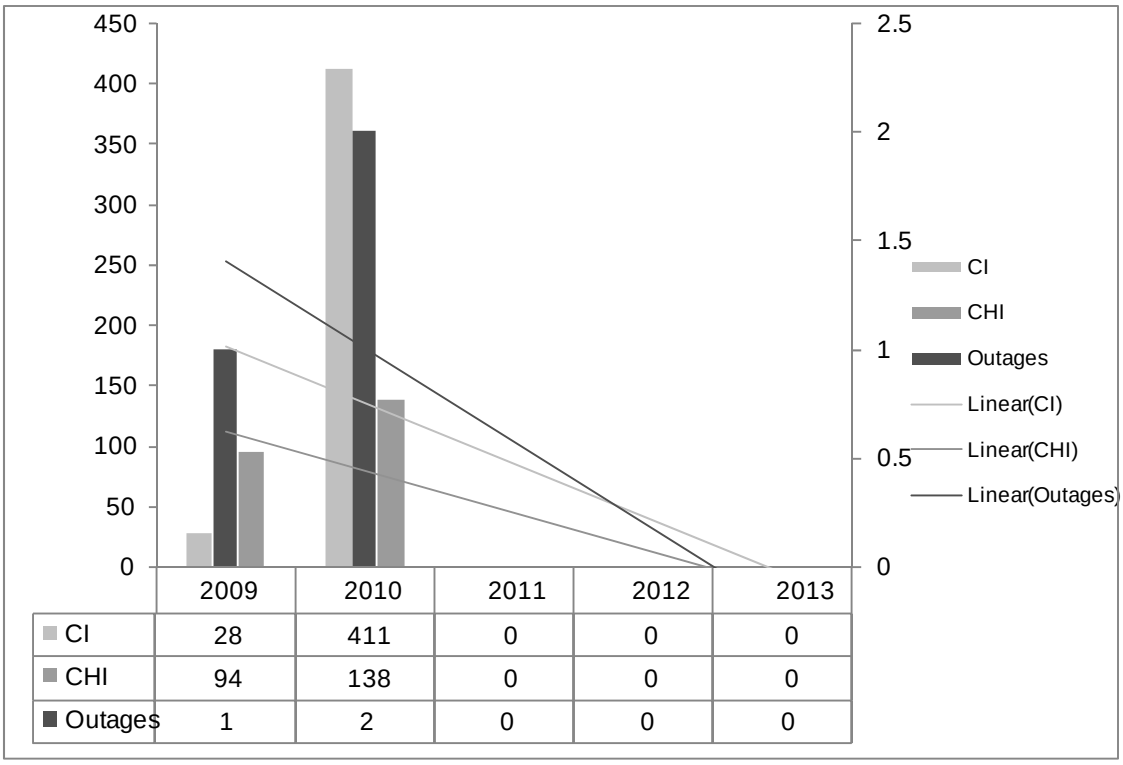
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 23: SUPPLEMENTAL DETAILS

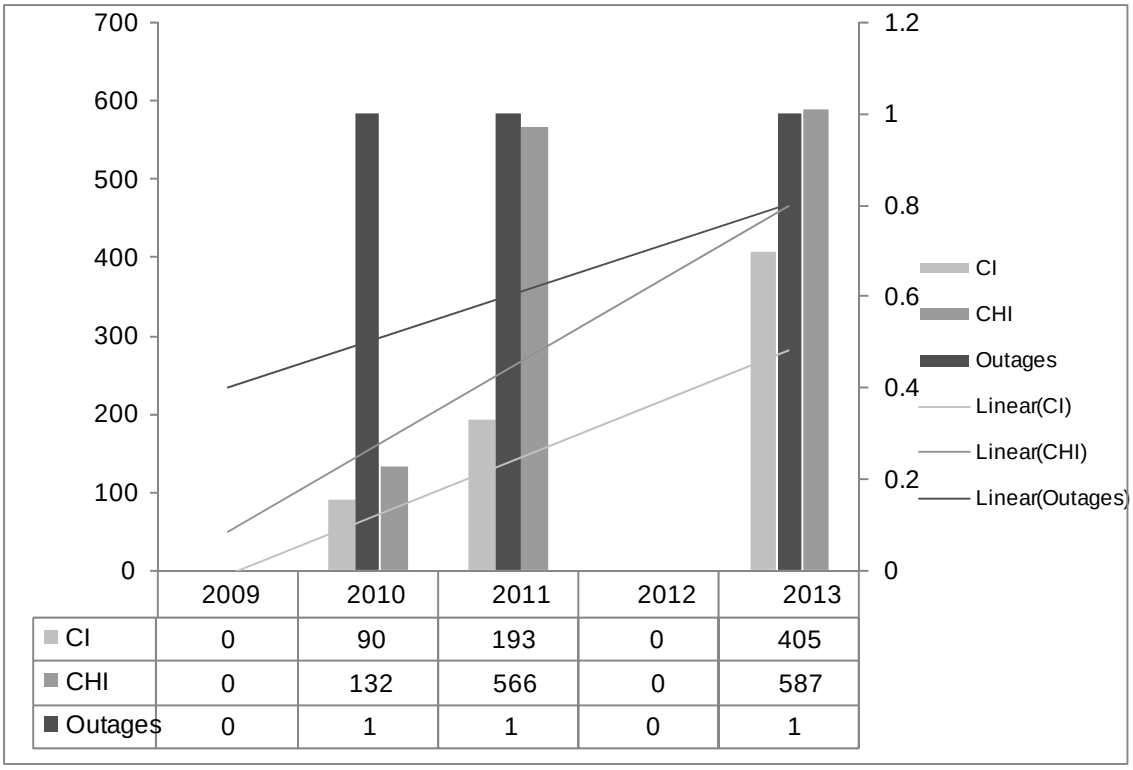
Supplemental Details	Description
Age/Condition	• Windfield MS built mid-1960. • Station equipment has reached the end of their useful service life
Reliability	• Windfield MS is an isolated 4kV distribution • Station lacks backup supply in the event of station failure • Station has experienced overloading in the past
Other (i.e. road moratoriums, etc)	• Voltage conversion in the area will address islanding and station overloading

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 37 to 39.



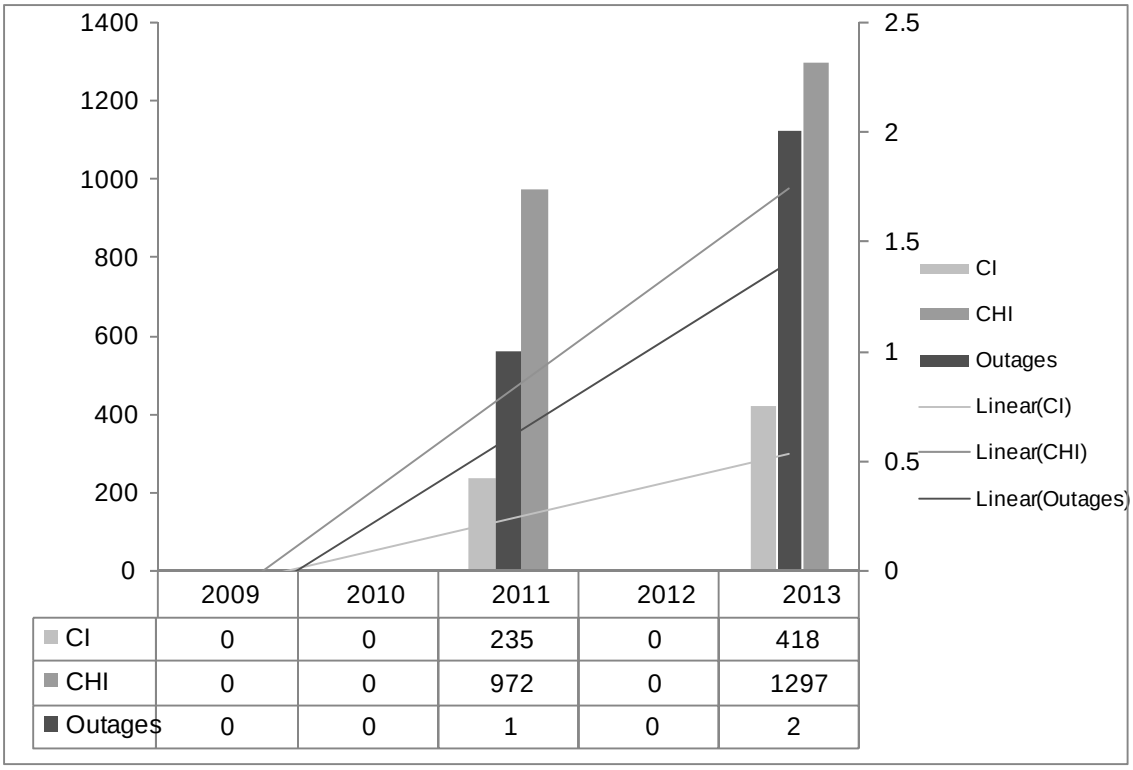
	2009	2010	2011	2012	2013
CI	28	411	0	0	0
CHI	94	138	0	0	0
Outages	1	2	0	0	0

FIGURE 37: HISTORICAL RELIABILITY DETAILS FOR NYSS27F1



	2009	2010	2011	2012	2013
CI	0	90	193	0	405
CHI	0	132	566	0	587
Outages	0	1	1	0	1

FIGURE 38: HISTORICAL RELIABILITY DETAILS FOR NYSS27F2



	2009	2010	2011	2012	2013
CI	0	0	235	0	418
CHI	0	0	972	0	1297
Outages	0	0	1	0	2

FIGURE 39: HISTORICAL RELIABILITY DETAILS FOR NYSS27F3

E12243 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12243 Durnford-Rylander-Tideswell Rebuild Ph2 Electrical (47M17)

Project Number: E12243

Project Year: 2015

Estimated Cost: $57,400

(i) Objective

Rebuild the old direct-buried and failing primary 3-phase distribution line passing along Durnford Rd, Rylander Blvd, Tideswell Blvd, Vandorf St and Sheppard Ave.

E12243 will complete the electrical portion of the project, which was ICM approved.

(ii) Scope of Work

TABLE 24: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough East
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCNA47M17

TABLE 25: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,998.85m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

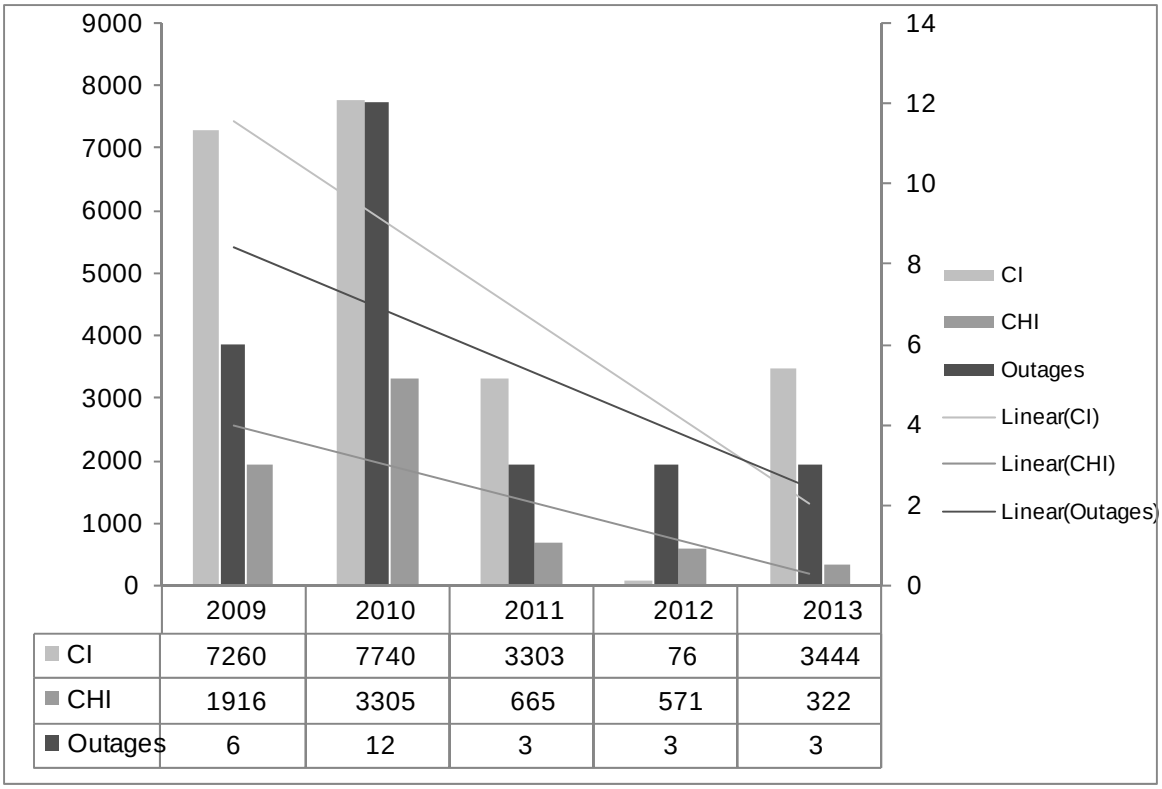
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 26: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1984 (30 years old)
Reliability	ƒ N/A
Other (i.e. road moratoriums, etc)	ƒ The adjacent areas have been rebuilt, which improved the reliability of the feeder ƒ It is prudent to complete the rebuild of the remaining adjacent area to maintain reliability improvements ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 40.



	2009	2010	2011	2012	2013
CI	7260	7740	3303	76	3444
CHI	1916	3305	665	571	322
Outages	6	12	3	3	3

1 FIGURE 40: HISTORICAL RELIABILITY DETAILS FOR SCNA47M17

E12244 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12244 Tallpine Rebuild Phase Electrical (47M17)

Project Number: E12244

Project Year: 2015

Estimated Cost: $688,805

(i) Objective

Rebuild the old direct-buried and failing primary single-phase distributions consisting three lateral loops supplying houses on Vandorf St, Tallpines Ct, John Graham Ct, a section of Sheppard Ave, Raycliff Ct, Shallice Ct, Porthclair Ct, Parsborough Ct, Durnford Rd, Rylander Blvd, Tideswell Blvd, Carlisle Cres and Durnford TH complex.

E12244 will complete the electrical portion of the project, which was ICM approved.

(ii) Scope of Work

TABLE 27: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough East
Station(s):	Sheppard TS (27.6kV)
Feeder(s):	SCNA 47M17

TABLE 28: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	4,417.94 m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

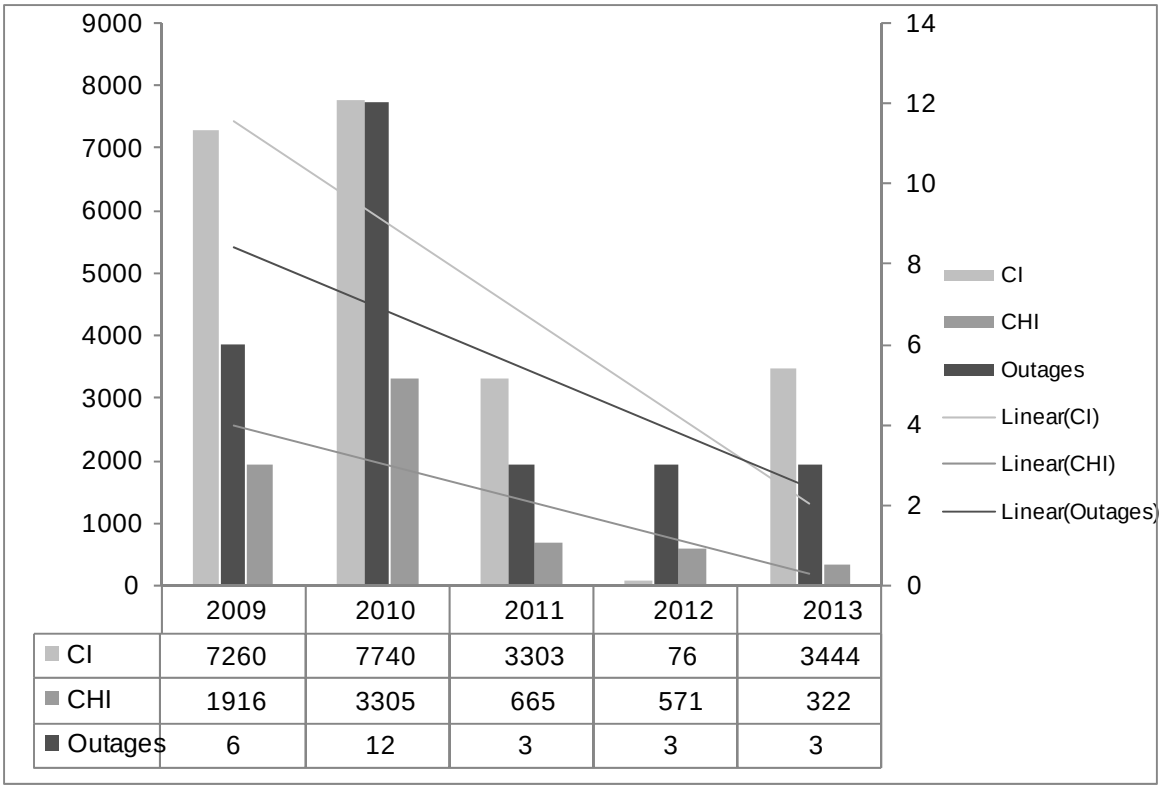
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 29: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1984 (30 years old)
Reliability	ƒ N/A
Other (i.e. road moratoriums, etc)	ƒ The adjacent areas have been rebuilt, which improved the reliability of the feeder ƒ It is prudent to complete the rebuild of the remaining adjacent area to maintain reliability improvements ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 41.



	2009	2010	2011	2012	2013
CI	7260	7740	3303	76	3444
CHI	1916	3305	665	571	322
Outages	6	12	3	3	3

1 FIGURE 41: HISTORICAL RELIABILITY DETAILS FOR SCNA47M17

E12251 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12251 Scenic Millway Rebuild SS27 - Electrical

Project Number: E12251

Project Year: 2015

Estimated Cost: $1,722,014

(i) Objective

Rebuild 4.16kV primary distribution system fed by Windfield MS (SS27) by converting to 27.6kV system. E12251 will complete the electrical portion of the project, which was ICM approved.

(ii) Scope of Work

TABLE 30: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Winfield MS (4.16kV)
Feeder(s):	NYSS27F2, NYSS27F3

TABLE 31: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,776.4m
Underground Transformers	14
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

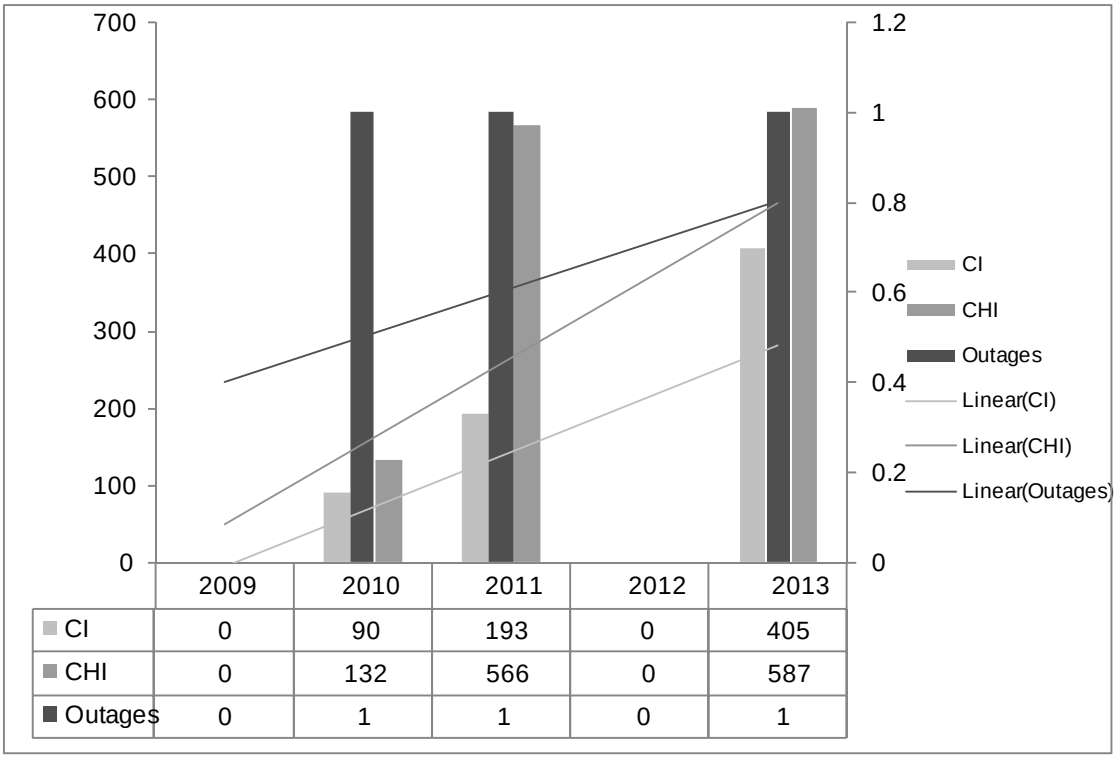
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 32: SUPPLEMENTAL DETAILS

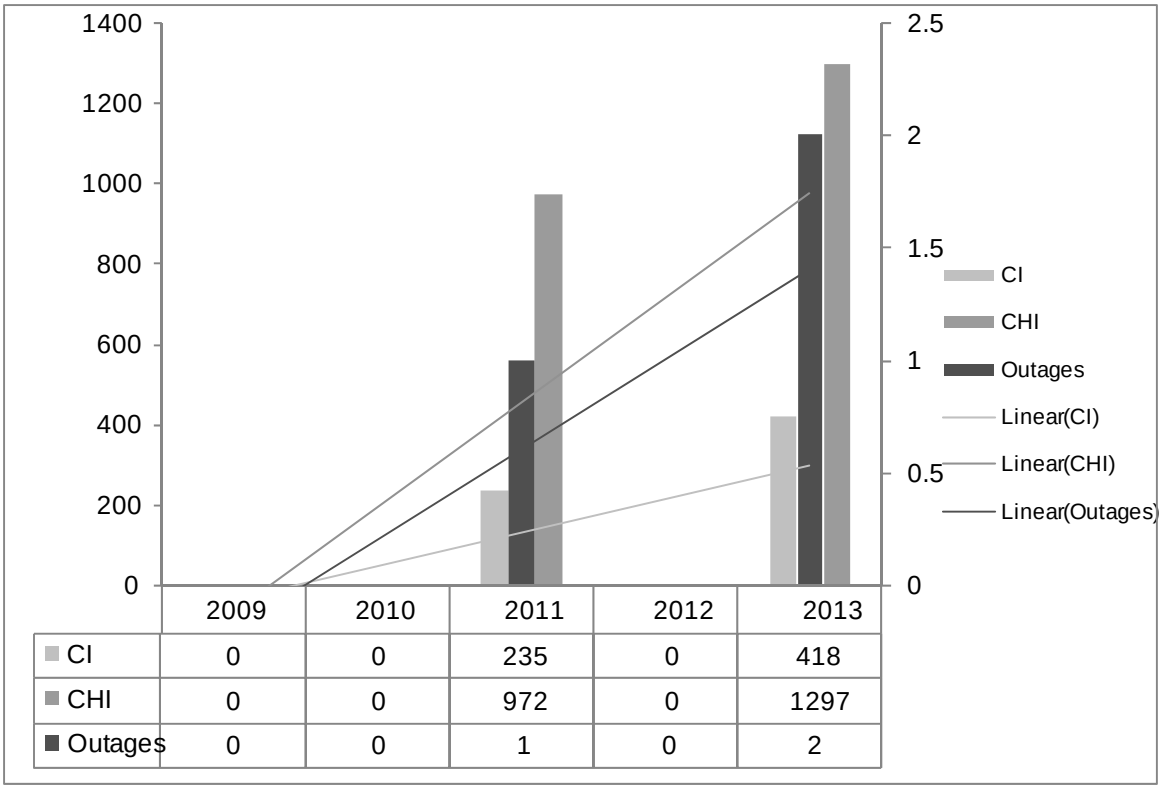
Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed around 1969 (approx. 45 years old)
Reliability	ƒ Reliability is seen to be getting worse over the past five years
Other (i.e. road moratoriums, etc)	ƒ This is part of multi phase voltage conversion job to eliminate overloading of 4.16kV feeders in an isolated 4.16kV system which lost one of the supplying 4kV municipal station (MS) ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 42 and 43.



	2009	2010	2011	2012	2013
CI	0	90	193	0	405
CHI	0	132	566	0	587
Outages	0	1	1	0	1

FIGURE 42: HISTORICAL RELIABILITY DETAILS FOR NYSS27F2



	2009	2010	2011	2012	2013
CI	0	0	235	0	418
CHI	0	0	972	0	1297
Outages	0	0	1	0	2

FIGURE 43: HISTORICAL RELIABILITY DETAILS FOR NYSS27F3

E12267 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12267 Clappis on Rebuild Electrical (47M17)

Project Number: E12267

Project Year: 2015

Estimated Cost: $229,602

(i) Objective

The objective of this project is to rebuild the old and failing primary distribution of Centennial Park II Subdivision (Clappison Blvd.) supplied by feeder NA47M17.

E12267 will complete the electrical portion of the project, which was ICM approved.

(ii) Scope of Work

TABLE 33: SCOPE OF WORK DETAILS

District Neighborhood	Parkdale-High Park
Station(s):	Sheppard TS (27.6kV)
Feeder(s):	SC NA47M17

TABLE 34: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	2,465.84 m
Underground Transformers	3
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

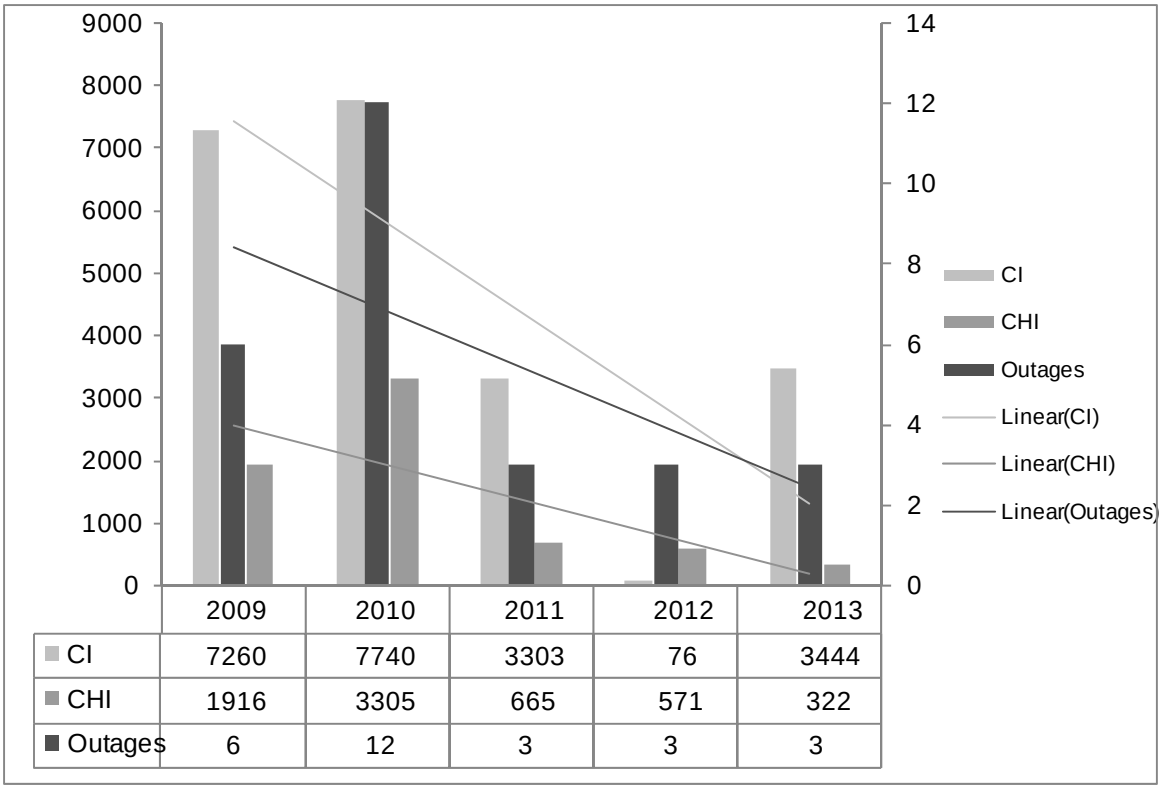
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 35: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed between 1972 and 1989 (ranging from 25 to 42 years old)
Reliability	ƒ Reliability has improved along this feeder due to recent rebuilds ƒ Imperative to complete rebuild in the project area to maintain feeder reliability
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 44.



	2009	2010	2011	2012	2013
CI	7260	7740	3303	76	3444
CHI	1916	3305	665	571	322
Outages	6	12	3	3	3

1 FIGURE 44: HISTORICAL RELIABILITY DETAILS FOR SCNA47M17

E12278 Project Description

Investment Category: **System Renewal**

Program: **Underground Circuit Renewal**

Project Title: **E12278 Nashdene-Tiffield UG Rebuild - Elec (NAR26M22)**

Project Number: **E12278**

Project Year: **2015**

Estimated Cost: **$3,628,734**

(i) Objective

Rebuild a portion of NAR26M22 out of Malvern TS to improve reliability and service to this industrial neighborhood. E12278 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 36: SCOPE OF WORK DETAILS

District Neighborhood	ScarboroughrRouge River
Station(s):	Malvern TS (27.6 kV)
Feeder(s):	SCNAR26M22

TABLE36A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	6,008.98 m
Underground Transformers	0
Underground Switch	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

IC

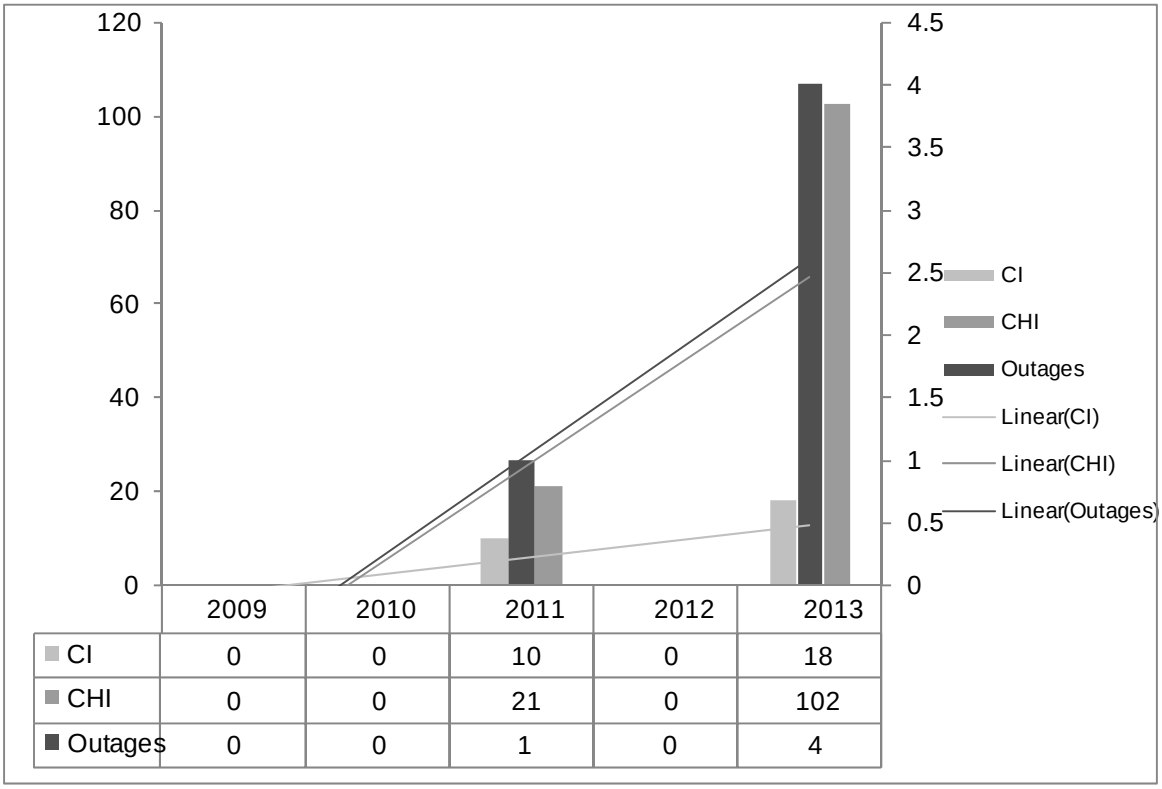
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 37: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1982 (32 years old)
Reliability	ƒ Reliability is getting worse.
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 45.



	2009	2010	2011	2012	2013
CI	0	0	10	0	18
CHI	0	0	21	0	102
Outages	0	0	1	0	4

FIGURE 45: HISTORICAL RELIABILITY DETAILS FOR SCNAR26M22

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E12302 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12302 McNicoll Maybrook SCNAR26M32 UG Rebuild - Civil

Project Number: E12302

Project Year: 2015

Estimated Cost: $1,378,994

(i) Objective

Rebuild a portion of NAR26M32 out of Malvern TS to improve reliability and service to customers. E12302 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 38: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Malvern TS (27.6kV)
Feeder(s):	SCNAR26M32

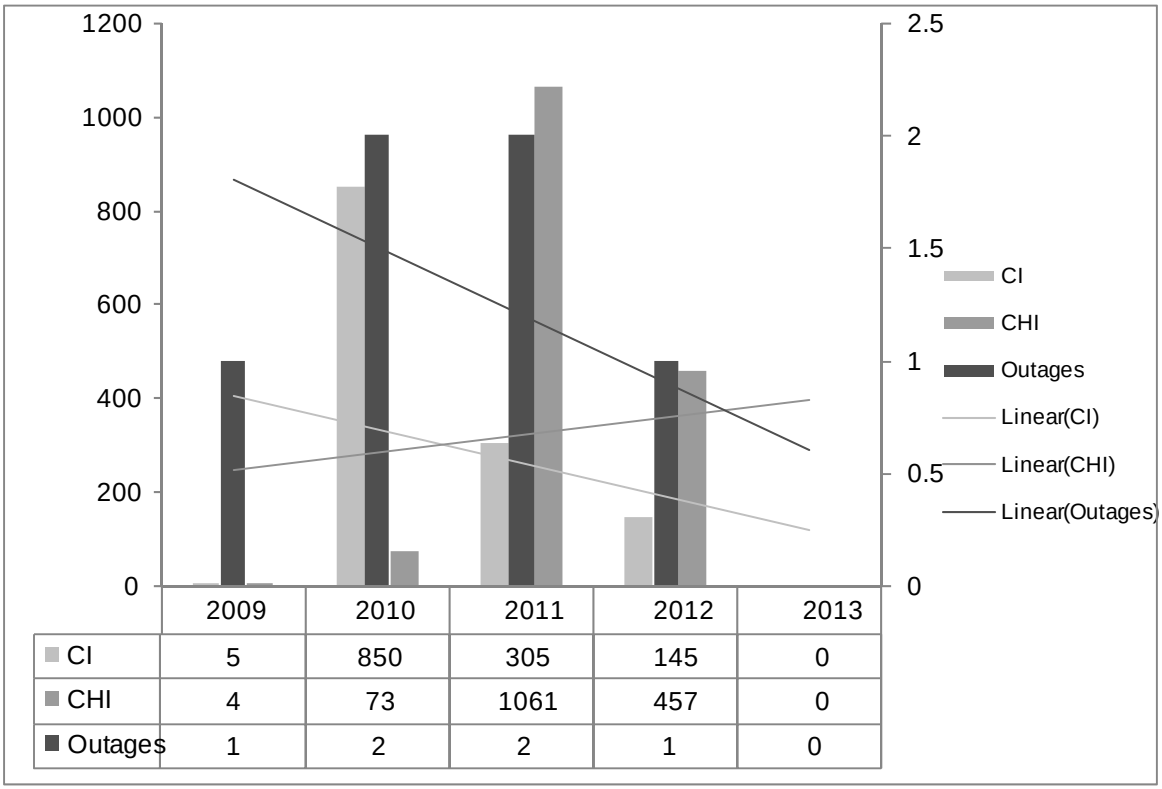
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 39: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1979 (35 years old)
Reliability	ƒ Cables in project area experienced 2 recent failures
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 46.



	2009	2010	2011	2012	2013
CI	5	850	305	145	0
CHI	4	73	1061	457	0
Outages	1	2	2	1	0

FIGURE 46: HISTORICAL RELIABILITY DETAILS FOR SCNAR26M32

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E12310, E12311 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Scunthorpe Invergordon UG Rebuild Ph A – Civil/Electrical H9M26 SCNAH9M26

Project Number: E12310, E12311

Project Year: 2015

Estimated Cost: $ 2,013,936.00

(i) Objective

Replace the old direct-buried 350kcmil primary cables in the area of Scunthrope Rd and Invergordon Ave supplied by feeder NAH9M26. The distribution will be reconfigured to increase operational flexibility and provide better protection.

E12310 will install the civil infrastructure necessary to complete the project; E12311 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 40: SCOPE OF WORK DETAILS

District/Neighborhood	Scarborough/Rouge River
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCNAH9M26

TABLE 41: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	134.1m
Underground Transformers	2
Underground Switchgear	2
Poles	0
Overhead Transformer	0

Assets to be Replaced	
Overhead Switch	0

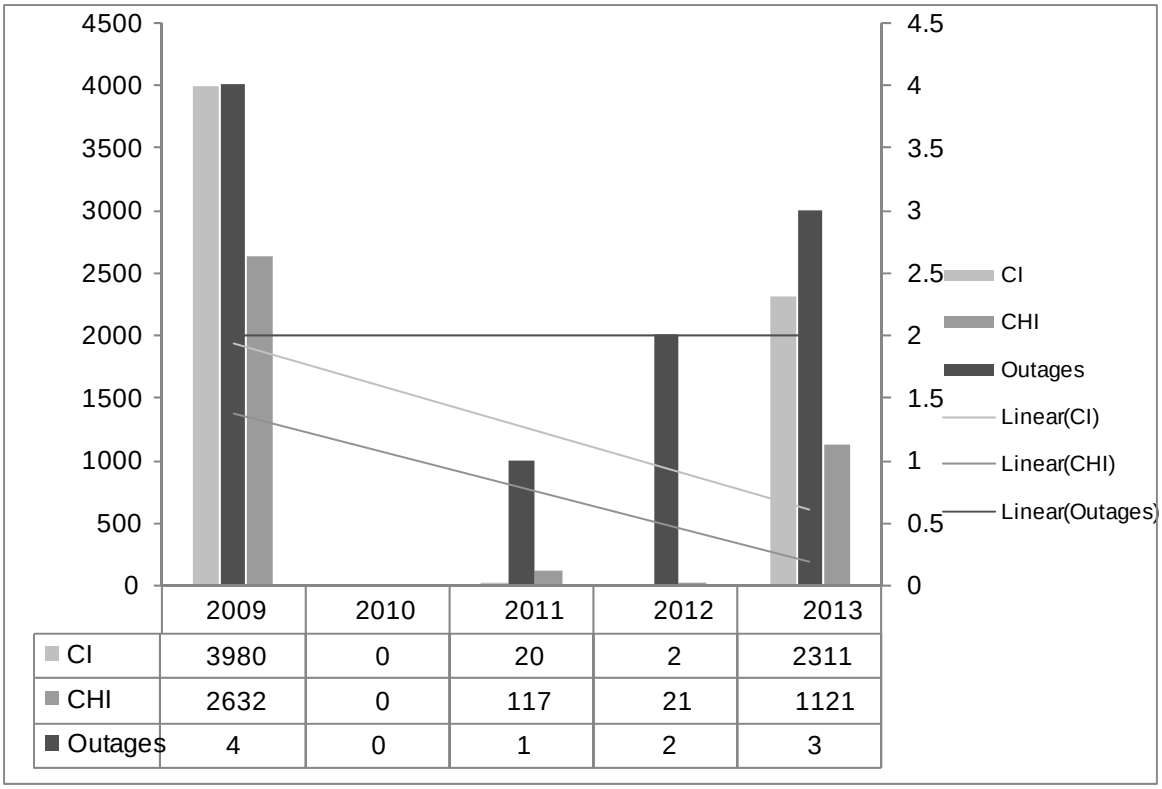
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 42: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1983 (31 years old)
Reliability	ƒ Increasing number of outages from 2011 to 2013, not including momentary outages ƒ High CI and CH ratings ƒ Majority of failures due to primary cable and transformers; both of which are targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ TTC is looking for a rebuild in the area right after the PANAM games ƒ Project needs to be completed before PANAM games, otherwise reliability improvements will be further deferred in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 47.



	2009	2010	2011	2012	2013
CI	3980	0	20	2	2311
CHI	2632	0	117	21	1121
Outages	4	0	1	2	3

FIGURE 47: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M26

E12324 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12324 Dynamic Dr /McNicoll - Electrical (NAR26M32)

Project Number: E12324

Project Year: 2015

Estimated Cost: $919,012

(i) Objective

Rebuild a portion of NAR26M32 out of Malvern TS to improve reliability and service to customers. E12324 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 43: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Malvern TS (27.6kV)
Feeder(s):	SC NAR26M32

TABLE 44: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	3,223.53 m
Underground Transformers	1
Underground Switchgear	1
Poles	0
Overhead Transformer	0
Overhead Switch	1

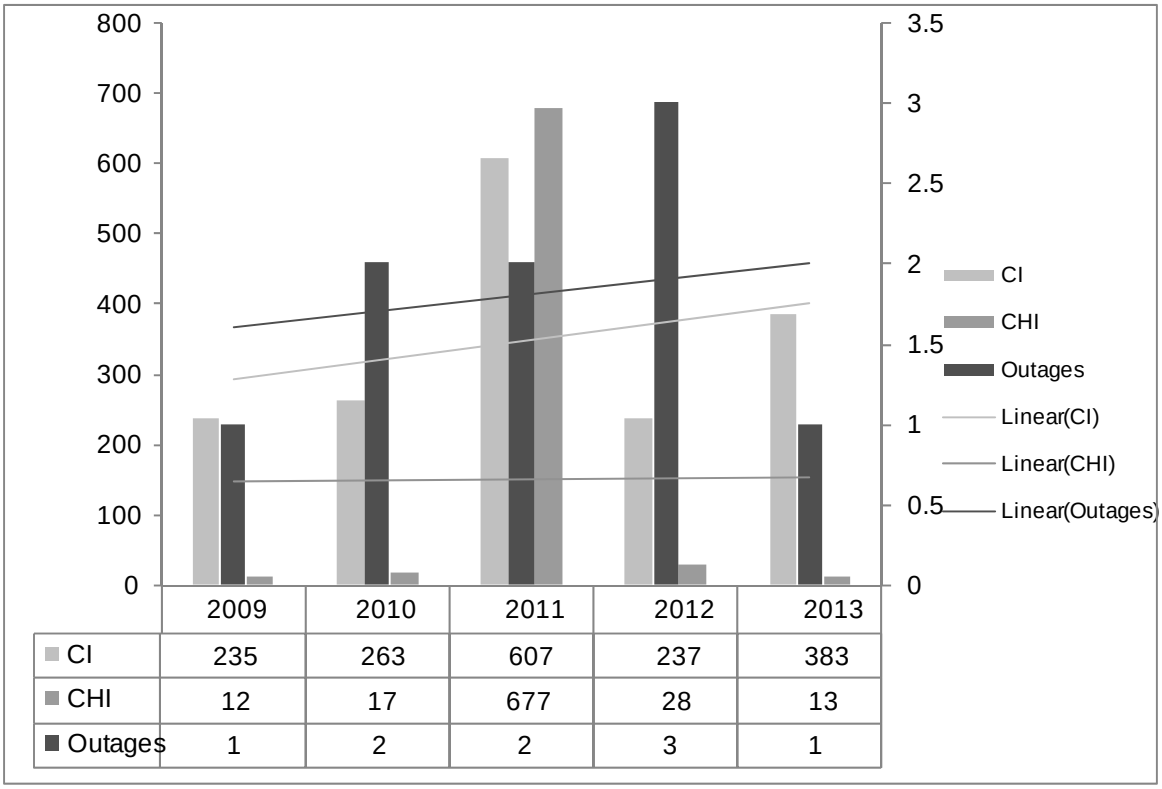
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 45: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1979 (35 years old)
Reliability	ƒ Cables in project area experienced 2 recent failures
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 48.



	2009	2010	2011	2012	2013
CI	235	263	607	237	383
CHI	12	17	677	28	13
Outages	1	2	2	3	1

FIGURE 48: HISTORICAL RELIABILITY DETAILS FOR SCNAR26M32

E12331 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12331 Civil Works for Rebuild of NYSS38F2 off Bunty Lane NYSS38F2

Project Number: E12331

Project Year: 2015

Estimated Cost: $51,856

(i) Objective

Rebuild the aged direct buried 13.8kV infrastructure via voltage conversion to 27.6kV. E12331 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 46: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Burbank MS, Leslie TS
Feeder(s):	NYSS38F2, NY51M8

(iii) Justification & Benefits

This project was created to replace the aged and unreliable assets to minimize both failure risk to the system and safety risk to field crews and the public while maintaining system reliability.

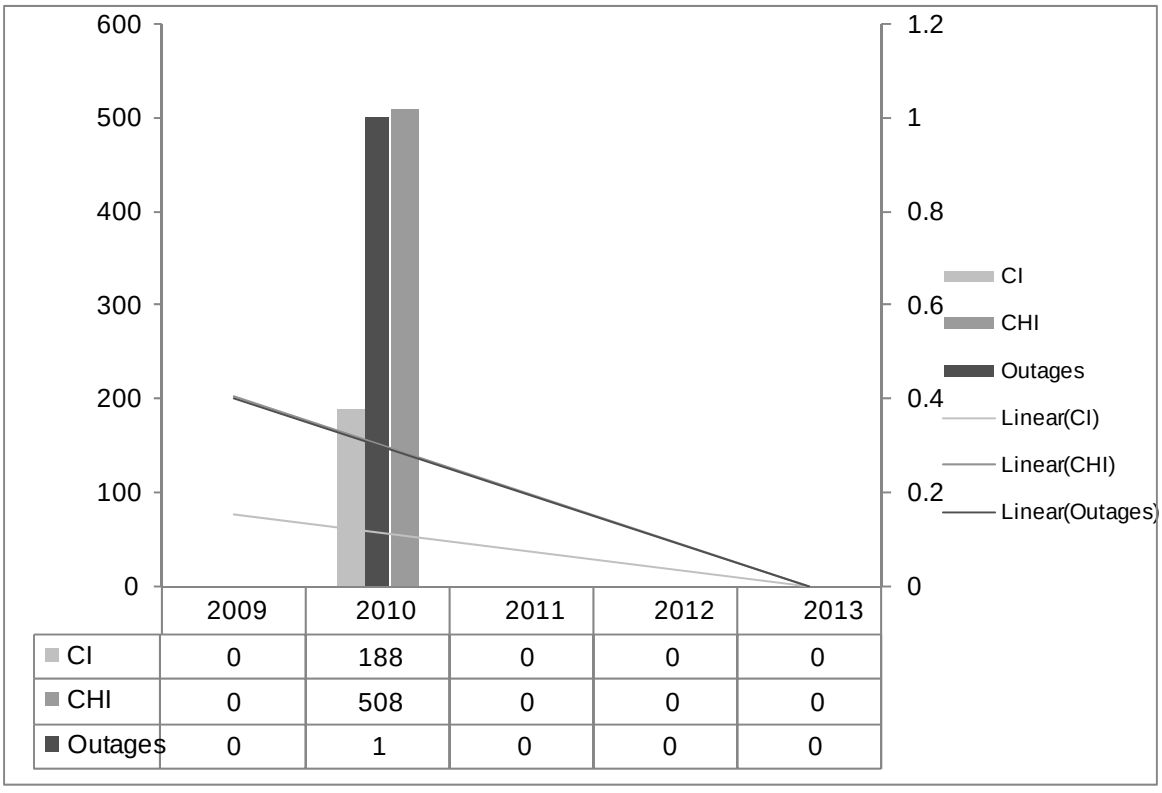
NOTE:

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 47: SUPPLEMENTAL DETAILS

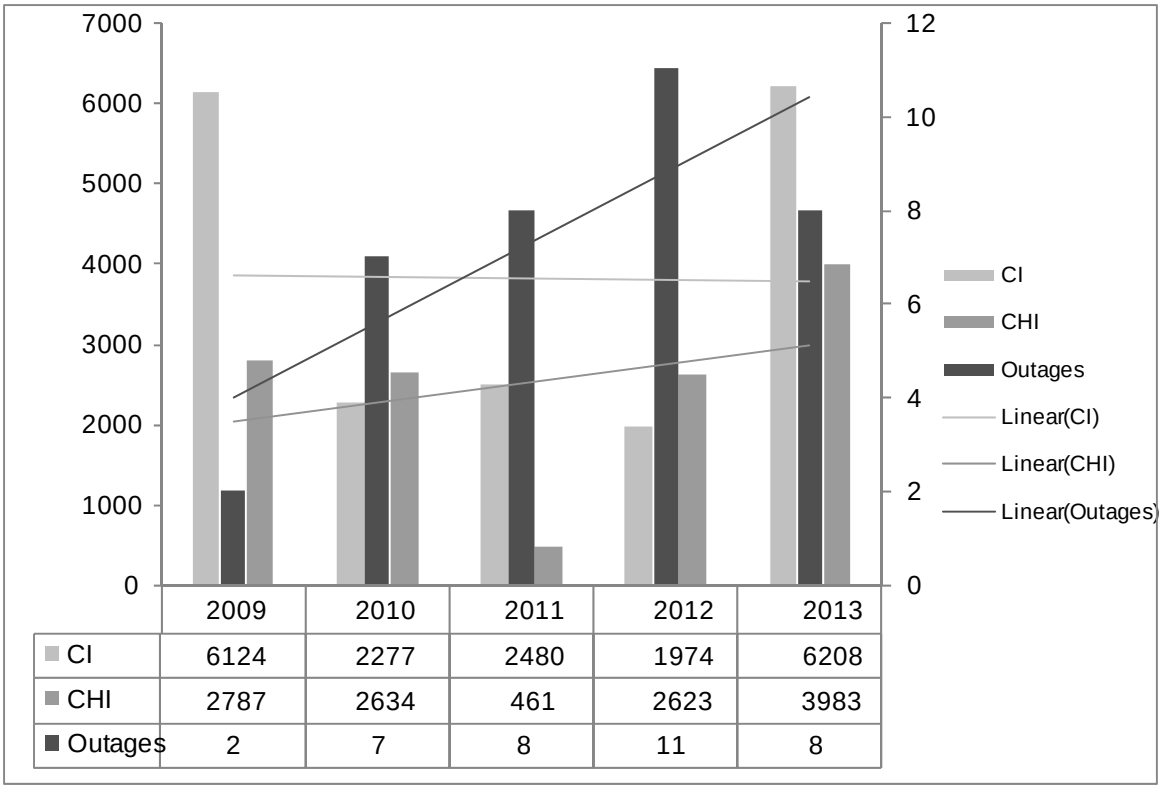
Supplemental Details	Description
Age/Condition	x Switches, transformers and direct buried cable ƒ Assets installed 1957 (57 years old)
Reliability	ƒ Instead of rebuilding of unreliable 4kV distribution, the existing load from Burbank MS is to be converted to 27.6kV that offers better back up supply in the event of contingency condition
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 49 and 50.



	2009	2010	2011	2012	2013
CI	0	188	0	0	0
CHI	0	508	0	0	0
Outages	0	1	0	0	0

FIGURE 49: HISTORICAL RELIABILITY DETAILS FOR NYSS38F2



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

FIGURE 50: HISTORICAL RELIABILITY DETAILS FOR NY51M8

E12346 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12346 Bluffwood Saddletree Electrical NY51M3

Project Number: E12346

Project Year: 2015

Estimated Cost: $124,286

(i) Objective

Rebuild a portion of NY51M3 out of Leslie I TS to improve reliability and service to customers. E12346 will complete the electrical portion of the project, which was ICM approved.

(ii) Scope of Work

TABLE 48: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie I TS (27.6kV)
Feeder(s):	NY51M3

TABLE 49: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	2,717.02 m
Underground Transformers	6
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

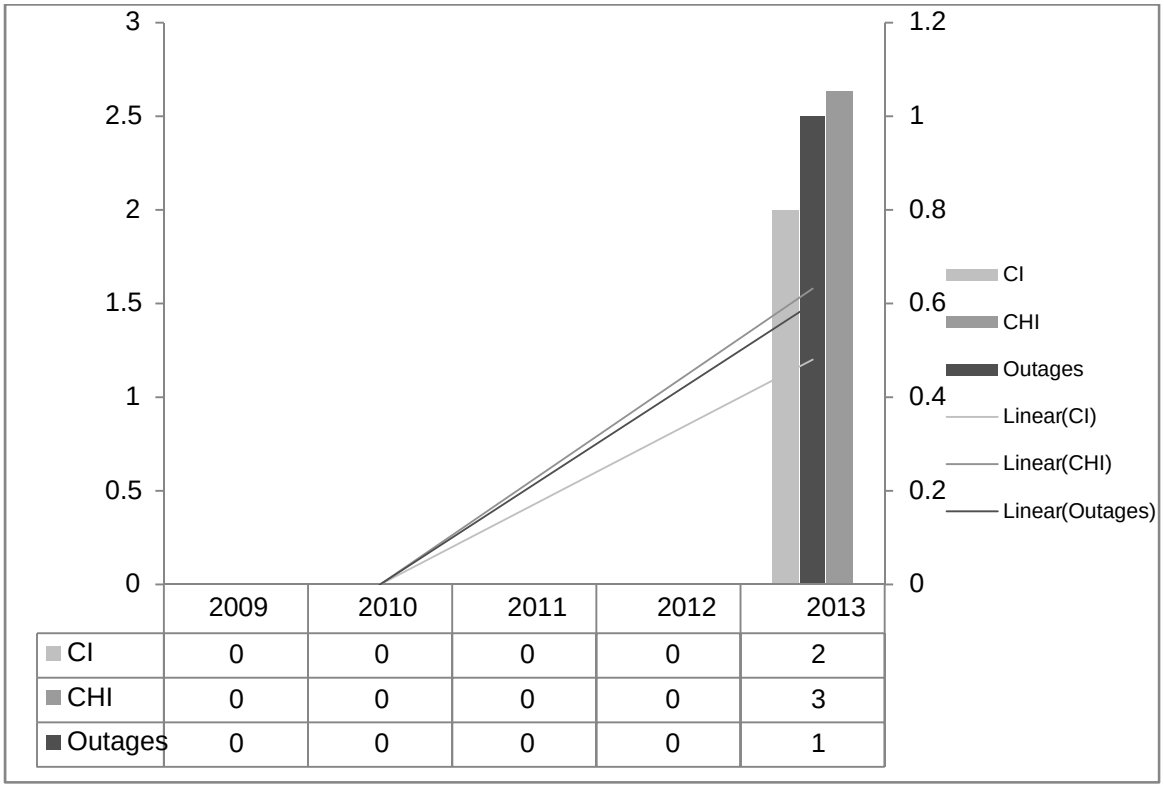
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 50: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1981 (33 years old)
Reliability	ƒ 51M3 has been performing poorly in the past 5 years with average of nearly 4 outages per year
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 51.



	2009	2010	2011	2012	2013
CI	0	0	0	0	2
CHI	0	0	0	0	3
Outages	0	0	0	0	1

FIGURE 51: HISTORICAL RELIABILITY DETAILS FOR NY51M3

E12428, E12380 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Rebuild of NY51M4 Consumers Rd & Victoria Park Areas – Civil/ Electrical NY51M4

Project Number: E12428, E12380

Project Year: 2015

Estimated Cost: $ 1,882,546.00

(i) Objective

Replace aged and failing assets along the feeder, proactively to increase system reliability and service to customers.

E12428 will install the civil infrastructure necessary to complete the project. E12380 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 51: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie-1 TS
Feeder(s):	NY51M4

TABLE 52: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	5,855.73m
Underground Transformers	0
Underground Switchgear	3
Poles	6
Overhead Transformer	0
Overhead Switch	0

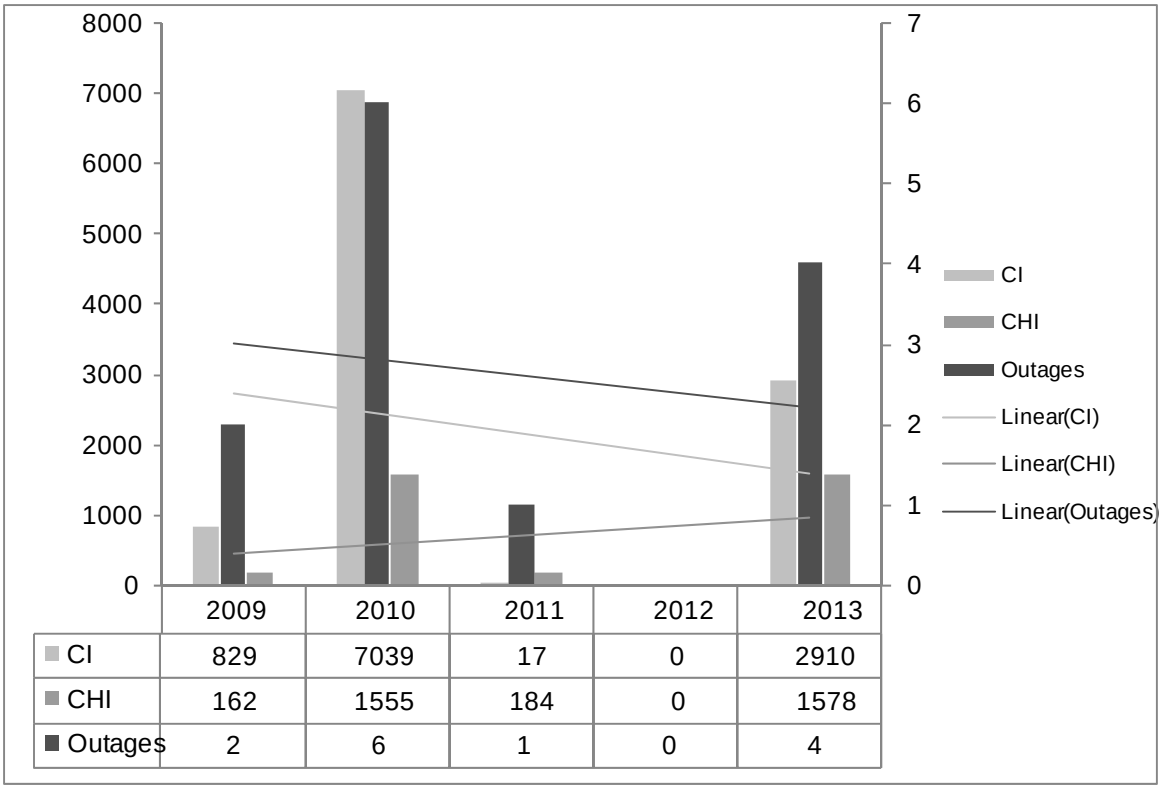
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 53: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1972 (42 years old)
Reliability	ƒ Project will include conversion of existing load supplied by Leslie MS ƒ Leslie MS is an isolated 13.8 kV distribution with no backup supply in the event of MS station failure
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 52.



	2009	2010	2011	2012	2013
CI	829	7039	17	0	2910
CHI	162	1555	184	0	1578
Outages	2	6	1	0	4

FIGURE 52: HISTORICAL RELIABILITY DETAILS FOR NY51M4

E12385, E12386 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Don Mills / Eglint on Rebuild – Civil/Electrical NY53M1

Project Number: E12385

Project Year: 2015

Estimated Cost: $416,495

(i) Objective

Replace the failing UG direct buried cable around the Don Mills/Eglinton intersection to improve reliability and service to the customers.

E12385 will install the civil infrastructure necessary to complete the project. E12386 will complete the electrical portion of the project. Both projects have been ICM approved.

(ii) Scope of Work

TABLE 54: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Bermondsey TS (27.6kV)
Feeder(s):	NY53M1

TABLE 55: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	2,014.98m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

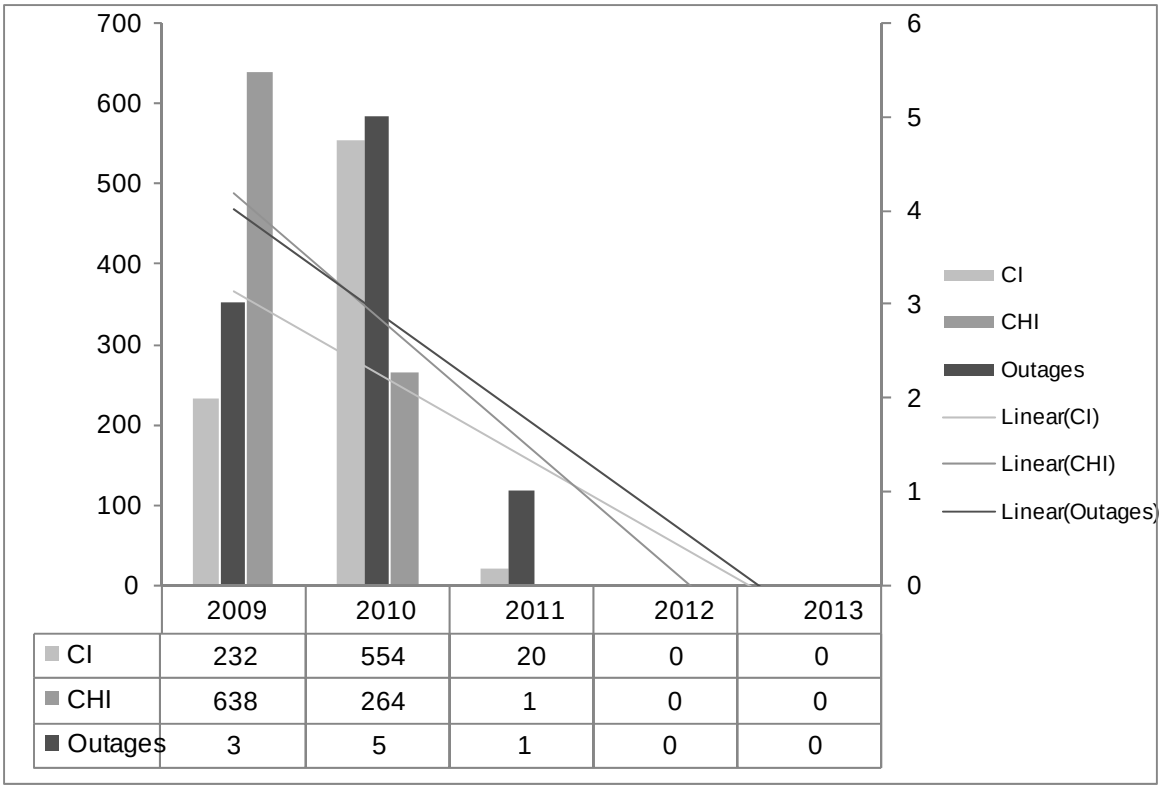
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 56: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	• Direct buried cables • Installed 1981 (33 years old)
Reliability	• No reliability issues in project area
Other (i.e. road moratoriums, etc)	• Direct buried cables in project area are operating past their estimated useful service life and need to be addressed before failures occur • Replacement needs to be completed before Eglinton LRT construction begins

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 53.



	2009	2010	2011	2012	2013
CI	232	554	20	0	0
CHI	638	264	1	0	0
Outages	3	5	1	0	0

1 FIGURE 53: HISTORICAL RELIABILITY DETAILS FOR NY53M1

E12400 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12400 Cass Ave UG VC NHF3 to 502M22 - Civil SCNHF3

Project Number: E12400

Project Year: 2015

Estimated Cost: $2,247,023

(i) Objective

Replace, via voltage conversion, the old and deteriorated primary cables in the area of Cass Ave and internal roads of the TH complexes at 2075 Warden Ave, 70 and 71 Cass Ave. E12400 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 57: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Agincourt
Station(s):	Malamute Sheppard
Feeder(s):	SCNHF3

(iii) Justification & Benefits

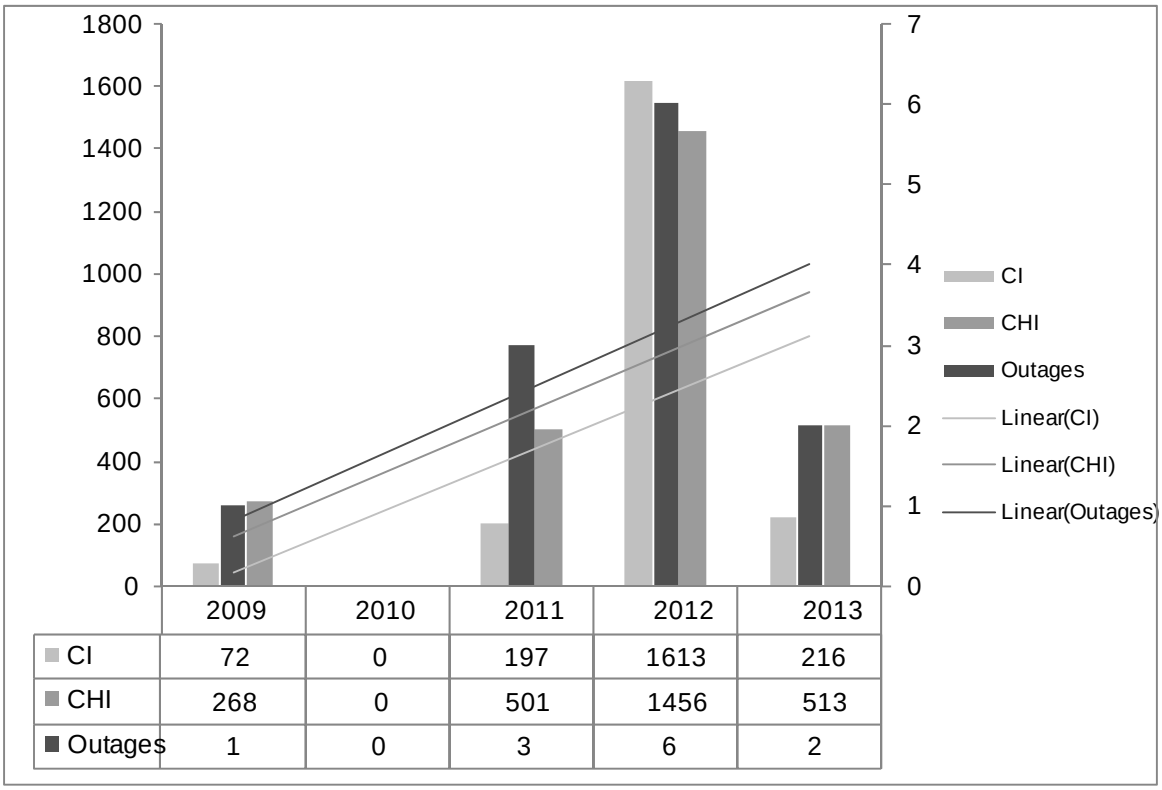
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 58: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1968 (46 years old)
Reliability	ƒ Reliability is weakening along this feeder ƒ Increasing CI, CHI and Outages seen over past five years ƒ Majority of underground outages have been due to primary cable and

Supplemental Details	Description
	submersible transformers; both assets will be targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ Work could not start prior to 2015 due to road moratorium that expires in 2014

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 54.



	2009	2010	2011	2012	2013
CI	72	0	197	1613	216
CHI	268	0	501	1456	513
Outages	1	0	3	6	2

FIGURE 54: HISTORICAL RELIABILITY DETAILS FOR SCNHF3

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E12406 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12406 Palmdale Dr UG VC NHF3 to 502M22 - Civil SCNHF3

Project Number: E12406

Project Year: 2015

Estimated Cost: $1,203,205

(i) Objective

Replace, via voltage conversion, the old and deteriorated primary cables in the area of Palmdale Dr and internal roads of 150 and 160 Palmdale Dr TH complexes. E12406 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 59: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Agincourt
Station(s):	Malamute / Sheppard
Feeder(s):	SCNHF3

(iii) Justification & Benefits

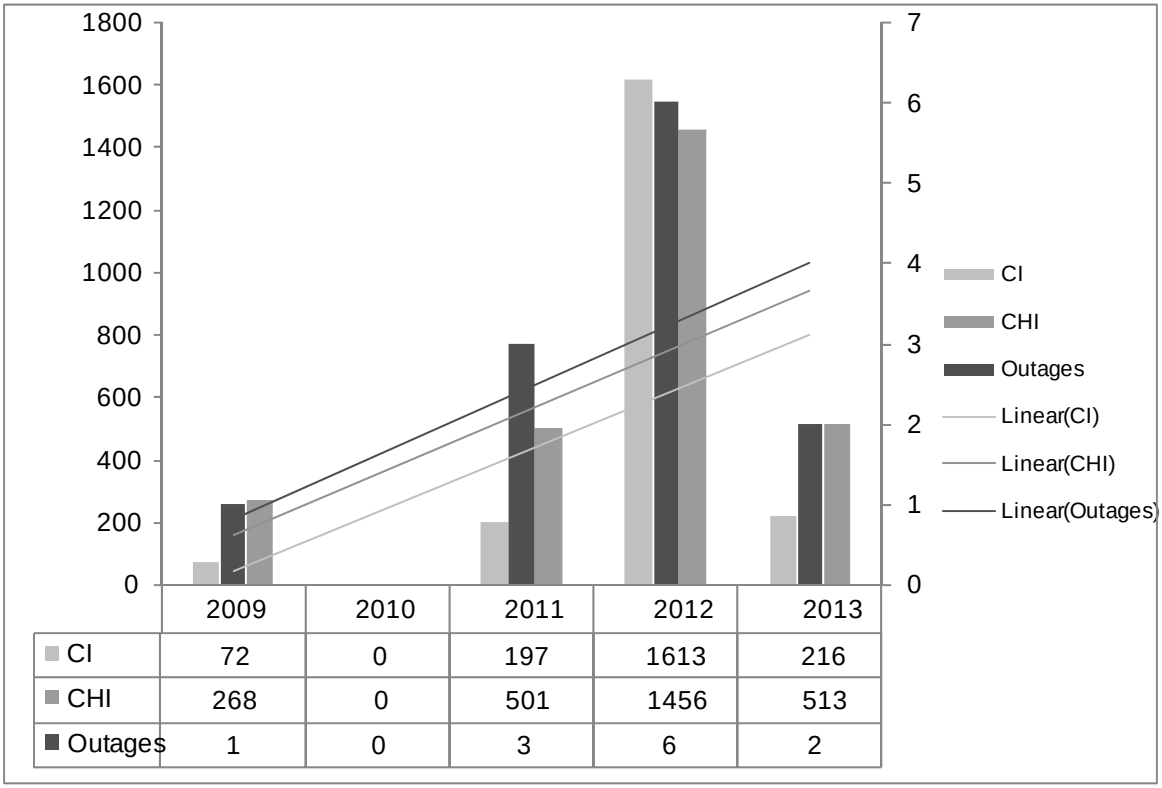
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 60: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1968 (46 years old)
Reliability	ƒ Reliability is weakening along this feeder ƒ Increasing CI, CHI and Outages seen over past five years ƒ Majority of underground outages have been due to primary cable and

Supplemental Details	Description
	submersible transformers; both assets will be targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ N/A

1 Historical reliability including number of customers interrupted (CI), customer hours interrupted
2 (CHI) and outages along the feeder are given in Figure 55.



	2009	2010	2011	2012	2013
CI	72	0	197	1613	216
CHI	268	0	501	1456	513
Outages	1	0	3	6	2

3 FIGURE 55: HISTORICAL RELIABILITY DETAILS FOR SCNHF3

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E12409 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12409 Thimble Berryway Aspenwood UG Rebuild Electrical NY51M3

Project Number: E12409

Project Year: 2015

Estimated Cost: $206,194

(i) Objective

Replace aged direct buried cable and non-switchable transformers on a portion of NY51M3 and NY51M27 out of Leslie I TS and Leslie II TS to improve reliability and service to the customer. E12409 will complete the electrical portion of the ICM approved project.

(ii) Scope of Work

TABLE 61: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie I TS (27.6kV), Leslie II TS (27.6kV)
Feeder(s):	NY51M3, NY51M27

TABLE 62: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,458.96m
Underground Transformers	11
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

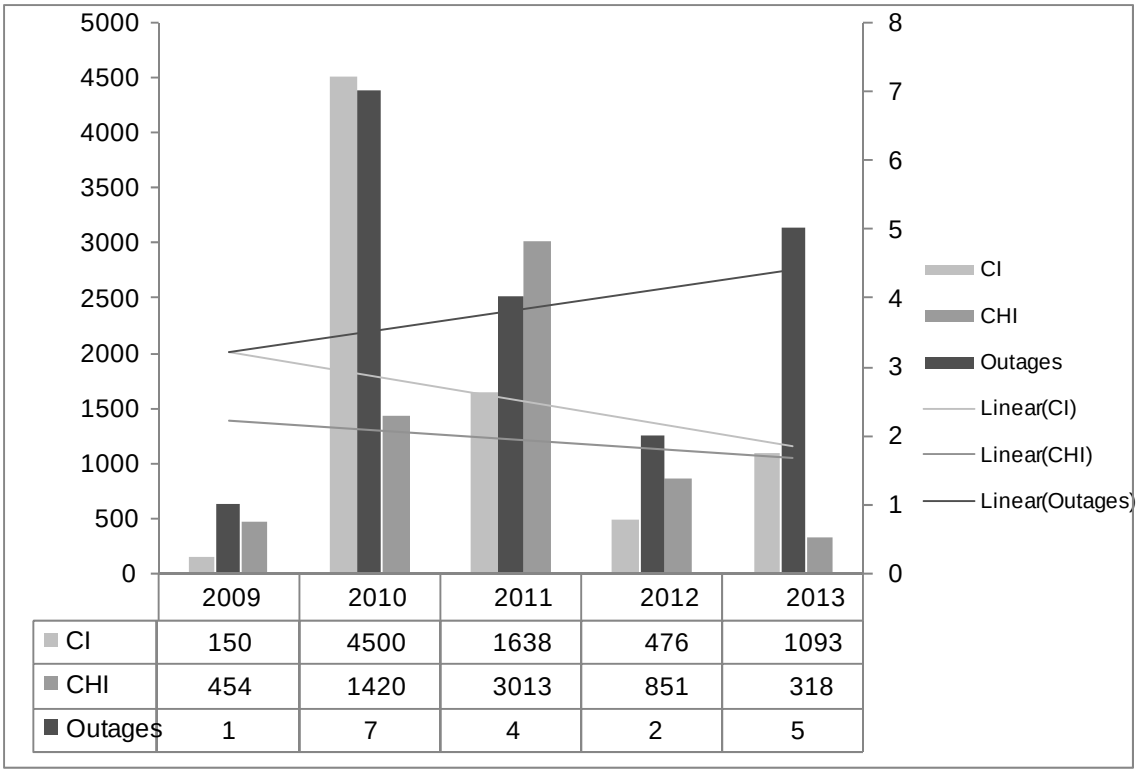
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 63: SUPPLEMENTAL DETAILS

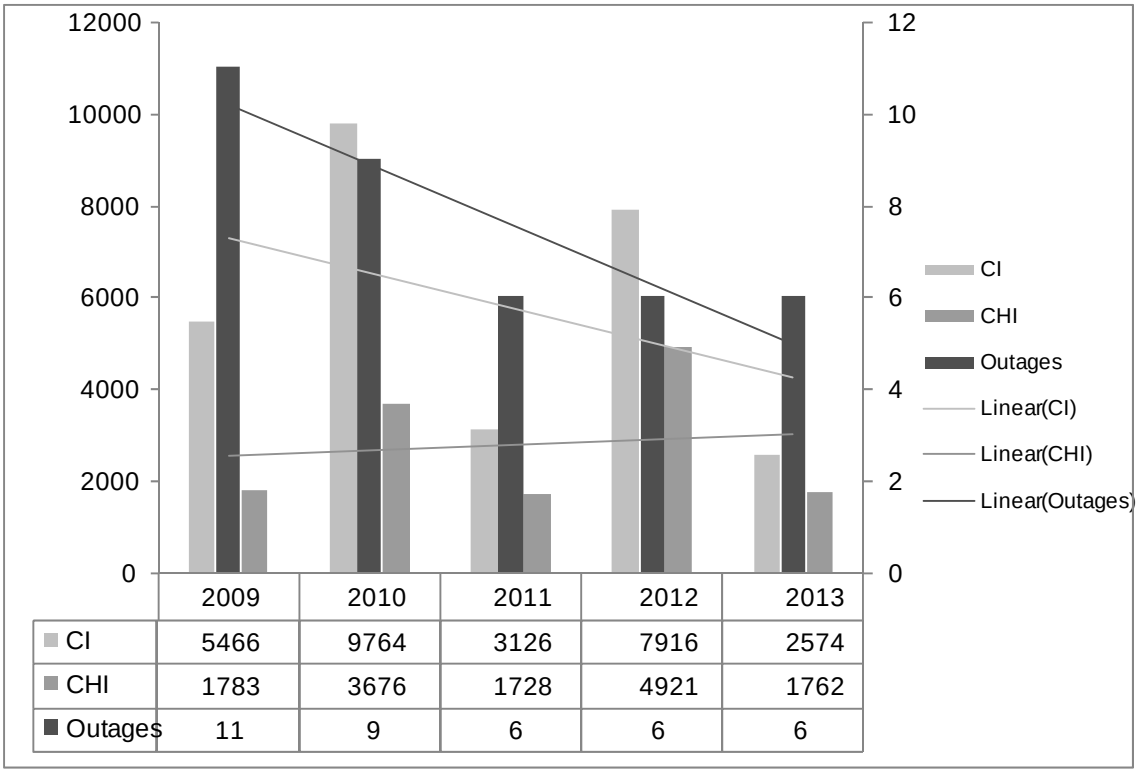
Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1972 (42 years old)
Reliability	ƒ 51M3 has been performing poorly in the past 5 years with average of nearly 4 outages per year
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figures 56 and 57.



	2009	2010	2011	2012	2013
CI	150	4500	1638	476	1093
CHI	454	1420	3013	851	318
Outages	1	7	4	2	5

FIGURE 56: HISTORICAL RELIABILITY DETAILS FOR NY51M3



	2009	2010	2011	2012	2013
CI	5466	9764	3126	7916	2574
CHI	1783	3676	1728	4921	1762
Outages	11	9	6	6	6

FIGURE 57: HISTORICAL RELIABILITY DETAILS FOR NY51M7

E12430 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12430 Cherrystone Aspenwood - Electrical (51M27)

Project Number: E12430

Project Year: 2015

Estimated Cost: $166,171

(i) Objective

Replace aged direct buried cable and non-switchable transformers on a portion of NY51M27 out of Leslie II TS to improve reliability and service to the customers. E12430 will complete the electrical portion of the ICM approved project.

(ii) Scope of Work

TABLE 64: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie II TS (27.6kV)
Feeder(s):	NY51M27

TABLE 65: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	2,087.33m
Underground Transformers	9
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

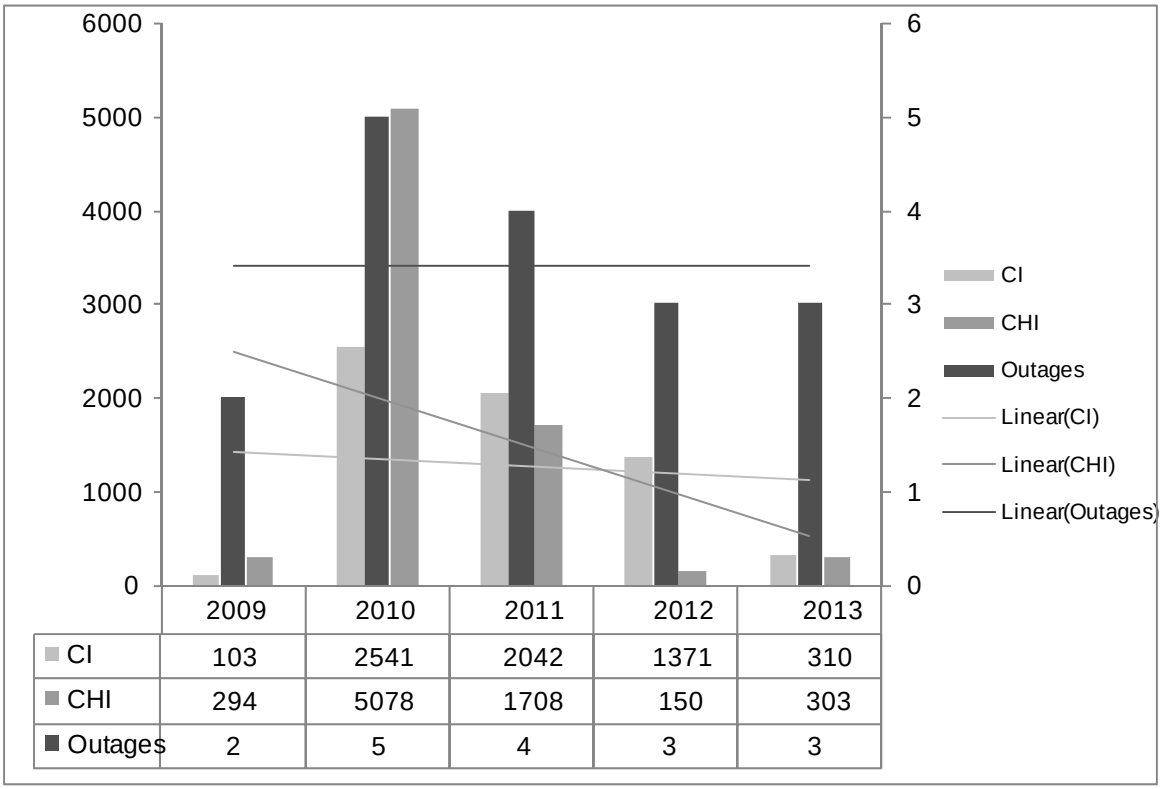
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 66: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1973 (41 years old)
Reliability	ƒ 51M27 has been performing poorly in the past 5 years with average of nearly 6 outages per year
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 58.



	2009	2010	2011	2012	2013
CI	103	2541	2042	1371	310
CHI	294	5078	1708	150	303
Outages	2	5	4	3	3

FIGURE 58: HISTORICAL RELIABILITY DETAILS FOR NY51M27

E12477 Project Description

Investment Category: **System Renewal**

Program: **Underground Circuit Renewal**

Project Title: **E12477 Middlefield Passmore StateCrown Civ SCNAR26M21** **/C**

Project Number: **E12477**

Project Year: **2015**

Estimated Cost: **$1,403,077**

(i) Objective

Rebuild a portion of SCNAR26M21 containing aged direct buried cable to improve reliability and service to the customer. E12477 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 67: SCOPE OF WORK DETAILS

District Neighborhood	ScarboroughrRouge River
Station(s):	Malvern TS (27.6 kV)
Feeder(s):	SCNAR26M21

(iii) Justification & Benefits

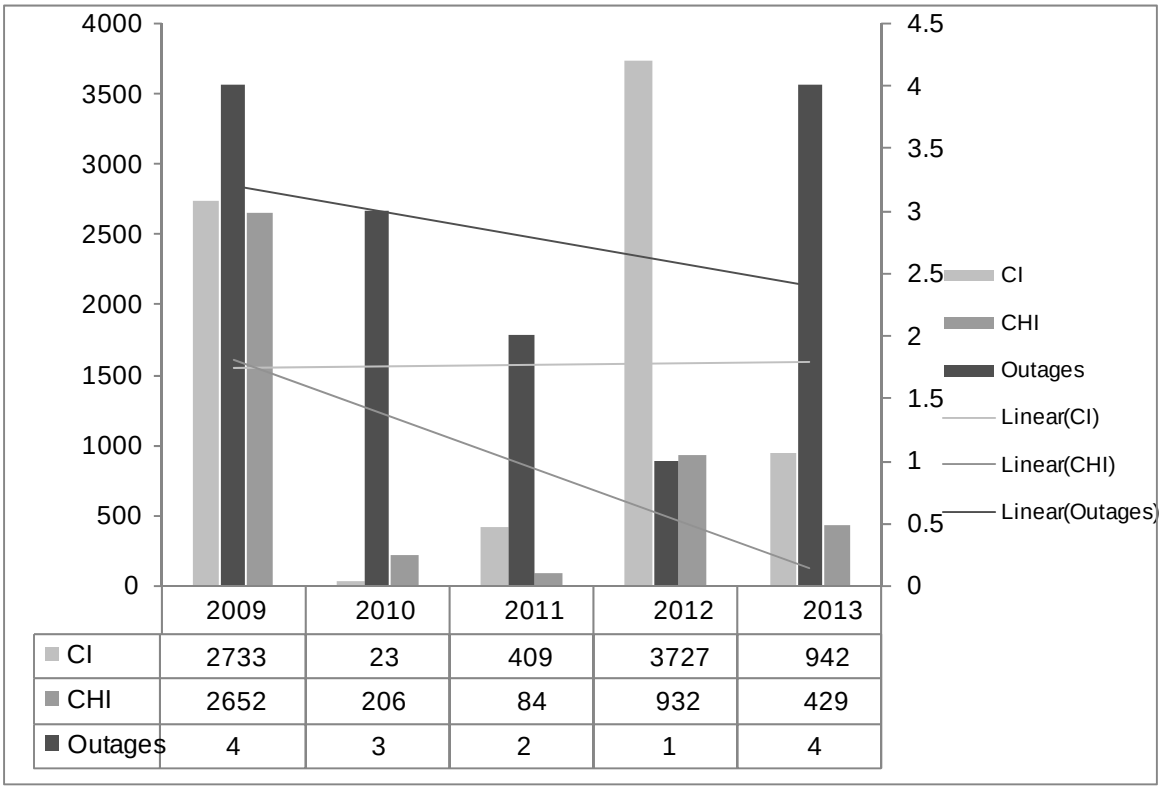
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 68: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1979 (35 years old)
Reliability	ƒ Reliability improved, but deteriorating again. ƒ Majority of outages due to primary cable and transformer failures both of which will be targeted for replacement in the Underground

Supplemental Details	Description
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 59.



	2009	2010	2011	2012	2013
CI	2733	23	409	3727	942
CHI	2652	206	84	932	429
Outages	4	3	2	1	4

FIGURE 59: HISTORICAL RELIABILITY DETAILS FOR SCNAR26M21

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E12487 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12487 Middlefield Industrial UG 63M6 Rebuild-Civil SCNT63M6

Project Number: E12487

Project Year: 2015

Estimated Cost: $859,191

(i) Objective

Rebuild a portion of SCNT63M6 containing aged direct buried cable to improve reliability and service to the customer. E12487 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 69: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Agincourt TS (27.6kV)
Feeder(s):	SCNT63M6

(iii) Justification & Benefits

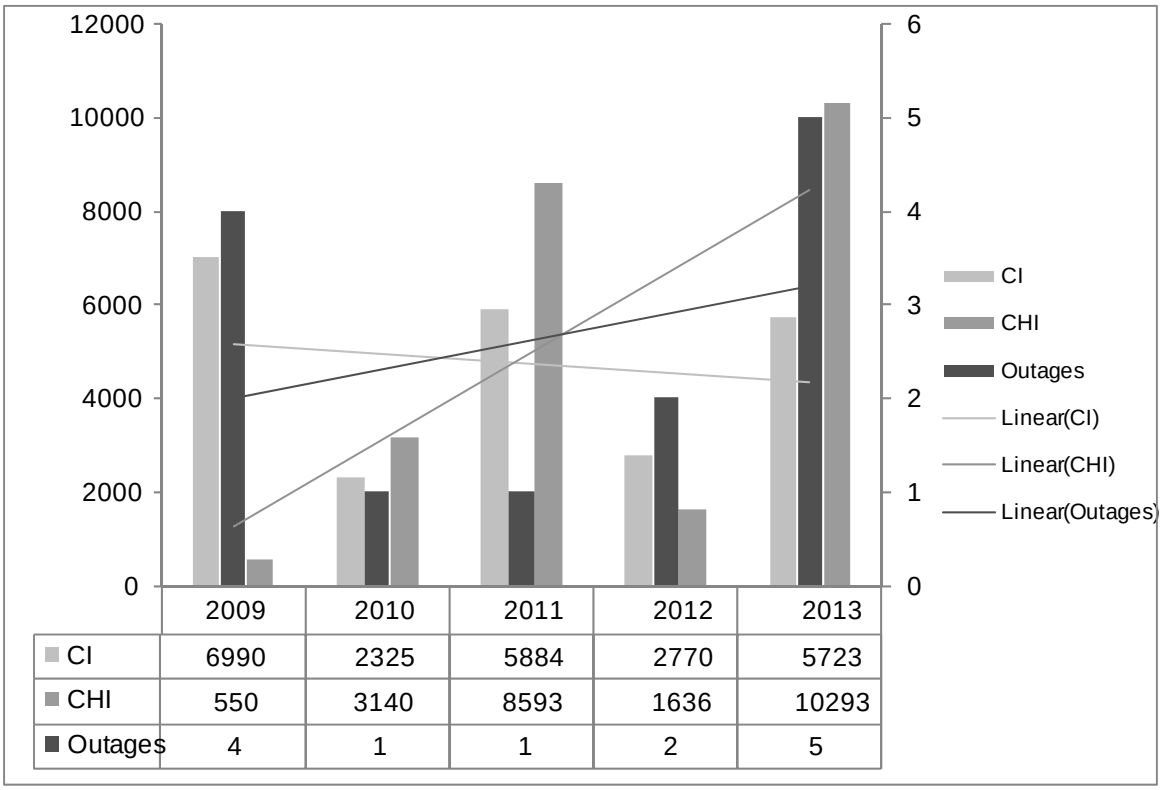
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 70: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1968 (46 years old)
Reliability	ƒ Reliability is weakening along this feeder ƒ Increasing CHI and Outages seen over past five years ƒ Majority of underground outages have been due to pad mounted

Supplemental Details	Description
	switches and primary cable; both assets will be targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 60.



	2009	2010	2011	2012	2013
CI	6990	2325	5884	2770	5723
CHI	550	3140	8593	1636	10293
Outages	4	1	1	2	5

FIGURE 60: HISTORICAL RELIABILITY DETAILS FOR SCNT63M6

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E13041 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E13041 Ironside Cre scent UG Rebuild Civil SCNAR26M21

Project Number: E13041

Project Year: 2015

Estimated Cost: $953,041

(i) Objective

Rebuild a portion of SCNAR26M21 containing aged direct buried cable to improve reliability and service to the customer. E13041 will install the civil infrastructure necessary to complete the ICM approved project.

(ii) Scope of Work

TABLE 71: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Malvern TS (27.6kV)
Feeder(s):	SCNAR26M21

(iii) Justificat ion & Benefits

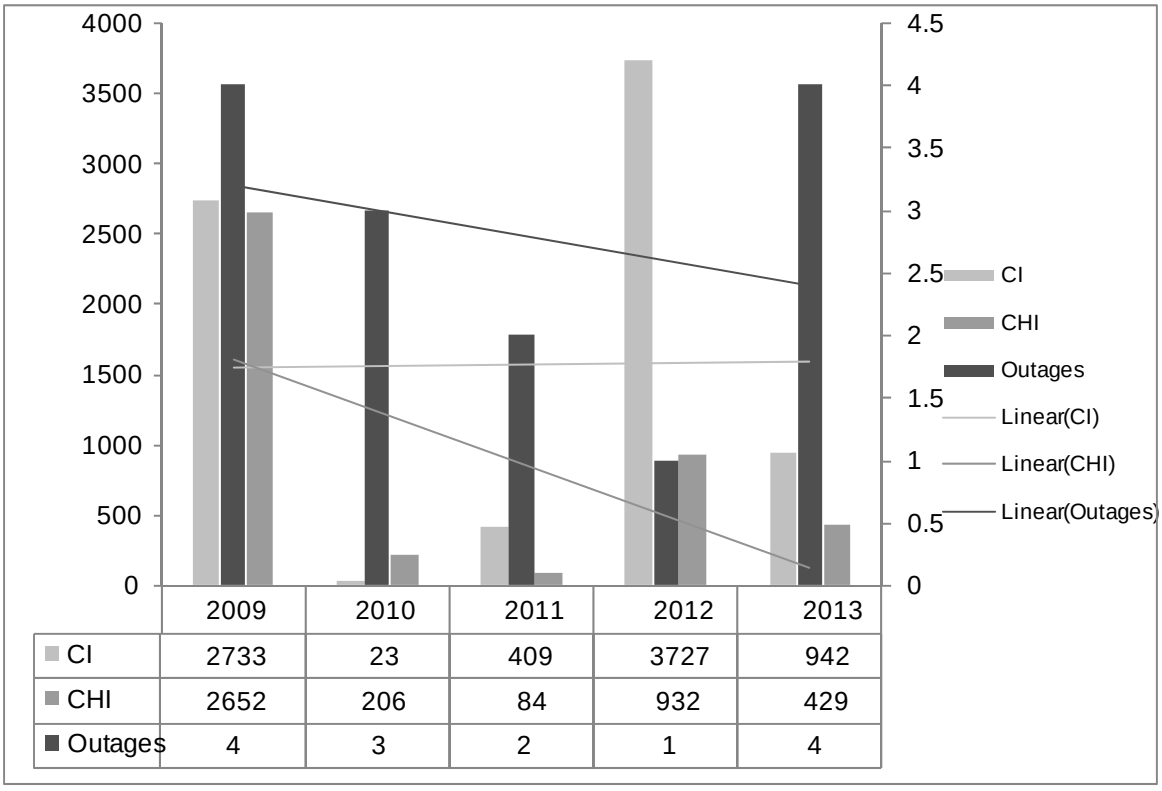
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 72: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1979 (35 years old)
Reliability	ƒ Reliability improved, but deteriorating again. ƒ Majority of outages due to primary cable and transformer failures both of which will be targeted for replacement in the Underground

Supplemental Details	Description
	Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 61.



	2009	2010	2011	2012	2013
CI	2733	23	409	3727	942
CHI	2652	206	84	932	429
Outages	4	3	2	1	4

FIGURE 61: HISTORICAL RELIABILITY DETAILS FOR SCNAR26M21

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E13046 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E13046 NY53M26 UG Rebuild in Curlew and Victoria Park areas – Civil

Project Number: E13046

Project Year: 2015

Estimated Cost: $348,912

(i) Objective

This project is to provide the necessary civil structures when solid-core direct buried cables are removed from the feeder in scope E13039 and replaced with those enclosed concrete encased ducts.

Replace the existing direct buried solid-core cables with TR-XLPE cable in concrete encased duct. E13046 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 73: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Bermondsey TS
Feeder(s):	NY53M26

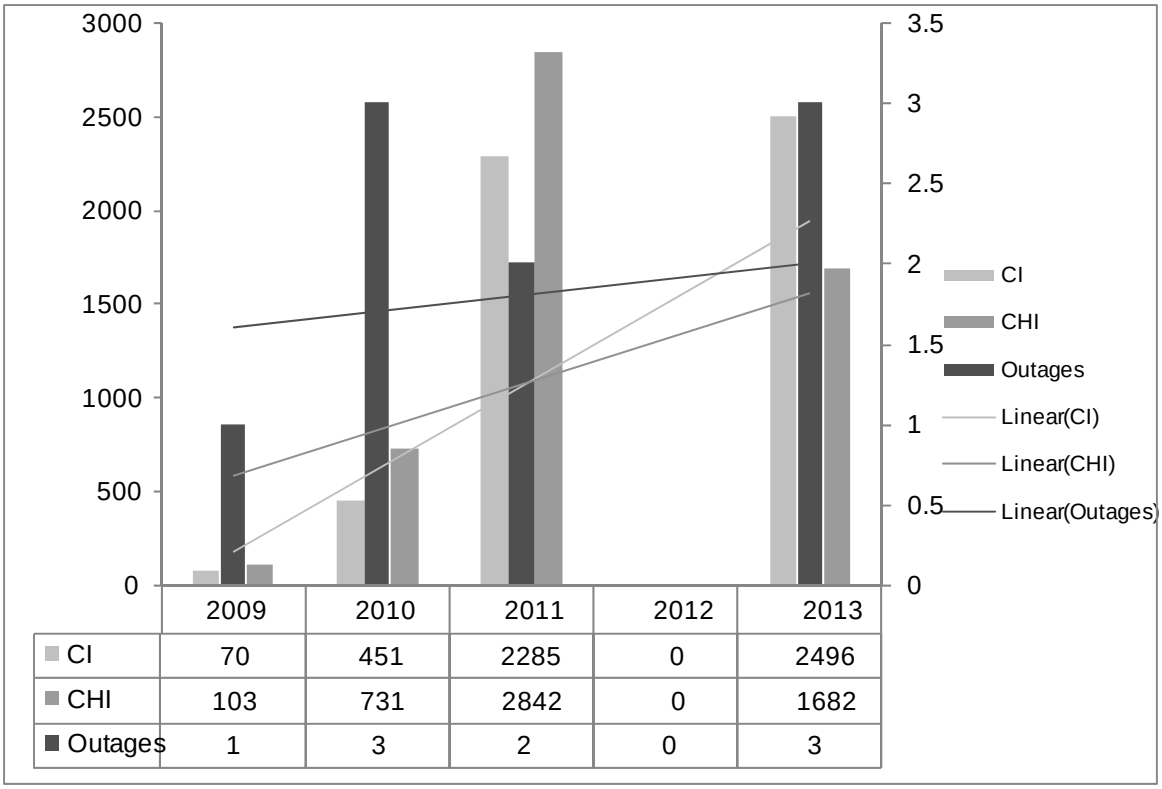
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 74: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cables ƒ Installed 1976 (38 years old)
Reliability	ƒ N/A
Other (i.e. road moratoriums, etc)	ƒ Direct buried cables in project area are operating past their estimated useful service life and need to be addressed before failures occur

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 62.



	2009	2010	2011	2012	2013
CI	70	451	2285	0	2496
CHI	103	731	2842	0	1682
Outages	1	3	2	0	3

FIGURE 62: HISTORICAL RELIABILITY DETAILS FOR NY53M26

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

Assets to be Replaced

E13065 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Rebuild of SCNAE5-1M25 by Brimley Rd and Skagway Avenue - Electrical

Project Number: E13065

Project Year: 2015

Estimated Cost: $392,239

(i) Objective

To address the cable failure reported in December 2010 per ITIS incident: F-2010-1473; proactively reduce the probability of a system failure by replacing the aged direct buried cable. E13065 will complete the electrical portion of the ICM approved project.

(ii) Scope of Work

TABLE 75: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie 1 TS
Feeder(s):	SCNAE5-1M25

TABLE 76: ASSETS TO BE REPLACED

Primary Cable	2,231.58 m
Underground Transformers	1
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	2

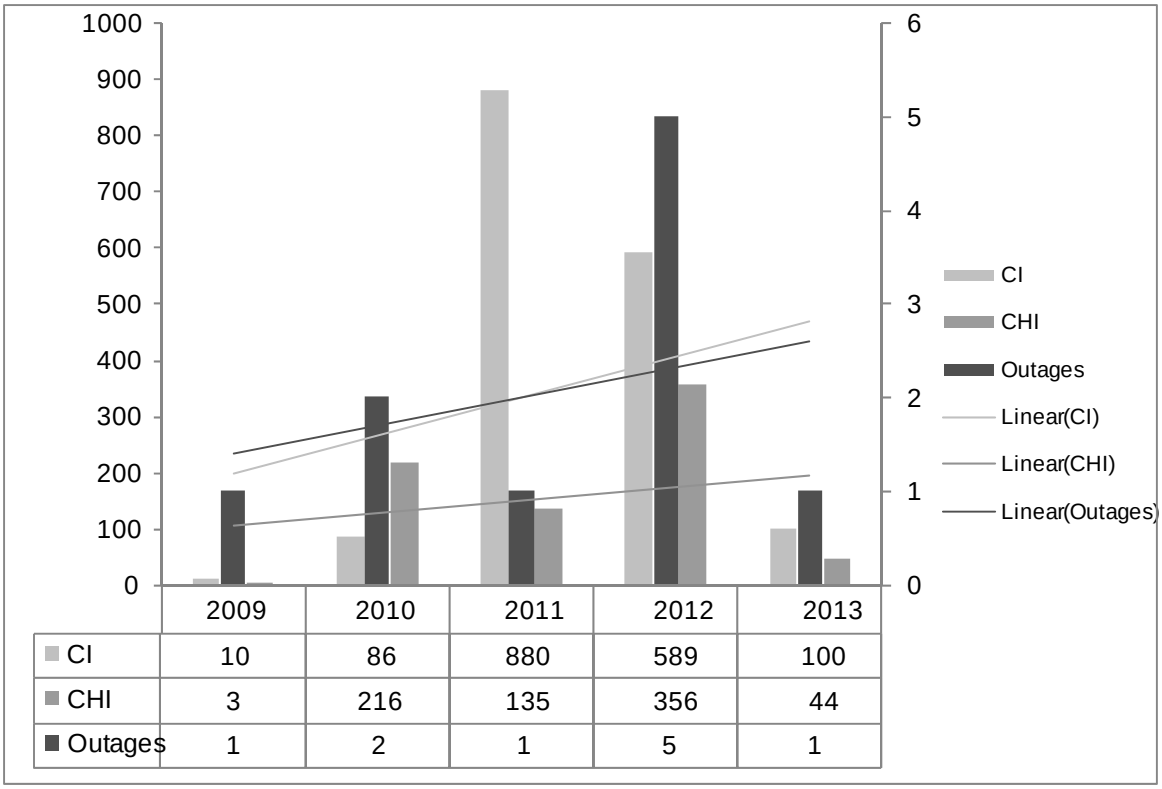
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 77: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	• Direct buried cables • Installed 1958 (56 years old)
Reliability	• 4 direct buried cable failures in project area
Other (i.e. road moratoriums, etc)	• Direct buried cables in project area are operating past their estimated useful service life and need to be addressed before failures occur • This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 63.



	2009	2010	2011	2012	2013
CI	10	86	880	589	100
CHI	3	216	135	356	44
Outages	1	2	1	5	1

1 FIGURE 63: HISTORICAL RELIABILITY DETAILS FOR SCNAE5-1M25

E13069 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E13069 NY51M24 UG Rebuild North of Finch – Civil

Project Number: E13069

Project Year: 2015

Estimated Cost: $430,208

(i) Objective

Replace aged direct buried cable from NY51M24 in the area northwest area of Finch Avenue E and Don Mills road intersection. E13069 will install the civil infrastructure necessary to complete the ICM approved project.

(ii) Scope of Work

TABLE 78: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie II TS
Feeder(s):	NY51M24, NY51M25

(iii) Justification & Benefits

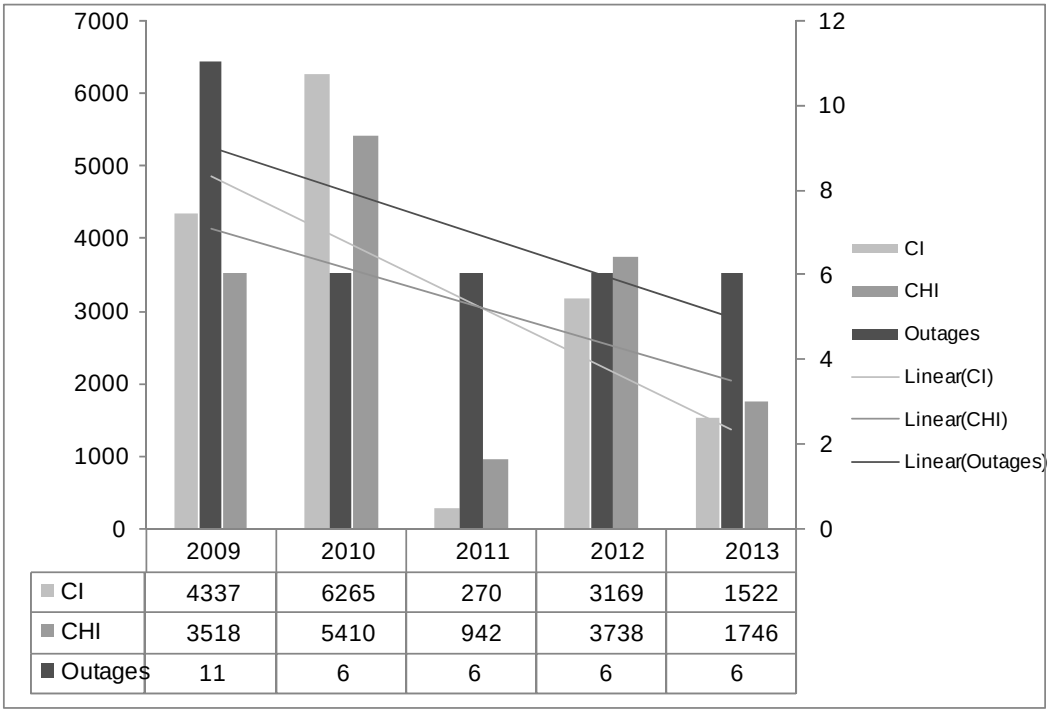
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 79: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed around 1979 – 1991 (approx. between 23 – 35 years old)
Reliability	ƒ 51M24 has been performing poorly during the last 5 years with an average of 7 outages per year
Other (i.e. road	ƒ N/A

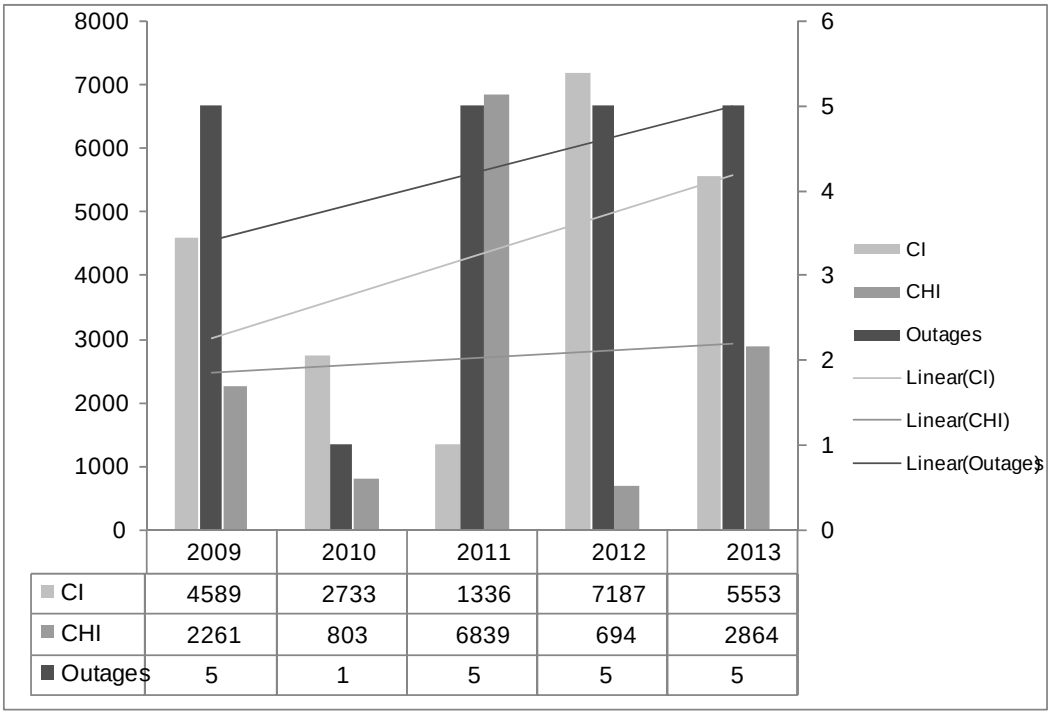
Supplemental Details	Description
moratoriums, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 64.



	2009	2010	2011	2012	2013
CI	4337	6265	270	3169	1522
CHI	3518	5410	942	3738	1746
Outages	11	6	6	6	6

FIGURE 64: HISTORICAL RELIABILITY DETAILS FOR NY51M24



	2009	2010	2011	2012	2013
CI	4589	2733	1336	7187	5553
CHI	2261	803	6839	694	2864
Outages	5	1	5	5	5

FIGURE 65: HISTORICAL RELIABILITY DETAILS FOR NY51M25

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E13194 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E13194 off Don Mills/Graydon Hall UG Rehab (NY51M29)

Project Number: E13194

Project Year: 2015

Estimated Cost: $2,066,416

(i) Objective

Replace aged and vulnerable assets from the feeder in the Don Mills Graydon Hall Drive and Duncan Mills area. E13194 will complete the electrical portion of the ICM approved project.

(ii) Scope of Work

TABLE 80: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie 1 TS
Feeder(s):	NY51M29

TABLE 81: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	4,282.92 m
Underground Transformers	19
Underground Switchgear	15
Poles	0
Overhead Transformer	0
Overhead Switch	0

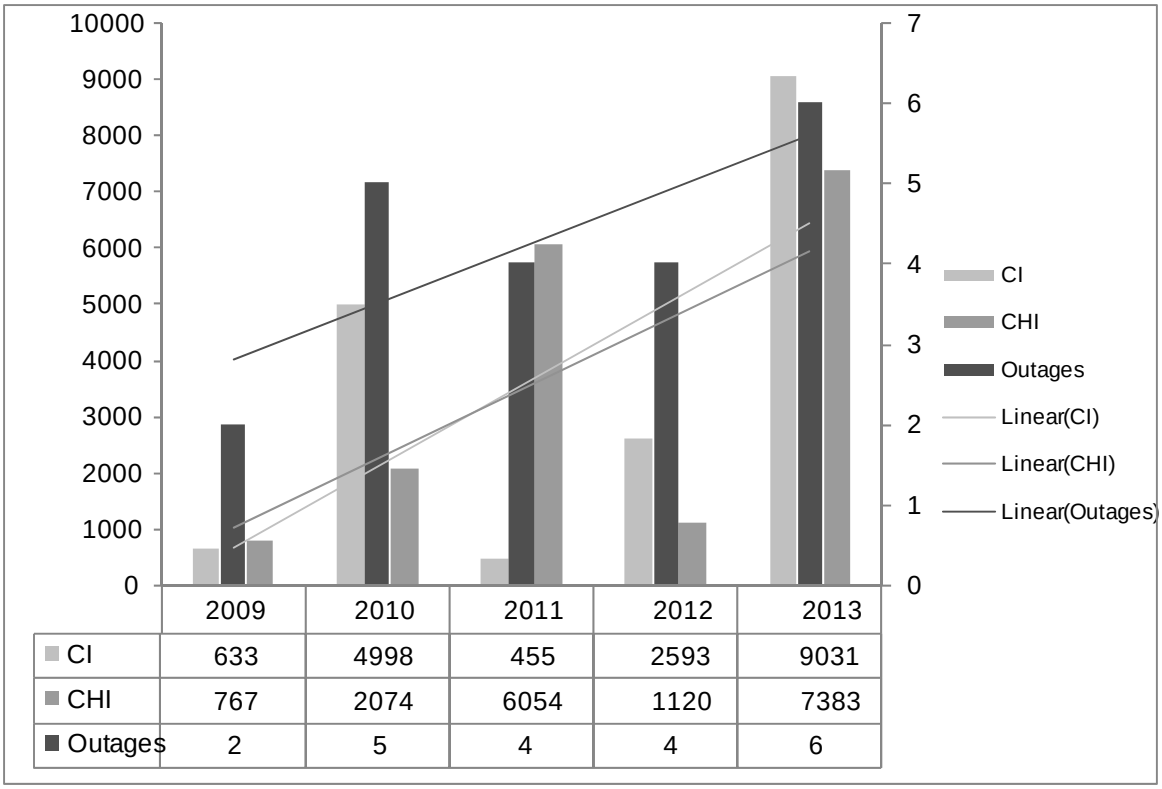
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 82: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Switches, transformers and direct buried cable ƒ Assets installed 1977 (37 years old)
Reliability	ƒ 51M29 has been performing poorly during the last 5 years with an average of 4 power outages per year ƒ Majority of failures over the past five years due to primary cable and transformer in the area both of which are targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 66.



	2009	2010	2011	2012	2013
CI	633	4998	455	2593	9031
CHI	767	2074	6054	1120	7383
Outages	2	5	4	4	6

FIGURE 66: HISTORICAL RELIABILITY DETAILS FOR SCNA51M29

E13212, E14035 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Teesdale Place UG Rehab Civil/Electrical (SCNAR43M27)

Project Number: E13212, E14035

Project Year: 2015

Estimated Cost: $600,695

(i) Objective

Rebuild a portion of SCNAR43M27 consisting of aged direct buried cable to improve reliability and service to the customer.

E13212 will install the civil infrastructure necessary to complete the project. E14035 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 83: SCOPE OF WORK DETAILS

District/Neighborhood	Scarborough Southwest
Station(s):	Warden TS (27.6kV)
Feeder(s):	SCNAR43M27

TABLE 84: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	581.31m
Underground Transformers	2
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

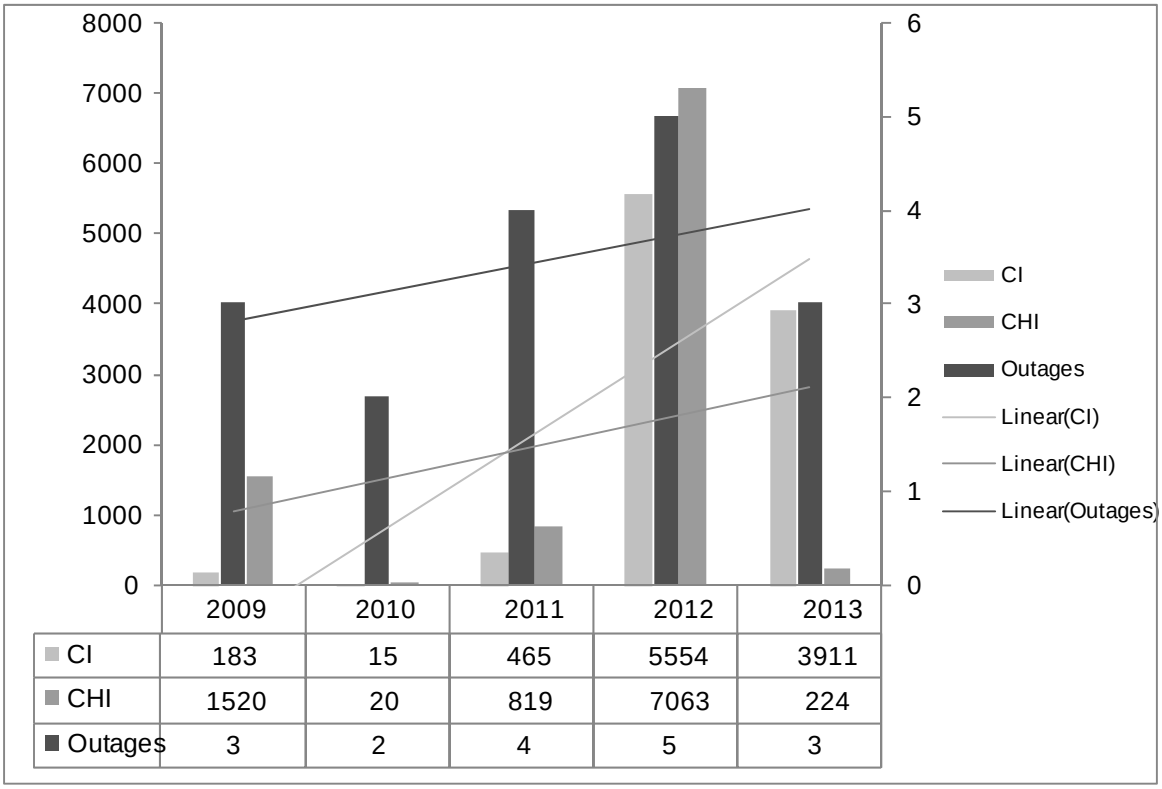
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 85: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cables ƒ Installed 1971 (43 years old)
Reliability	ƒ N/A
Other (i.e. road moratoriums, etc)	ƒ Direct buried cables in project area are operating past their estimated useful service life and need to be addressed before failures occur

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 67.



	2009	2010	2011	2012	2013
CI	183	15	465	5554	3911
CHI	1520	20	819	7063	224
Outages	3	2	4	5	3

FIGURE 67: HISTORICAL RELIABILITY DETAILS FOR SCNAR43M27

E13240 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E13240 51M22, 51M4 UG rehab off Sheppard & Victoria Park Intersection-Civil

Project Number: E13240

Project Year: 2015

Estimated Cost: $633,781

(i) Objective

Replace aged, direct buried cable with newer TR-XLPE cables in concrete encased duct. E13240 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 86: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie 1 TS
Feeder(s):	NY51M22, NY51M4

(iii) Justification & Benefits

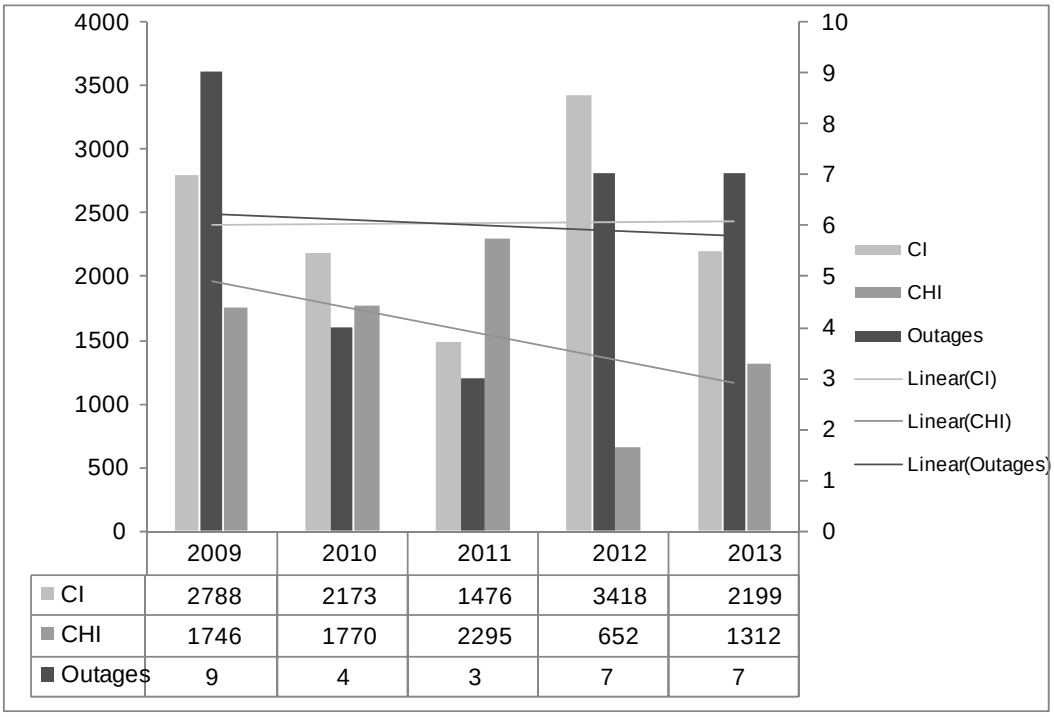
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 87: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1974 (40 years old)
Reliability	ƒ 51M22 has been performing poorly during the last 5 years with an average of 6 power outages per year ƒ 51M4 had an average of nearly 3 power outages per year

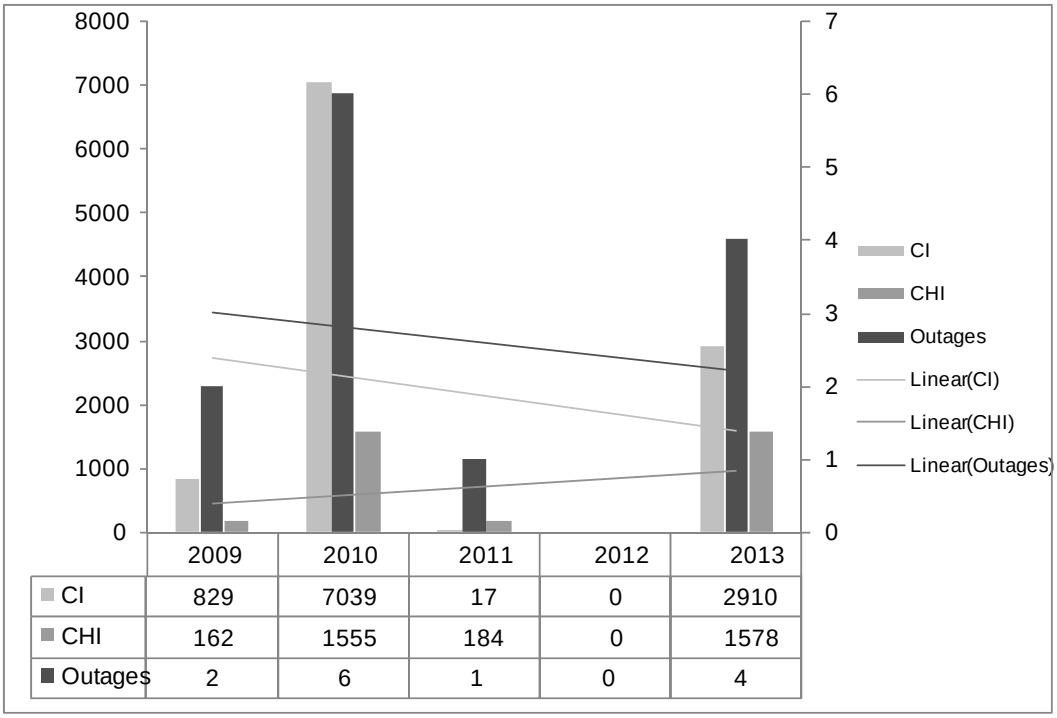
Supplemental Details	Description
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 68 and 69.



	2009	2010	2011	2012	2013
CI	2788	2173	1476	3418	2199
CHI	1746	1770	2295	652	1312
Outages	9	4	3	7	7

FIGURE 68: HISTORICAL RELIABILITY DETAILS FOR NY51M22



	2009	2010	2011	2012	2013
CI	829	7039	17	0	2910
CHI	162	1555	184	0	1578
Outages	2	6	1	0	4

FIGURE 69: HISTORICAL RELIABILITY DETAILS FOR NY51M4

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E13621 Project Description

Investment Category: **System Renewal**

Program: **Underground Circuit Renewal**

Project Title: **Brandy Court P and C Civil/Elec NY53M24**

Project Number: **E13621**

Project Year: **2015**

Estimated Cost: **$113,533**

(i) Objective

Replace US96182 with an SF6, PMH-9 equivalent pad switch as the current switch has a protection/control issue. E13621 replaces assets that pose a higher reliability risk to the system. To increase efficiency, this project combines the civil and electrical work.

(ii) Scope of Work

TABLE 88: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Bermondsey II TS (27.6 kV)
Feeder(s):	NY53M24

TABLE 88A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	0
Underground Transformers	0
Underground Switch	4
Poles	0
Overhead Transformer	0
Overhead Switch	0

IC

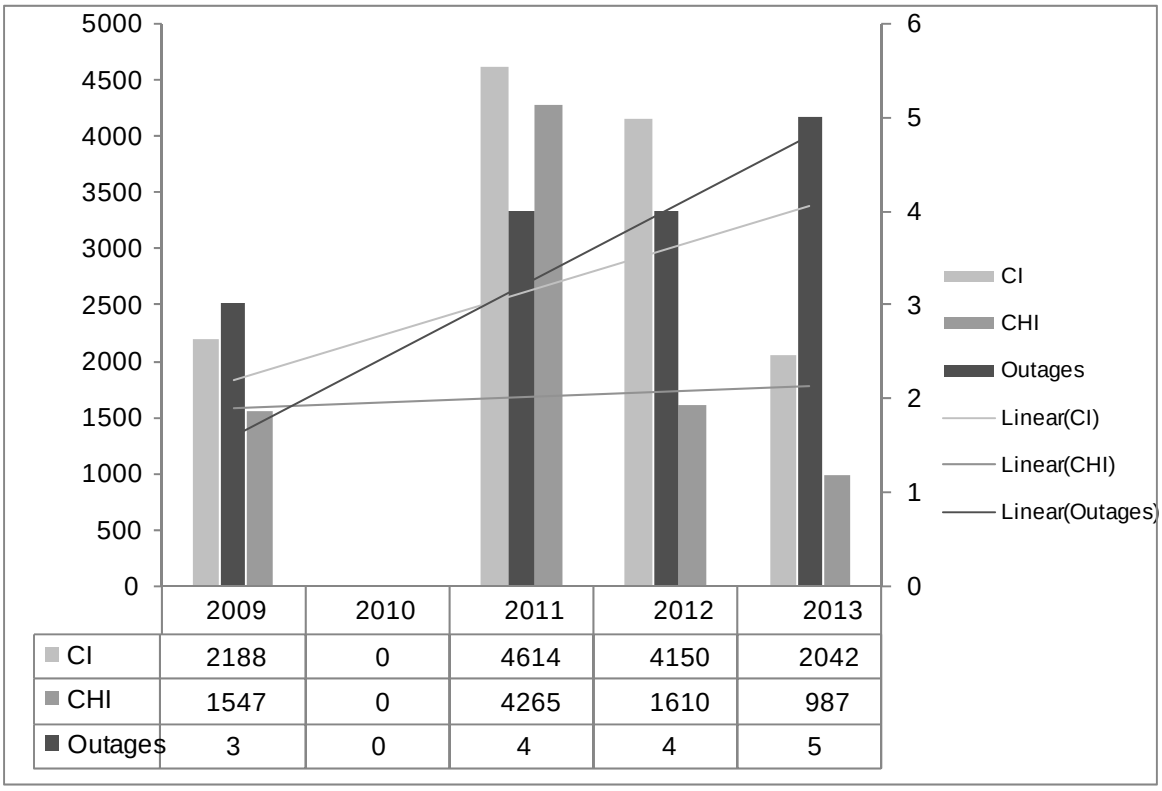
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 89: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Nonrstandard vacuum switch failed, replaced with same style until civil construction completed enabling upgrade to standard SF6 type pad mount switch
Reliability	ƒ Switch identified for upgrade to standard SF6 pad mount switch due to failure ƒ Feeder has experienced poor reliability with 9 outages in last 2 years
Other (i.e. road moratoriums, etc)	ƒ Protection and control issue will be mitigated at location with upgrade

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 70.



	2009	2010	2011	2012	2013
CI	2188	0	4614	4150	2042
CHI	1547	0	4265	1610	987
Outages	3	0	4	4	5

FIGURE 70: HISTORICAL RELIABILITY DETAILS FOR NY53M24

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E13673 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E13673 FESI mitigation 47M13 submersible transformer SCNA47M13

Project Number: E13673

Project Year: 2015

Estimated Cost: $75,664

(i) Objective

E13673 will replace submersible transformers which are causing reliability problems along SCNA47M13.

(ii) Scope of Work

TABLE 90: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Sheppard TS (27.6kV)
Feeder(s):	SCNA47M13

TABLE 91: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	0 m
Underground Transformers	4
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

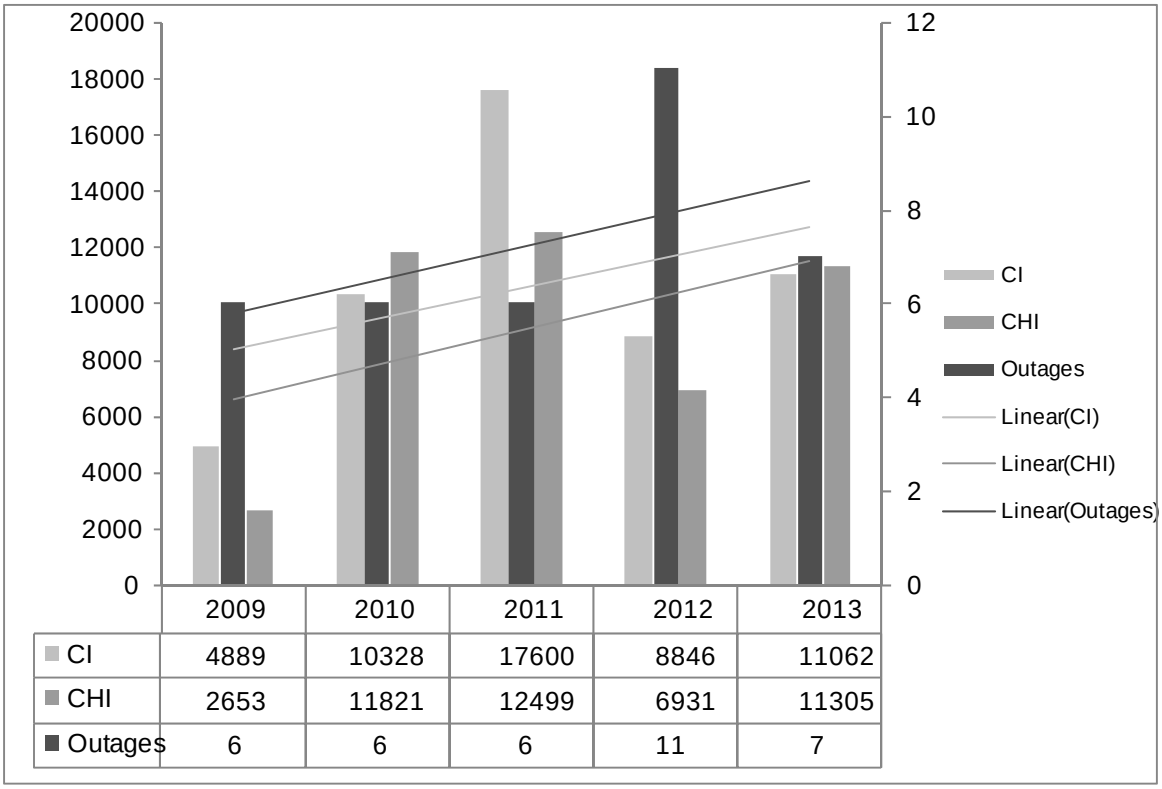
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 92: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ N/A
Reliability	ƒ Reliability is getting worse.
Other (i.e. road moratoriums, etc)	ƒ FESI inspection identified assets in the project area for replacement due to oil leaks and/or corrosion

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 71.



	2009	2010	2011	2012	2013
CI	4889	10328	17600	8846	11062
CHI	2653	11821	12499	6931	11305
Outages	6	6	6	11	7

FIGURE 71: HISTORICAL RELIABILITY DETAILS FOR SCNA47M13

E14008 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14008 Rebuild Trunk 502M1 M22 Birchmount – Electrical

Project Number: E14008

Project Year: 2015

Estimated Cost: $362,801

(i) Objective

Replace the old direct buried cable with new TR-XLPE cable in concrete encased duct along Birchmount Rd from Steeles Ave to Hydro One R.O.W South of McNicoll Ave. E14008 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 93: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Agincourt
Station(s):	Cavanaugh TS (27.6kV)
Feeder(s):	SCNA502M21, SCNA502M22

TABLE 94: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,942.92m
Underground Transformers	0
Underground Switchgear	3
Poles	0
Overhead Transformer	0
Overhead Switch	2

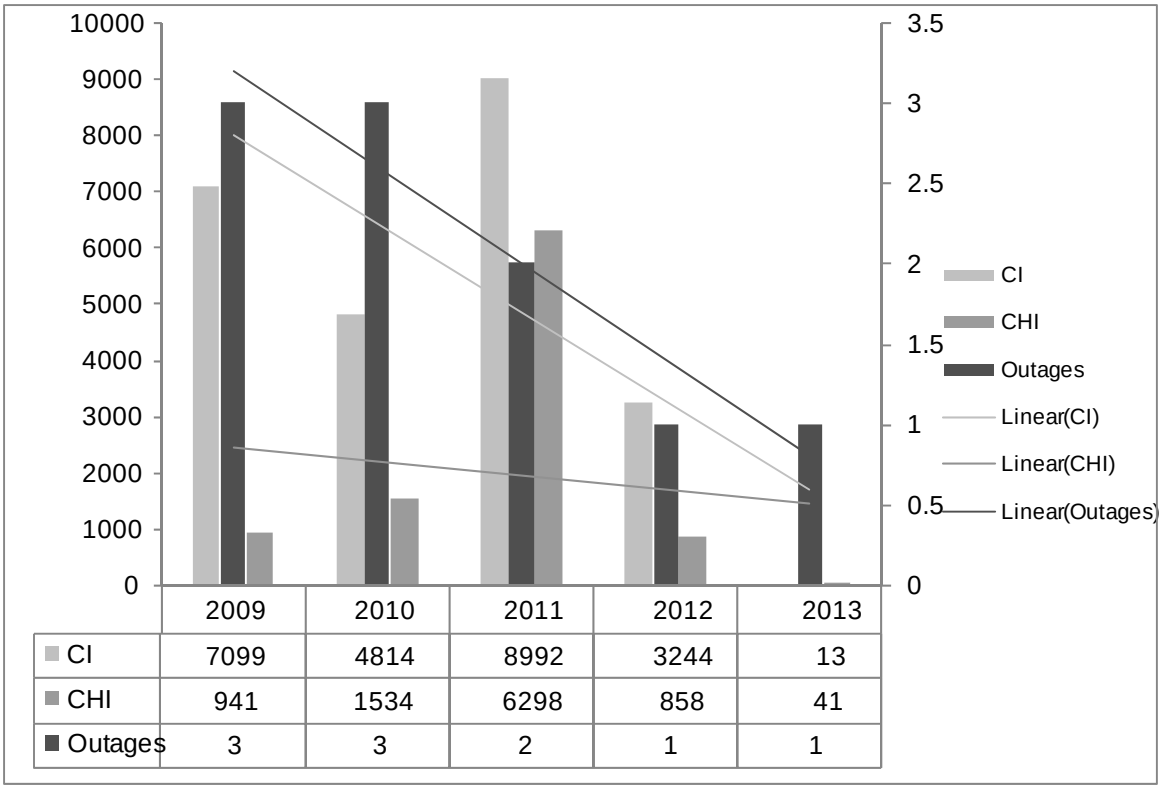
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 95: SUPPLEMENTAL DETAILS

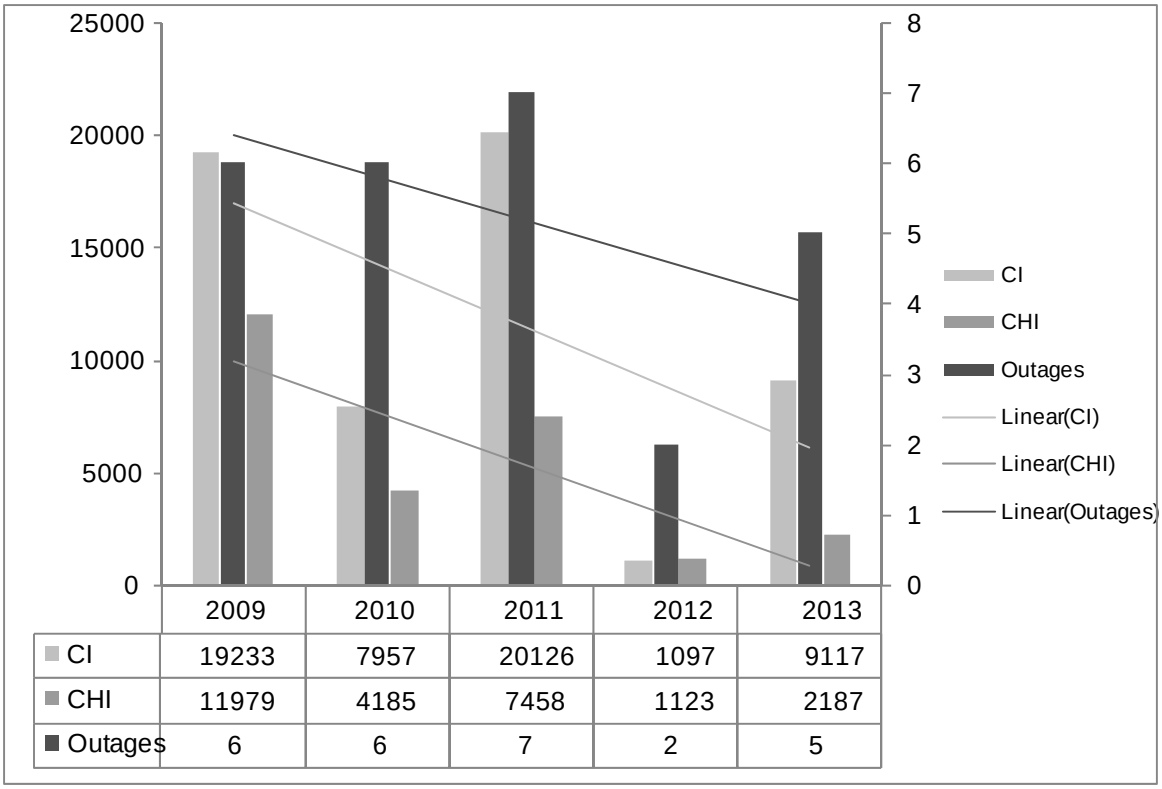
Supplemental Details	Description
Age/Condition	ƒ Undersized ƒ Direct buried trunk cable ƒ Installed 1973 (41 years old)
Reliability	ƒ Generally high CI and CHI over past five years ƒ Majority of underground outages have been due to primary cable and pad mounted switches; both assets will be targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 72 and 73.



	2009	2010	2011	2012	2013
CI	7099	4814	8992	3244	13
CHI	941	1534	6298	858	41
Outages	3	3	2	1	1

1 FIGURE 72: HISTORICAL RELIABILITY DETAILS FOR SCNA502M21



	2009	2010	2011	2012	2013
CI	19233	7957	20126	1097	9117
CHI	11979	4185	7458	1123	2187
Outages	6	6	7	2	5

FIGURE 73: HISTORICAL RELIABILITY DETAILS FOR SCNA502M22

E14116 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14116 DB Cable Replacements on SS63F1-Cummer & Maxome area-Civil

Project Number: E14116

Project Year: 2015

Estimated Cost: $262,347

(i) Objective

Replace direct buried cable along feeder NYSS63F1 specifically along Algo Court, Donna Court and the stretch from Maxome Avenue to Cummer Valley MS - areas located near Maxome Avenue and Cummer Avenue intersection in North York. This will help improve reliability and service to customer.

E14116 will install the civil infrastructure necessary to complete the project.

(i) Scope of Work

TABLE 96: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Estelle MS
Feeder(s):	NYSS63F1, NY80M4

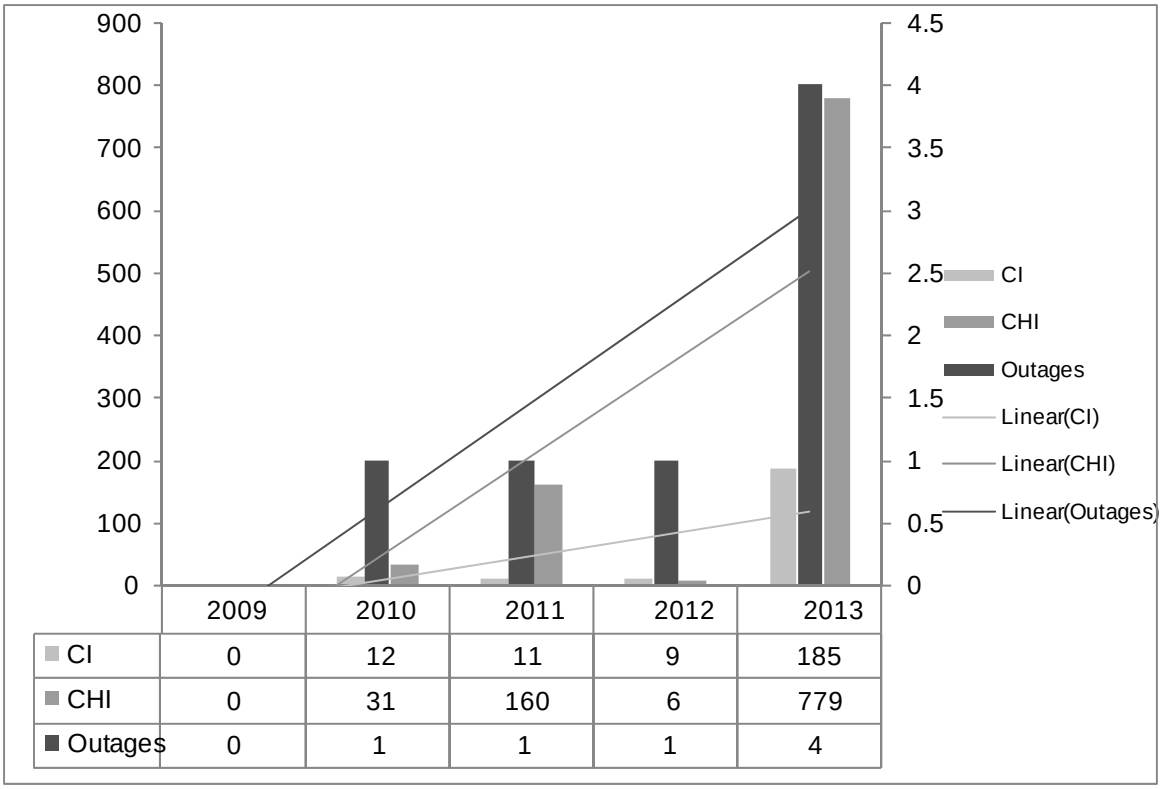
(ii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 97: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	x Switches, transformers and direct buried cable ƒ Assets installed 1958 (56 years old)
Reliability	ƒ Estelle MS has experienced power outage each year from 2009 to 2012 and escalated to 4 power outages in 2013
Other (i.e. road moratoriums, etc)	ƒ Result of an inspection in May 2011 confirmed the presence of Friable Asbestos, Corrosion, Dirt, Debris and Contamination as well as damaged doors in Estelle MS

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 74.



	2009	2010	2011	2012	2013
CI	0	12	11	9	185
CHI	0	31	160	6	779
Outages	0	1	1	1	4

FIGURE 74: HISTORICAL RELIABILITY DETAILS FOR NYSS63F1

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14141 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14141 UG Rebuild 502M32 Eastwood SD- Civil

Project Number: E14141

Project Year: 2015

Estimated Cost: $1,442,504

(i) Objective

Replace the old and failing primary cables in the area of Brownspring Rd, Hallbank Terr, Charterhouse Rd, Lawnmere Cres, Tidworth Sq, Hayward Cres, Keyworth Trail and a section of Pilfield Rd (area known as Eastwood subdivision) supplied by feeder NAE502M32. E14141 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 98: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough-Rouge River
Station(s):	Cavanaugh TS (27.6kV)
Feeder(s):	SCNA502M32

(iii) Justification & Benefits

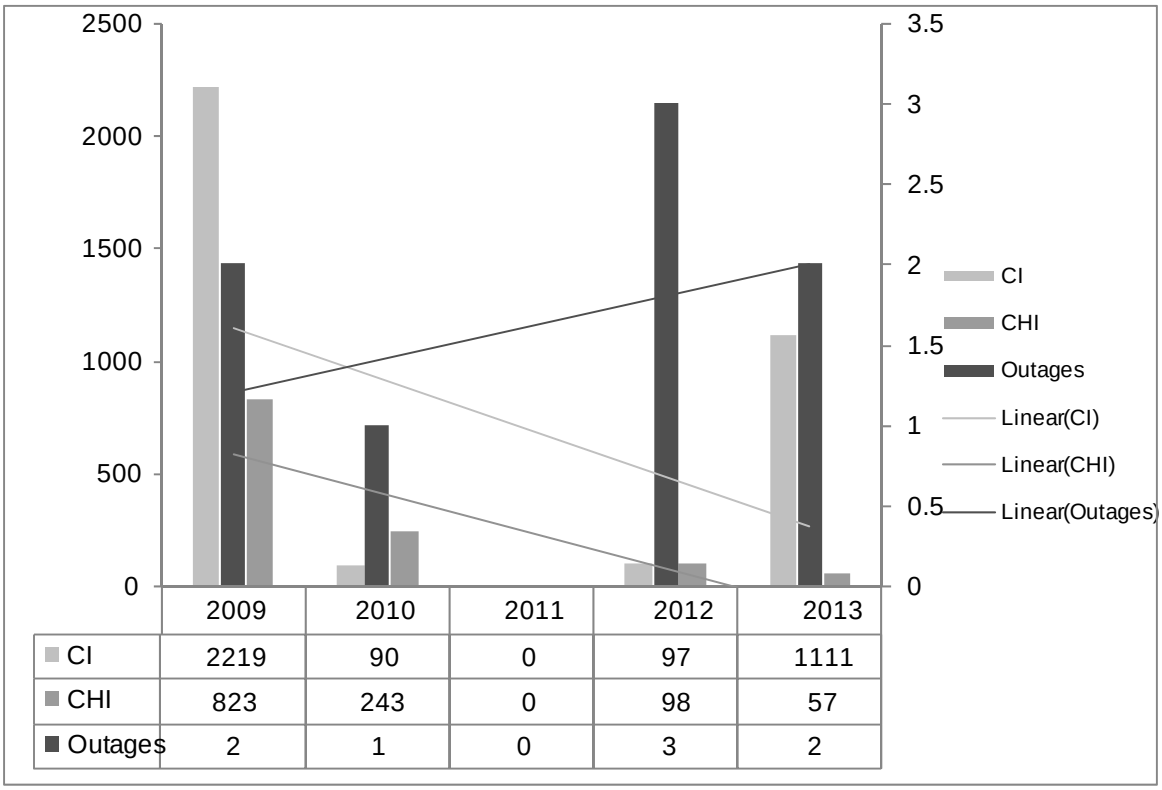
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 99: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Cable in direct buried duct ƒ Installed 1988 (26 years old)
Reliability	ƒ Moderate reliability along this feeder ƒ Majority of underground outages have been due to submersible

Supplemental Details	Description
	transformers which are targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ All transformers in the project area are due for replacement in 2015 ƒ Cables in direct buried duct are due for replacement in 2017; ƒ It is more prudent and cost effective to initiate the replacement in 2015. In this way the project will be completed by 2016 (i.e. cables replaced a year earlier and transformers replaced a year later than scheduled)

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 75.



	2009	2010	2011	2012	2013
CI	2219	90	0	97	1111
CHI	823	243	0	98	57
Outages	2	1	0	3	2

FIGURE 75: HISTORICAL RELIABILITY DETAILS FOR SCNA502M32

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14160 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14160 UG Cable Replacement 53M25 Cassandra 3Ph – Electrical

Project Number: E14160

Project Year: 2015

Estimated Cost: $408,725

(i) Objective

Replace the old and deteriorated 3-phase primary cables in the area of Cassandra Bv, Welsford Gdns, Avonwick Gt, and Ranchdale Cres installed around 1968 in CE ducts (as per GEAR). E14160 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 100: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Bermondsey TS (27.6 kV)
Feeder(s):	NY53M25

TABLE 101: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	4,057.36 m
Underground Transformers	2
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

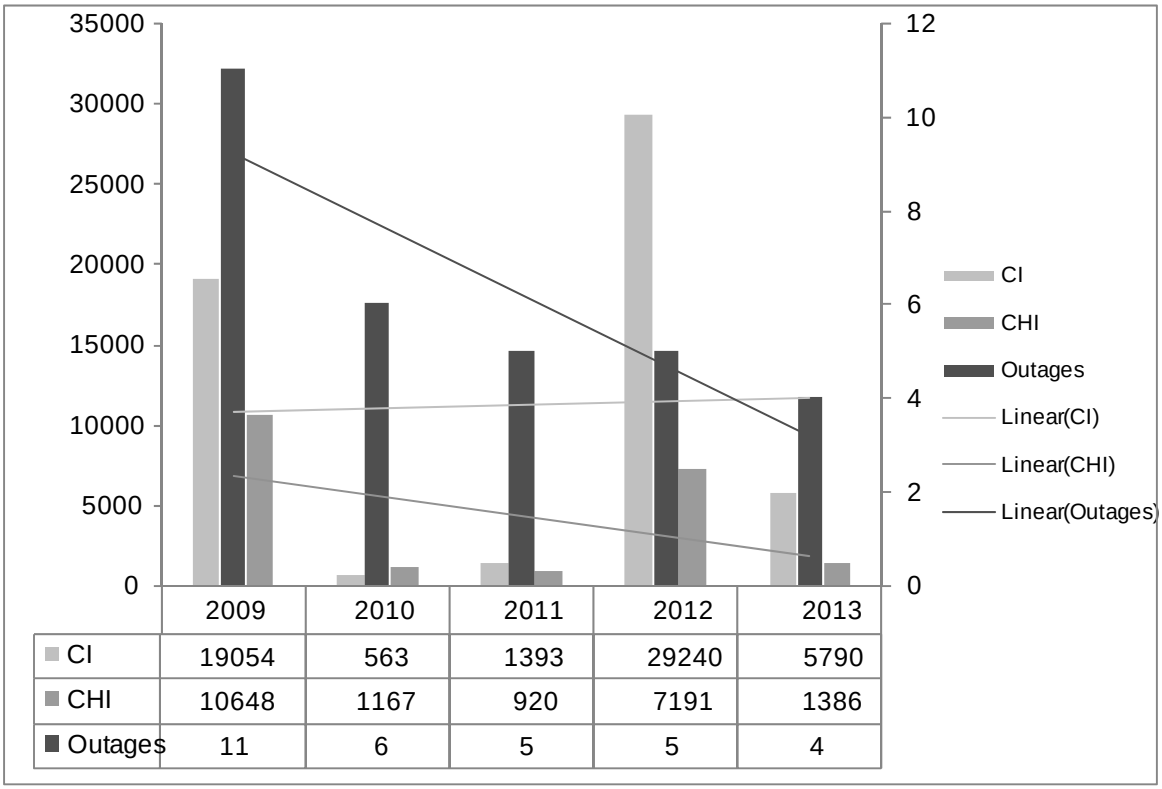
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 102: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ End of life cable in duct ƒ Installed in 1968 (46 years old)
Reliability	ƒ Feeder has experienced poor reliability with 9 outages in last 2 years
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 76.



	2009	2010	2011	2012	2013
CI	19054	563	1393	29240	5790
CHI	10648	1167	920	7191	1386
Outages	11	6	5	5	4

FIGURE 76: HISTORICAL RELIABILITY DETAILS FOR NY53M25

E14177 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14177 UG Rebuild 502M29 Carabob Crt – Civil

Project Number: E14177

Project Year: 2015

Estimated Cost: $415,952

(i) Objective

Replace direct buried primary cables installed between 1971 to 1980 in the area of Carabob Crt. E14177 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 103: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Agincourt
Station(s):	Cavanaugh TS (27.6kV)
Feeder(s):	SCNA502M29

(iii) Justification & Benefits

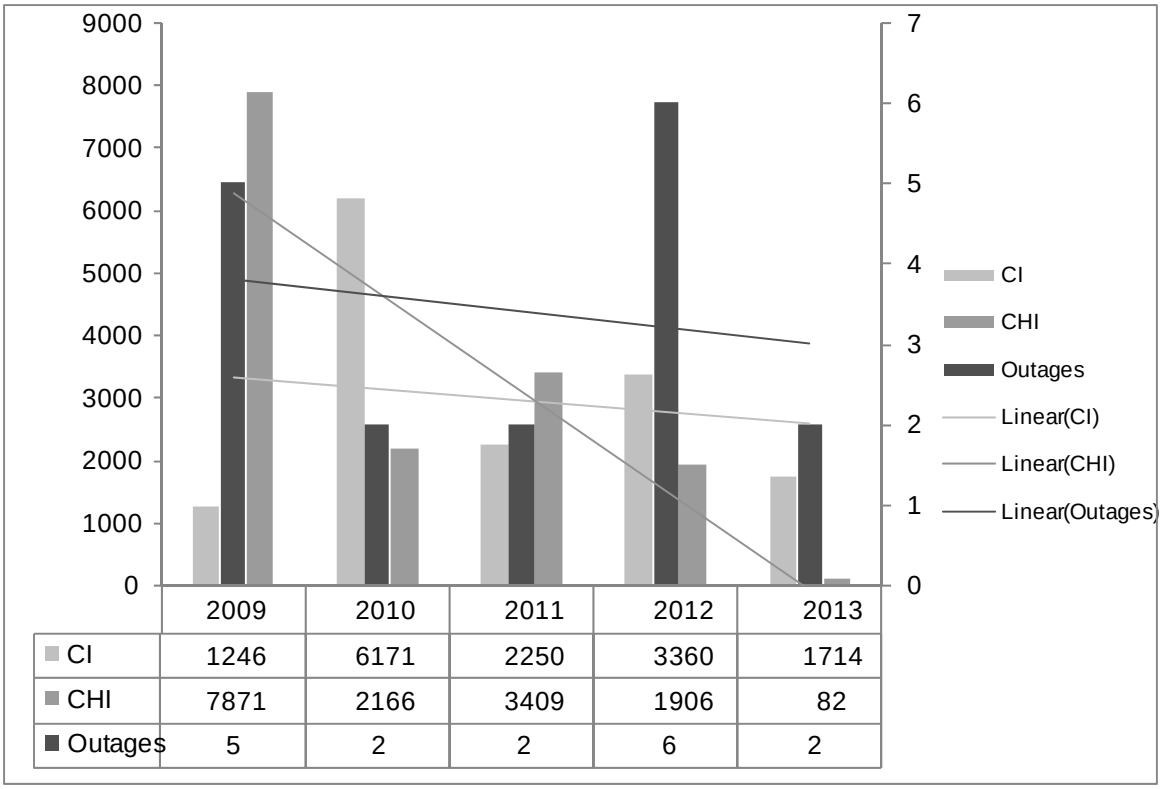
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 104: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	• End of life Cable in duct • Installed between 1971 – 1980 (between 34 – 43 years old)
Reliability	• Moderate reliability along this feeder • Majority of outages in the project area have been due to mini rupters Installed building vaults which is targeted for replacement in the Underground Circuit Renewal program

Supplemental Details	Description
Other (i.e. road moratoriums, etc)	ƒ Replacement of switches will minimize the safety related problems associated with this asset type

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 77.



	2009	2010	2011	2012	2013
CI	1246	6171	2250	3360	1714
CHI	7871	2166	3409	1906	82
Outages	5	2	2	6	2

FIGURE 77: HISTORICAL RELIABILITY DETAILS FOR SCNA502M29

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14179 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14179 UG Rebuild 502M29 Bonis King Henrys- Civil

Project Number: E14179

Project Year: 2015

Estimated Cost: $936,238

(i) Objective

Replace direct buried primary cables installed between 1971 to 1980 in the area of Bonis Ave and King Henrys Blvd. E14179 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 105: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Agincourt
Station(s):	Cavanaugh TS (27.6 kV)
Feeder(s):	SCNA502M29

(iii) Justification & Benefits

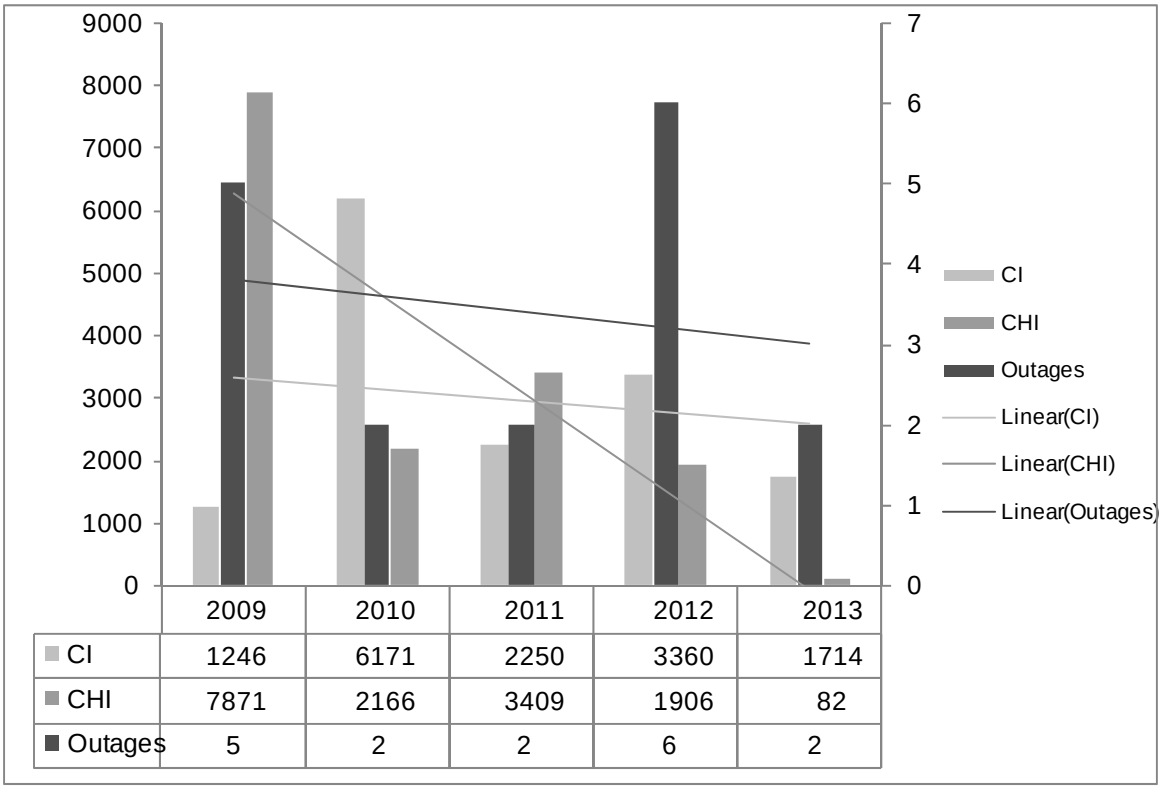
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 106: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	x Combination of direct buried cable and end of life cable in duct ƒ Installed between 1971 – 1980 (between 34 – 43 years old)
Reliability	ƒ Moderate reliability along this feeder ƒ Majority of outages in the project area have been due to mini rupters which is targeted for replacement in the Underground Circuit

Supplemental Details	Description
	Renewal program
Other (i.e. road moratoriums, etc)	ƒ Replacement of switches will minimize the safety related problems associated with this asset type

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 78.



	2009	2010	2011	2012	2013
CI	1246	6171	2250	3360	1714
CHI	7871	2166	3409	1906	82
Outages	5	2	2	6	2

FIGURE 78: HISTORICAL RELIABILITY DETAILS FOR SCNA502M29

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14191 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14191 UG Rebuild H9M30 Kingston Mason –Electrical

Project Number: E14191

Project Year: 2015

Estimated Cost: $623,791

(i) Objective

Replace direct buried primary cables installed between 1975 to 1977 in the area of Mason Rd, Rain St and TH complex of 3420-3430 Kingston Rd. E14191 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 107: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Southwest
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCN AH9M30

TABLE 108: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,518.46m
Underground Transformers	10
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

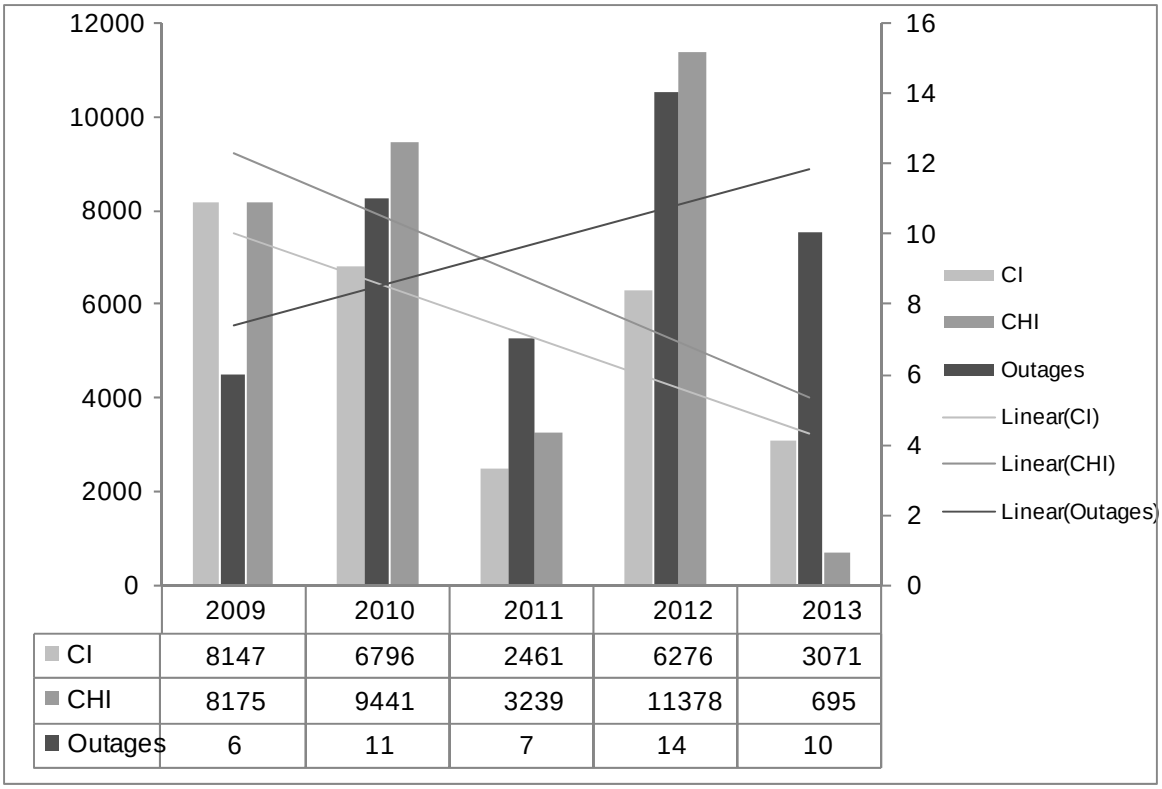
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 109: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1976 (38 years old)
Reliability	ƒ Overall increasing number of outages from 2009 to 2013, averaging 10/year ƒ High CI and CHI ratings ƒ Majority of failures due to primary cable and transformers; both of which are targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 79.



	2009	2010	2011	2012	2013
CI	8147	6796	2461	6276	3071
CHI	8175	9441	3239	11378	695
Outages	6	11	7	14	10

FIGURE 79: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M30

E14230 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14230 Manse Road 209-245 UG Rebuild Civil

Project Number: E14230

Project Year: 2015

Estimated Cost: $744,400

(i) Objective

Replace direct buried cable infrastructure installed in 1981 to improve reliability and service to the customer. E14230 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 110: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough East
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCN AH9M29

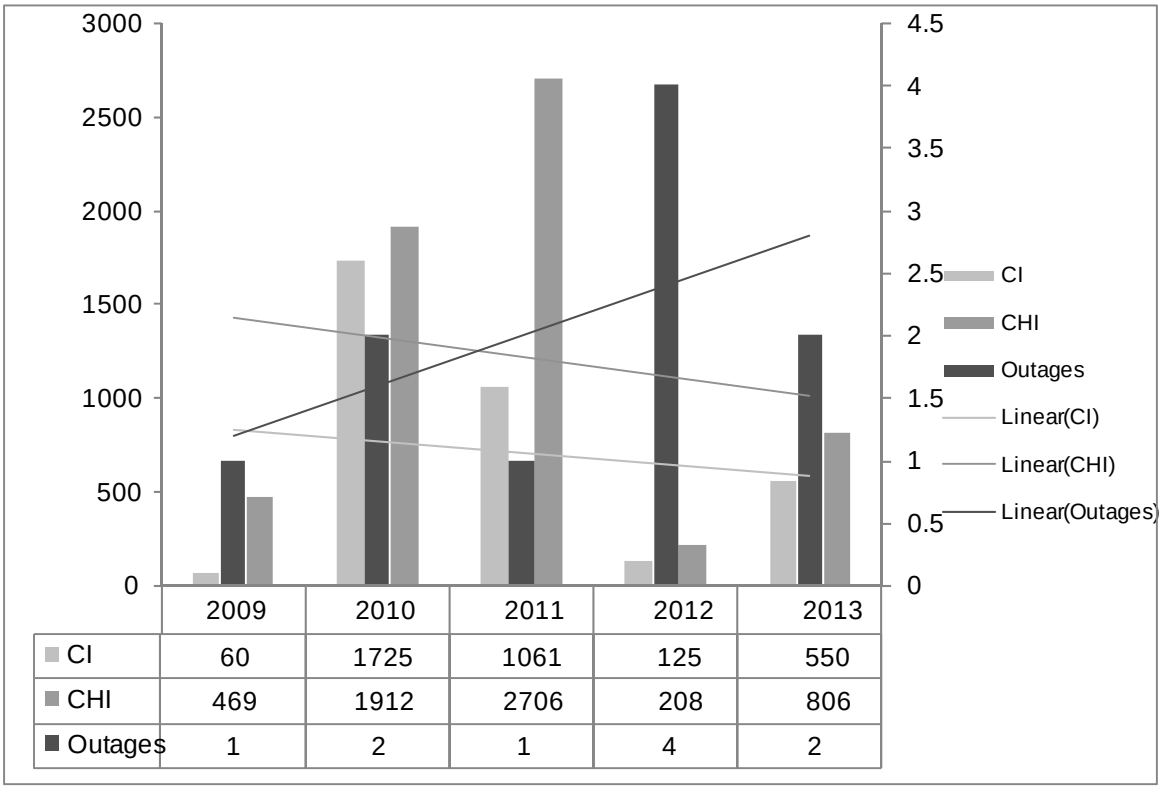
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 111: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cables ƒ Installed 1981 (33 years old)
Reliability	ƒ Feeder has experienced poor reliability with 6 outages in last 2 years
Other (i.e. road moratoriums, etc)	ƒ Project needs to be completed prior to water main reconstruction 2017

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 80.



	2009	2010	2011	2012	2013
CI	60	1725	1061	125	550
CHI	469	1912	2706	208	806
Outages	1	2	1	4	2

FIGURE 80: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M29

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14234 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14234 Grenoble Gateway UG Rebuild Civil NY53M9

Project Number: E14234

Project Year: 2015

Estimated Cost: $297,997

(i) Objective

To split the three phase loop and install appropriate sized fuses for the protection of the distribution. E14234 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 112: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Bermondsey TS (27.6kV)
Feeder(s):	NY53M9, NY53M1

TABLE 113: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	2,487.13 m
Underground Transformers	8
Underground Switchgear	12
Poles	0
Overhead Transformer	0
Overhead Switch	0

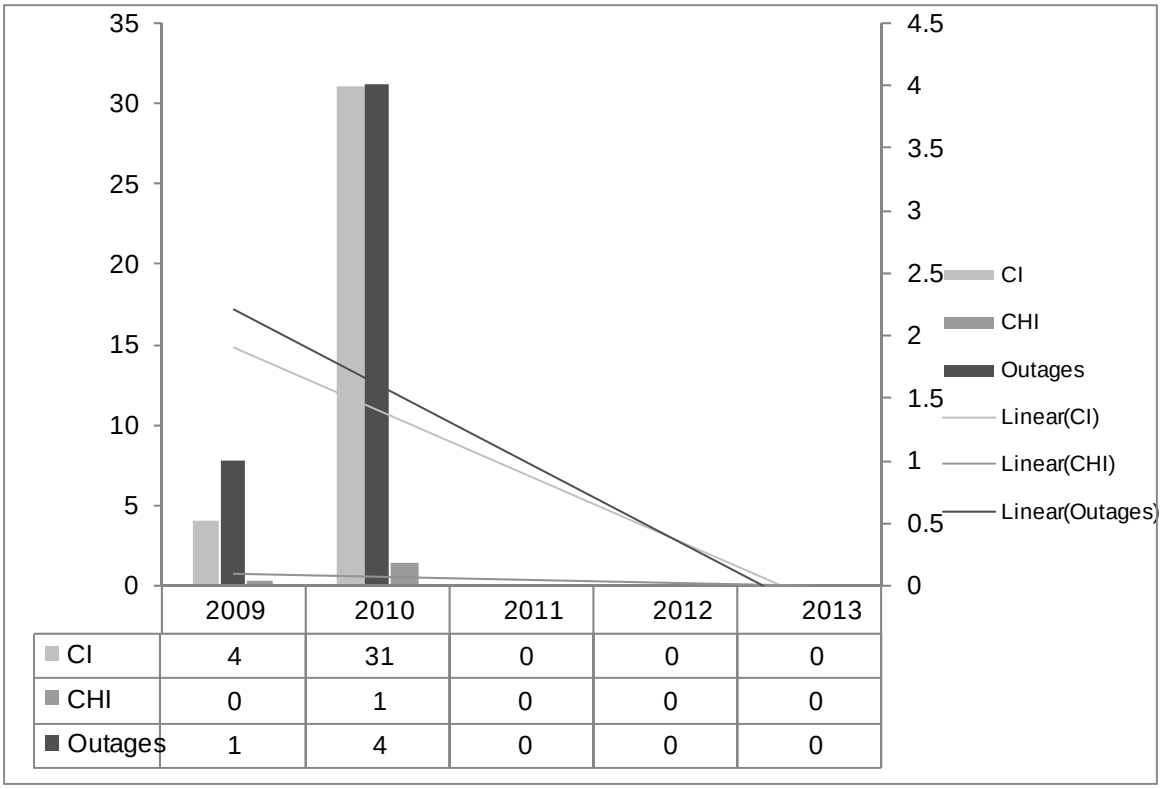
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 114: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cables ƒ Installed 1989 (25 years old)
Reliability	ƒ N/A
Other (i.e. road moratoriums, etc)	ƒ Loop reconfiguration part of project to address load growth ƒ Direct buried cables in project area are operating past their estimated useful service life and need to be addressed before failures occur

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 81.



	2009	2010	2011	2012	2013
CI	4	31	0	0	0
CHI	0	1	0	0	0
Outages	1	4	0	0	0

FIGURE 81: HISTORICAL RELIABILITY DETAILS FOR NY53M9

E14236 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14236 185 Galloway UG Rebuild SCNAH9M29 – Civil

Project Number: E14236

Project Year: 2015

Estimated Cost: $457,867

(i) Objective

Replace direct buried cable infrastructure installed in 1981 to improve reliability and service to the customer.

(ii) Scope of Work

TABLE 115: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough East
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCNAH9M29

(iii) Justification & Benefits

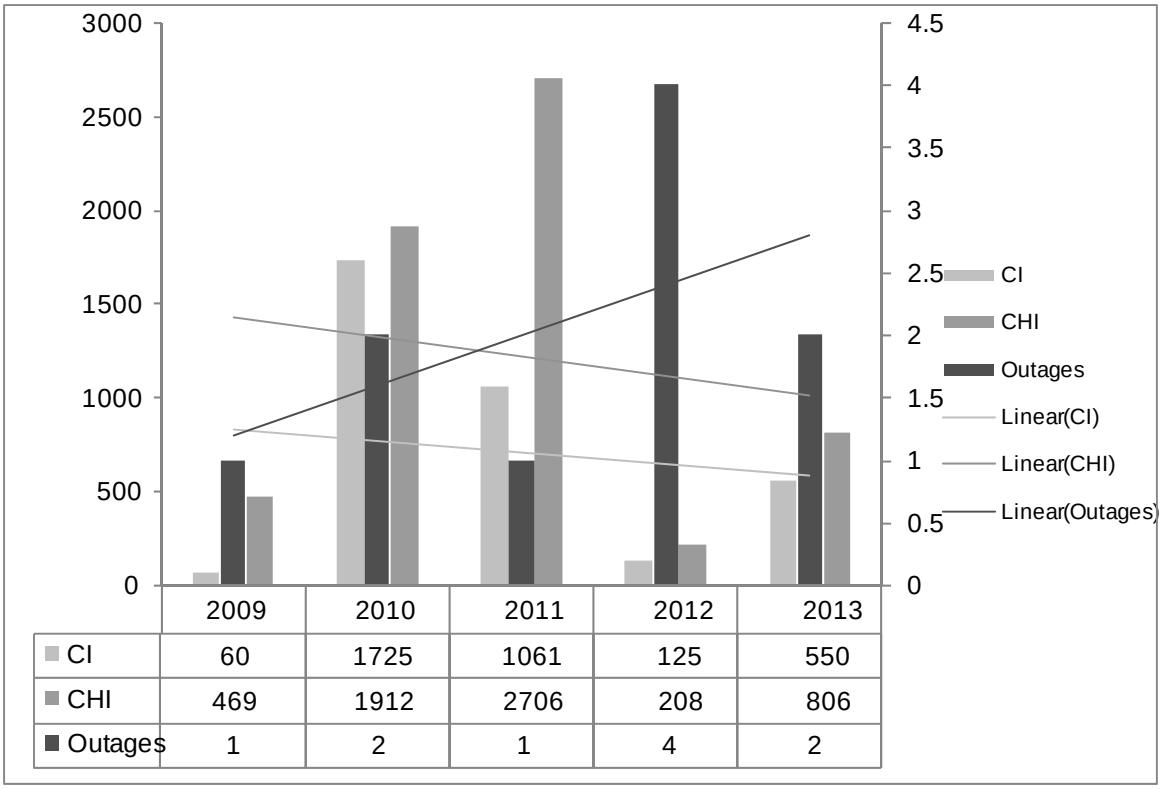
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 116: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1976 (38 years old)
Reliability	ƒ Overall increasing number of outages from 2009 to 2013, averaging 10/year ƒ High CI and CH ratings ƒ Majority of failures due to primary cable and transformers; both of

Supplemental Details	Description
	which are targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 82.



	2009	2010	2011	2012	2013
CI	60	1725	1061	125	550
CHI	469	1912	2706	208	806
Outages	1	2	1	4	2

FIGURE 82: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M29

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14281 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14281 UG Rebuild VC 64F2 to 51M5 Argonne Simeon- Civil

Project Number: E14281

Project Year: 2015

Estimated Cost: $1,175,981

(i) Objective

Replace direct buried 4.16kV primary cables installed in 1968 in the area of Argonne Cres, Oakhurst Dr and Simeon Crt. Via voltage conversion to 27.6kV. E14281 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 117: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Ruddington MS (4.16kV)
Feeder(s):	NYSS 64F2

(iii) Justification & Benefits

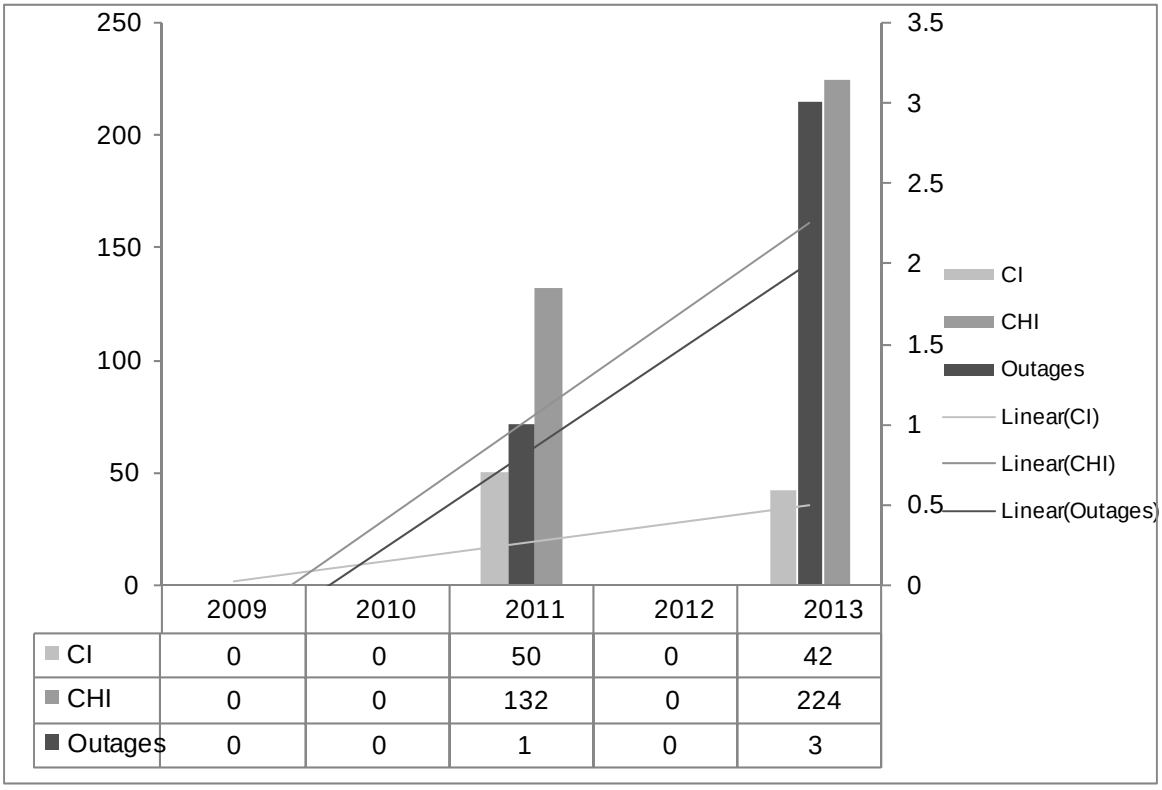
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 118: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1968 (46 years old)
Reliability	ƒ Existing supply is from Ruddington MS that was built in the 1960's. ƒ It contains aged and unreliable assets which affect feeder reliability.
Other (i.e. road	ƒ Voltage conversion in the area will address reliability concerns

Supplemental Details	Description
moratoriums, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 83.



	2009	2010	2011	2012	2013
CI	0	0	50	0	42
CHI	0	0	132	0	224
Outages	0	0	1	0	3

FIGURE 83: HISTORICAL RELIABILITY DETAILS FOR NYSS64-F2

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14322 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14322 Establish Neilson Tapscott R26M34 Main – Electrical

Project Number: E14322

Project Year: 2015

Estimated Cost: $737,921

(i) Objective

To establish Neilson to Tapscott R26M34 feeder main (running along Finch Ave) by replacing the existing old and direct buried cable. Operations needs this circuit as part of feeder main linking R26M22. E14322 will complete the electrical portion of the ICM approved project.

(ii) Scope of Work

TABLE 119: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Malvern TS (27.6kV)
Feeder(s):	SCNAR26M34

TABLE 120: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,077.64m
Underground Transformers	0
Underground Switchgear	3
Poles	0
Overhead Transformer	0
Overhead Switch	0

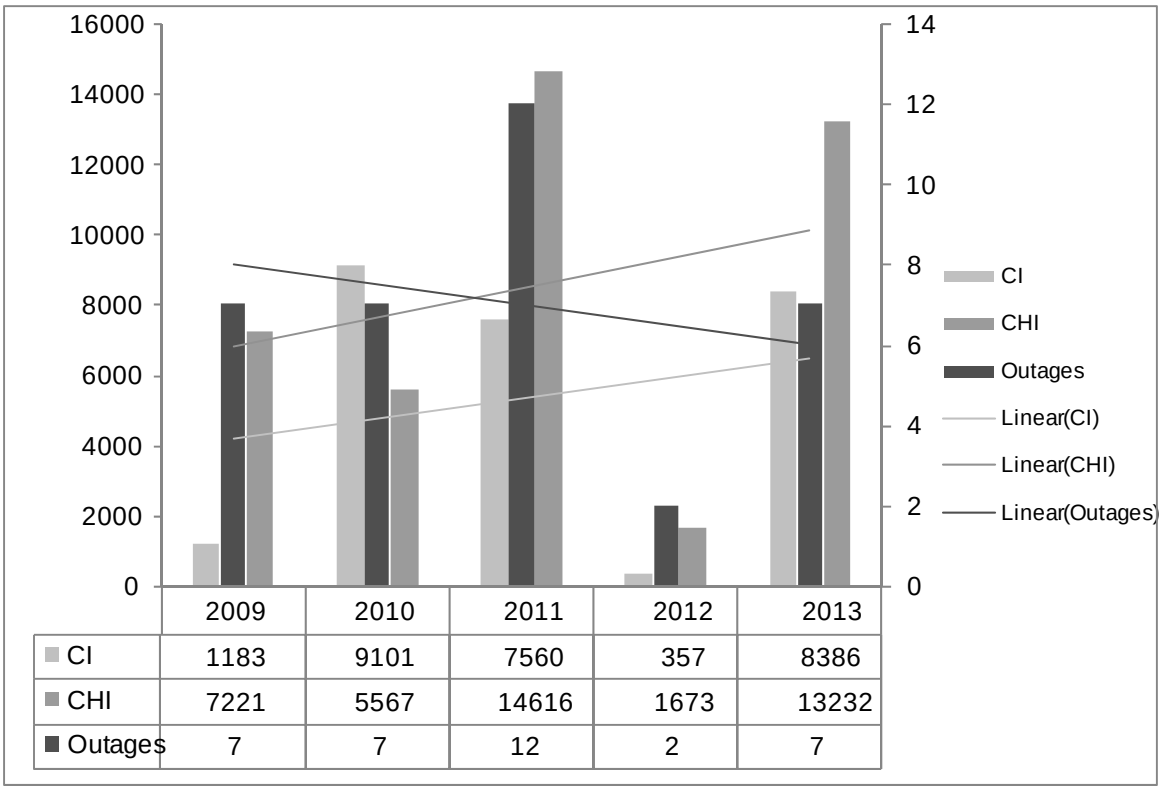
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 121: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1977 (37 years old)
Reliability	ƒ Reliability is weakening along this feeder
Other (i.e. road moratoriums, etc)	ƒ Existing trunk is undersized and cannot operate as a suitable backup in the event of a failure; operations has suggested to upgrade the trunk cable to 1000 kcmil to maintain reliability ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 84.



	2009	2010	2011	2012	2013
CI	1183	9101	7560	357	8386
CHI	7221	5567	14616	1673	13232
Outages	7	7	12	2	7

FIGURE 84: HISTORICAL RELIABILITY DETAILS FOR SCNAR26M34

E14411 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14411 Crow Tr Remaining UG Rebuild Civ and Elec R26M34 SCNAR26M34

Project Number: E14411

Project Year: 2015

Estimated Cost: $473,989

(i) Objective

To complete the rebuild of the crow trail distribution by replacing the old direct buried cables in the remaining area. This project will install a SCADA SF6 pad switch (PMH-11 type) replacing the existing air insulated one. This was an operational requirement suggested by Operations group. E 14411 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 122: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Malvern TS (27.6kV)
Feeder(s):	SCNAR26M34

TABLE 123: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	790.36m
Underground Transformers	1
Underground Switchgear	4
Poles	0
Overhead Transformer	0
Overhead Switch	0

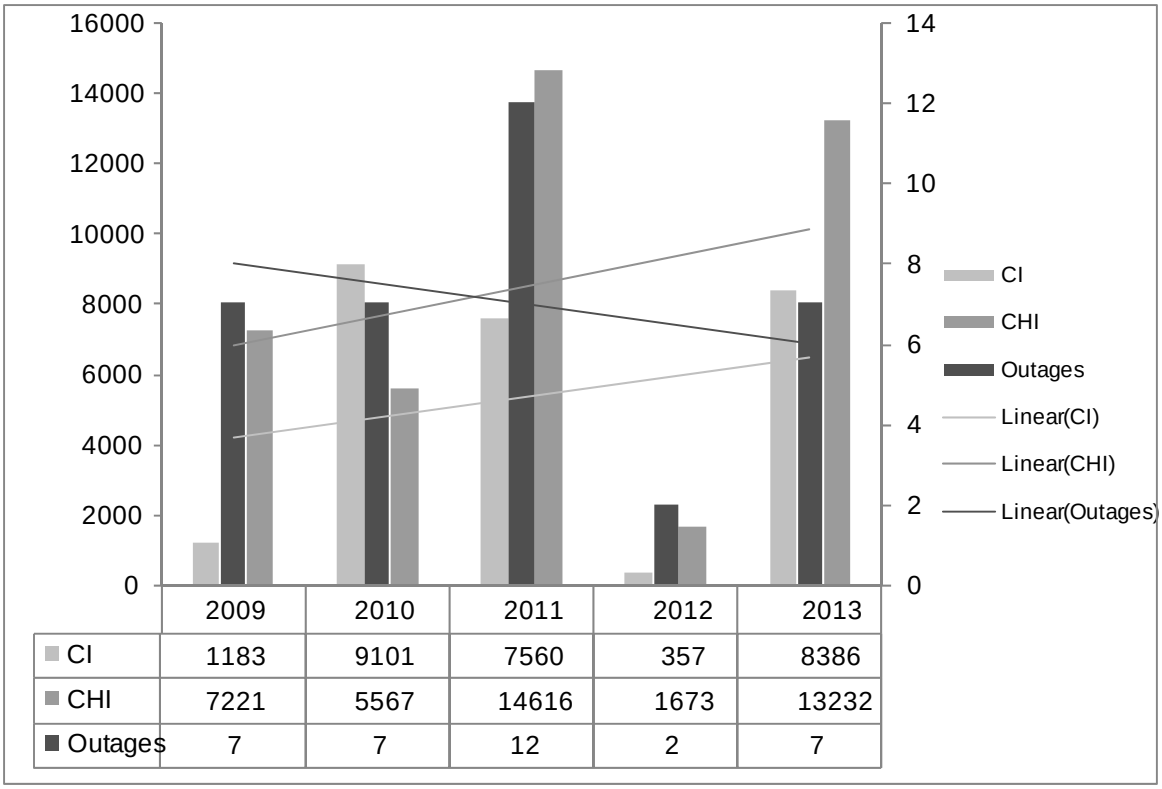
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 124: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1977 (37 years old)
Reliability	ƒ Reliability is weakening along this feeder
Other (i.e. road moratoriums, etc)	ƒ This rebuild was supposed to be completed earlier. It was delayed because of a City's moratorium

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 85.



	2009	2010	2011	2012	2013
CI	1183	9101	7560	357	8386
CHI	7221	5567	14616	1673	13232
Outages	7	7	12	2	7

FIGURE 85: HISTORICAL RELIABILITY DETAILS FOR SCNAR26M34

E14432 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E14432 P01 47M1 Mammoth Hall UG Rebuild Ph3 (Electrical) SCNT47M1

Project Number: E14432

Project Year: 2015

Estimated Cost: $855,398

(i) Objective

Replace and redesign the 3-phase distribution system in the Mammoth Hall Neighborhood. The redesign was broken into three phases. E14432 is the third phase and will complete the electrical portion of the ICM approved project.

(ii) Scope of Work

TABLE 125: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Sheppard TS (27.6kV)
Feeder(s):	SCNT47M1

TABLE 126: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,792.55m
Underground Transformers	0
Underground Switchgear	2
Poles	0
Overhead Transformer	0
Overhead Switch	1

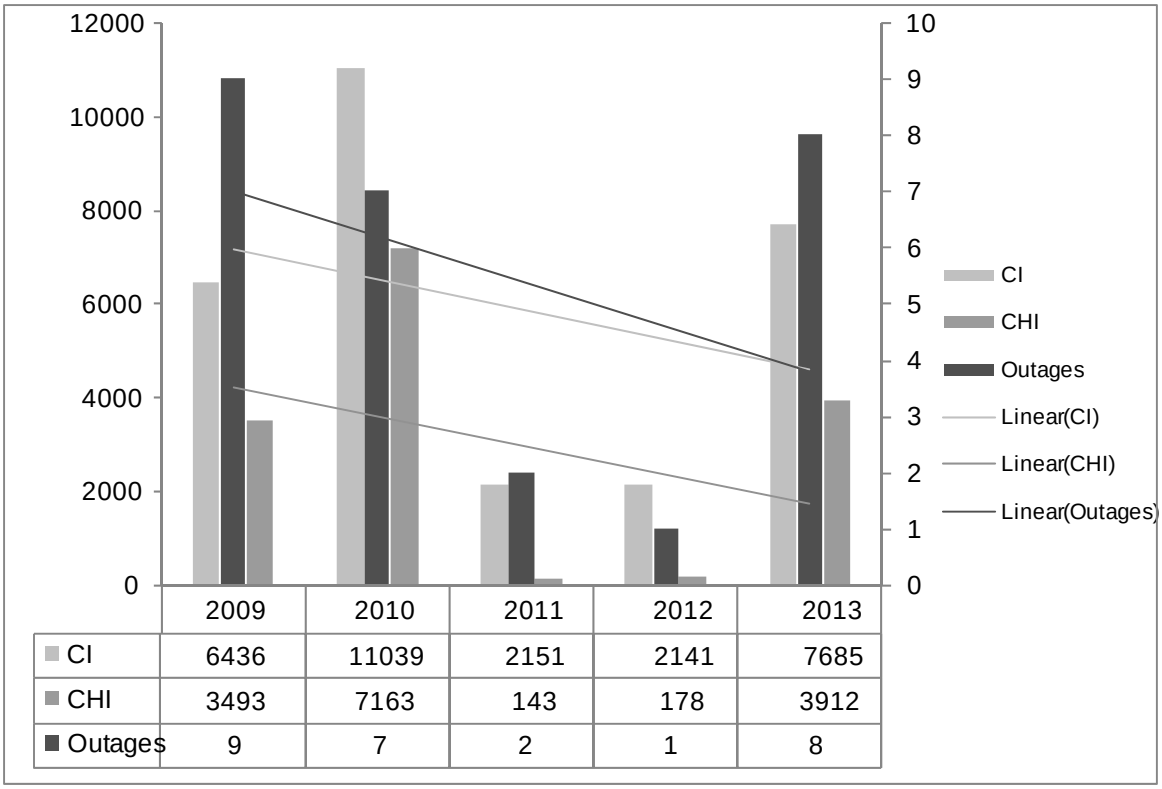
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 127: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable Installed 1979 (35 years old)
Reliability	ƒ Reliability improvements seen up until 2012 ƒ Reliability weakened in 2013, with the feeder experiencing 8 sustained outages in 2013 alone
Other (i.e. road moratoriums, etc)	ƒ This is the electrical part of the project and should be carried out to complete the project

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 86.



	2009	2010	2011	2012	2013
CI	6436	11039	2151	2141	7685
CHI	3493	7163	143	178	3912
Outages	9	7	2	1	8

FIGURE 86: HISTORICAL RELIABILITY DETAILS FOR SCNT47M1

E15024 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15024 P01 Sheppard UG DB Cable Rehab Elec

Project Number: E15024

Project Year: 2015

Estimated Cost: $429,796

(i) Objective

Rebuild the underground direct-buried circuit along Sheppard Ave East between Markham Rd and McCowan Rd. E15024 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 128: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCNAH9M23, SCNAH9M32

TABLE 129: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	2,676.4m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	2

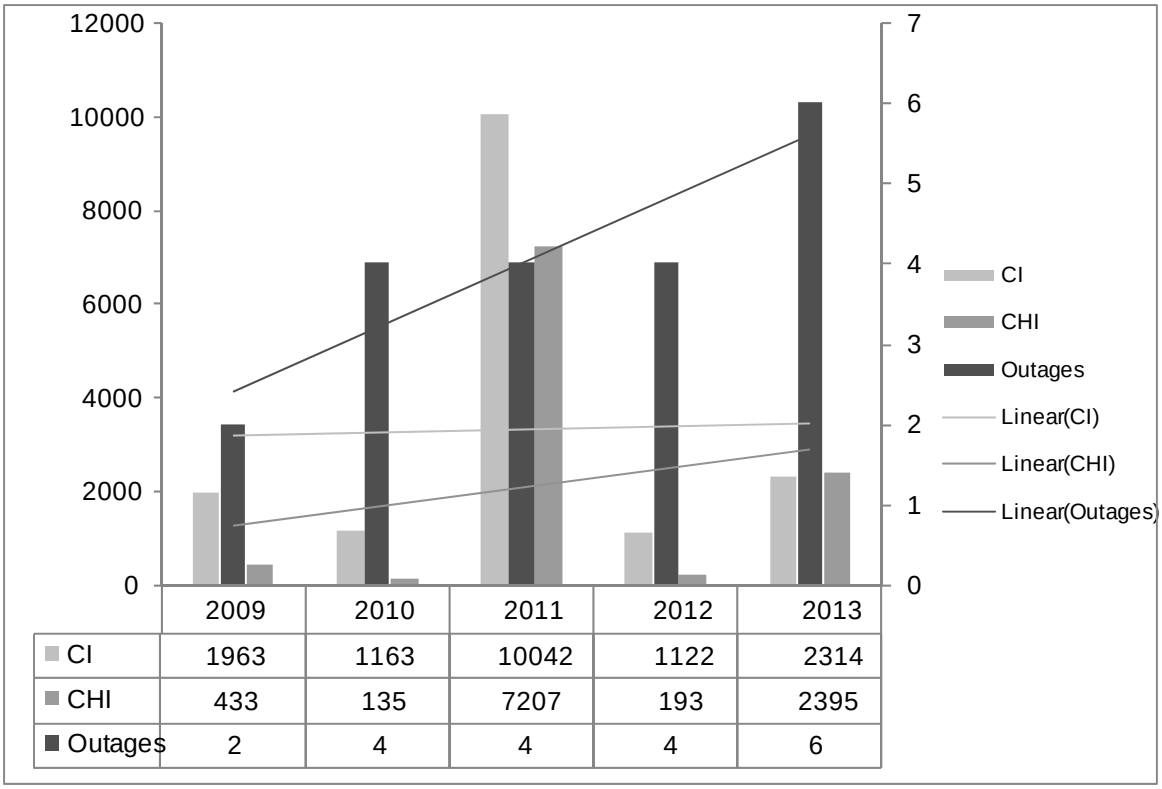
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 130: SUPPLEMENTAL DETAILS

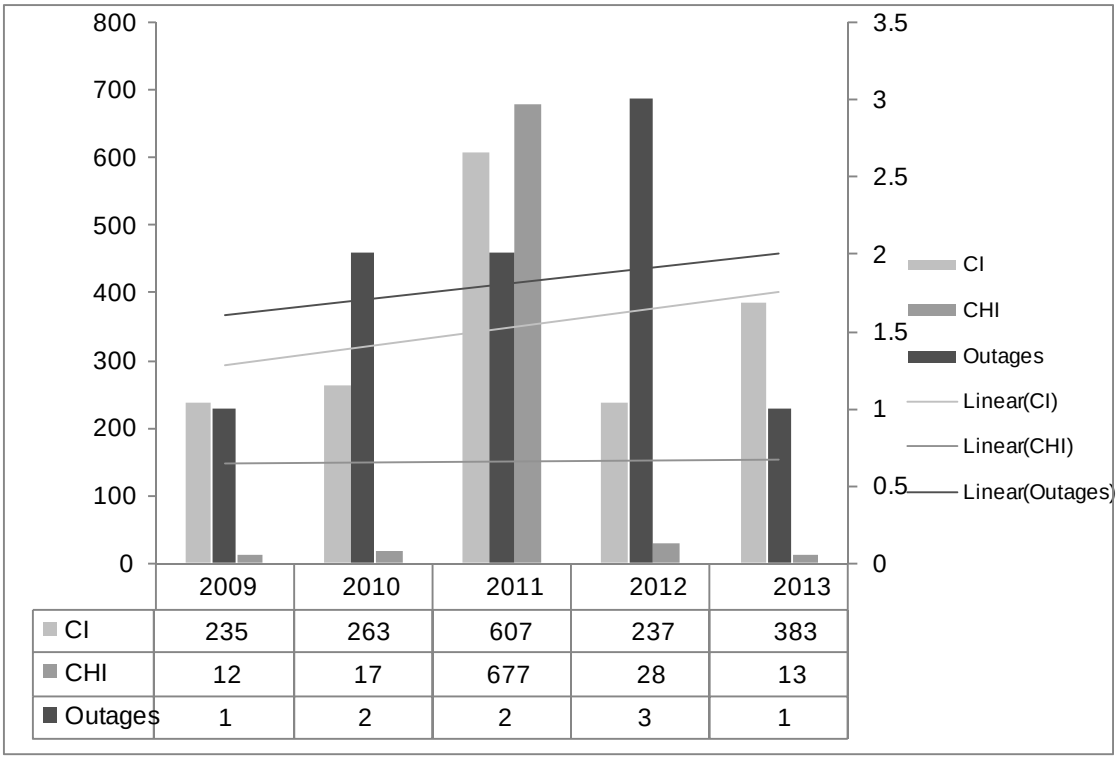
Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1970 (44 years old)
Reliability	x The normal feeder H9M23 and the backup feeder H9M32, both show a deteriorating reliability trend. ƒ Four outages have been recorded in the project area alone
Other (i.e. road moratoriums, etc)	ƒ This is the electrical part of the project and should be carried out to complete the project

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 87 and 88.



	2009	2010	2011	2012	2013
CI	1963	1163	10042	1122	2314
CHI	433	135	7207	193	2395
Outages	2	4	4	4	6

FIGURE 87: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M23



	2009	2010	2011	2012	2013
CI	235	263	607	237	383
CHI	12	17	677	28	13
Outages	1	2	2	3	1

FIGURE 88: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M32

E15193 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15193 Leslie-Clovercrest-UG Renewal-Civil & Elec-51M6 NY51M6

Project Number: E15193

Project Year: 2015

Estimated Cost: $540,298

(i) Objective

Replace existing underground asset that is near or passed their useful service life. E15193 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 131: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie TS (27.6kV)
Feeder(s):	NY51M6

TABLE 132: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	508.56m
Underground Transformers	4
Underground Switchgear	1
Poles	0
Overhead Transformer	0
Overhead Switch	0

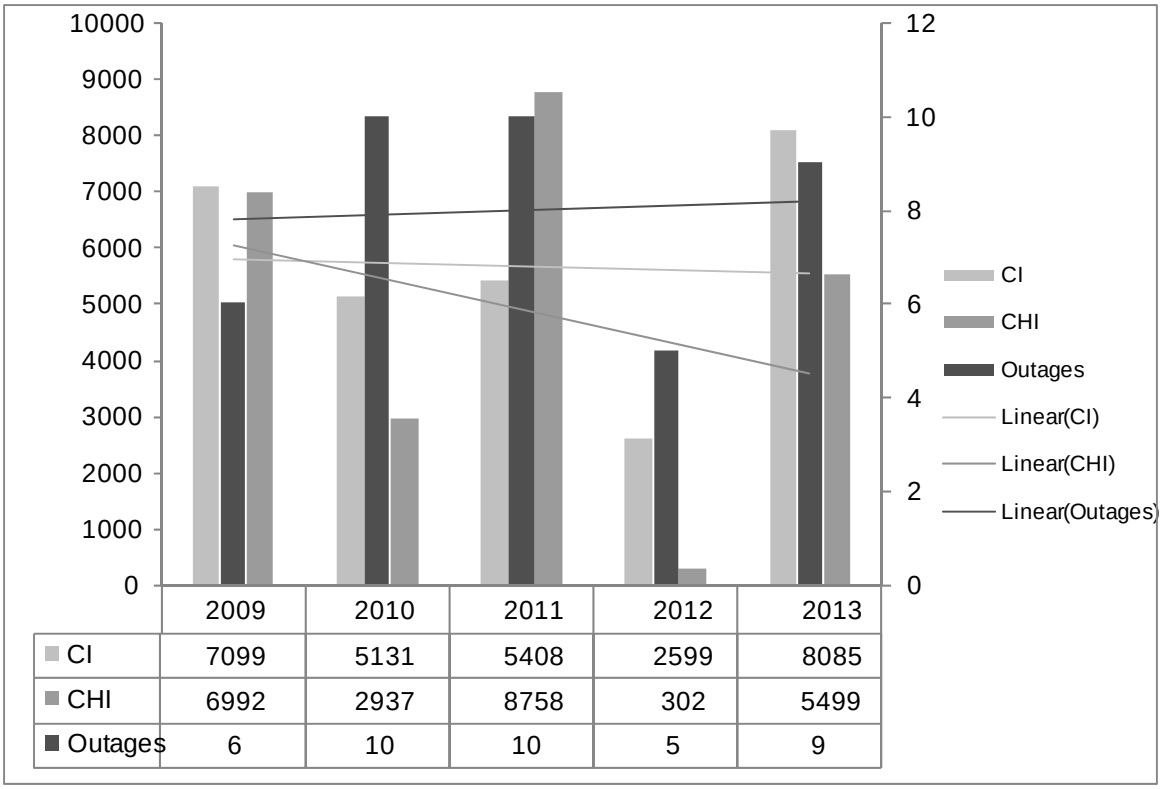
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 133: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed around 1950 (approx. 64 years old)
Reliability	ƒ 51M6 has been performing poorly with an average of 8 power outages per year during the past 5 years ƒ Majority of failures seen in the past five years due to primary cable and submersible transformers; both of which are targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 89.



	2009	2010	2011	2012	2013
CI	7099	5131	5408	2599	8085
CHI	6992	2937	8758	302	5499
Outages	6	10	10	5	9

FIGURE 89: HISTORICAL RELIABILITY DETAILS FOR NY51M6

E15195, E16071 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Morningside Ave UG Trunk-Civil/Electri cal NT47M3 SCNT47M3

Project Number: E15195, E16071

Project Year: 2015

Estimated Cost: $840,597

(i) Objective

Replace old, direct buried with new TR-XLPE cable in concrete encased duct on the feeder trunk of 47M3 between PS2403 and PS83591.

E15195 will install the civil infrastructure necessary to complete the project. E16071 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 134: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Sheppard TS (27.6kV)
Feeder(s):	SCNT47M3

TABLE 135: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	472.18m
Underground Transformers	0
Underground Switchgear	2
Poles	0
Overhead Transformer	0
Overhead Switch	0

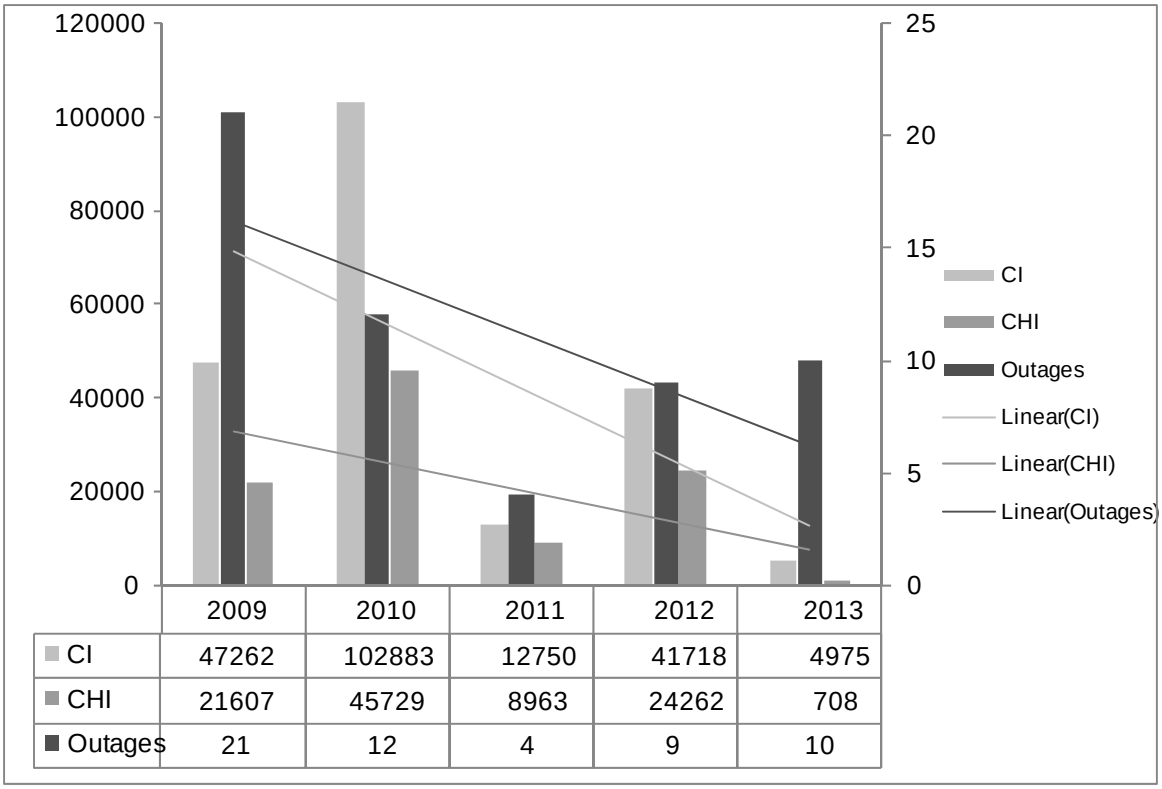
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 136: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed around 1969 (approx. 45 years old)
Reliability	ƒ The feeder was the Worst Performing Feeder (WPF) from 2005 to 2012 ƒ Reliability improvements seen due to recent rebuilds, however feeder is still ranks second in the WPF list with 10 sustained outages in 2013 alone
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 90.



	2009	2010	2011	2012	2013
CI	47262	102883	12750	41718	4975
CHI	21607	45729	8963	24262	708
Outages	21	12	4	9	10

FIGURE 90: HISTORICAL RELIABILITY DETAILS FOR SCNT47M3

E15197 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15197 P01-Finch-Sheppard-Replacement 51M22 trunk-Elec-51M22-Leslie Ts

Project Number: E15197

Project Year: 2015

Estimated Cost: $539,483

(i) Objective

Replace existing underground trunk cable for feeder 51M22 that was installed in 1968 to increase reliability and service to the customer. E15197 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 137: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie II TS (27.6kV)
Feeder(s):	NY51M22

TABLE 138: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	4,313.53m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

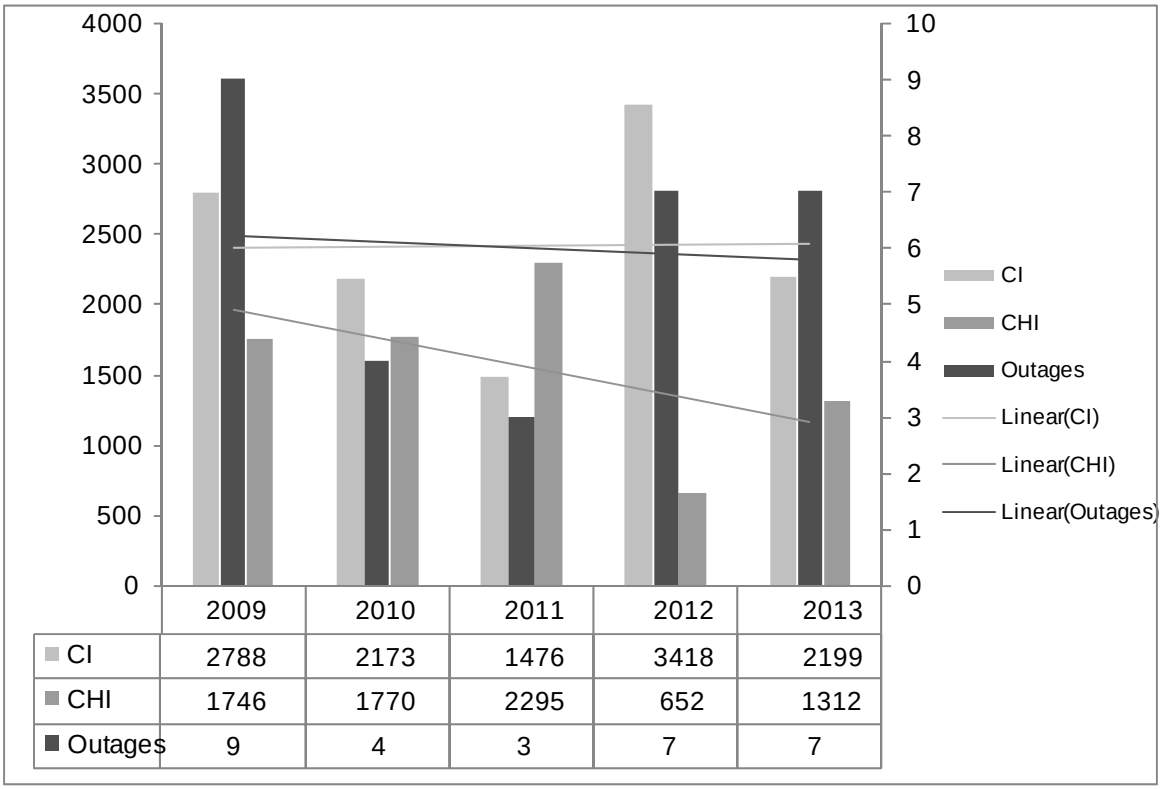
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 139: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1968 (46 years old)
Reliability	ƒ 51M22 has been performing poorly during the last 5 years with an average of 6 power outages per year
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 91.



	2009	2010	2011	2012	2013
CI	2788	2173	1476	3418	2199
CHI	1746	1770	2295	652	1312
Outages	9	4	3	7	7

FIGURE 91: HISTORICAL RELIABILITY DETAILS FOR NY51M22

E15198 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15198 Finch-Sheppard-trunk cable Repl.-Elec NY51M28

Project Number: E15198

Project Year: 2015

Estimated Cost: $476,680

(i) Objective

Replace existing underground trunk cable for feeder 51M28 that was installed in 1968 to improve reliability and service to the customer. E15198 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 140: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie II TS (27.6kV)
Feeder(s):	NY51M28

TABLE 141: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	4,676.93m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

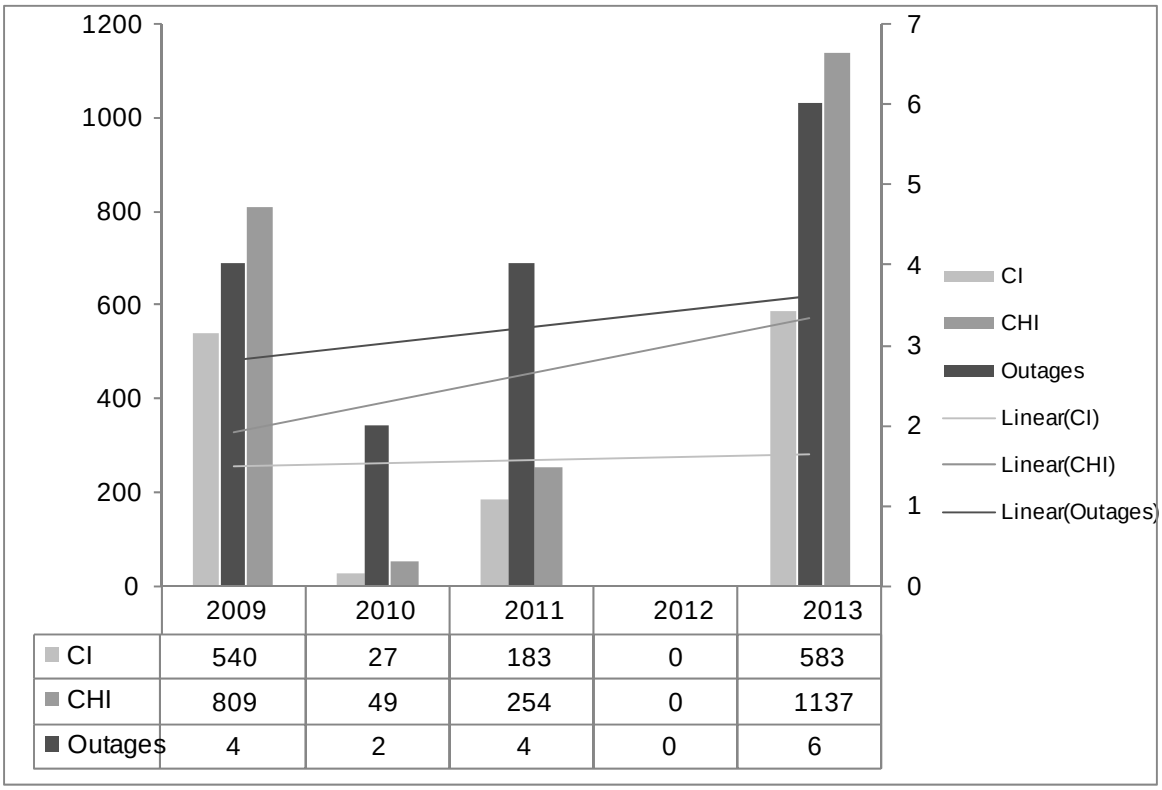
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 142: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1968 (46 years old)
Reliability	ƒ Feeder 51M28 has been performing poorly with an average of 3 power outages per year during the last 5 years
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 92.



	2009	2010	2011	2012	2013
CI	540	27	183	0	583
CHI	809	49	254	0	1137
Outages	4	2	4	0	6

FIGURE 92: HISTORICAL RELIABILITY DETAILS FOR NY51M28

E15231 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15231 Leslie/Finch Replace UG cable-Elec, NY51M23

Project Number: E15231

Project Year: 2015

Estimated Cost: $137,417

(i) Objective

Replace a portion of aged underground egress cable on Leslie TS feeder 51M23. E15231 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 143: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie II TS (27.6kV)
Feeder(s):	NY51M23

TABLE 144: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,583.23m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

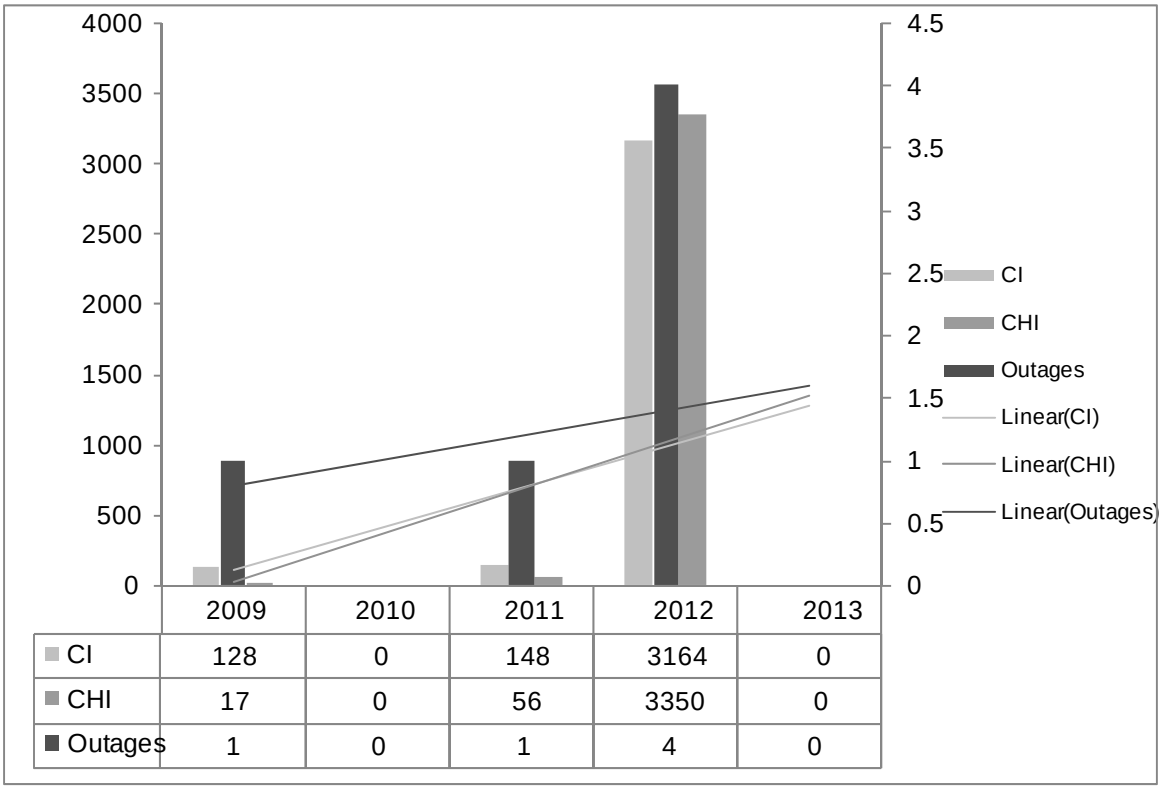
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 145: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1954 (60 years old)
Reliability	ƒ 51M23 is showing increasing trend of power outages. It had 1 outage in 2011 and rose to 4 outages in 2012
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 93.



	2009	2010	2011	2012	2013
CI	128	0	148	3164	0
CHI	17	0	56	3350	0
Outages	1	0	1	4	0

FIGURE 93: HISTORICAL RELIABILITY DETAILS FOR NY51M23

E15232 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15232 Leslie/Finch Replace UG trunk cable-Elec, NY51M7

Project Number: E15232

Project Year: 2015

Estimated Cost: $123,896

(i) Objective

Replace portion of aged underground egress cable on Leslie TS feeder 51M7. E15232 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 146: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie TS (27.6kV)
Feeder(s):	NY51M7

TABLE 147: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,810.38 m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0

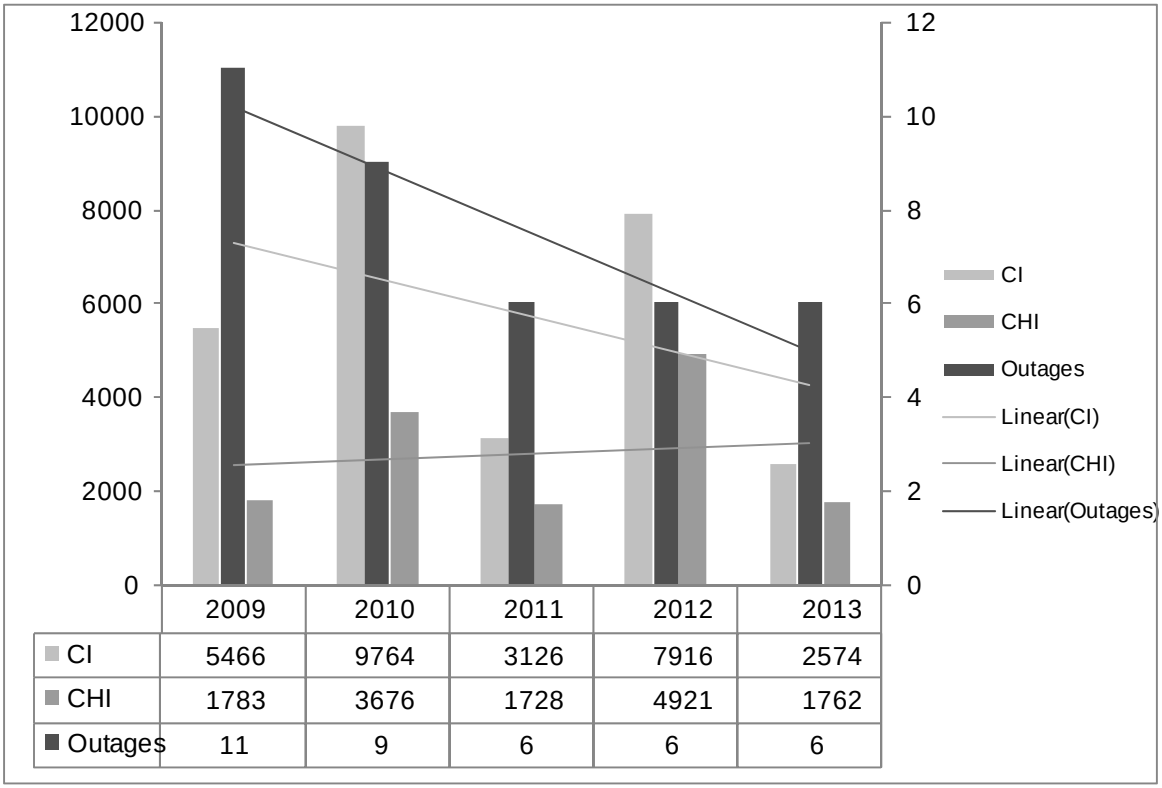
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 148: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1954 (60 years old)
Reliability	ƒ Feeder 51M7 has been performing poorly with average of 7.6 power outages per year during the past 5 years
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 94.



	2009	2010	2011	2012	2013
CI	5466	9764	3126	7916	2574
CHI	1783	3676	1728	4921	1762
Outages	11	9	6	6	6

FIGURE 94: HISTORICAL RELIABILITY DETAILS FOR NY51M7

E15233 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15233 Woody Vineway & Curly Vineway UG renewal 51M6 NY51M6

Project Number: E15233

Project Year: 2015

Estimated Cost: $290,478

(i) Objective

Replace aged underground assets installed in the area of "Woody Vineway" and "Curly Vineway" on Leslie St south of Fince Av. E. E15233 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 149: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie TS (27.6kV)
Feeder(s):	NY51M6

TABLE 150: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,241.27m
Underground Transformers	18
Underground Switchgear	1
Poles	0
Overhead Transformer	0
Overhead Switch	0

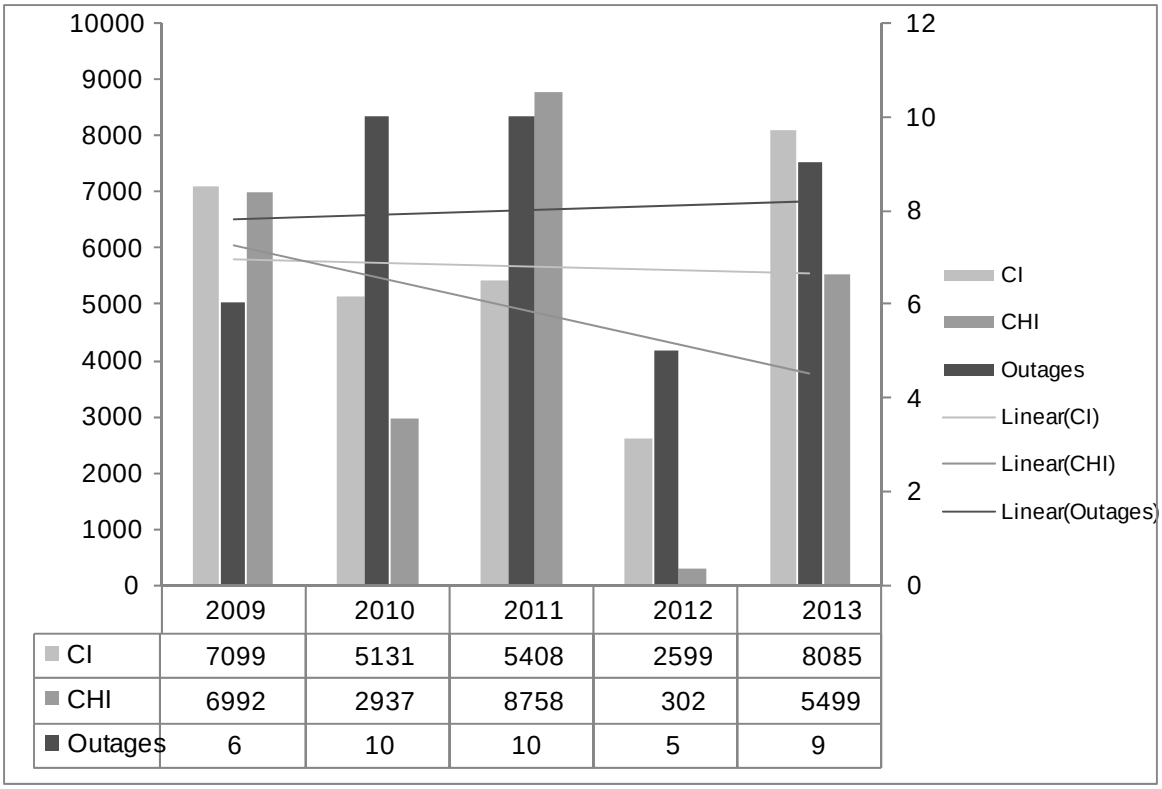
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 151: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed around 1950 (approx. 64 years old)
Reliability	ƒ 51M6 has been performing poorly with an average of 8 power outages per year during the past 5 years ƒ Majority of failures seen in the past five years due to primary cable and submersible transformers; both of which are targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 95.



	2009	2010	2011	2012	2013
CI	7099	5131	5408	2599	8085
CHI	6992	2937	8758	302	5499
Outages	6	10	10	5	9

FIGURE 95: HISTORICAL RELIABILITY DETAILS FOR NY51M6

E15267 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15267 -P162 Bermondsey Trunk UG Renewal Elec 53M2, M12, M27, M28 NY

Project Number: E15267

Project Year: 2015

Estimated Cost: $1,687,487

(i) Objective

Replace assets on feeders 53M2, 53M12, 53M27 and 53M28 which have reached and/or exceeded their estimated useful service life. E15267 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 152: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Bermondsey TS (27.6kV)
Feeder(s):	NY53M27, NY53M28, NY53M12, NY53M2

TABLE 153: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	5,276.02m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

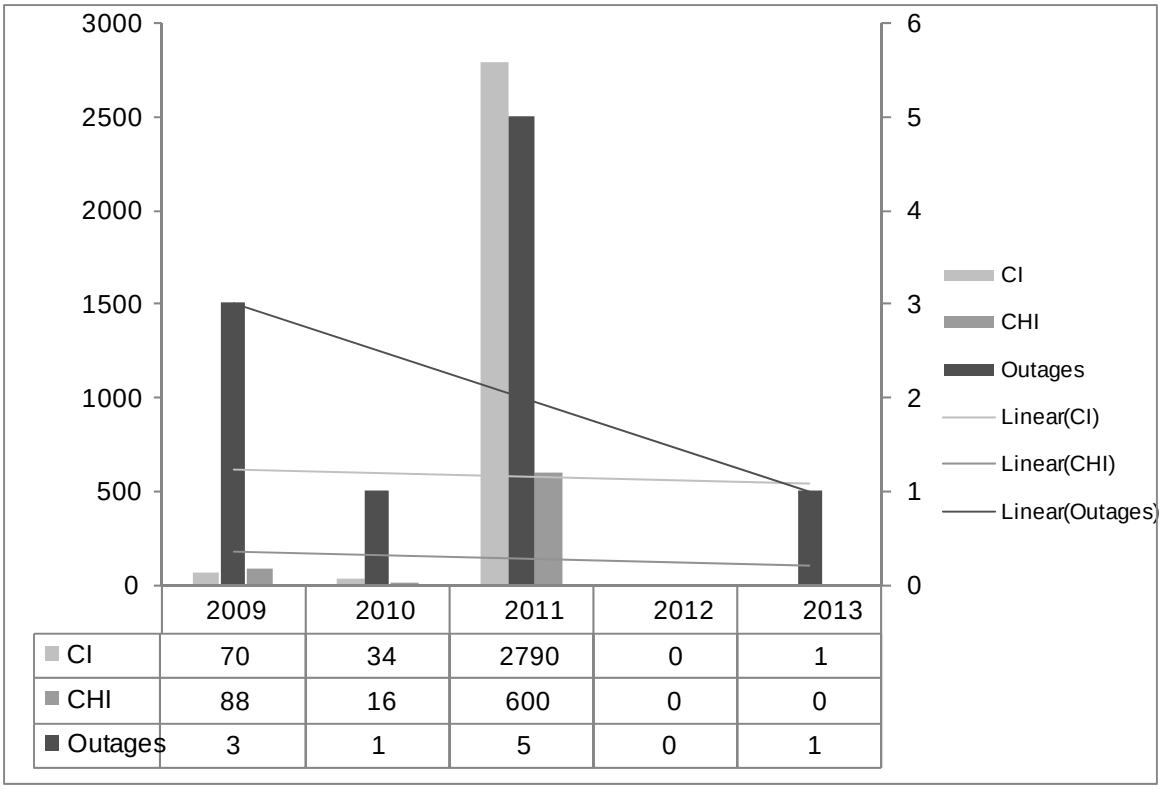
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 154: SUPPLEMENTAL DETAILS

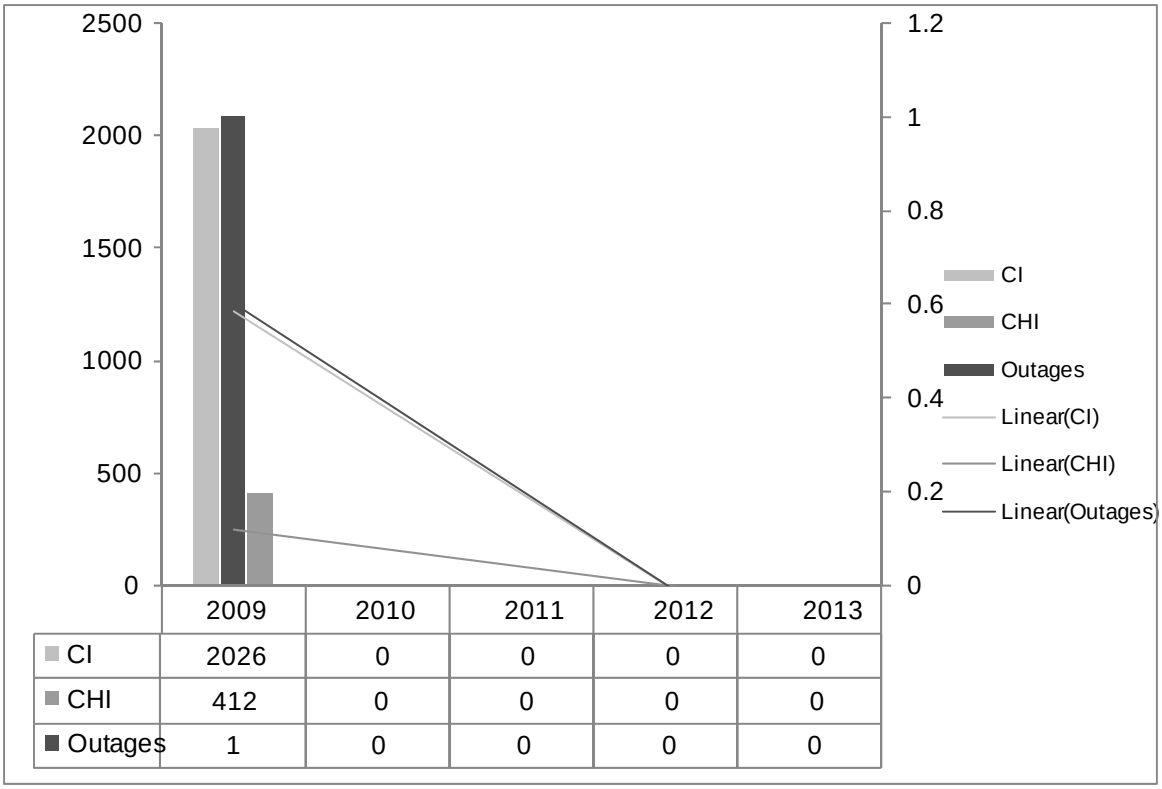
Supplemental Details	Description
Age/Condition	• Cables in duct Installed in 1981 (33 years old)
Reliability	• Cables in adjacent duct bank with similar age and environmental conditions have experienced failures • Feeder 53M27 has experienced 11 outages in last 2 years
Other (i.e. road moratoriums, etc)	• Upgrading feeder trunk cables from 1000 kcmil aluminum to 1000 kcmil copper, this will increase feeder capacity from 500A to 600A to accommodate load growth and maintain reliability • This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 96 to 99.



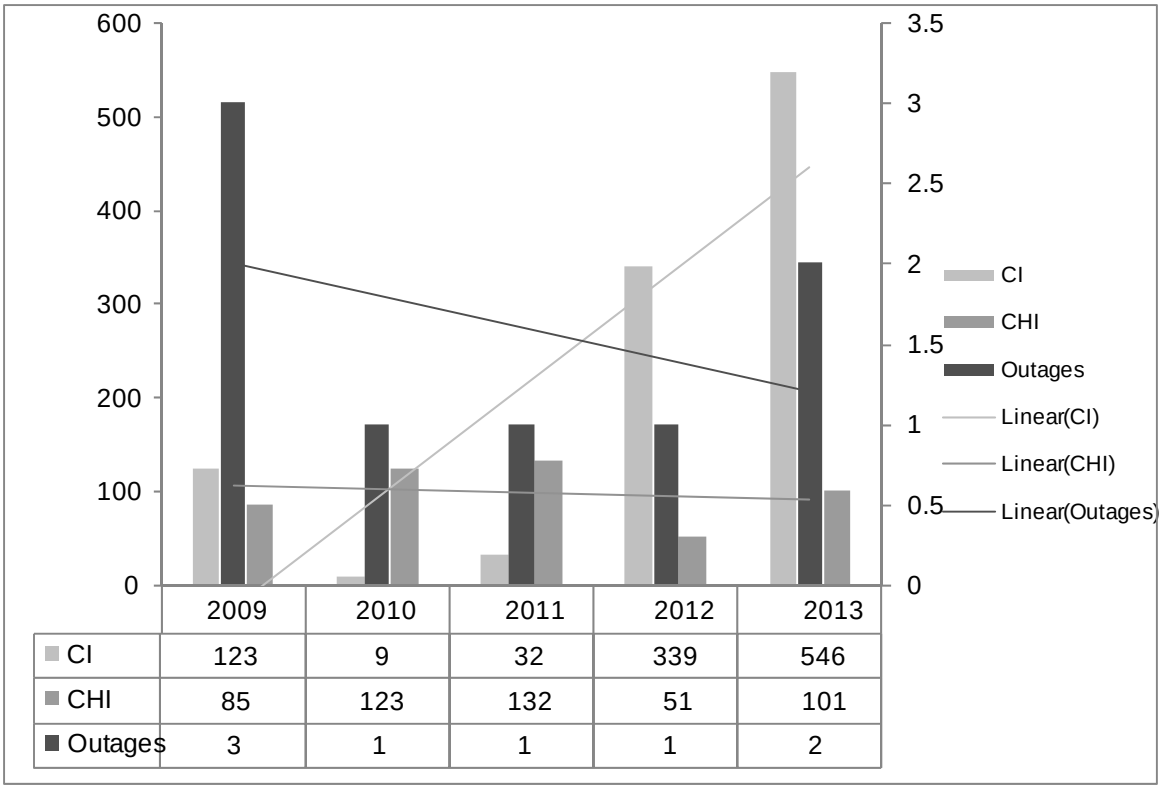
	2009	2010	2011	2012	2013
CI	70	34	2790	0	1
CHI	88	16	600	0	0
Outages	3	1	5	0	1

FIGURE 96: HISTORICAL RELIABILITY DETAILS FOR NY53M2



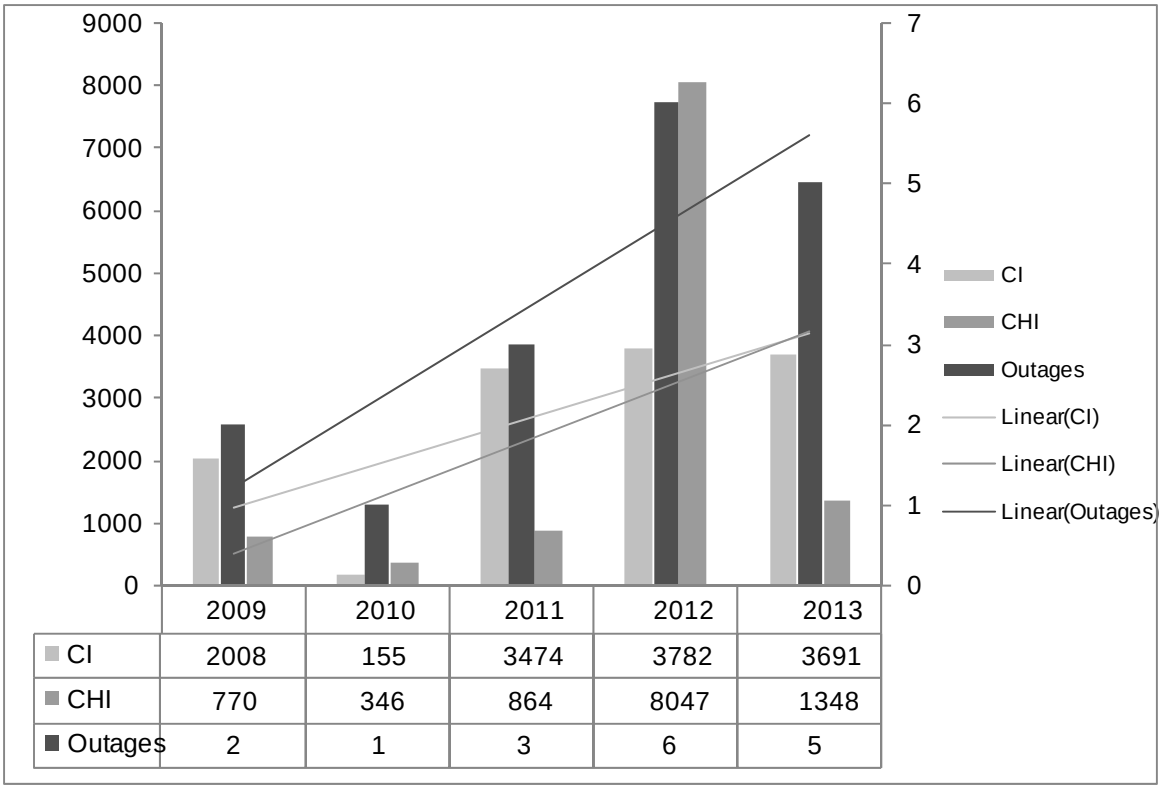
	2009	2010	2011	2012	2013
CI	2026	0	0	0	0
CHI	412	0	0	0	0
Outages	1	0	0	0	0

FIGURE 97: HISTORICAL RELIABILITY DETAILS FOR NY53M12



	2009	2010	2011	2012	2013
CI	123	9	32	339	546
CHI	85	123	132	51	101
Outages	3	1	1	1	2

FIGURE 98: HISTORICAL RELIABILITY DETAILS FOR NY53M28



	2009	2010	2011	2012	2013
CI	2008	155	3474	3782	3691
CHI	770	346	864	8047	1348
Outages	2	1	3	6	5

FIGURE 99: HISTORICAL RELIABILITY DETAILS FOR NY53M27

E15270 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15270 Victoria Park Gordon Baker UG renewal Phase II Civil 51M32 NY51M3

Project Number: E15270

Project Year: 2015

Estimated Cost: $1,456,519

(i) Objective

Replace aged underground assets installed in sub-divisions near Victoria Park Av. and Gordon Baker Rd. E15270 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 155: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie II TS (27.6kV)
Feeder(s):	NY51M32

(iii) Justification & Benefits

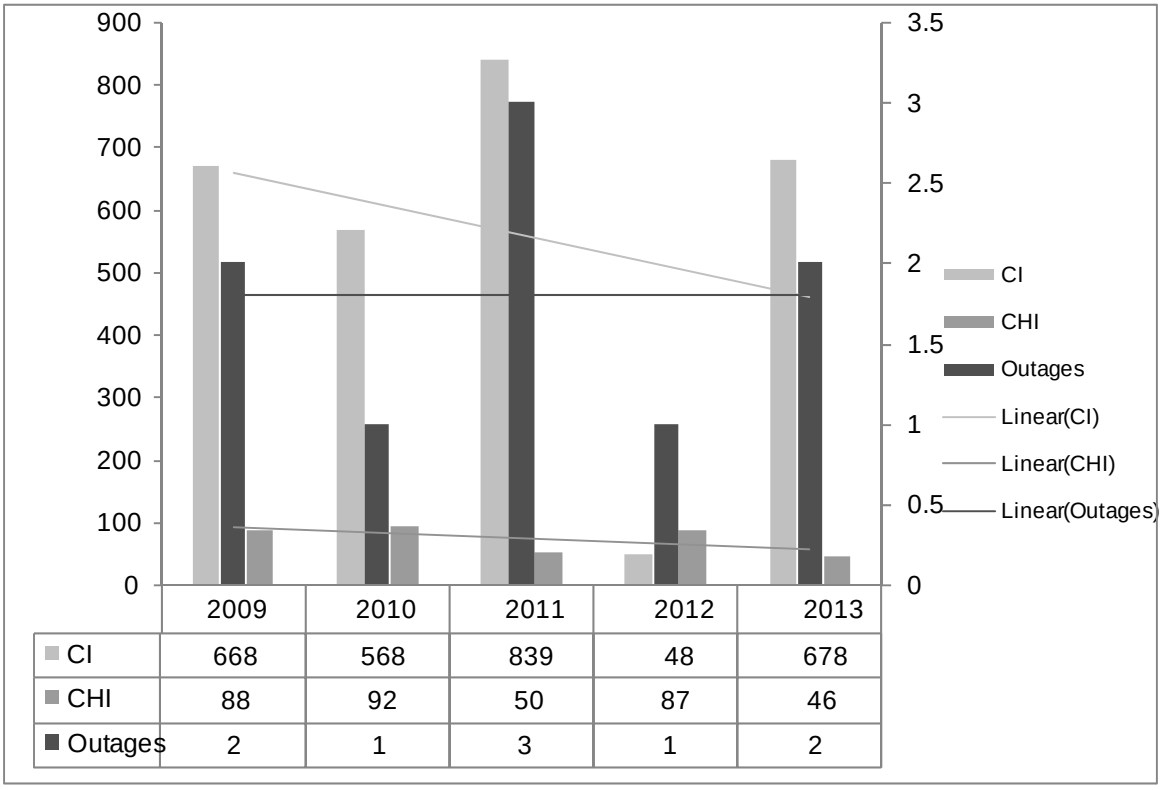
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 156: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed around 1950 (approx. 64 years old)
Reliability	ƒ 51M32 has an average of almost 2 power interruptions per year during the last 5 years
Other (i.e. road	ƒ N/A

Supplemental Details	Description
moratoriums, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure XYZ.



	2009	2010	2011	2012	2013
CI	668	568	839	48	678
CHI	88	92	50	87	46
Outages	2	1	3	1	2

FIGURE 100: HISTORICAL RELIABILITY DETAILS FOR NY51M32

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15273 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15273 Wynford Heights Crescent UG Renewal Elec NY53M2

Project Number: E15273

Project Year: 2015

Estimated Cost: $378,823

(i) Objective

Replace assets on feeder 53M2 which have reached and/or exceeded their estimated useful service life. E15273 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 157: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Bermondsey TS (27.6kV)
Feeder(s):	NY53M2

TABLE 158: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	870.76m
Underground Transformers	0
Underground Switchgear	6
Poles	0
Overhead Transformer	0
Overhead Switch	0

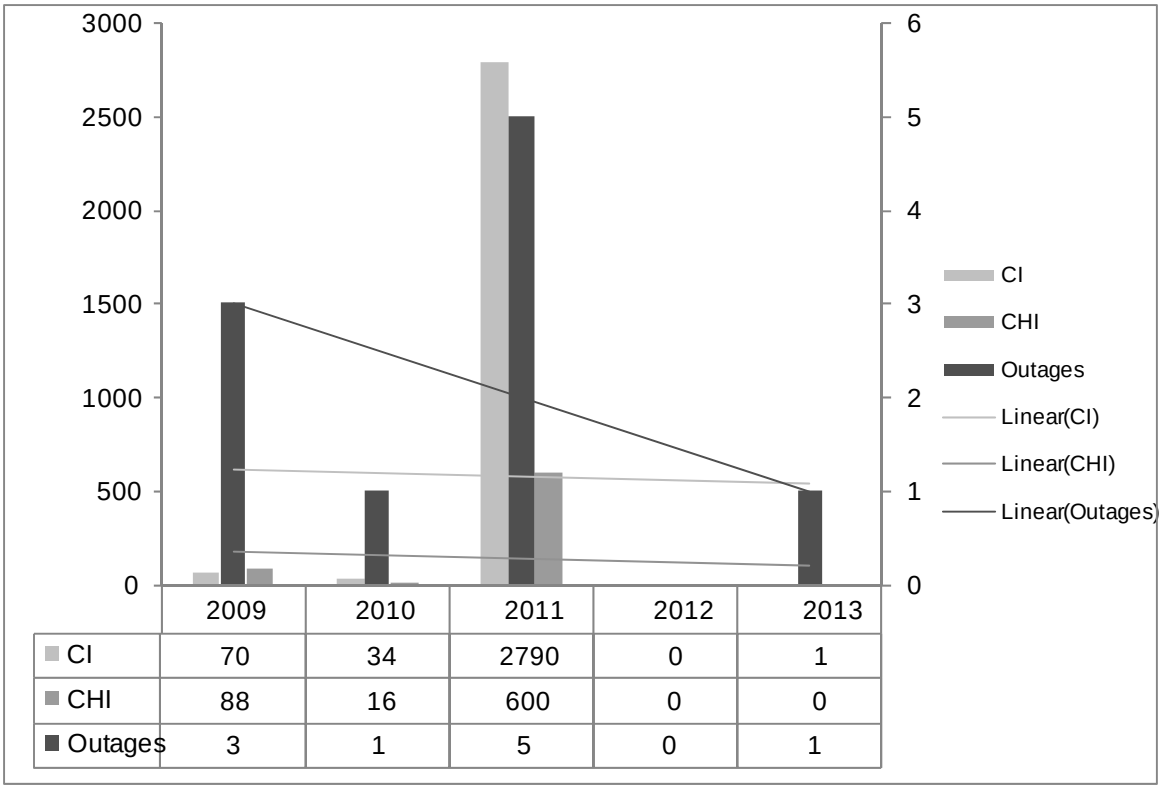
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 159: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	• End of life cables in duct • Installed in 1969 (45 years old)
Reliability	• No reliability issues
Other (i.e. road moratoriums, etc)	• Direct buried cables in project area are operating past their estimated useful service life and need to be addressed before failures occur • This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 101.



	2009	2010	2011	2012	2013
CI	70	34	2790	0	1
CHI	88	16	600	0	0
Outages	3	1	5	0	1

FIGURE 101: HISTORICAL RELIABILITY DETAILS FOR NY53M2

E15306 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15306 Leslie Francine Gideon Conversion Civil SS68-F10 to 51M3 NYSS68F1

Project Number: E15306

Project Year: 2015

Estimated Cost: $2,695,018

(i) Objective

Replace via voltage conversion, the unreliable direct buried primary cables and associated transformers from Leslie MS feeder SS68F10 in Leslie-Francine-Gideon subdivision. E15306 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 160: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie MS (13.8kV)
Feeder(s):	NYSS68F10

(iii) Justification & Benefits

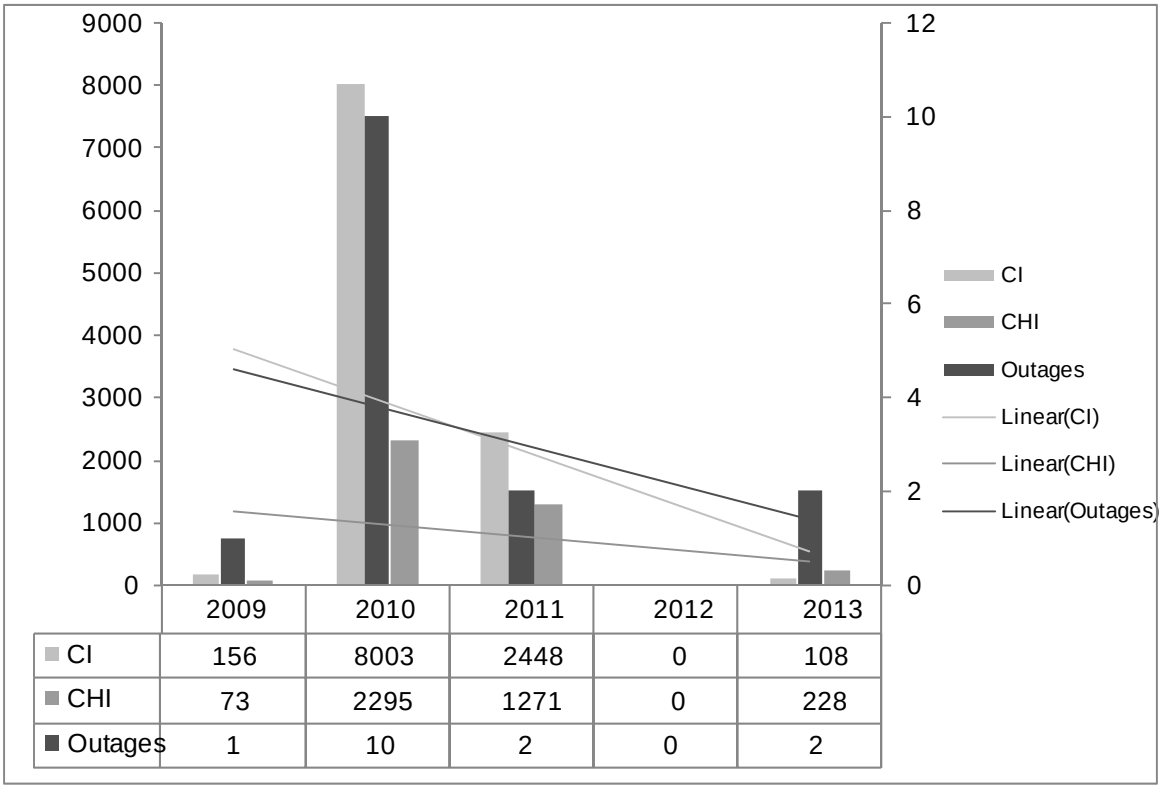
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 161: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ N/A
Reliability	ƒ Project will include conversion of existing load supplied by Leslie MS ƒ Leslie MS is an isolated 13.8kV distribution with no backup supply in the event of MS station failure

Supplemental Details	Description
Other (i.e. road moratoriums, etc)	ƒ Voltage conversion in the area will address islanding and station overloading

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 102.



	2009	2010	2011	2012	2013
CI	156	8003	2448	0	108
CHI	73	2295	1271	0	228
Outages	1	10	2	0	2

FIGURE 102: HISTORICAL RELIABILITY DETAILS FOR NYSS68F10

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15307, E15317, E15318 Project Description

Investment Category: **System Renewal**

Program: **Underground Circuit Renewal**

Project Title: **Bridgeport UG Rebuild Ph1, 2 and 3 - Civil SCNA47M13**

Project Number: **E15307, E15317, E15318**

Project Year: **2015**

Estimated Cost: **$5,693,725**

(i) Objective

Rebuild the direct buried distribution of Port Union Village. This project has been divided into three phases. E15307, E15317 and E15318 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

District Neighborhood:
Station(s):
Feeder(s):

TABLE 162: SCOPE OF WORK DETAILS

District Neighborhood	ParkdalerHigh Park
Station(s):	Sheppard TS (27.6 kV)
Feeder(s):	SCNA47M13

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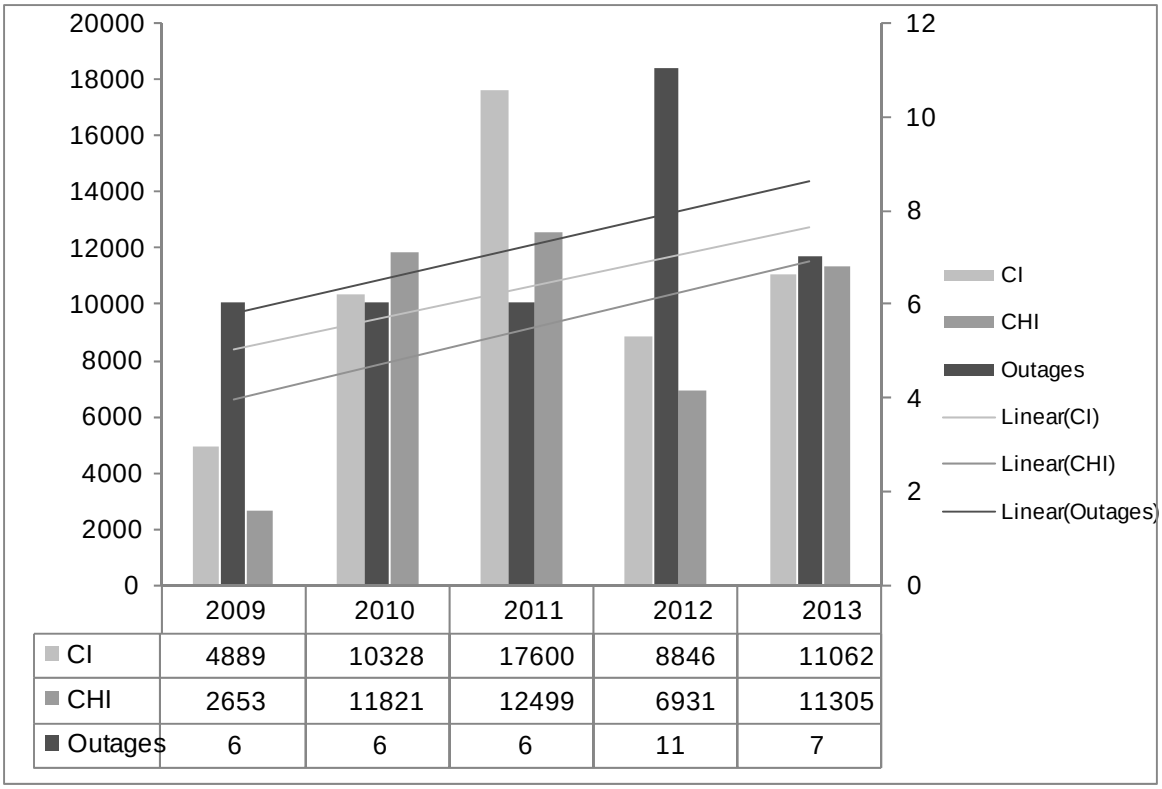
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 163: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1988 (26 years old)
Reliability	ƒ Feeder reliability is weakening
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 103.



	2009	2010	2011	2012	2013
CI	4889	10328	17600	8846	11062
CHI	2653	11821	12499	6931	11305
Outages	6	6	6	11	7

FIGURE 103: HISTORICAL RELIABILITY DETAILS FOR SCNA47M13

E15316 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15316 Leslie Threadneedle Clansman Conversion SS68F10 to 51M3 NYSS68F10

Project Number: E15316

Project Year: 2015

Estimated Cost: $501,360

(i) Objective

To convert 13.8kV primary cables and transformers installed in 1993 in Leslie-Threadneedle-Clansman subdivision with new 27.6kV supply installed in existing concrete encased duct. E15316 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 165: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie MS (13.8kV)
Feeder(s):	NYSS68F10

TABLE 166: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	4,791.47m
Underground Transformers	30
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	1

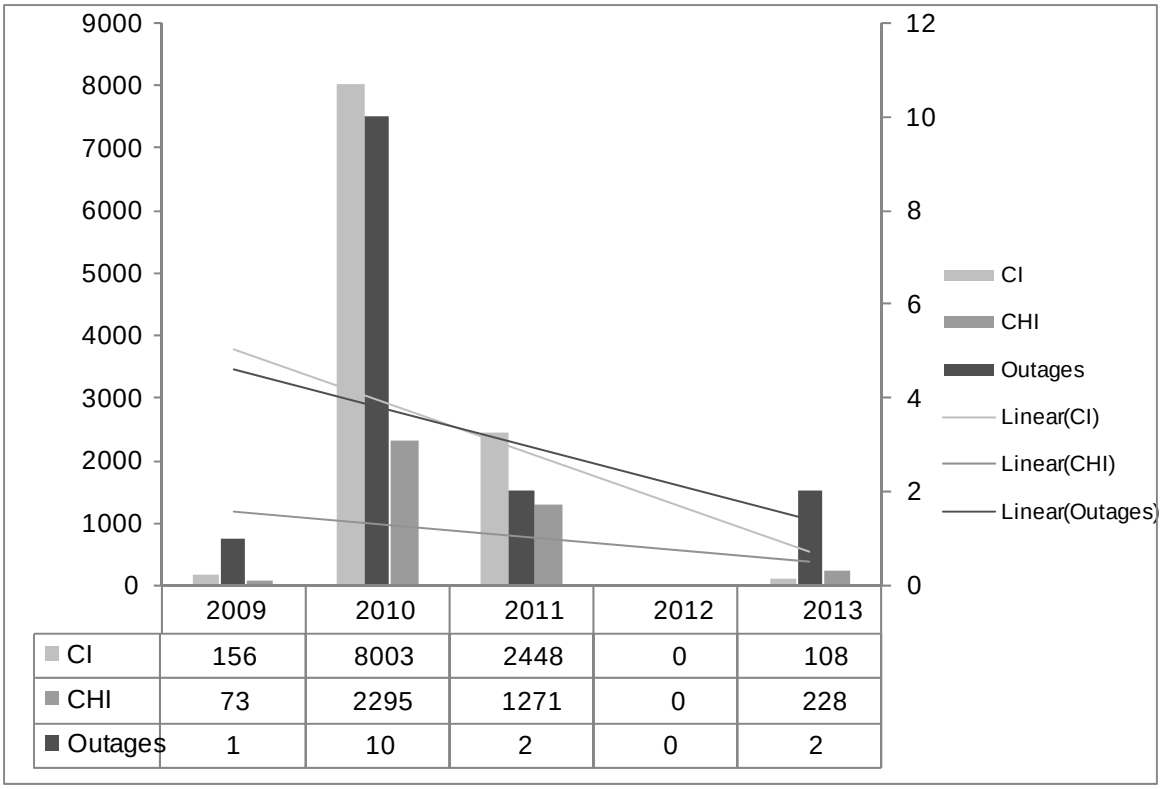
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 167: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ N/A
Reliability	ƒ Project will include conversion of existing load supplied by Leslie MS ƒ Leslie MS is an isolated 13.8 kV distribution with no backup supply in the event of MS station failure
Other (i.e. road moratoriums, etc)	ƒ Voltage conversion in the area will address islanding and station overloading ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 104.



	2009	2010	2011	2012	2013
CI	156	8003	2448	0	108
CHI	73	2295	1271	0	228
Outages	1	10	2	0	2

FIGURE 104: HISTORICAL RELIABILITY DETAILS FOR NYSS68F10

E15324, E15325 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Paul Markway Conversion Civi/Electrical SS68-F10 to 51M27 NYSS68F10

Project Number: E15324, E15325

Project Year: 2015

Estimated Cost: $682,972

(i) Objective

Replace old, aged direct buried primary cables installed in 1971 in Paul Markway area.

E15324 will install the civil infrastructure necessary to complete the project; E15325 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 168: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie MS (13.8kV)
Feeder(s):	NYSS68F10

TABLE 169: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	269.88m
Underground Transformers	2
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

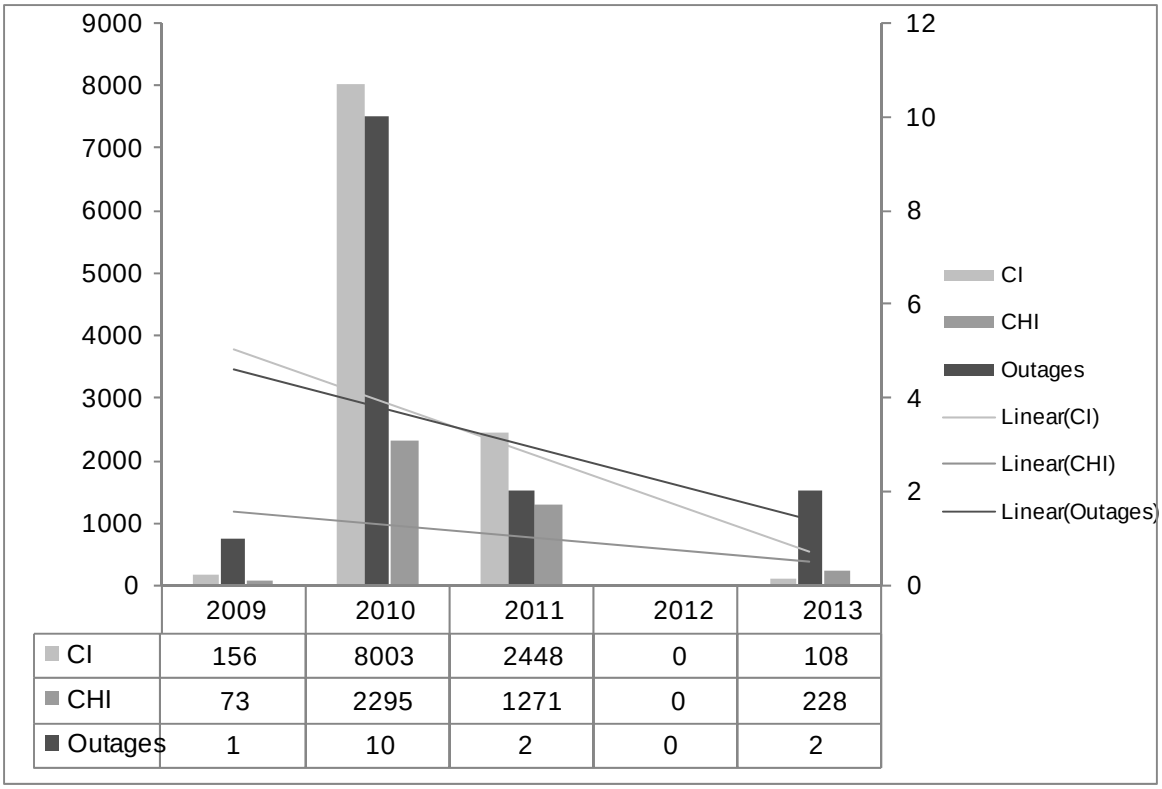
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 170: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ N/A
Reliability	ƒ Project will include conversion of existing load supplied by Leslie MS ƒ Leslie MS is an isolated 13.8 kV distribution with no backup supply in the event of MS station failure
Other (i.e. road moratoriums, etc)	ƒ Voltage conversion in the area will address islanding and station overloading

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 105.



	2009	2010	2011	2012	2013
CI	156	8003	2448	0	108
CHI	73	2295	1271	0	228
Outages	1	10	2	0	2

FIGURE 105: HISTORICAL RELIABILITY DETAILS FOR NYSS68F10

E15328 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15328 McNicoll Leslie Conversion Civil SS68F10 to 51M3 NYSS68F10

Project Number: E15328

Project Year: 2015

Estimated Cost: $2,933,082

(i) Objective

Replace via voltage conversion, unreliable direct buried primary cables and associated transformers from Leslie MS feeder SS68F10 in Leslie St.-McNicoll Av. E15328 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 171: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie MS (13.8kV)
Feeder(s):	NYSS68F10

(iii) Justification & Benefits

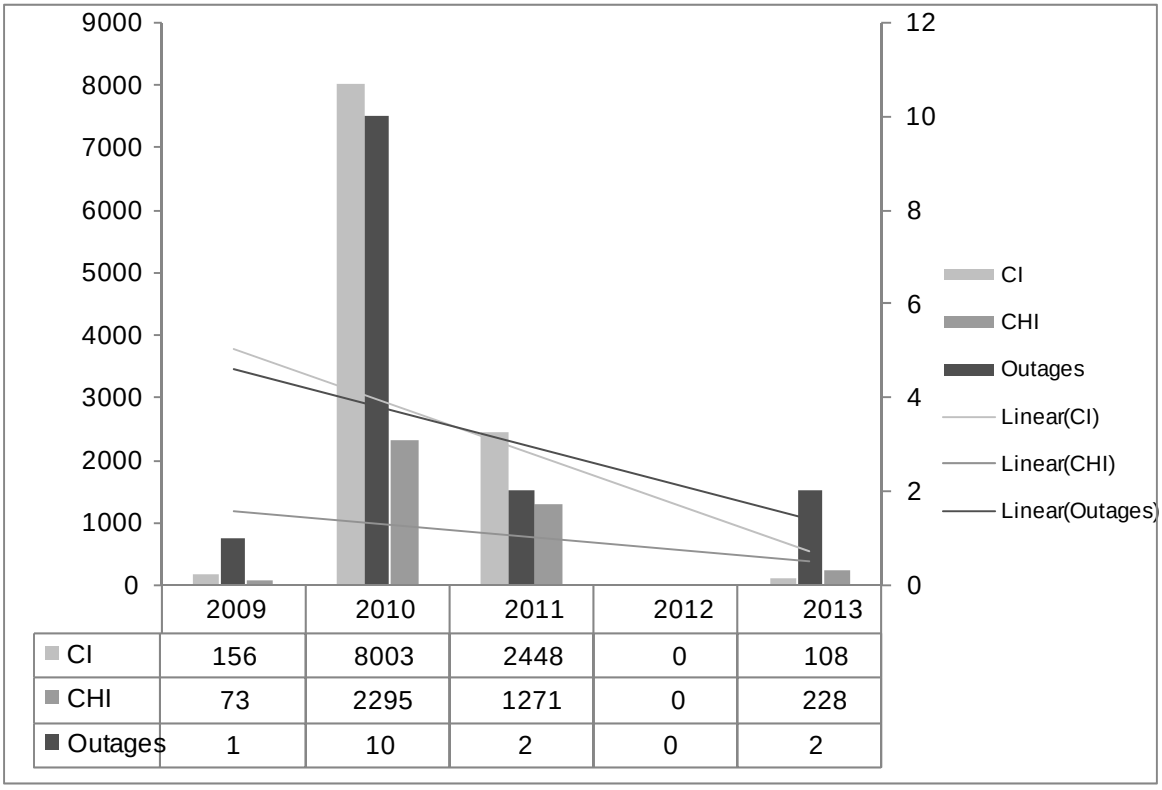
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 172: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ N/A
Reliability	ƒ Project will include conversion of existing load supplied by Leslie MS ƒ Leslie MS is an isolated 13.8kV distribution with no backup supply in the event of MS station failure
Other (i.e. road	ƒ Voltage conversion in the area will address islanding and station

Supplemental Details	Description
moratoriums, etc)	overloading

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 106.



	2009	2010	2011	2012	2013
CI	156	8003	2448	0	108
CHI	73	2295	1271	0	228
Outages	1	10	2	0	2

FIGURE 106: HISTORICAL RELIABILITY DETAILS FOR NYSS68F10

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15332, E16110 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Guildpark Pathway UG Rebuild – Civil/Electrical H9M30 SCNA H9M30

Project Number: E15332, E16110

Project Year: 2015

Estimated Cost: $720,012

(i) Objective

Replace old, direct buried cables and transformers in the Cromwell complex. E15332 will install the civil infrastructure necessary to complete the project; E16110 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 173: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Southwest
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCNA H9M30

TABLE 174: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	304.07m
Underground Transformers	5
Underground Switchgear	0
Poles	2
Overhead Transformer	0
Overhead Switch	2

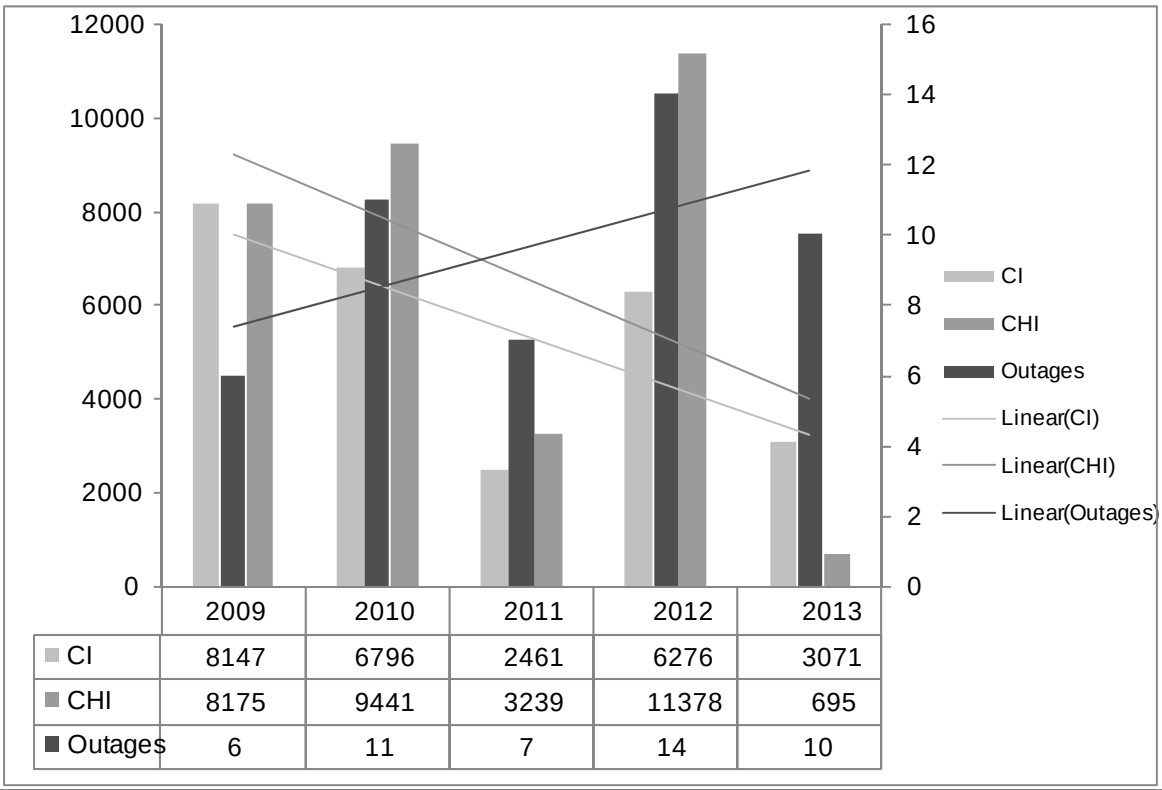
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 175: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1993 (21 years old)
Reliability	ƒ Overall increasing number of outages from 2009 to 2013, averaging 10/year ƒ High CI and CHI ratings
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 107.



	2009	2010	2011	2012	2013
CI	8147	6796	2461	6276	3071
CHI	8175	9441	3239	11378	695
Outages	6	11	7	14	10

FIGURE 107: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M30

E15342 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15342 Tahoe Court UG Rebuild Civil NY53M24

Project Number: E15342

Project Year: 2015

Estimated Cost: $243,928

(i) Objective

Replace underground assets on 53M24 which have reached and/or exceeded their useful service life. E15342 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 176: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Bermondsey TS (27.6kV)
Feeder(s):	NY53M24

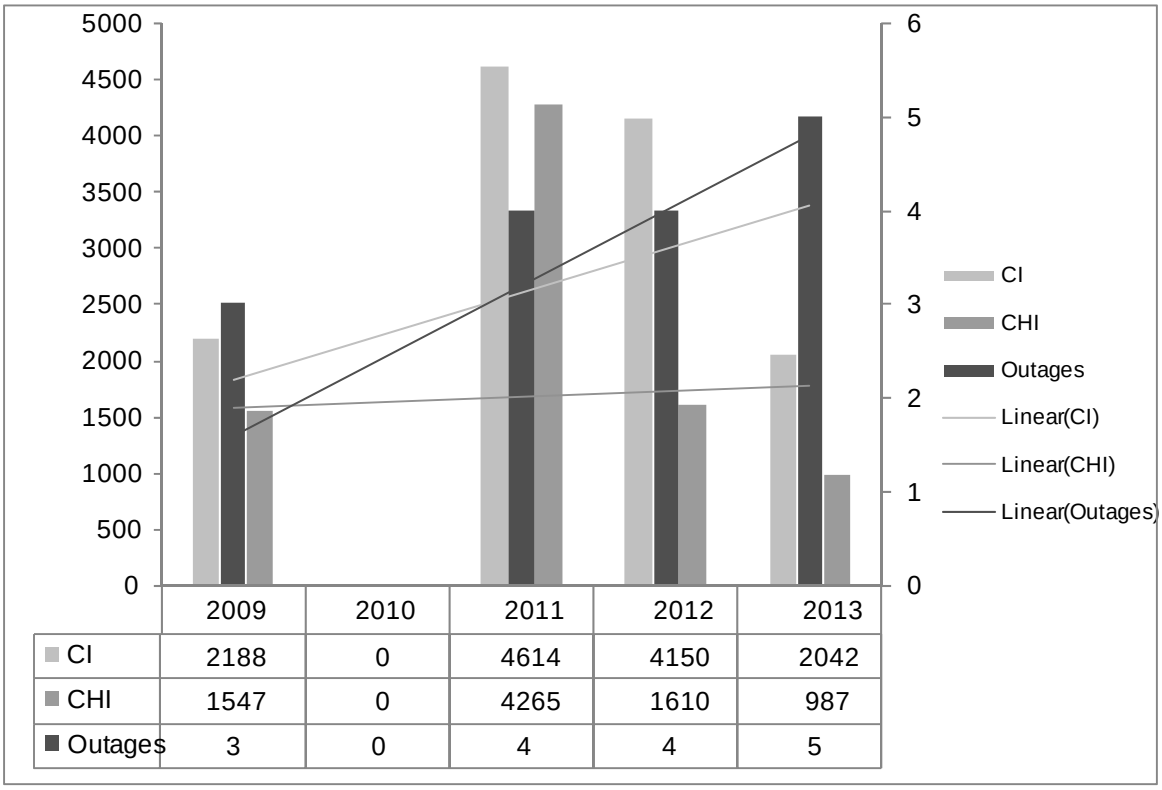
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 177: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cables ƒ Installed 1985 (29 years old)
Reliability	Feeder has experienced poor reliability with 9 outages in last 2 years
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 108.



	2009	2010	2011	2012	2013
CI	2188	0	4614	4150	2042
CHI	1547	0	4265	1610	987
Outages	3	0	4	4	5

FIGURE 108: HISTORICAL RELIABILITY DETAILS FOR NY53M24

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15350 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15350 Confederation Angora UG Rebuild - Civil H9M30 SCNA H9M30

Project Number: E15350

Project Year: 2015

Estimated Cost: $2,007,342

(i) Objective

Rebuild the direct buried distribution of Cedar Ridge and Cedar Bray Subdivision. E15350 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 178: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough East
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCNA H9M30

(iii) Justification & Benefits

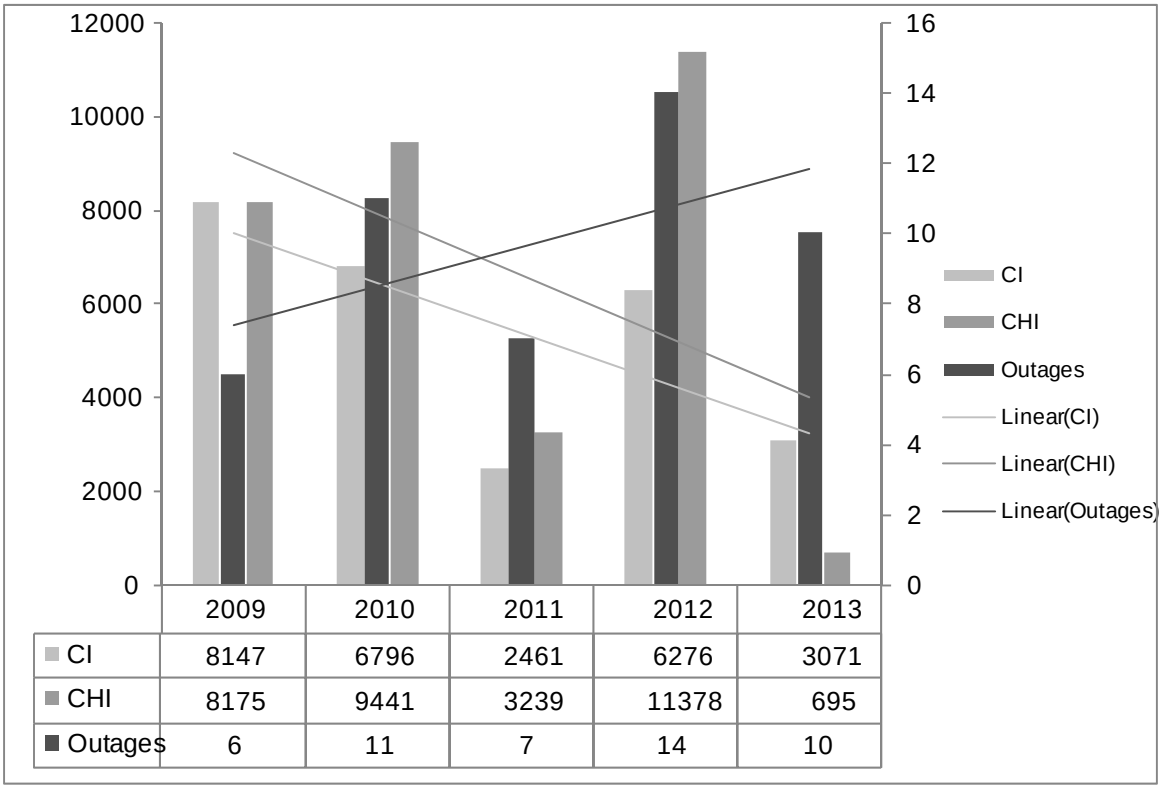
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 179: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Cables in direct buried PVC and HDPE ducts ƒ Installed 1966 (48 years old)
Reliability	ƒ Overall increasing number of outages from 2009 to 2013, averaging 10/year ƒ High CI and CH ratings

Supplemental Details	Description
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 109.



	2009	2010	2011	2012	2013
CI	8147	6796	2461	6276	3071
CHI	8175	9441	3239	11378	695
Outages	6	11	7	14	10

FIGURE 109: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M30

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15353 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15353 Brahms Clansman Don Mills Conversion Civil SS68-F1 to 51M27

Project Number: E15353

Project Year: 2015

Estimated Cost: $569,495

(i) Objective

Replace, via voltage conversion, the unreliable direct buried primary cables and associated transformers from Leslie MS feeder SS68-F1 in Brahms/Clansman/Don Mills area. E15353 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 180: SCOPE OF WORK DETAILS

District Neighborhood	Willowdale
Station(s):	Leslie MS (13.8 kV)
Feeder(s):	NYSS68F1

(iii) Justification & Benefits

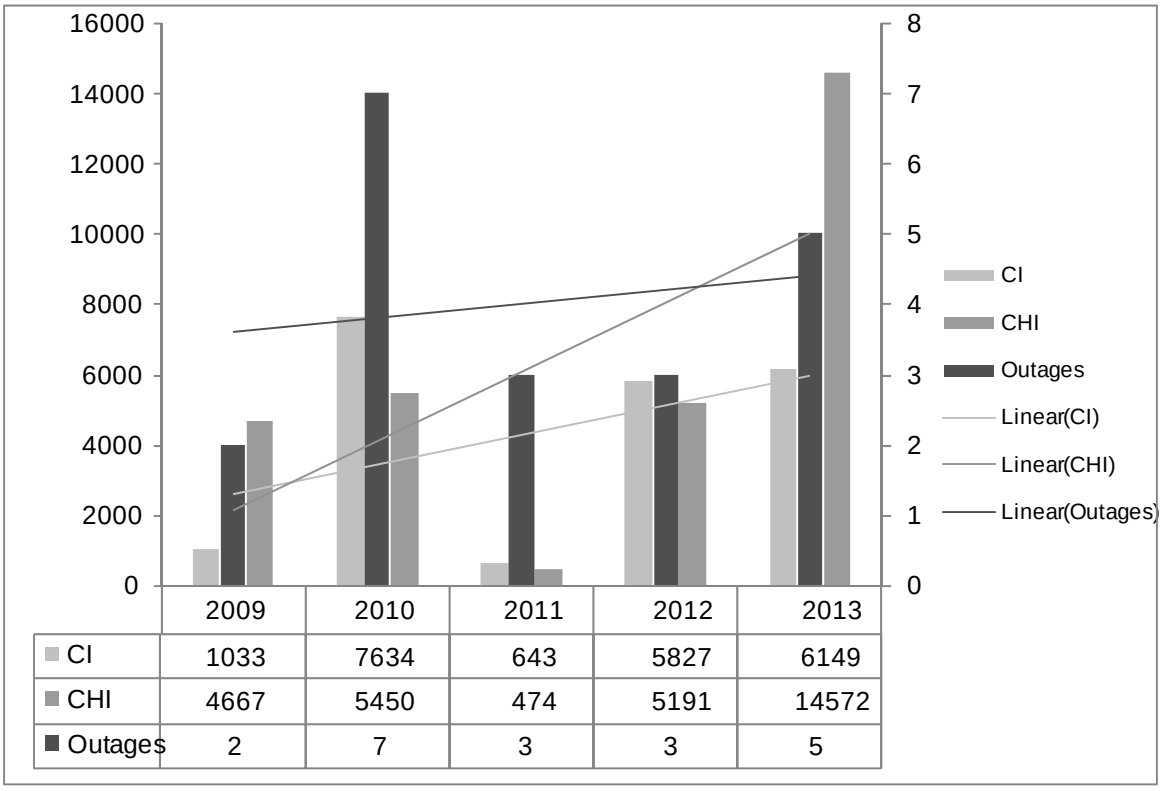
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 181: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ N/A
Reliability	ƒ Project will include conversion of existing load supplied by Leslie MS ƒ Leslie MS is an isolated 13.8 kV distribution with no backup supply in the event of MS station failure

Supplemental Details	Description
Other (i.e. road moratoriums, etc)	ƒ Voltage conversion in the area will address islanding and station overloading

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 110.



	2009	2010	2011	2012	2013
CI	1033	7634	643	5827	6149
CHI	4667	5450	474	5191	14572
Outages	2	7	3	3	5

FIGURE 110: HISTORICAL RELIABILITY DETAILS FOR NYSS68F1

E15355, E15356 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Gracemount UG Rebu ild – Civil/Electrical H9M30 SCNAH9M30

Project Number: E15355, E15356

Project Year: 2015

Estimated Cost: $1,315,946

(i) (i) Objective

Rebuild the direct buried distribution of Shoredale Subdivision. E15355 will install the civil infrastructure necessary to complete the project; E15356 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 182: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough East
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCNAH9M30

TABLE 183: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	604.63m
Underground Transformers	5
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	3

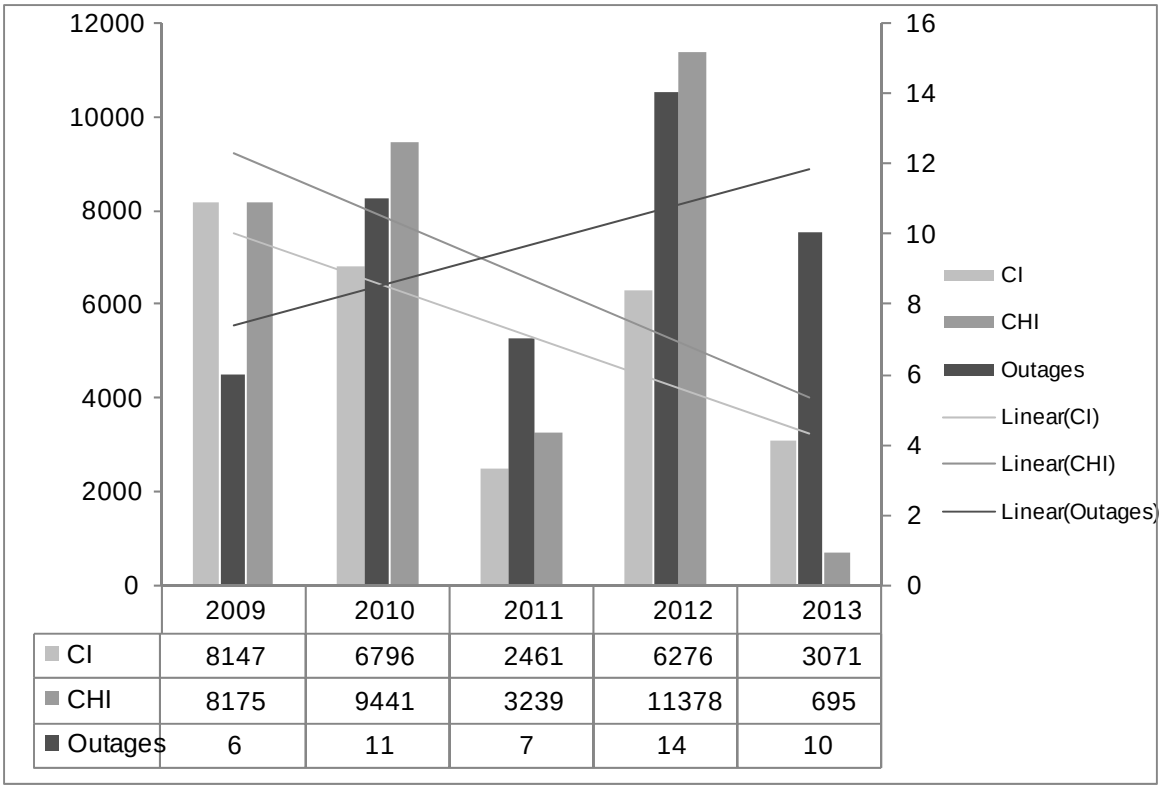
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 184: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1976 (38 years old)
Reliability	ƒ Overall increasing number of outages from 2009 to 2013 ƒ High CI and CHI ratings
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 111.



	2009	2010	2011	2012	2013
CI	8147	6796	2461	6276	3071
CHI	8175	9441	3239	11378	695
Outages	6	11	7	14	10

1 FIGURE 111: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M30

E15379 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15379 Victoria Park York Mills UG cable replacement 51M25 NY51M25

Project Number: E15379

Project Year: 2015

Estimated Cost: $817,406

(i) Objective

Replace aged underground assets on Leslie TS feeder 51M25 installed in area on Victoria Park Av. from Sheppard Av. E. to York Mills Rd. as well as underground lateral service, primary cable and transformers on Parkwood Village Dr. E15379 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 185: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie II TS (27.6kV)
Feeder(s):	NY51M25

TABLE 186: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	3,302.75m
Underground Transformers	14
Underground Switchgear	1
Poles	0
Overhead Transformer	0
Overhead Switch	0

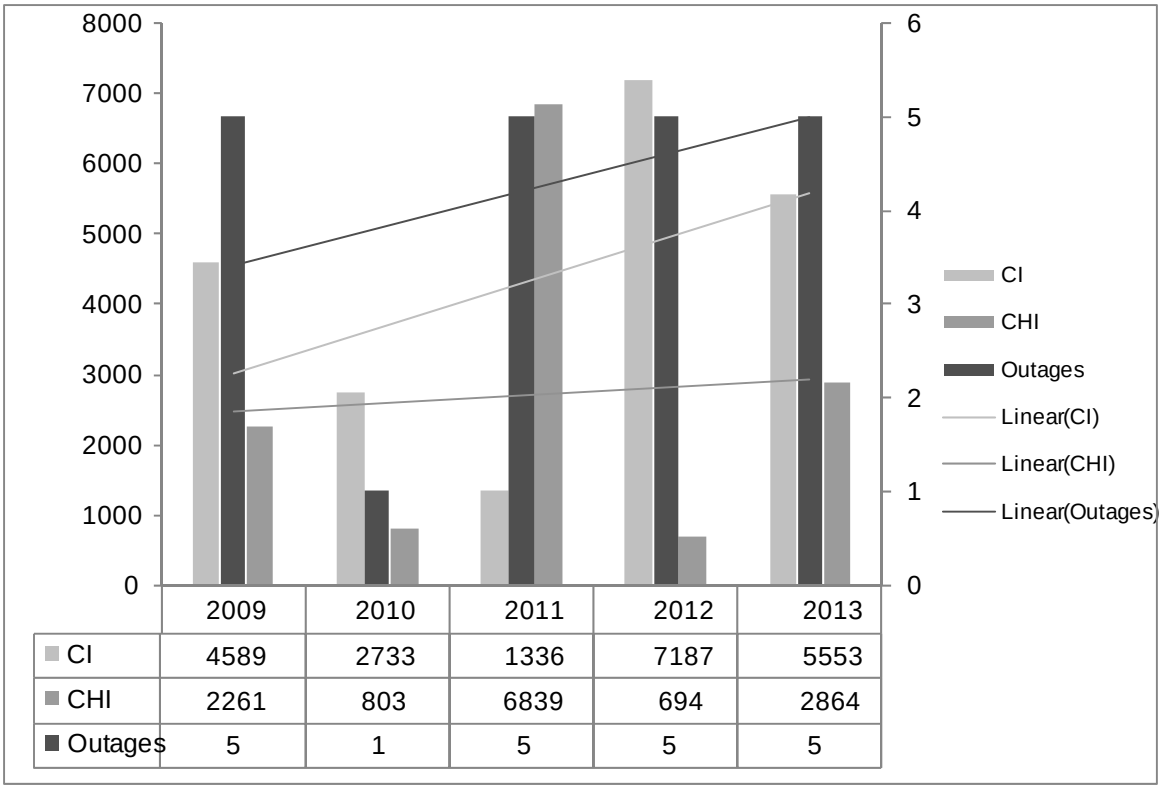
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 187: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1960 (approx. 54 years old)
Reliability	ƒ Feeder 51M25 has been performing poorly with an average of 4 power outages per year during the last 5 years
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 112.



	2009	2010	2011	2012	2013
CI	4589	2733	1336	7187	5553
CHI	2261	803	6839	694	2864
Outages	5	1	5	5	5

FIGURE 112: HISTORICAL RELIABILITY DETAILS FOR NY51M25

E15390, E15392, E15393, E15397 E16131 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Scunthorpe Invergordon UG Rebuild Phases B, D, E and G - Civil SCNAH9M26; Scunthorpe Invergordon UG Rebuild Phase D - Electrical SCNAH9M26

Project Number: E15390, E15392, E15393, E15397, E16131

Project Year: 2015

Estimated Cost: $5,421,180

(i) Objective

Replace old, direct-buried primary cables in the area of Scunthrope Rd and Invergordon Ave. The distribution will be reconfigured to have more operational flexibility and better protection. E15390 will install the civil infrastructure necessary to complete this project.

E15392 will install the civil infrastructure necessary to replace the single phase direct-buried primary cables in the area of West Burton Ct, Prince William Crt, 5021 Sheppard Ave TH, Wyper Sq, part of Massie St and Thistlewaite Cres,. E16131 will complete the electrical portion of this project.

E15393 will install the civil infrastructure necessary to replace the single phase old direct-buried primary cables in the area of Plum Brook Cres, sections of Massie St, Thistlewaite Cres, Invergordon Ave.

E15397 will install the civil infrastructure necessary to replace the single phase old direct-buried primary cables in the area of Spring Forest Sq, Pennybrook Ln and Scunthorpe Rd.

(ii) Scope of Work

TABLE 188: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCNAH9M26

TABLE 189: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	2,146.78 m
Underground Transformers	13
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

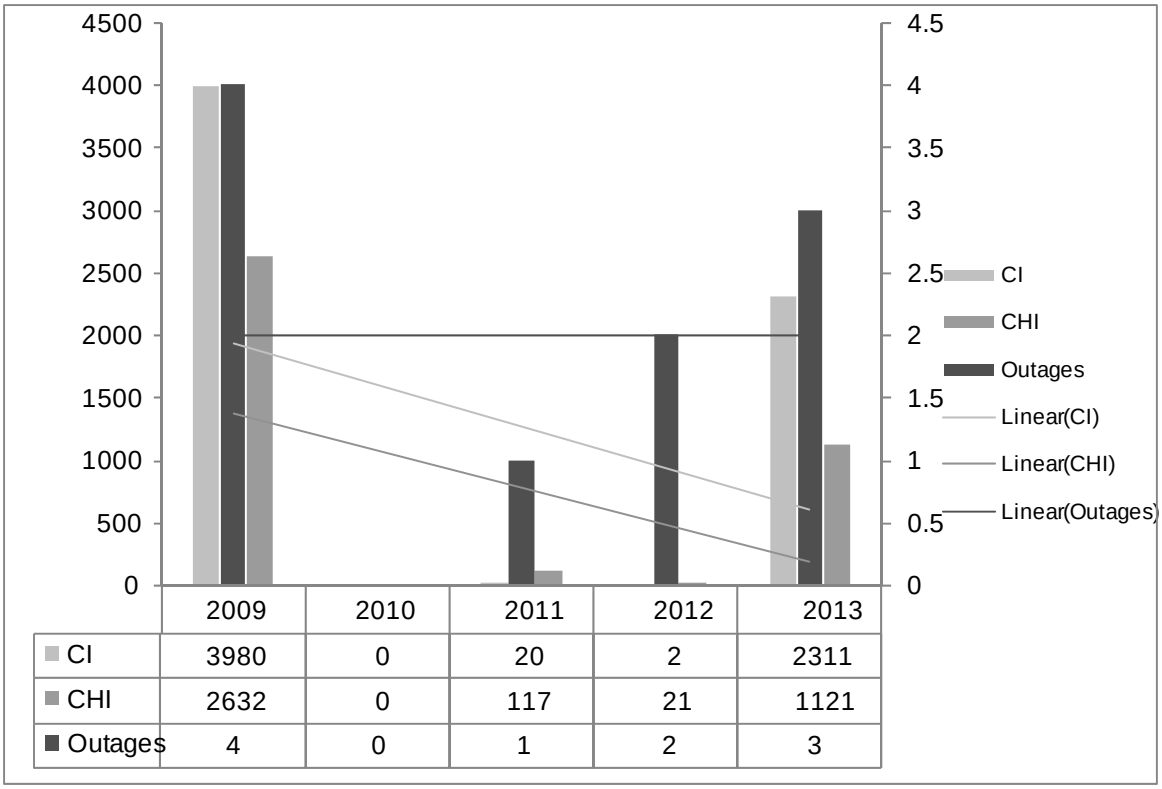
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 190: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1983 (31 years old)
Reliability	ƒ Overall increasing number of outages from 2009 to 2013 and high CI and CH ratings ƒ Majority of failures due to primary cable and pad mounted switches; both of which are targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ TTC conflict coming up, if the civil is not done it may be delayed beyond 2018

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 113.



	2009	2010	2011	2012	2013
CI	3980	0	20	2	2311
CHI	2632	0	117	21	1121
Outages	4	0	1	2	3

FIGURE 113: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M26

E15395 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15395 Consumers Rd Sheppard UG Renewal 51M28 NY51M28

Project Number: E15395

Project Year: 2015

Estimated Cost: $929,773

(i) Objective

Replace aged underground assets on Leslie TS feeder 51M28 installed in area around Sheppard Av. E. and Consumers Rd. E15395 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 191: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leslie II TS (27.6 kV)
Feeder(s):	NY51M28

TABLE 192: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	3,525.22 m
Underground Transformers	0
Underground Switchgear	3
Poles	0
Overhead Transformer	0
Overhead Switch	0

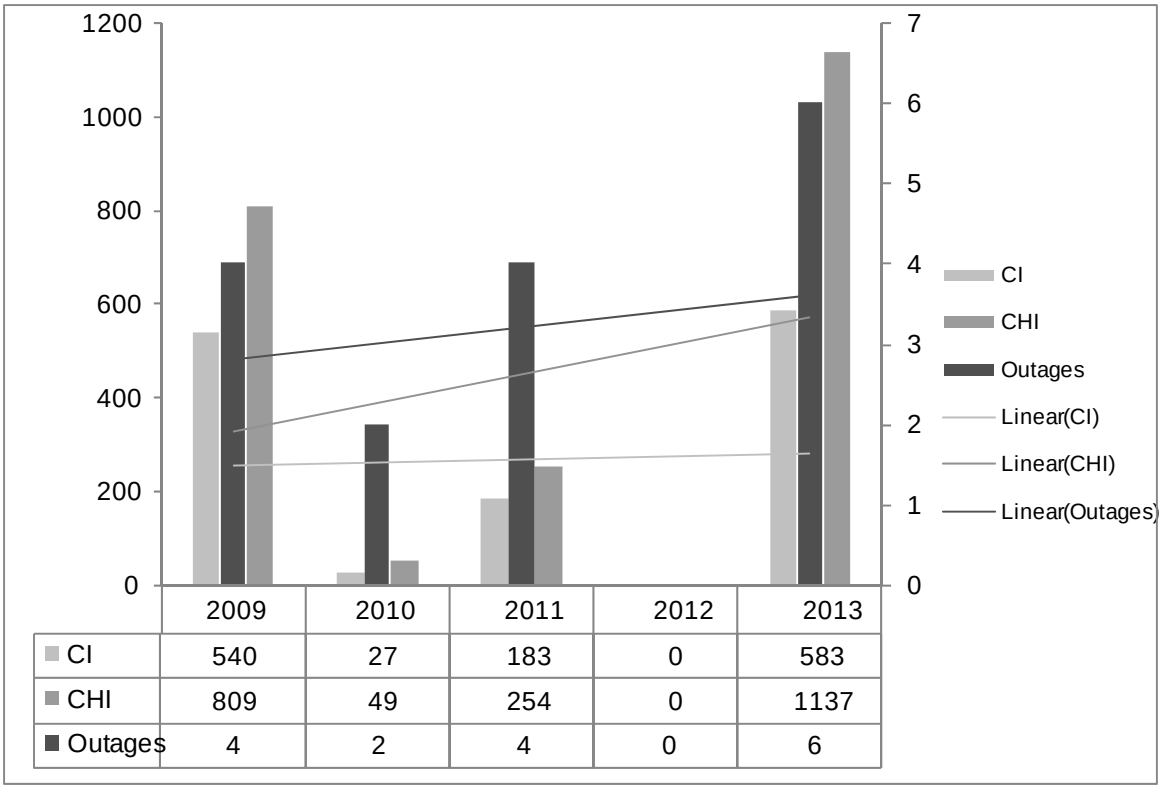
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 193: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1960 (approx. 54 years old)
Reliability	ƒ Feeder 51M28 has been performing poorly with an average of 3 power outages per year during the last 5 years
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 114.



	2009	2010	2011	2012	2013
CI	540	27	183	0	583
CHI	809	49	254	0	1137
Outages	4	2	4	0	6

FIGURE 114: HISTORICAL RELIABILITY DETAILS FOR NY51M28

E15429, E15558 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15429 Bridletowne-Warden 1-Ph,3-Ph UG Rehab Civ SCNA502M22

Project Number: E15429

Project Year: 2015

Estimated Cost: $1,835,377

(i) Objective

To further increase reliability in the Bridletowne-Warden area. This part of the project deals with the civil work only.

(ii) Scope of Work

TABLE 194: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Agincourt
Station(s):	Cavanagh
Feeder(s):	SCNA502M22

(iii) Justification & Benefits

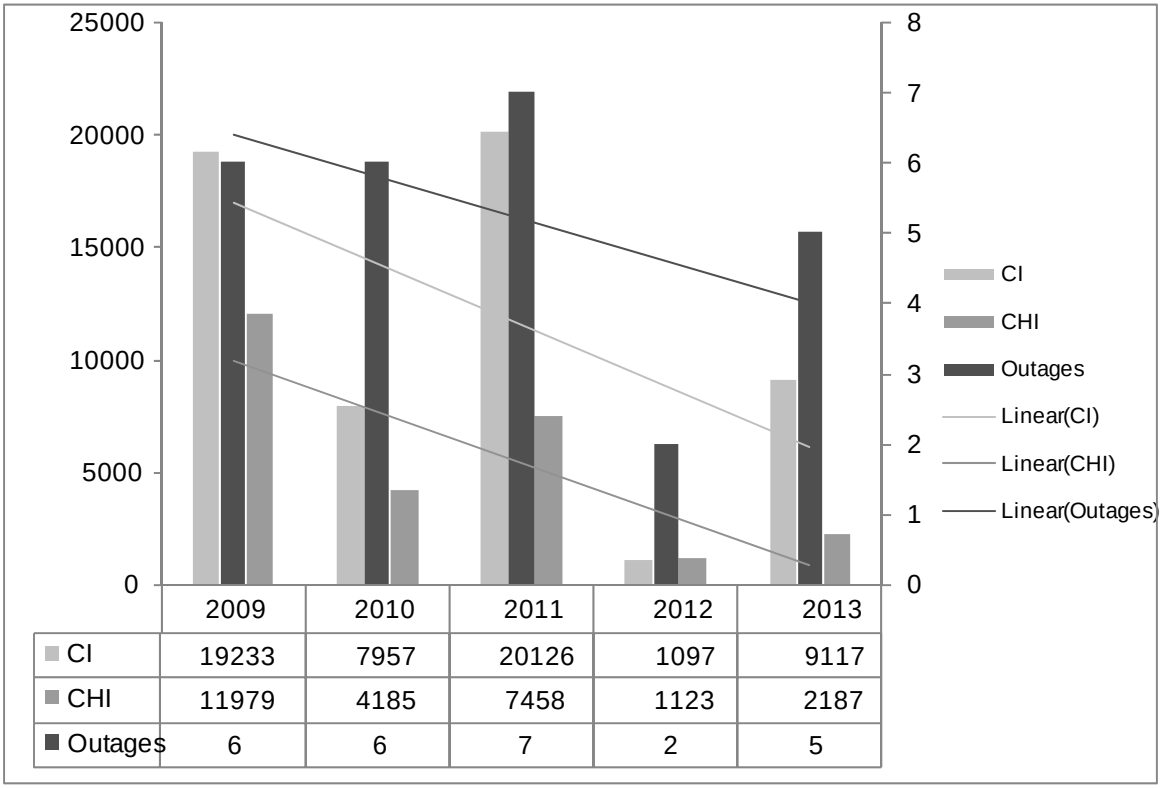
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 195: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1998 (16 years old)
Reliability	ƒ Reliability is weakening along this feeder ƒ Increasing CI, CHI and Outages seen over past five years ƒ The project area experienced five outages in 2011 related to direct buried cable

Supplemental Details	Description
	ƒ A total CI of 10,484 and CHI of 6,524 can be directly related to the five outages between 2011-2013
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 115.



	2009	2010	2011	2012	2013
CI	19233	7957	20126	1097	9117
CHI	11979	4185	7458	1123	2187
Outages	6	6	7	2	5

FIGURE 115: HISTORICAL RELIABILITY DETAILS FOR SCNA502M22

E15442 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15442 McGrisken Rd UG Rebuild -Electrical H9M23 SCNA H9M23

Project Number: E15442

Project Year: 2015

Estimated Cost: $180,272

(i) Objective

Rebuild a portion of SCNA H9M23 containing aged direct buried cable that has reached the end of its useful service life to improve reliability and service to the customer. E15442 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 196: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Rouge River
Station(s):	Ellesmere TS (27.6kV)
Feeder(s):	SCNA H9M23

TABLE 197: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	844.5m
Underground Transformers	0
Underground Switchgear	2
Poles	0
Overhead Transformer	0
Overhead Switch	0

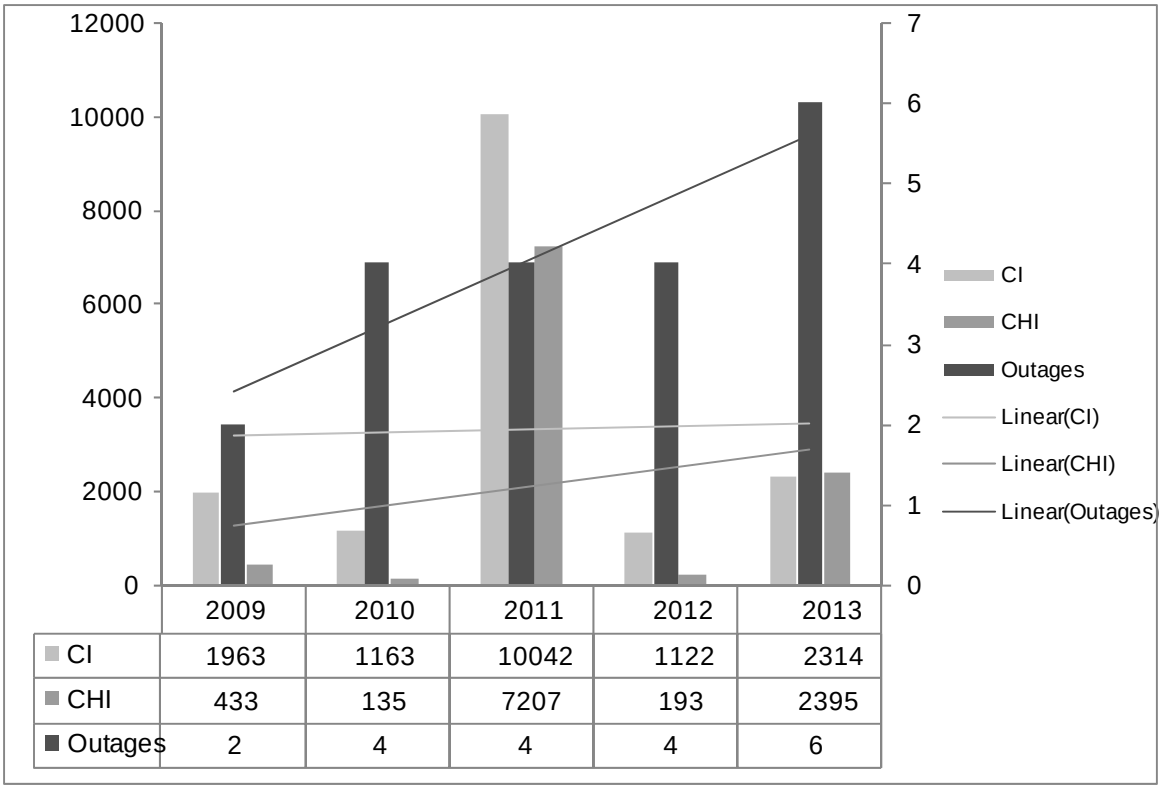
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 198: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1974 (40 years old)
Reliability	ƒ Increasing number of outages from 2009 to 2013, not including momentary outages ƒ Majority of outages due to switches, which will be targeted for replacement in the Underground Circuit Renewal program
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 116.



	2009	2010	2011	2012	2013
CI	1963	1163	10042	1122	2314
CHI	433	135	7207	193	2395
Outages	2	4	4	4	6

FIGURE 116: HISTORICAL RELIABILITY DETAILS FOR SCNAH9M23

E15445 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E15445 Cromwell Senator UG Rebuild -Civil 47M14 SCNA47M14

Project Number: E15445

Project Year: 2015

Estimated Cost: $1,594,380

(i) Objective

Rebuild the distribution of Cromwell subdivision (Dale Ave, Senator Blvd, Cranston Manor Crt and part of Cromwell Rd) by replacing the old direct buried cables and transformers. E15445 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 199: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Southwest
Station(s):	Sheppard TS (27.6kV)
Feeder(s):	SCNA47M14

(iii) Justification & Benefits

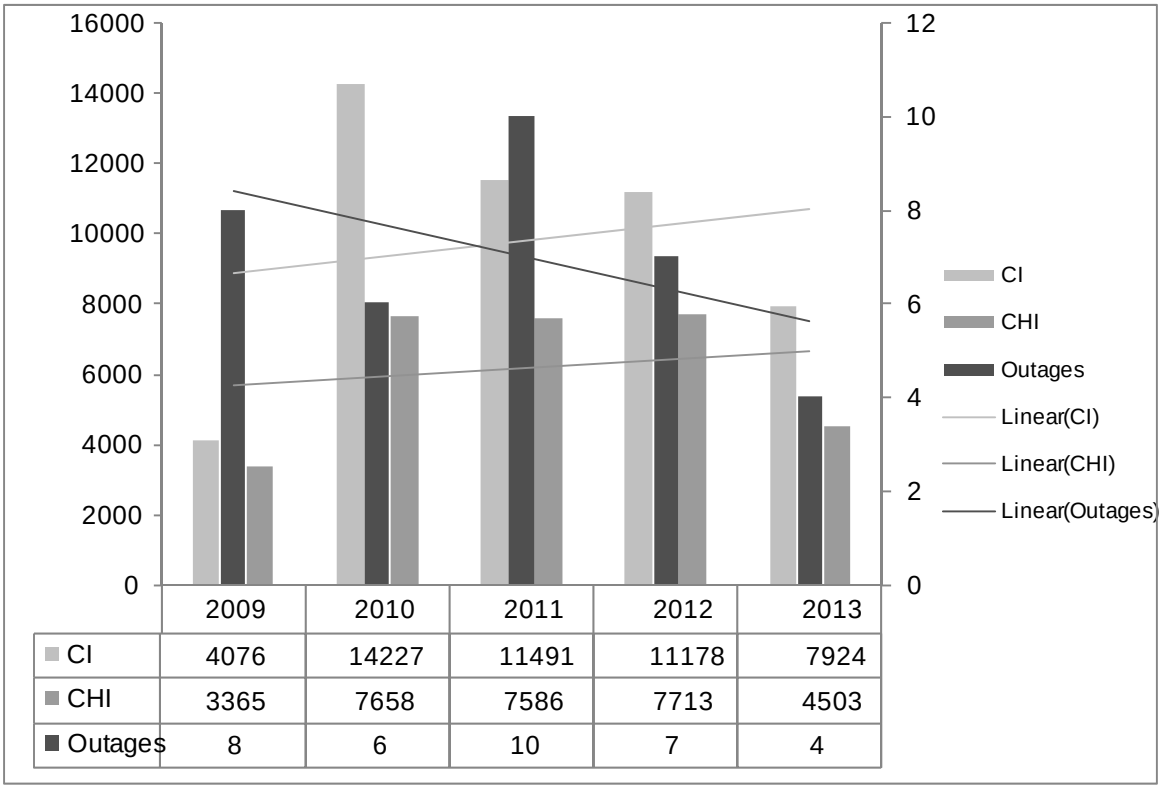
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 200: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1984 (30 years old)
Reliability	x Reliability is slowly showing improvement ƒ This project needs to be executed to maintain reliability improvements seen in along the feeder

Supplemental Details	Description
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 117.



	2009	2010	2011	2012	2013
CI	4076	14227	11491	11178	7924
CHI	3365	7658	7586	7713	4503
Outages	8	6	10	7	4

FIGURE 117: HISTORICAL RELIABILITY DETAILS FOR SCNA47M14

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15476, E15477 Project Description

Investment Category: **System Renewal**

Program: **Underground Circuit Renewal**

Project Title: **45 Birchmount Road UG Rebuild Civil/Electrical SCNAR43M24**

Project Number: **E15476, E15477**

Project Year: **2015**

Estimated Cost: **$185,563**

(i) Objective

Replace underground assets on 43M24 that have reached and/or exceeded their useful service life. E15476 will install the civil infrastructure necessary to complete the project; E15477 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 200: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Southwest
Station(s):	Warden TS (27.6 kV)
Feeder(s):	SCNAR43M24

TABLE 201: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	82.18 m
Underground Transformers	2
Underground Switch	0
Poles	0
Overhead Transformer	0
Overhead Switch	2

/C

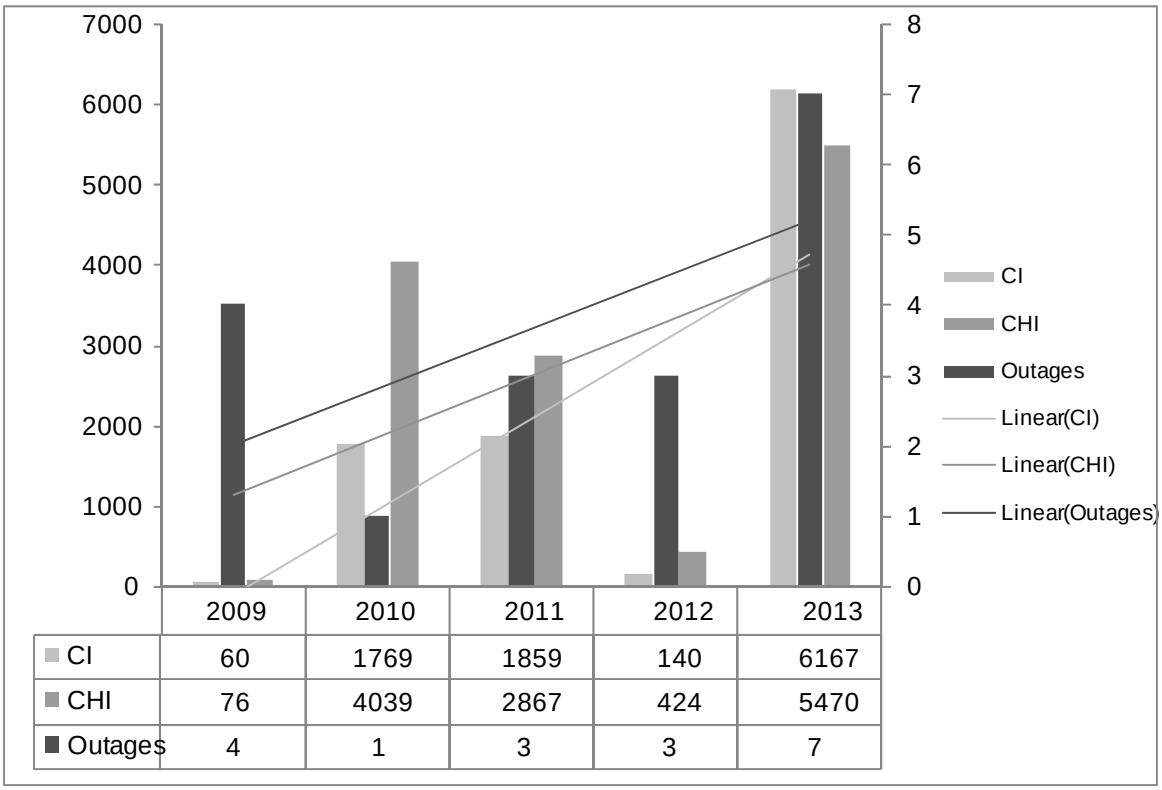
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 203: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cables ƒ Installed 1981 (33 years old)
Reliability	ƒ Feeder has experienced poor reliability with 10 outages in last 2 years
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 118.



	2009	2010	2011	2012	2013
CI	60	1769	1859	140	6167
CHI	76	4039	2867	424	5470
Outages	4	1	3	3	7

FIGURE 118: HISTORICAL RELIABILITY DETAILS FOR SCNAR43M24

E15587 Project Description-

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: 1123 Leslie St at Eglinton UG cable replacement 34M5

Project Number: E15587

Project Year: 2015

Estimated Cost: $32,837

(i) Objective

Replace aged underground cable from Leaside TS feeder 34M5 that supplies power to 1123 Leslie St. E15587 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 204: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Leaside TS (27.6 kV)
Feeder(s):	EY M5L

TABLE 205: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	270.76m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

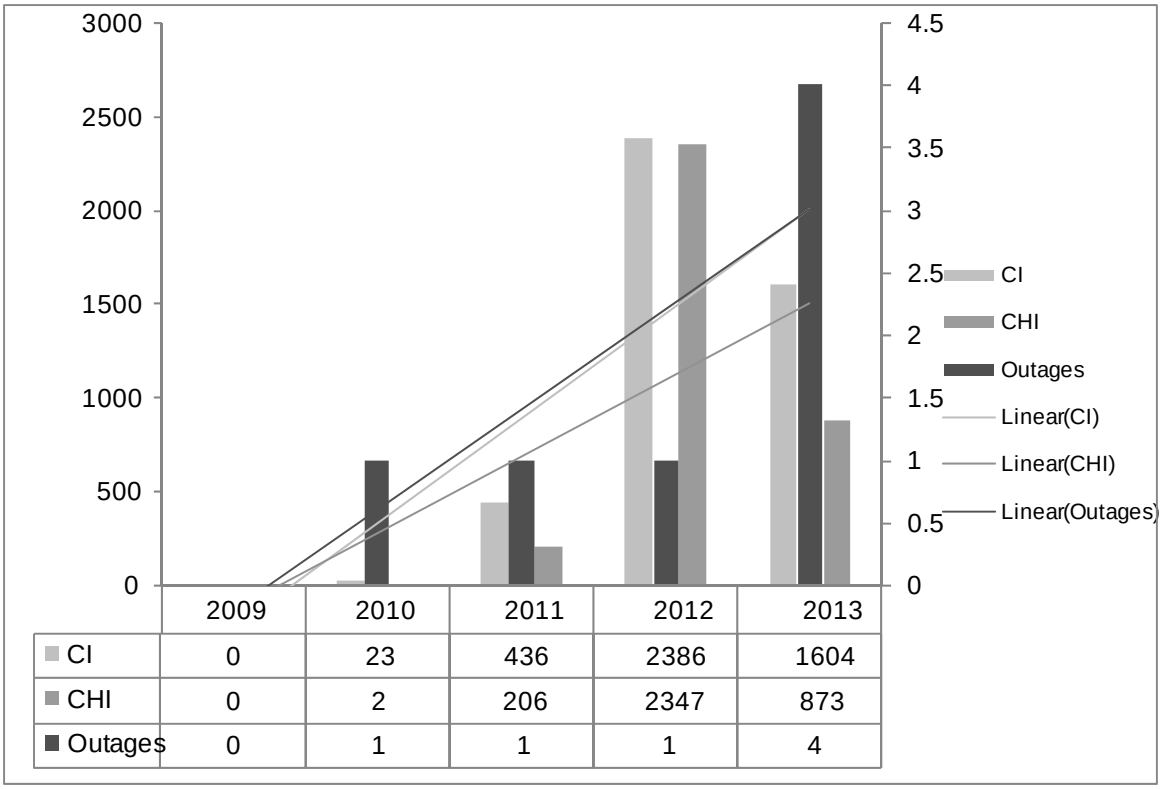
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 206: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ This work is required to replace existing cable that are found to be in poor condition with low insulation resistance
Reliability	ƒ There has been a previous failure on the same segment of cable that is being replaced
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 119.



	2009	2010	2011	2012	2013
CI	0	23	436	2386	1604
CHI	0	2	206	2347	873
Outages	0	1	1	1	4

FIGURE 119: HISTORICAL RELIABILITY DETAILS FOR NY34M5

W11156 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: 35M10, M2, M4 & M9 Fairbank TS PILC Cable Replacement (Revised)

Project Number: W11156

Project Year: 2015

Estimated Cost: $826,754

(i) Objective

Replace the existing 1/C-1500 MCM, Cu, PILC cable with new TR-XLPE cable between Fairbank TS and riser on p#24 - 423 Whitmore Ave. W11156 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 207: SCOPE OF WORK DETAILS

District Neighborhood	Eglinton Lawrence
Station(s):	Fairbanks (27.6kV)
Feeder(s):	YK35M10

TABLE 208: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,815.68m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

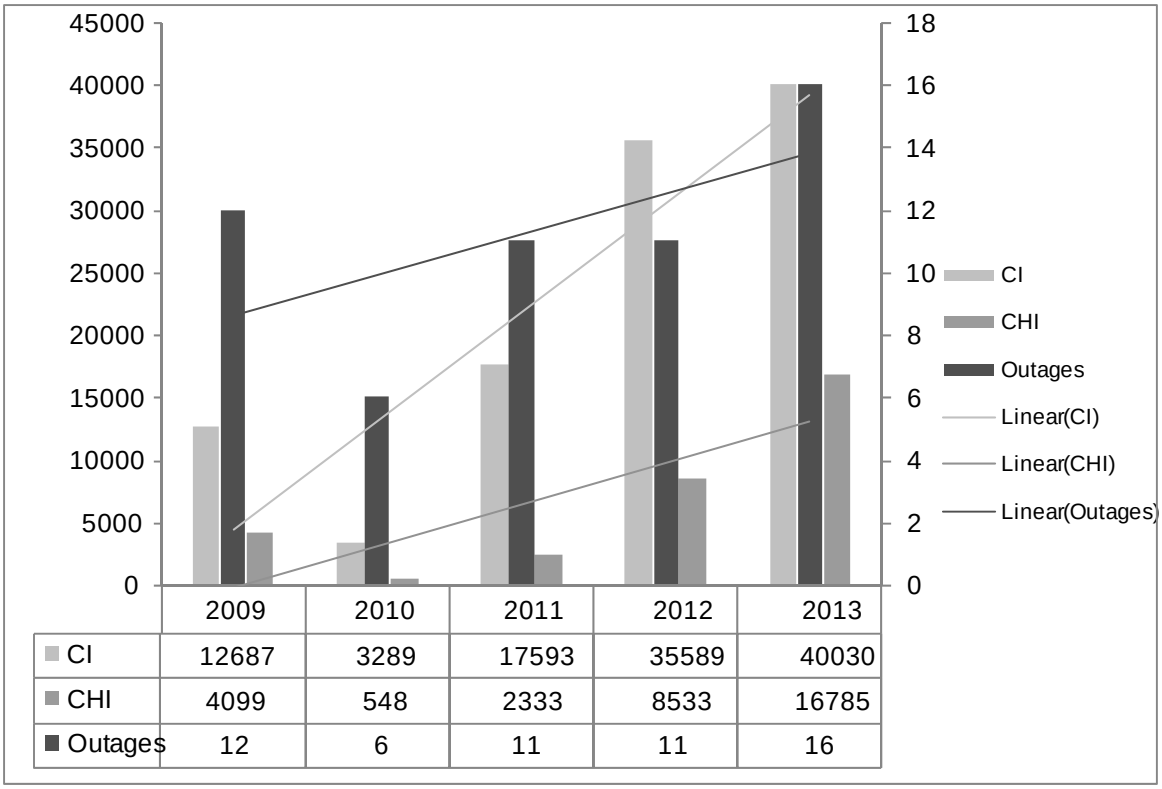
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 209: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	• Cable in duct • Installed around 1980 (approx. 34 years old)
Reliability	• The feeders within the cable chambers have experience six outages due to underground failure • The egress cable (overhead or underground) is one of the most important sections of the feeder, since it is the supply point from the circuit breaker to the feeder. If the egress cable fails, the entire feeder and all customers connected will experience and outage • Three out of four underground egress cables in the project area are Paper Insulated Lead Covered (PILC) cable and one is XLPE unshielded cable • Heat generated from the XLPE unshielded cable is causing the PILC to fail significantly sooner than expected. • PILC cables have started to melt due to the heat resulting in outages within the cable chambers • Field inspections and photos have shown the damage and the deterioration of the cable
Other (i.e. road moratoriums, etc)	• PILC cable is not a standard cable due to high cost, work difficulties and environmental concerns • This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 120.



	2009	2010	2011	2012	2013
CI	12687	3289	17593	35589	40030
CHI	4099	548	2333	8533	16785
Outages	12	6	11	11	16

FIGURE 120: HISTORICAL RELIABILITY DETAILS FOR YK35M10

W11161 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W11161 35M9 Fairbank TS PILC Cable Replacmnt

Project Number: W11161

Project Year: 2015

Estimated Cost: $74,025

(i) Objective

Replace the existing 750 MCM, Cu, PILC cable with new TR-XLPE cable between riser on pole #45 at #1 Jesmond and riser on p#6 at #2A Rogers. W11161 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 210: SCOPE OF WORK DETAILS

District Neighborhood	Eglinton-Lawrence
Station(s):	Fairbanks (27.6kV)
Feeder(s):	YK35M9

TABLE 211: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	376.85m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

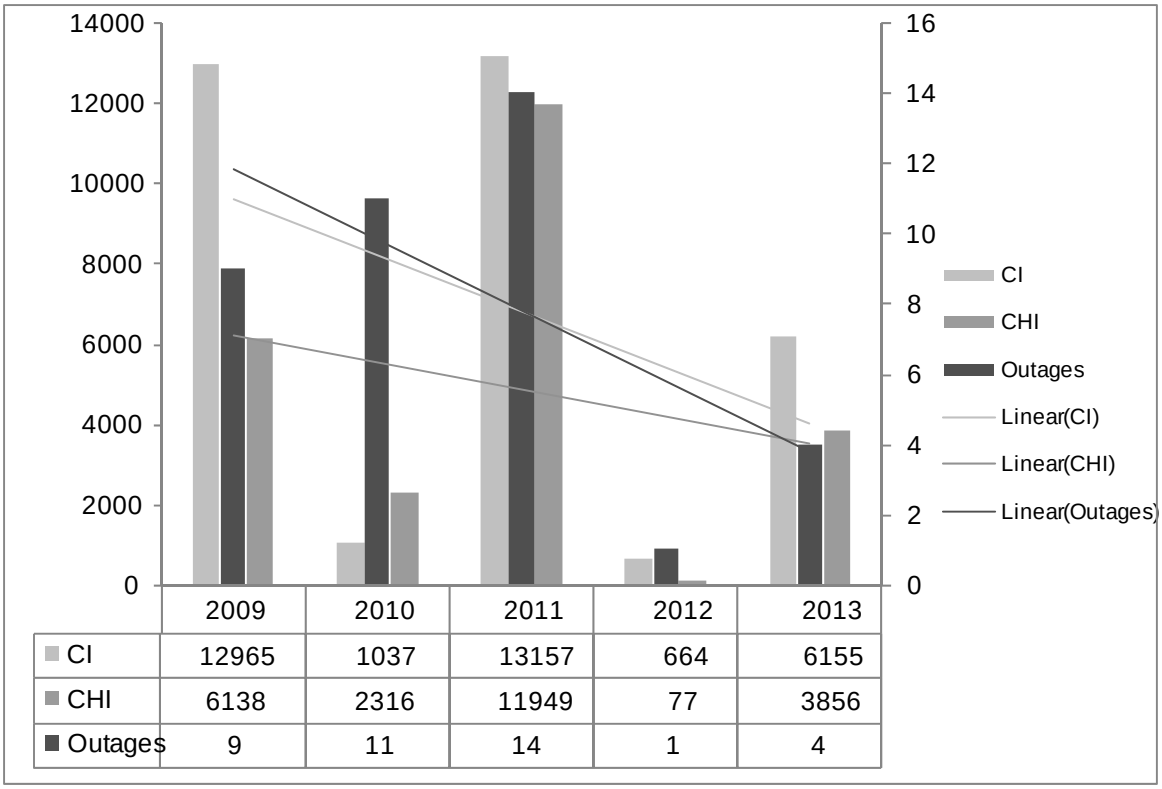
(iii) Justificat ion & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 212: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Cable in duct ƒ Installed around 1980 (approx. 34 years old)
Reliability	ƒ The feeder has experienced six outages due to underground failure, specifically due to failing PILC cable ƒ The egress cable and main trunk (overhead or underground) is an important part of the feeder, since it is the supply point from the circuit breaker to the feeder. If the egress cable fails, the entire feeder and all customers connected will experience and outage ƒ Due to reliability concerns initiated in W11156 it was determine to replace all PILC cables which are part of the main truck of the feeder
Other (i.e. road moratoriums, etc)	ƒ PILC cable is not a standard cable due to high cost, work difficulties and environmental concerns ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 121.



	2009	2010	2011	2012	2013
CI	12965	1037	13157	664	6155
CHI	6138	2316	11949	77	3856
Outages	9	11	14	1	4

FIGURE 121: HISTORICAL RELIABILITY DETAILS FOR YK35M9

W11170 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W11170 35M4 Fairbank TS PILC Cable Replacmnt

Project Number: W11170

Project Year: 2015

Estimated Cost: $215,957

(i) Objective

Replace the existing 750 MCM, Cu, PILC with new TR-XLPE cable between vault BOO at #145 Marlee and vault XEJ at #377 Ridelle. W11170 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 213: SCOPE OF WORK DETAILS

District Neighborhood	Eglinton Lawrence
Station(s):	Fairbanks (27.6kV)
Feeder(s):	YK35M4

TABLE 214: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	148.45m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

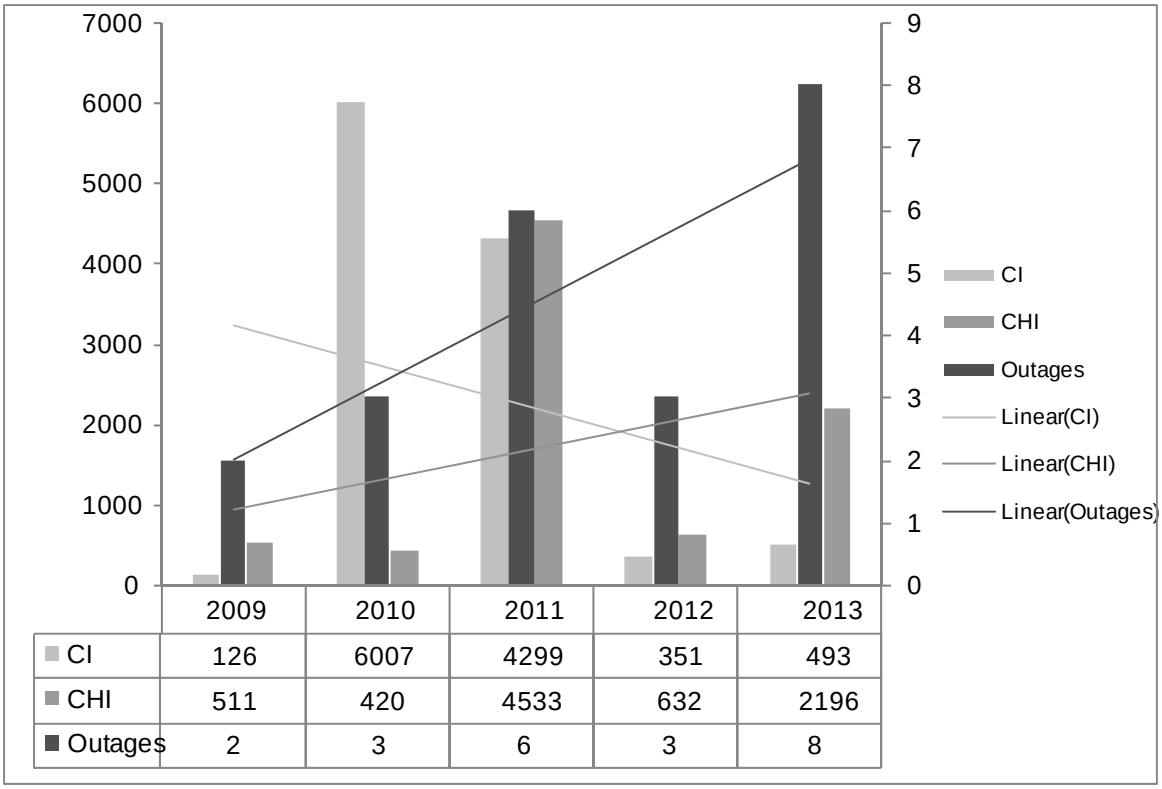
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 215: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Cable in duct ƒ Installed around 1980 (approx. 34 years old)
Reliability	ƒ The feeder has experienced six outages due to underground failure, specifically due to failing PILC cable ƒ The egress cable and main trunk (overhead or underground) is an important part of the feeder, since it is the supply point from the circuit breaker to the feeder. If the egress cable fails, the entire feeder and all customers connected will experience and outage ƒ Due to reliability concerns initiated in W11156 it was determine to replace all PILC cables which are part of the main truck of the feeder
Other (i.e. road moratoriums, etc)	ƒ PILC cable is not a standard cable due to high cost, work difficulties and environmental concerns ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 122.



	2009	2010	2011	2012	2013
CI	126	6007	4299	351	493
CHI	511	420	4533	632	2196
Outages	2	3	6	3	8

FIGURE 122: HISTORICAL RELIABILITY DETAILS FOR YK35M4

W11287 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W11287 FESI - NY55M22 - Lateral Cable Replacmnt - Rowntree (Ph4)

Project Number: W11287

Project Year: 2015

Estimated Cost: $718,430

(i) Objective

Replace four XLPE primary service sub-loops on feeder 55M22 with TR-XLPE cable from OH supply poles through submersible transformer vaults back to OH feeder. W11287 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 216: SCOPE OF WORK DETAILS

District Neighborhood	York West
Station(s):	Finch II TS (27.6kV)
Feeder(s):	NY55M22

TABLE 217: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,849.63 m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

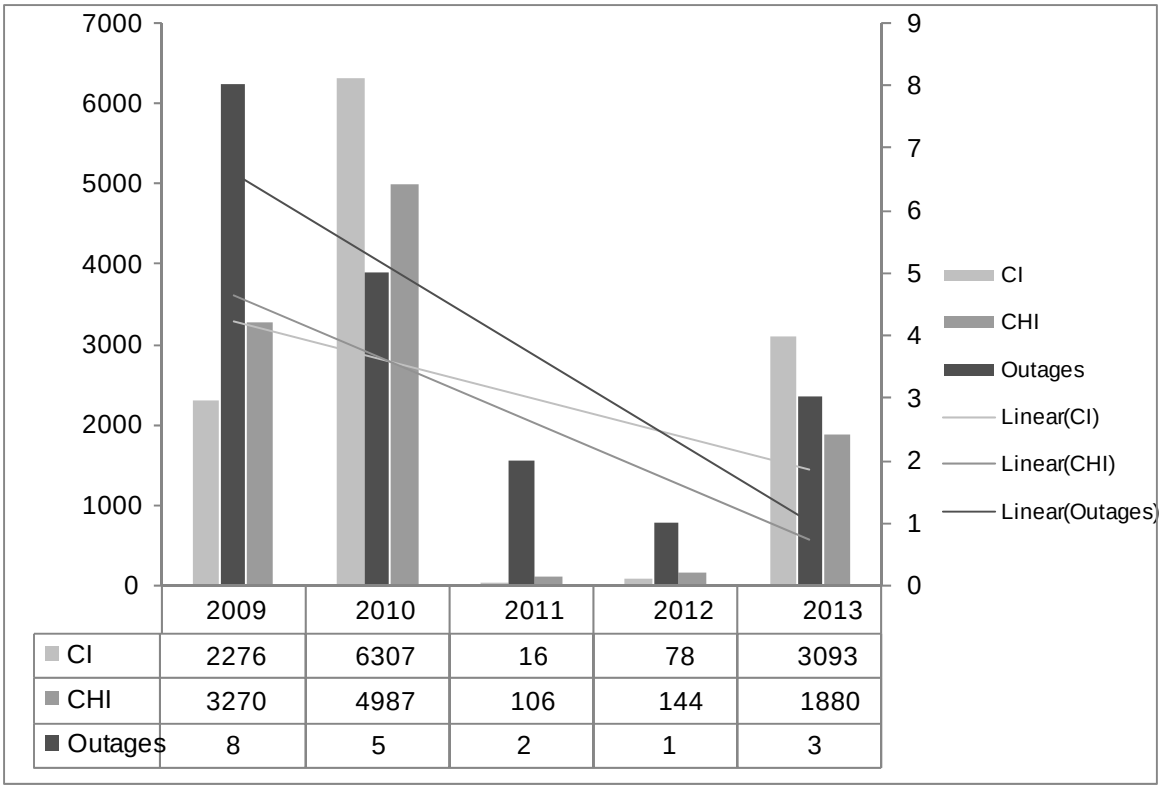
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 218: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Transformers and direct buried cable ƒ Assets installed around 1968 – 1978 (approx. between 36 – 46 years old)
Reliability	ƒ The overall reliability of the feeder has improved over the past five years ƒ The feeder still continues to experience outages due to poor performance of assets that are past their end of life like underground transformers and cable
Other (i.e. road moratoriums, etc)	ƒ This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 123.



	2009	2010	2011	2012	2013
CI	2276	6307	16	78	3093
CHI	3270	4987	106	144	1880
Outages	8	5	2	1	3

FIGURE 123: HISTORICAL RELIABILITY DETAILS FOR NY55M22

W11288 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W11288 FESI 55M22 LA TERAL CABLE REPLACEMENT-ISLINGTON

Project Number: W11288

Project Year: 2015

Estimated Cost: $332,907

(i) Objective

Replace all XLPE primary service laterals and/or primary service sub-loops on feeder 55M22 with TR-XLPE cable from OH feeder to transformer vault/pad/room on private property along Islington.W11288 will complete the electrical portion of the.

(ii) Scope of Work

TABLE 219: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke Centre
Station(s):	Finch II TS (27.6kV)
Feeder(s):	NY55M22

TABLE 220: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	638.89m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

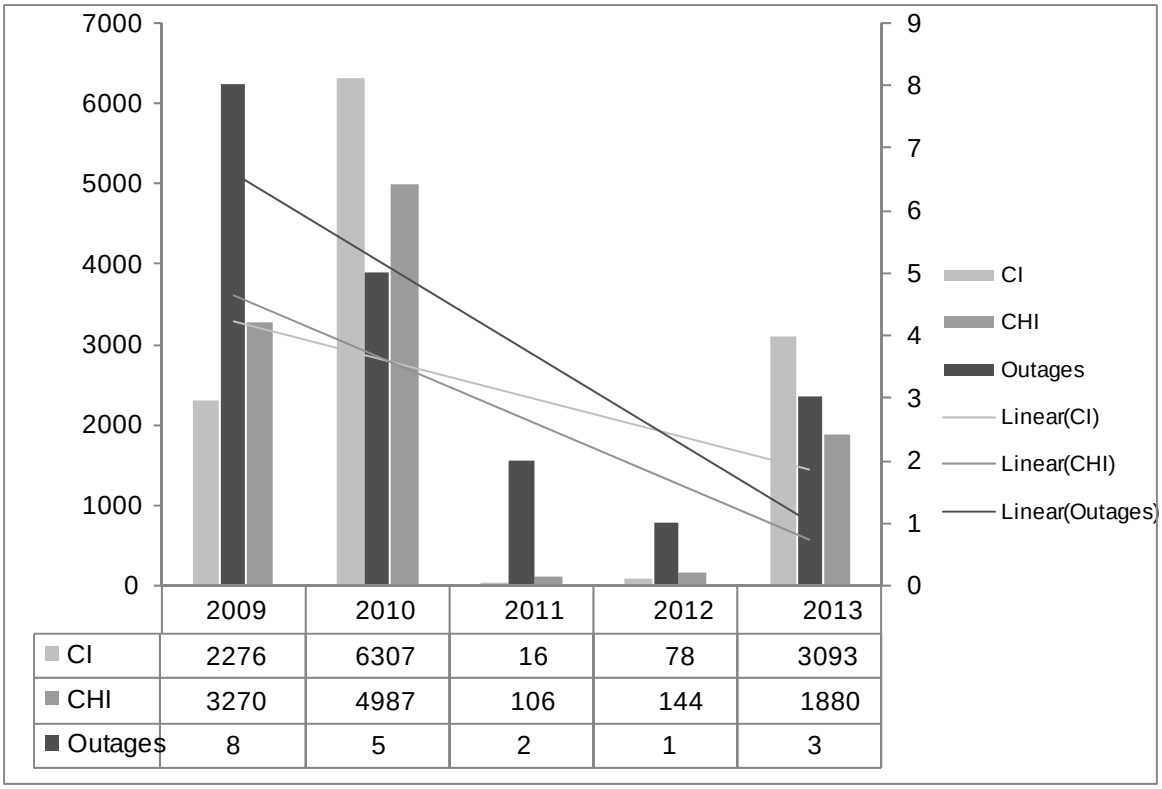
(iii) Justificat ion & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 221: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	• Transformers and cable in duct • Assets installed around 1975 - 1978 (approx. between 36 to 39 years old) • Field inspections have reported that the structure of some of the submersible transformers are in poor condition
Reliability	• The overall reliability of the feeder has improved over the past five years • The feeder still continues to experience outages due to poor performance of assets that are past their end of life like underground transformers and cable
Other (i.e. road moratoriums, etc)	• The underground laterals in this project are concrete encased however, project will be removing XLPE #1 Solid cable and replacing with 1/0 TR-XLPE cable • This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 124.



	2009	2010	2011	2012	2013
CI	2276	6307	16	78	3093
CHI	3270	4987	106	144	1880
Outages	8	5	2	1	3

FIGURE 124: HISTORICAL RELIABILITY DETAILS FOR NY55M22

W12077 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Hoggs Hollow PH4

Project Number: W12077

Project Year: 2015

Estimated Cost: $1,722,014

(i) Objective

Replace the direct buried primary distribution in the area known as Hogg's Hollow to improve reliability and service to customers. W12077 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 221: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Fairchild II TS(27.6 kV)
Feeder(s):	NY80M30, NY55M29

TABLE 222A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	16,563.95
Underground Transformers	2
Underground Switch	1
Poles	1
Overhead Transformer	24
Overhead Switch	0

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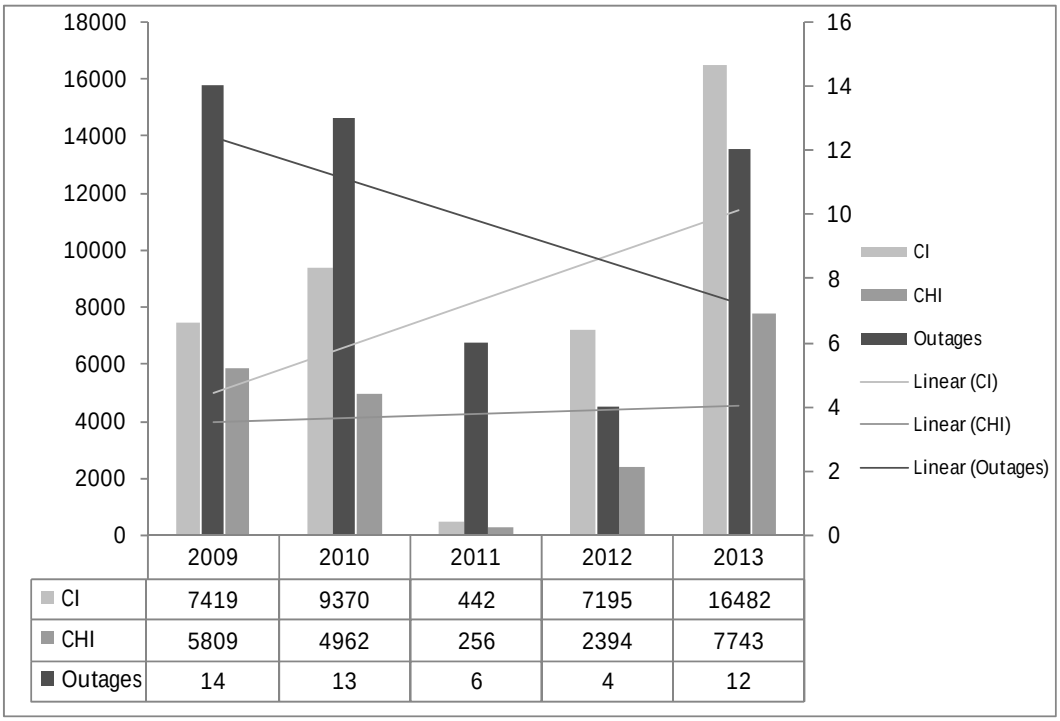
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 222: SUPPLEMENTAL DETAILS

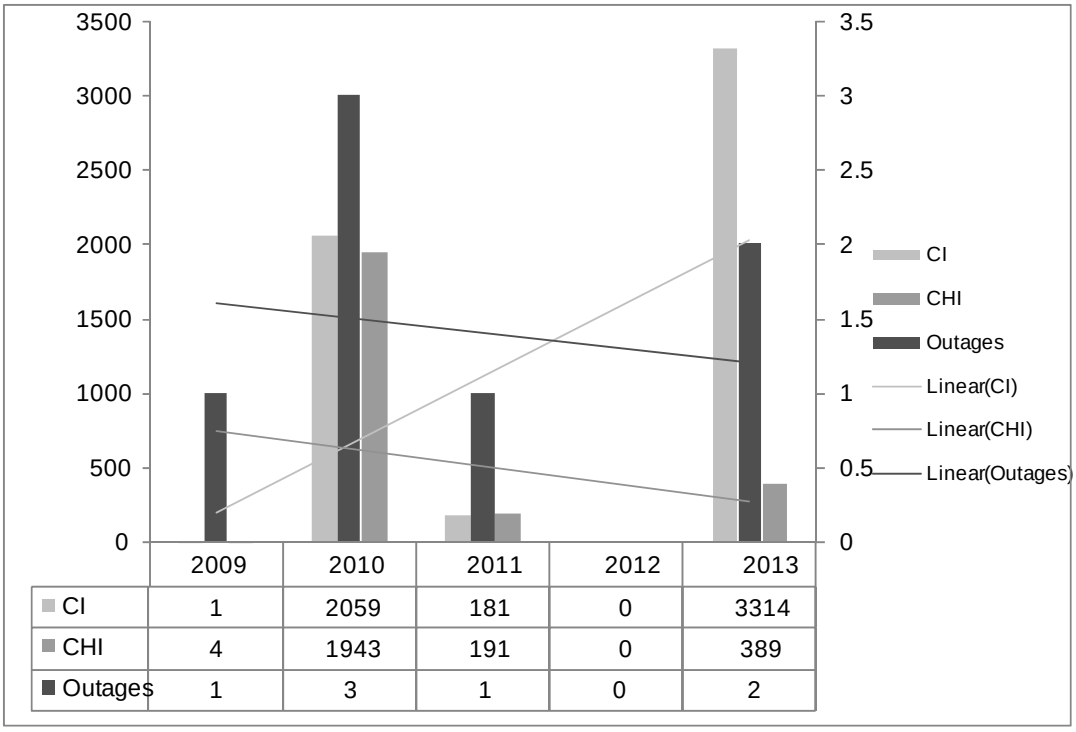
Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1984 (30 years old)
Reliability	ƒ Feeder 80M30 has been performing very poorly with an average of nearly 10 power outages per year during the past 5 years
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure XYZ.



	2009	2010	2011	2012	2013
CI	7419	9370	442	7195	16482
CHI	5809	4962	256	2394	7743
Outages	14	13	6	4	12

FIGURE 125: HISTORICAL RELIABILITY DETAILS FOR NY80M30



	2009	2010	2011	2012	2013
CI	1	2059	181	0	3314
CHI	4	1943	191	0	389
Outages	1	3	1	0	2

FIGURE 126: HISTORICAL RELIABILITY DETAILS FOR NY55M29

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W12308 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W12308 FESI Clubhouse Crt and Brookwell Dr Rebuild

Project Number: W12308

Project Year: 2015

Estimated Cost: $1,290,728

(i) Objective

Replace direct buried primary with new TRXLPE. E12308 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 224: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke North
Station(s):	Finch II TS (27.6 kV)
Feeder(s):	NY55M25

TABLE 225: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,469.31 m
Underground Transformers	6
Underground Switchgear	0
Poles	2
Overhead Transformer	1
Overhead Switch	0

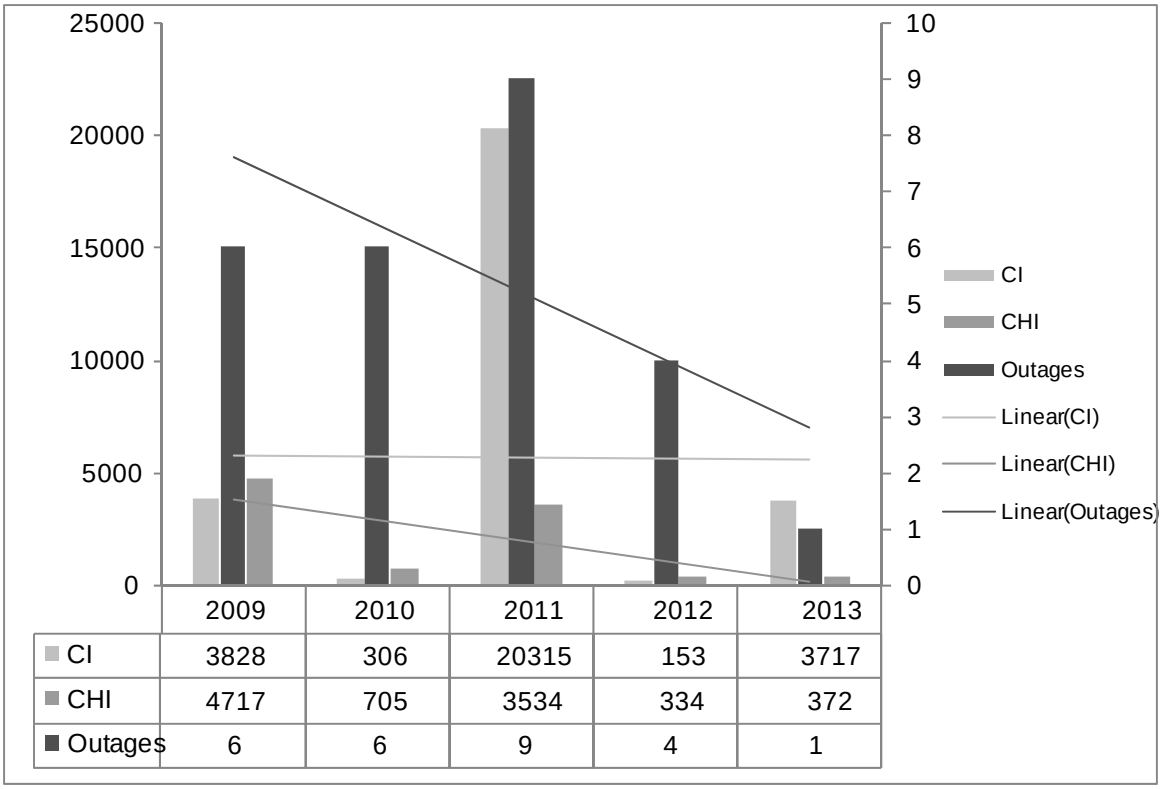
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 226: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	• Direct buried cable • Installed around 1982 - 1988 (approx. between 26 - 32 years old)
Reliability	• The overall reliability of the feeder has improved over the past five years • The feeder still continues to experience outages due to poor performance of assets that are past their end of life like underground transformers and cable
Other (i.e. road moratoriums, etc)	• Project will include a reconfiguration of the area • This is the electrical portion of the project and needs to be completed to help improve reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 127.



	2009	2010	2011	2012	2013
CI	3828	306	20315	153	3717
CHI	4717	705	3534	334	372
Outages	6	6	9	4	1

FIGURE 127: HISTORICAL RELIABILITY DETAILS FOR NY55M25

W12480, W13114 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Primary Trunk Cable Replacement - The East Mall

Project Number: W12480, W13114

Project Year: 2015

Estimated Cost: $1,182,468

(i) Objective

To improve reliability of poorly performing feeders: ETHL-F1 and ETHL-H3. W12480 combines the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 227: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke Centre
Station(s):	Blaketon (4.16kV)
Feeder(s):	ETHL-F1, ETHL-F3

TABLE 228: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	2,361.37m + 2,218.72m
Underground Transformers	7
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

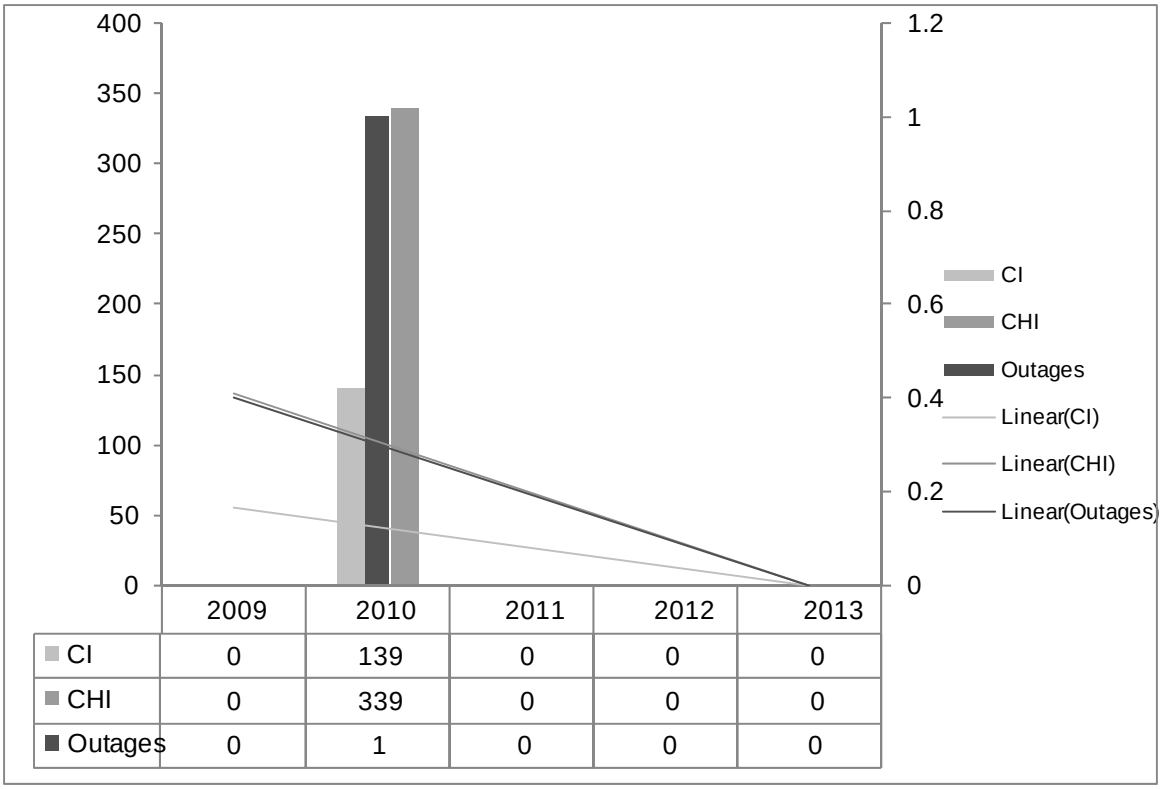
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 229: SUPPLEMENTAL DETAILS

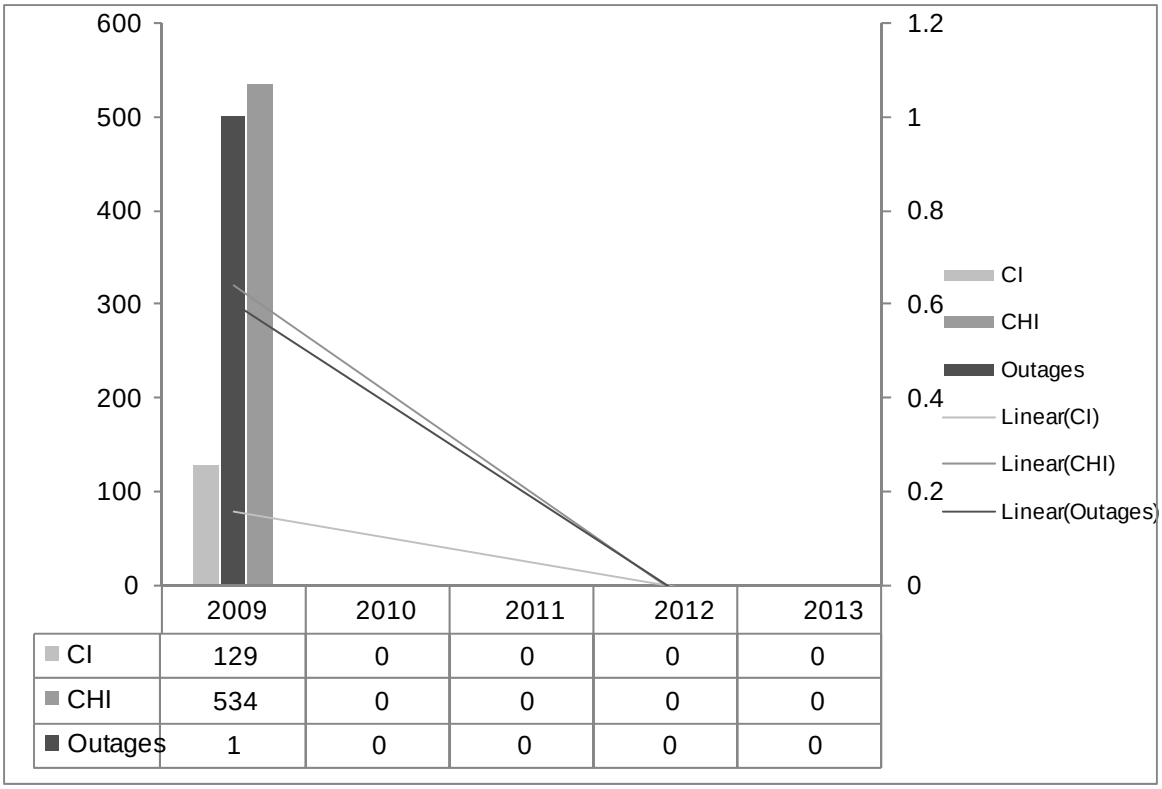
Supplemental Details	Description
Age/Condition	ƒ End of life switches, transformers and cable in duct ƒ Assets installed around 1964 (over 50 years old)
Reliability	ƒ Reliability weakening along feeders ƒ Increasing CI, CHI and Outages seen along HLF2, HLF3 and HLF4
Other (i.e. road moratoriums, etc)	ƒ Customers in the area had complained of the high incidence of outages in 2013 ƒ Cables include egress from Blaketon MS which makes failures high impact as all 275 customers are served by cables to be replaced by these scopes

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 128 and 129.



	2009	2010	2011	2012	2013
CI	0	139	0	0	0
CHI	0	339	0	0	0
Outages	0	1	0	0	0

FIGURE 128: HISTORICAL RELIABILITY DETAILS FOR ETHLF1



	2009	2010	2011	2012	2013
CI	129	0	0	0	0
CHI	534	0	0	0	0
Outages	1	0	0	0	0

FIGURE 129: HISTORICAL RELIABILITY DETAILS FOR ETHLF3

W13284, W13287 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: UG Lateral Replacement Phase 1 and Phase 2

Project Number: W13284, W13287

Project Year: 2015

Estimated Cost: $ 3,461,392.00

(i) Objective

To improve reliability on feeder NY55M31, W13284 (Phase 1) and W13287 (Phase 2) combine the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 230: SCOPE OF WORK DETAILS

District Neighborhood	York West
Station(s):	Finch II TS (27.6kV)
Feeder(s):	NY55M31

TABLE 231: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	406.64m
Underground Transformers	14
Underground Switchgear	0
Poles	15
Overhead Transformer	0
Overhead Switch	1

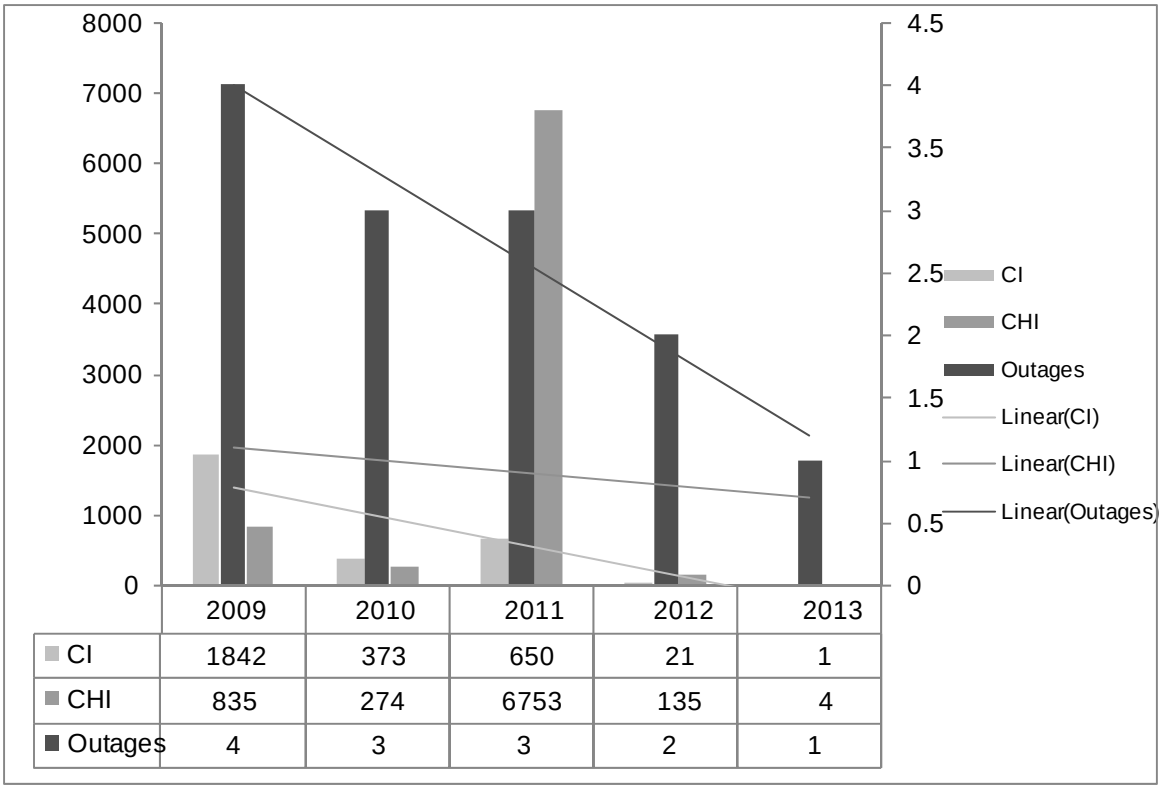
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 232: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Transformers and direct buried cable ƒ Assets installed around 1970 (approx. 44 years old)
Reliability	ƒ Feeder continues to experience interruptions due to underground transformer and cable ƒ The replacement of end of life assets will minimize reactive repair costs
Other (i.e. road moratoriums, etc)	ƒ Some sections of the underground cable that will be replaced is XLPE #1 Solid cable

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 130.



	2009	2010	2011	2012	2013
CI	1842	373	650	21	1
CHI	835	274	6753	135	4
Outages	4	3	3	2	1

FIGURE 130: HISTORICAL RELIABILITY DETAILS FOR NY55M31

W14130 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Rebuild Russfax & Twin Circle Crt

Project Number: W14130

Project Year: 2015

Estimated Cost: $439,236

(i) Objective

Rebuild the OH and UG distribution on Russfax and Twin Circle Crt to improve reliability. W14130 combines both the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 233: SCOPE OF WORK DETAILS

District Neighborhood	York Centre
Station(s):	Bathurst TS (27.6kV)
Feeder(s):	NY85M7

TABLE 234: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	888.93m
Underground Transformers	15
Underground Switchgear	0
Poles	19
Overhead Transformer	0
Overhead Switch	6

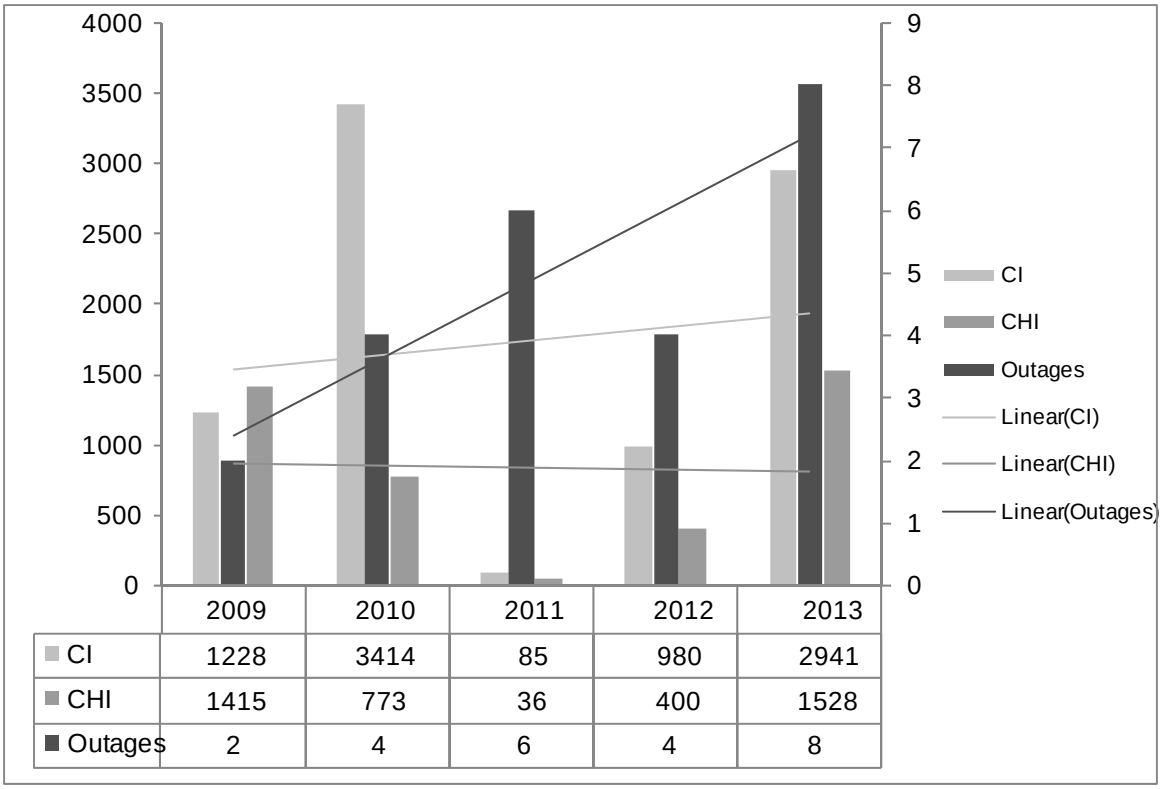
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 235: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed around 1974 (approx. 40 years old)
Reliability	ƒ Many outages on this feeder contributed by direct buried faults ƒ Reliability in project area is poor ƒ
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 131.



	2009	2010	2011	2012	2013
CI	1228	3414	85	980	2941
CHI	1415	773	36	400	1528
Outages	2	4	6	4	8

1 FIGURE 131: HISTORICAL RELIABILITY DETAILS FOR NY85M7

W14217 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: UG Lateral Cable Replacement - Signet/Kenhar 55M1

Project Number: W14217

Project Year: 2015

Estimated Cost: $1,063,379

(i) Objective

Replace all XLPE UG primary service laterals in the area of Signet/Kenhar to improve reliability and service to the customer. W14217 combines the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 236: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke York
Station(s):	Finch TS (27.6kV)
Feeder(s):	NY55M1

TABLE 237: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	699.17m
Underground Transformers	12
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

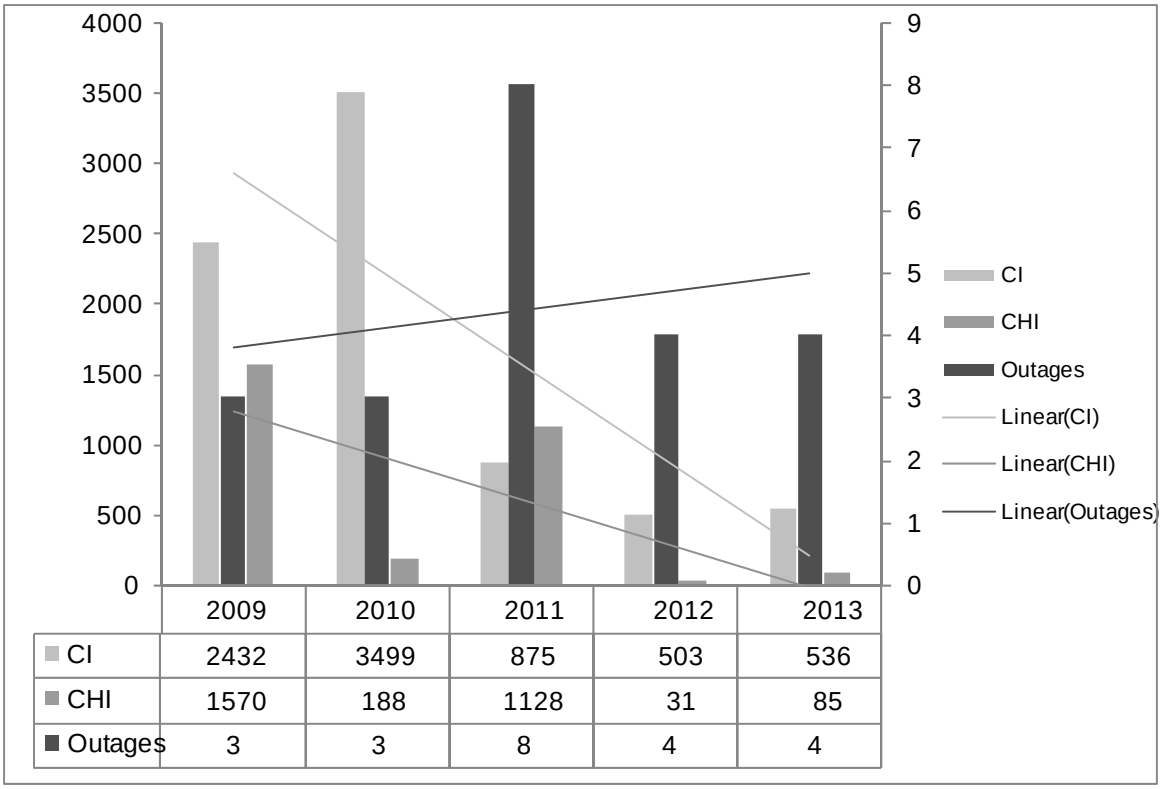
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 238: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Combination of direct buried cable and end of life cable in duct ƒ Assets installed around 1970 – 1980 (approx. between 34 – 44 years old)
Reliability	ƒ Feeder has experienced several underground transformer outages ƒ The primary failure mode of the feeder is overhead defective equipment ƒ Due to poor conditions of the poles that have to be replaced, including riser poles, the underground XLPE Cable will be replaced, along with transformers that have reached end of life.
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 132.



	2009	2010	2011	2012	2013
CI	2432	3499	875	503	536
CHI	1570	188	1128	31	85
Outages	3	3	8	4	4

1 FIGURE 132: HISTORICAL RELIABILITY DETAILS FOR NY55M1

W14274 Project Description

Investment Category: **System Renewal**

Program: **Underground Circuit Renewal**

Project Title: **UG Lateral Cable Replacement -Fenmar/Ormout 55M1 Civil/Elec** /C

Project Number: **W14274**

Project Year: **2015**

Estimated Cost: **$1,055,354**

(i) Objective

Replace all XLPE UG primary service laterals in the area of Fenmar/Ormout to improve reliability and service to the customer. W14274 combines the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 238: SCOPE OF WORK DETAILS

District Neighborhood	York West
Station(s):	Finch I TS (27.6 kV)
Feeder(s):	NY55M1

TABLE 239A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,287.39 m
Underground Transformers	12
Underground Switch	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

/C

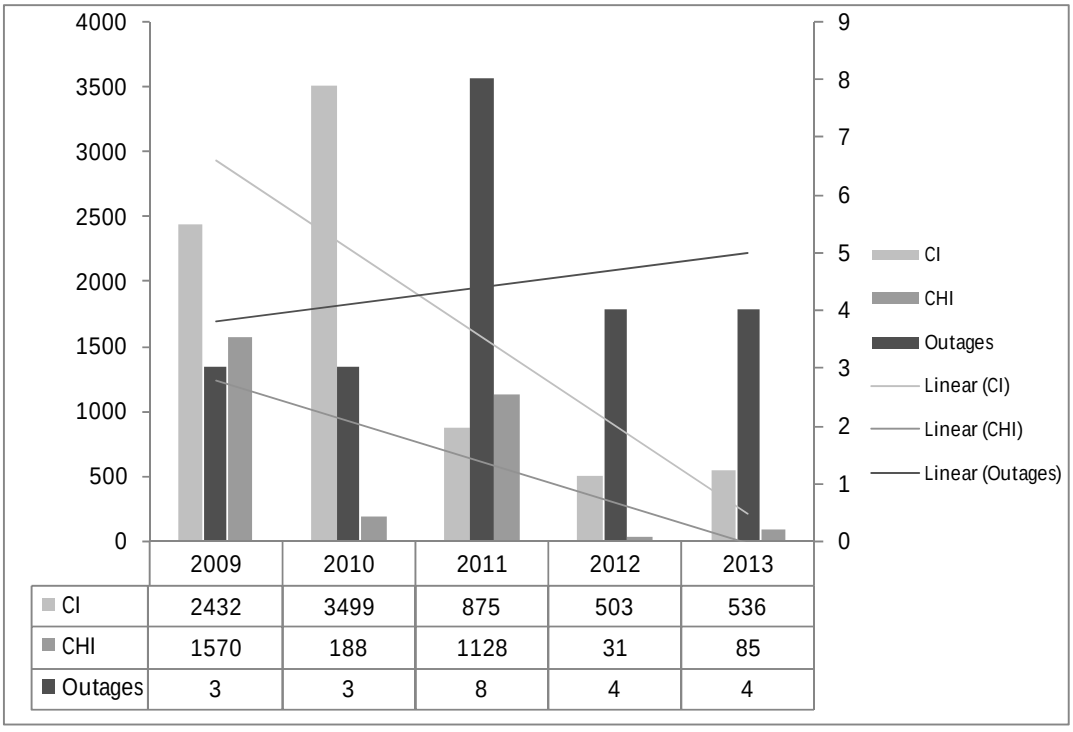
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 239: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Combination of direct buried cable and endrofrlife cable in duct ƒ Assets installed around 1970r 1980 (approx. between 34r44 years old)
Reliability	ƒ Feeder has experienced several underground transformer outages ƒ The primary failure mode of the feeder is overhead defective equipment ƒ Due to poor conditions of the poles that have to be replaced, including riser poles, the underground XLPE cable will be replaced, along with transformers that have reached endrofrlife.
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 133.



	2009	2010	2011	2012	2013
CI	2432	3499	875	503	536
CHI	1570	188	1128	31	85
Outages	3	3	8	4	4

FIGURE 133: HISTORICAL RELIABILITY DETAILS FOR NY55M1

W14653 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W14653-P01-Richview Feeder Egress via Kelfield Rd

Project Number: W14653

Project Year: 2015

Estimated Cost: $1,341,461

(i) Objective

Build an underground egress for feeders to exit Richview TS and extend beyond the congested ROW and highways around the station. W14653 installs the civil infrastructure necessary to complete the ICM approved project.

(ii) Scope of Work

TABLE 241: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke York
Station(s):	Richview (27.6kV)
Feeder(s):	88 M3

(iii) Justification & Benefits

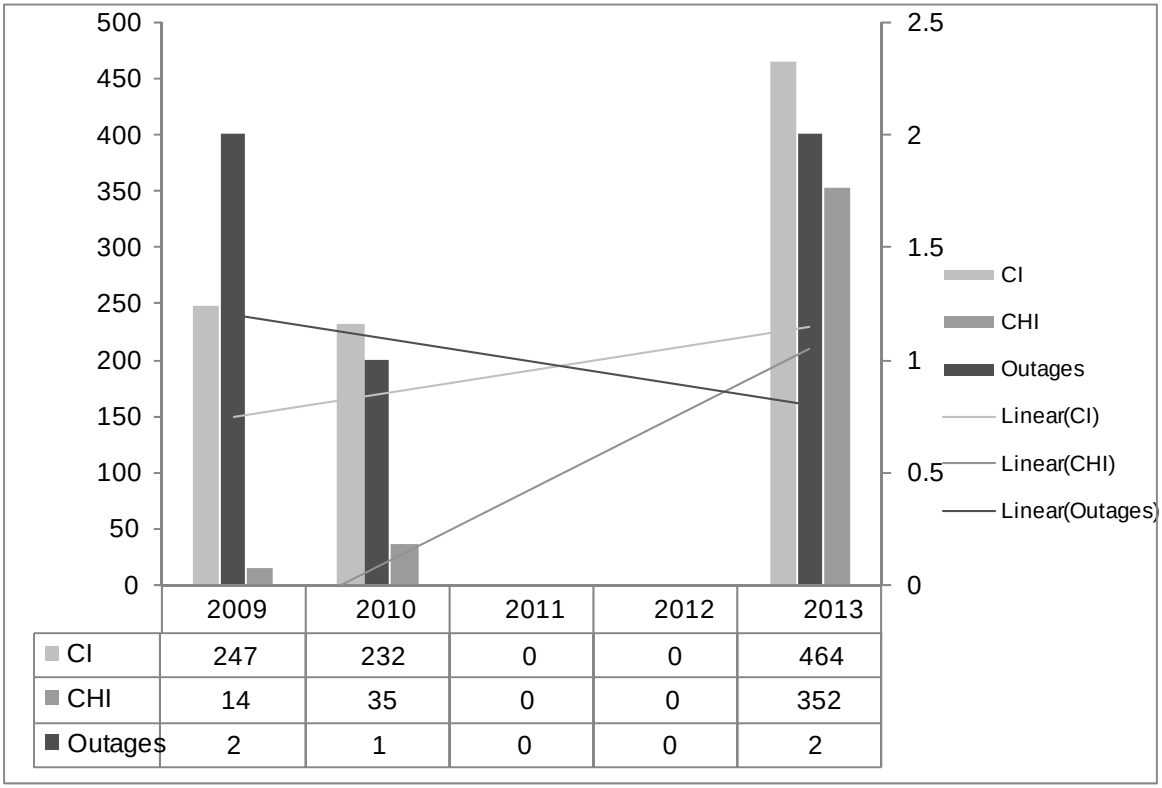
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 242: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ N/A (project created to accommodate new egress cables)
Reliability	ƒ Will provide capacity relief to South Etobicoke and power Eglinton LRT

Supplemental Details	Description
	ƒ Provide contingency to re-supply areas that are high loaded and are at risk of being stranded during an outage
Other (i.e. road moratoriums, etc)	ƒ New duct banks to accommodate new feeders out of Richview TS ƒ Egress to extend cables out of congested area and right of ways ƒ Moratorium on Dixon expires in 2015 ƒ Extension in 2016 to at risk areas

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 134.



	2009	2010	2011	2012	2013
CI	247	232	0	0	464
CHI	14	35	0	0	352
Outages	2	1	0	0	2

FIGURE 134: HISTORICAL RELIABILITY DETAILS FOR NY88M3

W14730 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W14730-P01-Cable Upgrade to Increase Capacity on 88M46

Project Number: W14730

Project Year: 2015

Estimated Cost: $116,478

(i) Objective

Replace XLPE cable with new TR-XLPE to increase the capacity of 88M46. W14730 combines the civil and electrical work required to complete this project.

(ii) Scope of Work

TABLE 243: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Richview TS
Feeder(s):	88M46

TABLE 244: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	396.33m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	2

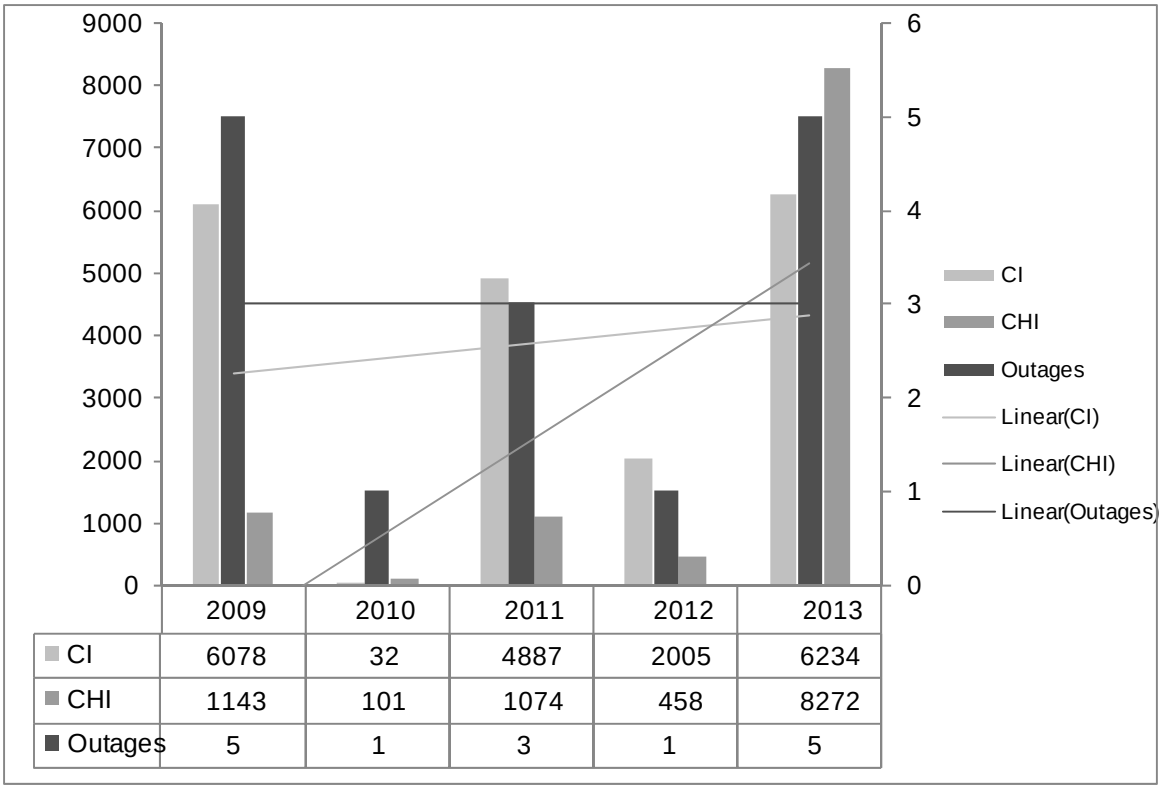
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 245: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cable ƒ Installed 1984 (30 years old) ƒ Cable is undersized and de-rating the capacity of the entire feeder
Reliability	ƒ Cable close to the station and failure leads to high CI and CHI. ƒ Feeder used to supply most of the tie feeder in the area, reduces capacity to backup feeders in a highly loaded area
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 135.



	2009	2010	2011	2012	2013
CI	6078	32	4887	2005	6234
CHI	1143	101	1074	458	8272
Outages	5	1	3	1	5

FIGURE 135: HISTORICAL RELIABILITY DETAILS FOR 88M46

W15268, W15269 Project Description

Investment Category: **System Renewal**

Program: **Underground Circuit Renewal**

Project Title: **P01 - Red Robinway & Arnott UG Direct-Buried Cable Renewal Civil/Electrical**

Project Number: **W15268, W15269**

Project Year: **2015**

Estimated Cost: **$1,086,141**

(i) Objective

Rebuild the direct-buried cable in the Robinway and Arnott area distribution, which has been subjected to multiple historical cable failures.

W15268 will install the civil infrastructure necessary to complete the project; W15269 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 245: SCOPE OF WORK DETAILS

District Neighborhood	York Centre
Station(s):	Fairchild I TS (27.6 kV)
Feeder(s):	NY80M8

TABLE 246A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,188.76 m
Underground Transformers	6
Underground Switch	4
Poles	3
Overhead Transformer	0
Overhead Switch	0

IC

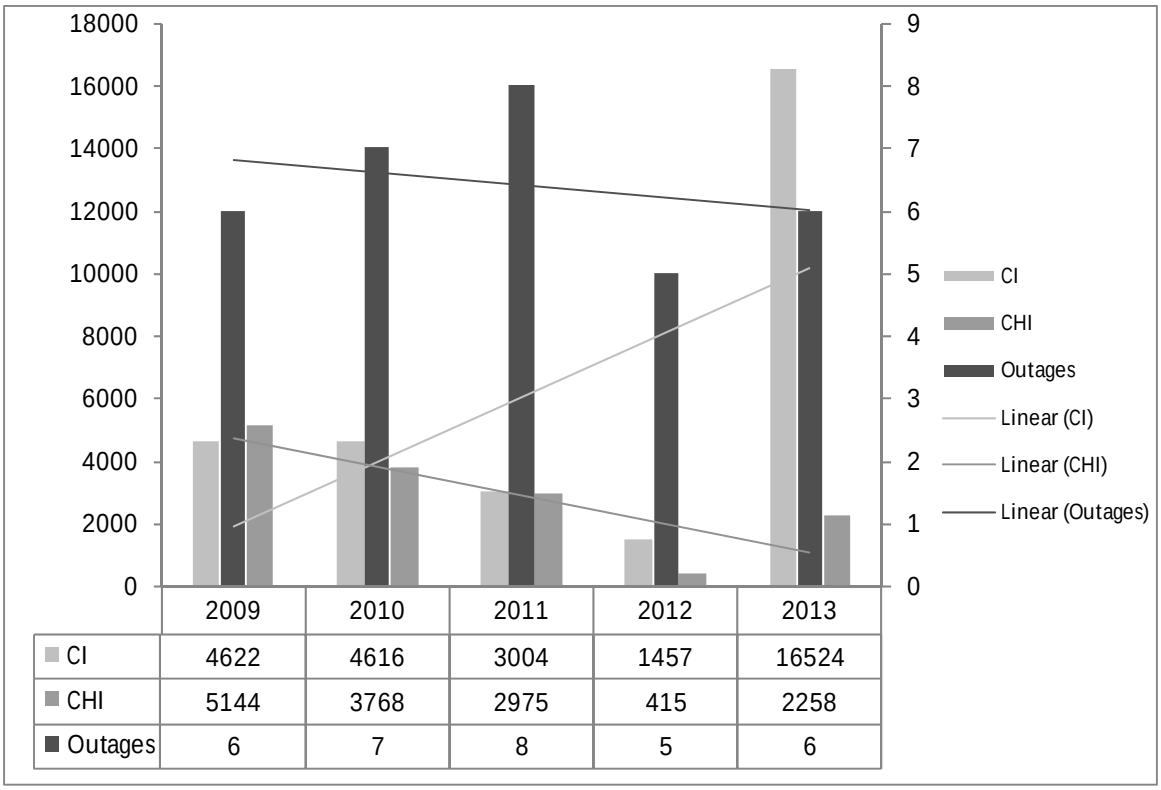
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 246: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ This project replaces directly buried cable supplies Red Robinway and Arnott area that is aged and in poor condition.
Reliability	ƒ Segment of cable in the scope area had experienced multiple failures that has lasted long durations
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 136.



	2009	2010	2011	2012	2013
CI	4622	4616	3004	1457	16524
CHI	5144	3768	2975	415	2258
Outages	6	7	8	5	6

FIGURE 136: HISTORICAL RELIABILITY DETAILS FOR NY80M8

W15278 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W15278 The East Mall area UG Voltage Conversion Civil LDF1, LDF2 and LDF3 LDF1

Project Number: W15278

Project Year: 2015

Estimated Cost: $622,916

(i) Objective

Rebuild laterals off the OH feeder 38M10 to renew the aging and mal-operating infrastructure thereby restoring distribution reliability in the area. W15278 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 248: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke Lakeshore
Station(s):	Cloverdale MS
Feeder(s):	LDF1, LDF2 and LDF3

(iii) Justification & Benefits

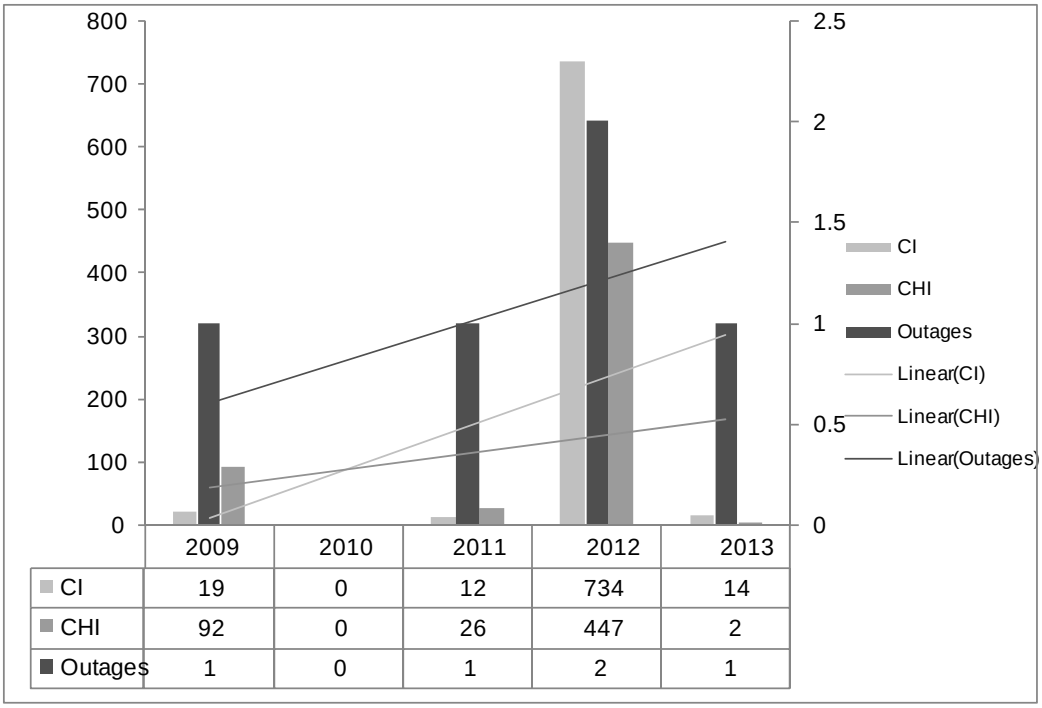
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 249: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ End of life switches, transformers and cable in duct ƒ Assets installed around 1964 (over 50 years old) ƒ Feeder patrols in the summer of 2013 have confirmed that the condition of Cloverdale MS feeders LDF1, LDF2 and LDF3 are

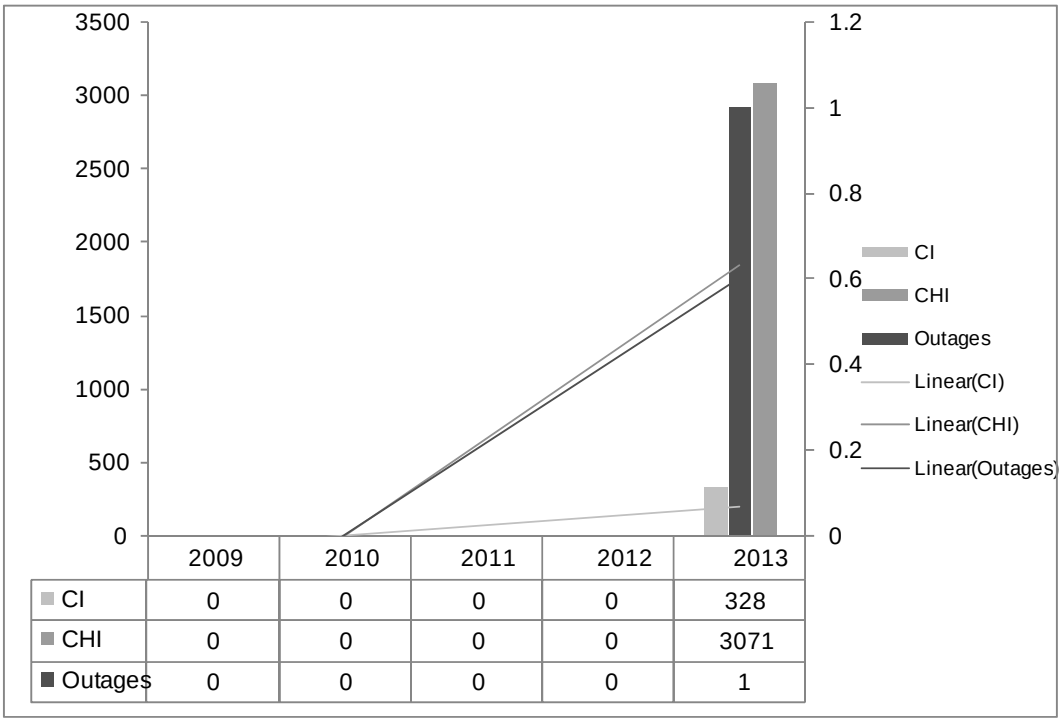
Supplemental Details	Description
	deteriorated and need to be replaced with newer assets (via this voltage conversion project)
Reliability	• Reliability has been weakening over past two years for both LDF-1 and LDF-2 • Increasing CI and CHI for the past two years • The renewal OH and UG infrastructure in the scope addresses and mitigates the increasing number of outage incidents due to feeder equipment defects and failures
Other (i.e. road moratoriums, etc)	• Customers in the area had complained of the high incidence of outages in 2013 • Cloverdale MS has a difficult operating situation as there are currently no RTUs in the station. This scope enables the complete close-out of the substation, avoiding the need for capital investment in new communication equipment

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 137 and 138.



	2009	2010	2011	2012	2013
CI	19	0	12	734	14
CHI	92	0	26	447	2
Outages	1	0	1	2	1

1 FIGURE 137: HISTORICAL RELIABILITY DETAILS FOR LDF1



	2009	2010	2011	2012	2013
CI	0	0	0	0	328
CHI	0	0	0	0	3071
Outages	0	0	0	0	1

FIGURE 138: HISTORICAL RELIABILITY DETAILS FOR LDF2

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W15279 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W15279 - Dundas/Shaver area UG VC Civil QCF1, QCF2 and QCF3

Project Number: W15279

Project Year: 2015

Estimated Cost: $617,408

(i) Objective

Rebuild laterals off the OH feeder 38M10 to renew the aging and mal-operating infrastructure thereby restoring distribution reliability in the area. W15279 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 250: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke Centre
Station(s):	Shaver MS
Feeder(s):	QCF1, QCF2 and QCF3

(iii) Justification & Benefits

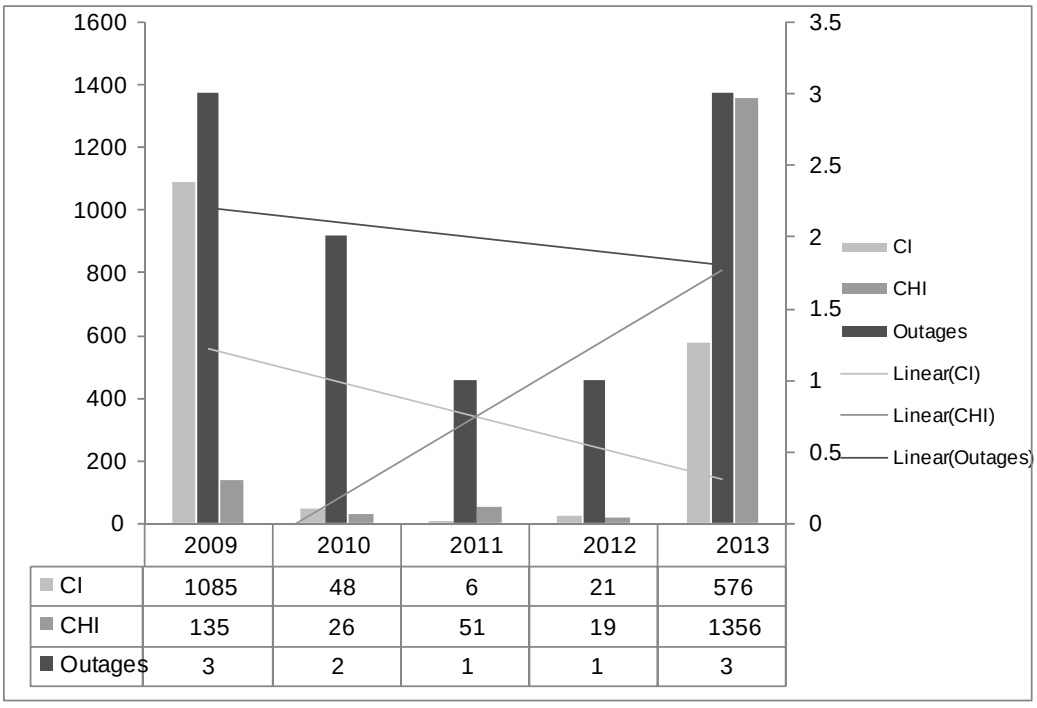
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 251: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ End of life switches, transformers and cable in duct ƒ Assets installed around 1964 (over 50 years old) ƒ Feeder patrols in the summer of 2013 have confirmed that the condition of Shaver MS feeders QCF1, QCF2 and QCF3 are deteriorated and need to be replaced with newer assets (via this voltage conversion project)

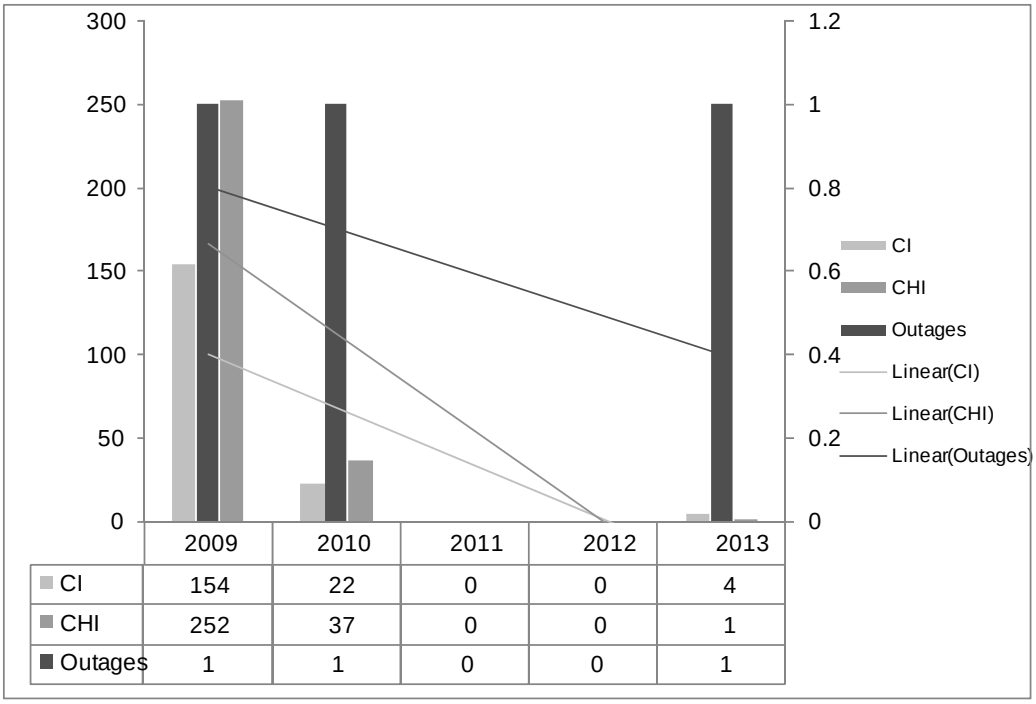
Supplemental Details	Description
Reliability	ƒ There was a sharp increase in the number of outage incidents in the area between 2012 and 2013 ƒ The renewal OH and UG infrastructure in the scope addresses and mitigates the increasing number of outage incidents due to feeder equipment defects and failures
Other (i.e. road moratoriums, etc)	ƒ Customers in the area have complained of the high incidence of outages in 2013

1 Historical reliability including number of customers interrupted (CI), customer hours interrupted
2 (CHI) and outages along the feeders are given in Figures 139 and 140.



	2009	2010	2011	2012	2013
CI	1085	48	6	21	576
CHI	135	26	51	19	1356
Outages	3	2	1	1	3

3 FIGURE 139: HISTORICAL RELIABILITY DETAILS FOR QCF1



	2009	2010	2011	2012	2013
CI	154	22	0	0	4
CHI	252	37	0	0	1
Outages	1	1	0	0	1

FIGURE 140: HISTORICAL RELIABILITY DETAILS FOR QCF3

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W15298 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W15298 West of Kipling Avenue, UG Voltage Conversion AHF2, AHF5

Project Number: W15298

Project Year: 2015

Estimated Cost: $573,753

(i) Objective

Rebuild parts of the Fieldway MS feeders west of Kipling Avenue via voltage conversion before the end of 2015 to avoid islanding of the distribution in the area after feeders from Shaver MS and West Islington MS have been converted by scopes W14658, W14659 and W15276 in 2014. W15298 will combine the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 252: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke Lakeshore
Station(s):	Fieldway MS
Feeder(s):	AHF2 and AHF5

TABLE 253: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,083m
Underground Transformers	3
Underground Switchgear	1
Poles	0
Overhead Transformer	0
Overhead Switch	6

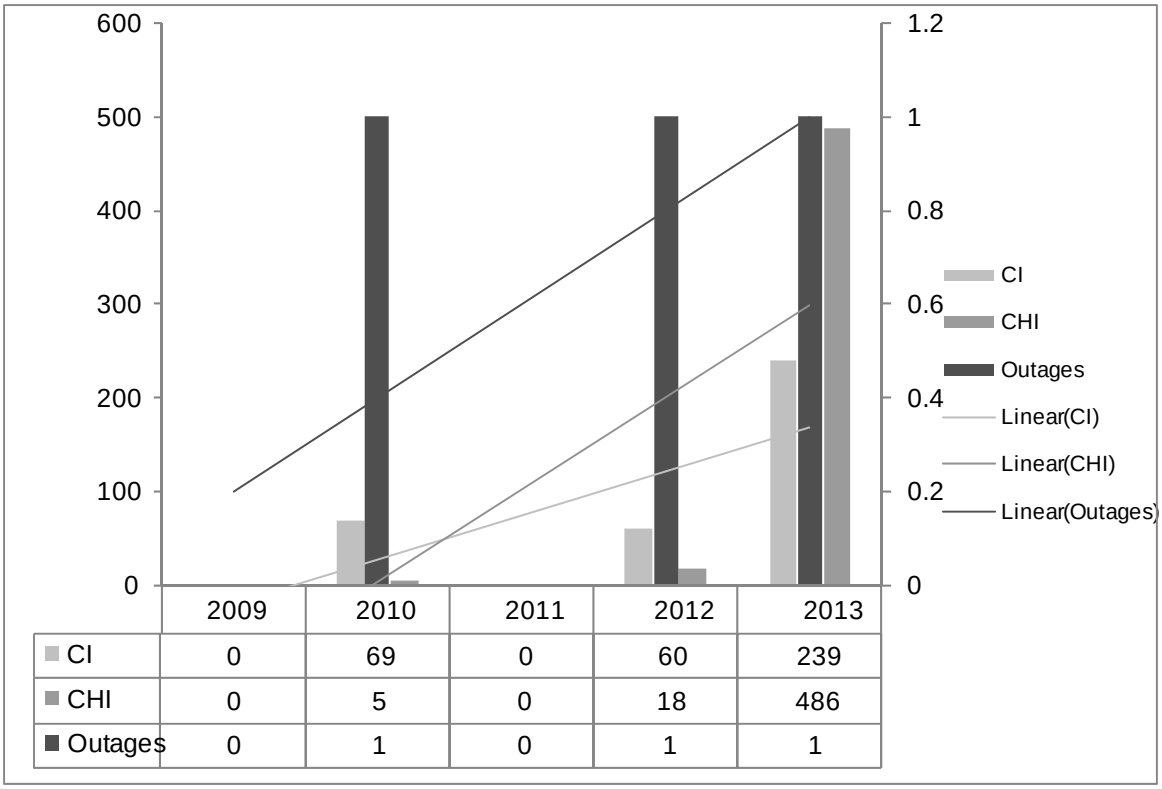
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 254: SUPPLEMENTAL DETAILS

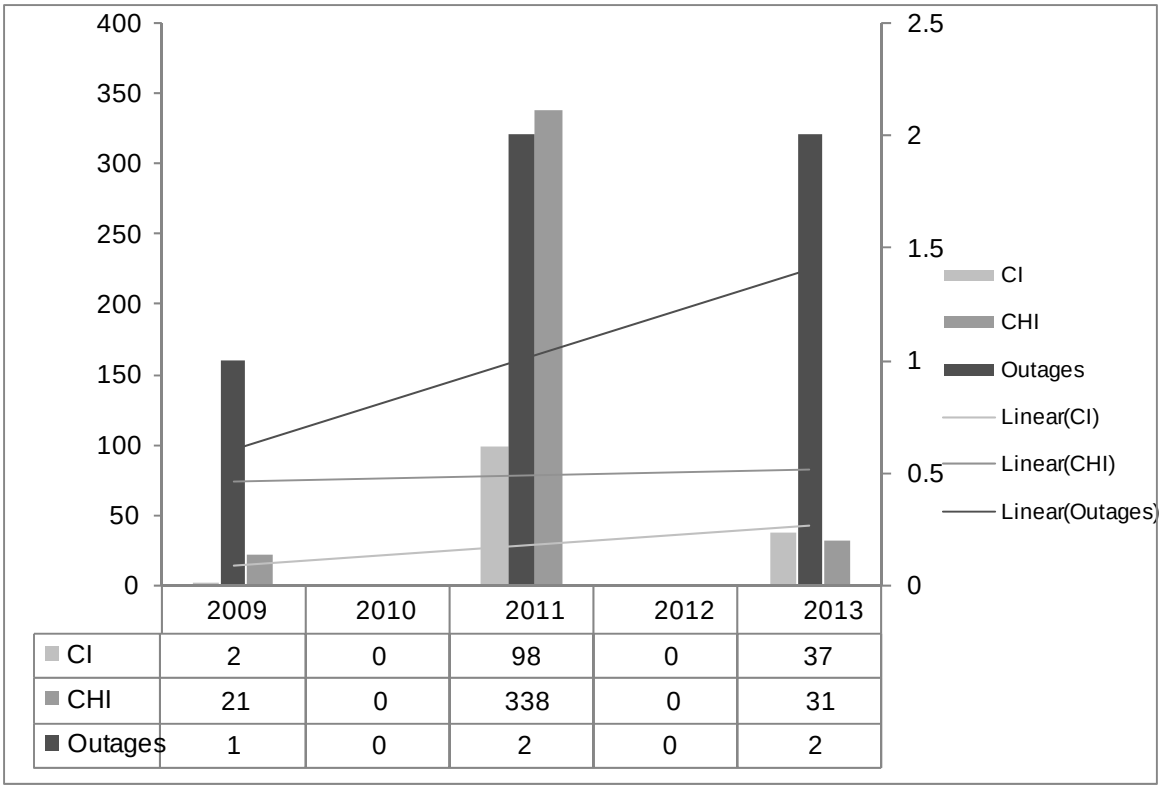
Supplemental Details	Description
Age/Condition	ƒ End of life switches, transformers and cable in duct ƒ Assets installed around 1964 (over 50 years old) ƒ Feeder patrols in the summer of 2013 have confirmed that the condition of feeders AHF2 and AHF5 are deteriorated and need to be replaced with newer assets (via this voltage conversion project)
Reliability	ƒ Increasing CI, CHI and Outages seen in 2013 ƒ The renewal OH and UG infrastructure in the scope addresses and mitigates the increasing number of outage incidents due to feeder equipment defects and failures.
Other (i.e. road moratoriums, etc)	ƒ Feeders in the area, from West Islington MS, Cloverdale MS and Shaver MS will all be completely converted to 27kV by the end of 2015 leaving parts of the feeders AHF2 and AHF5 west of Kipling Avenue with no back-up. For this reason it is critical to complete this voltage conversion job in 2015

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 141 and 142.



	2009	2010	2011	2012	2013
CI	0	69	0	60	239
CHI	0	5	0	18	486
Outages	0	1	0	1	1

FIGURE 141: HISTORICAL RELIABILITY DETAILS FOR AHF2



	2009	2010	2011	2012	2013
CI	2	0	98	0	37
CHI	21	0	338	0	31
Outages	1	0	2	0	2

FIGURE 142: HISTORICAL RELIABILITY DETAILS FOR AHF5

W15357 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W15357 270 The Kingsway, Upgrade PT44103 Humbertown Plaza, 38-M7

Project Number: W15357

Project Year: 2015

Estimated Cost: $208,386

(i) Objective

Replace the defective switchgear / transformer unit Loc. #PT44103 - Humbertown Plaza at #270 The Kingsway. W15357 will combine the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 255: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke York
Station(s):	Manby TS
Feeder(s):	38 M7

(iii) Justification & Benefits

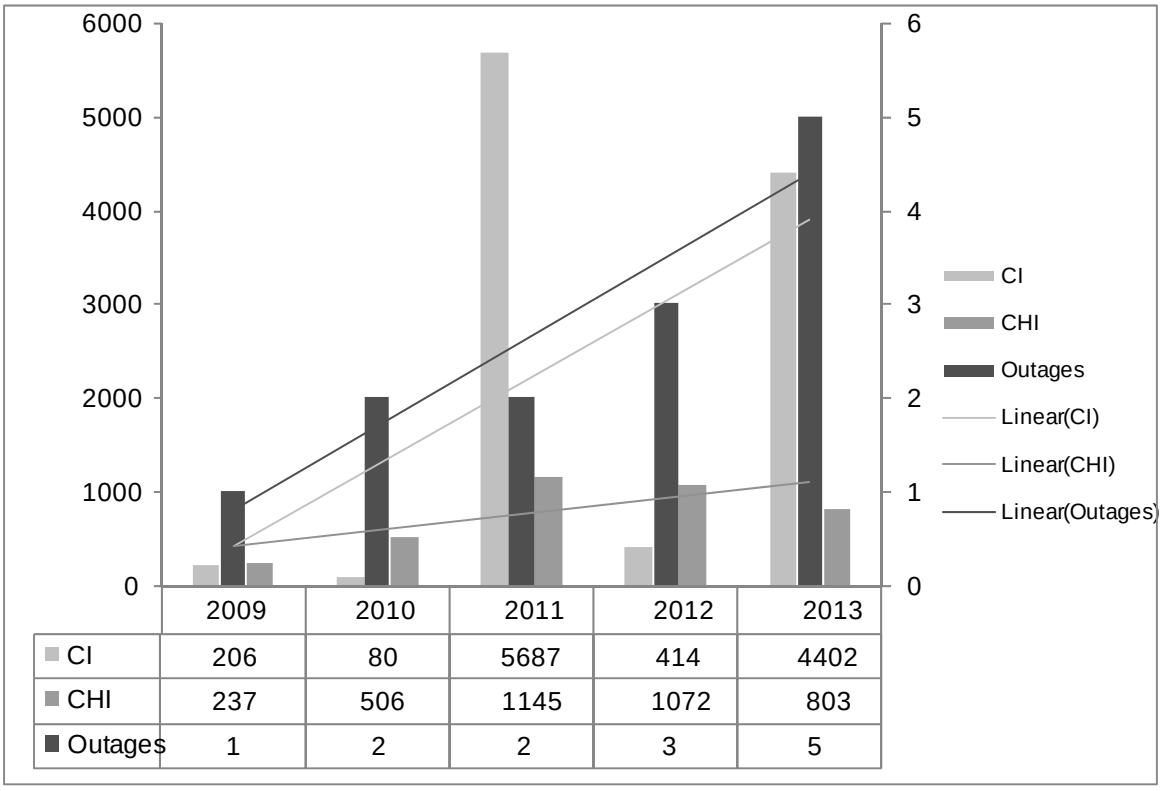
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 256: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ End of life cable in duct ƒ Assets installed around 1964 (over 50 years old)
Reliability	ƒ In 2013 38M7 has had high CI and CHI as well 13 forced outages
Other (i.e. road	ƒ Customer has had a history of 3 to 15% overloading in the summer

Supplemental Details	Description
moratoriums, etc)	months over the last 5 years • Switches have a combination of porcelain and epoxy insulators • Excessive moisture in the incoming high voltage compartments of the switch led to flashover in 2008

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 143.



	2009	2010	2011	2012	2013
CI	206	80	5687	414	4402
CHI	237	506	1145	1072	803
Outages	1	2	2	3	5

FIGURE 143: HISTORICAL RELIABILITY DETAILS FOR NY38M7

W15363 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W15363 150 Berry Rd VC of Tx/Sw at loc PT7257 to feeder 38M29 T-F1

Project Number: W15363

Project Year: 2015

Estimated Cost: $386,009

(i) Objective

Replace the defective pad transformer at the location PT7257. W15363 will combine the civil and electrical work required to complete this project.

(ii) Scope of Work

TABLE 257: SCOPE OF WORK DETAILS

District Neighborhood	Etobicoke Lakeshore
Station(s):	Berry MS
Feeder(s):	T-F1

TABLE 258: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	62.13m
Underground Transformers	1
Underground Switchgear	0
Poles	4
Overhead Transformer	1
Overhead Switch	1

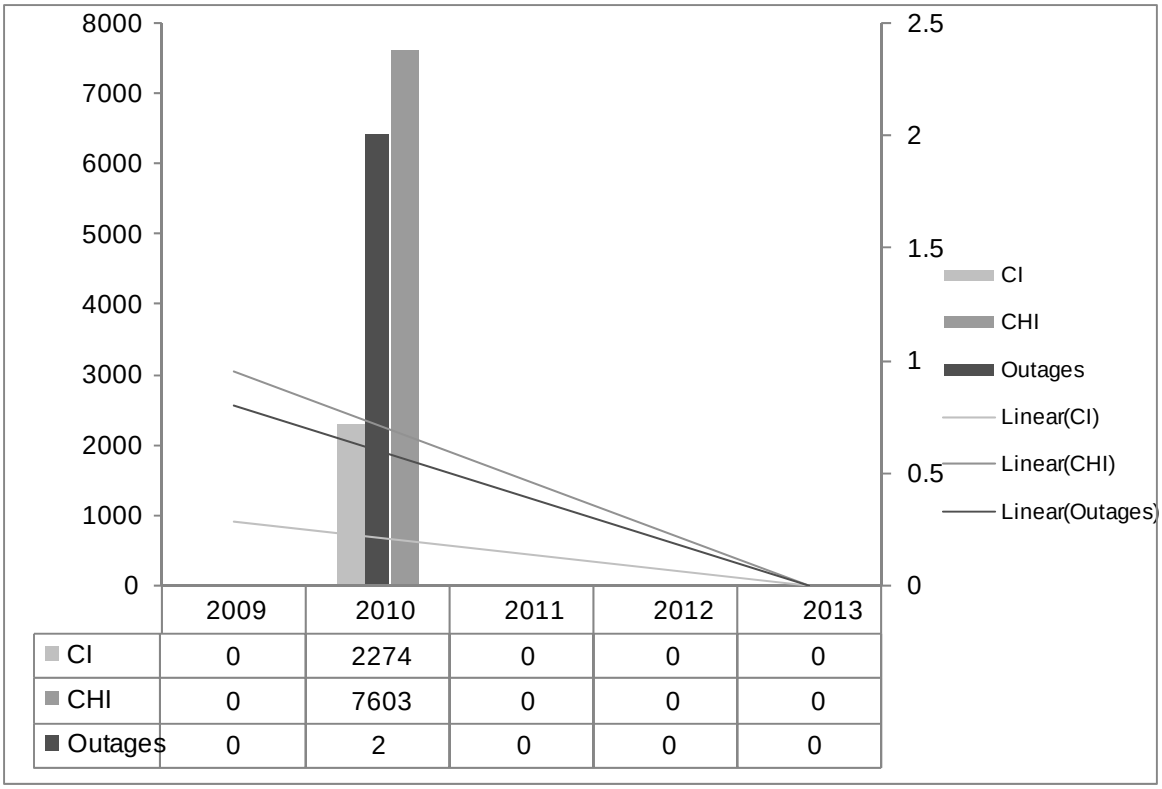
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 259: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Overloaded transformer ƒ Installed 1977 (approx. 37 years old)
Reliability	ƒ Field inspection noted high levels of ethane and ethylene emission from transformer due to overloading ƒ Transformer isolated to mitigate safety and reliability risks
Other (i.e. road moratoriums, etc)	ƒ Project will replace defective transformer and switch to maintain reliability in the area

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 144.



	2009	2010	2011	2012	2013
CI	0	2274	0	0	0
CHI	0	7603	0	0	0
Outages	0	2	0	0	0

FIGURE 144: HISTORICAL RELIABILITY DETAILS FOR TF1

W15462 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W15462 Alcester Crt Underground Rebuild 35M7

Project Number: W15462

Project Year: 2015

Estimated Cost: $304,772

(i) Objective

Rebuild the underground direct buried supply at Alcester Crt. W15462 will combine the civil and electrical work required to complete this project.

(ii) Scope of Work

TABLE 260: SCOPE OF WORK DETAILS

District Neighborhood	Eglinton Lawrence
Station(s):	Fairbanks TS
Feeder(s):	35M7

TABLE 261: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	506.34m
Underground Transformers	2
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

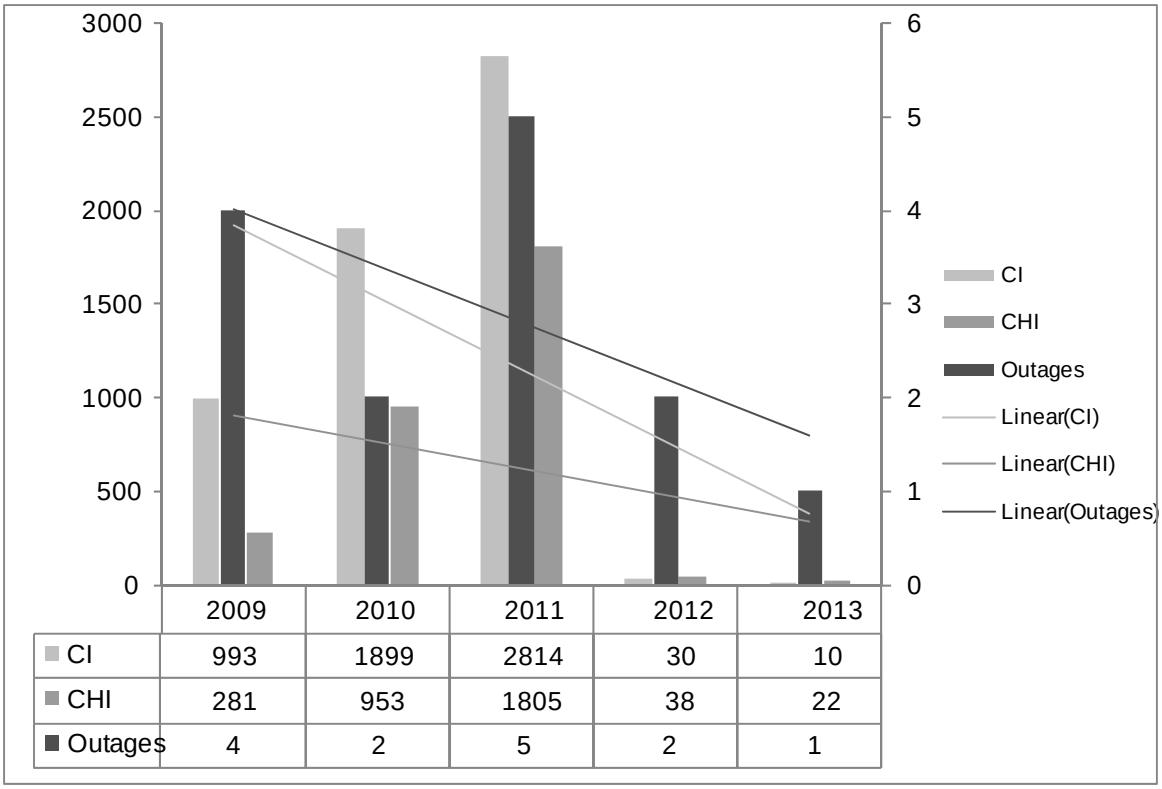
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 262: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried (solid #1) cable ƒ Installed 1970 – 1980 (between 34 – 44 years old)
Reliability	ƒ 35M7 has experienced two underground outages in the area of Alcester Crt. due to defective underground cable
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 145.



	2009	2010	2011	2012	2013
CI	993	1899	2814	30	10
CHI	281	953	1805	38	22
Outages	4	2	5	2	1

FIGURE 145: HISTORICAL RELIABILITY DETAILS FOR NY35M7

W16076 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: W16076 - P01 Mayall Avenue Underground Rebuild 55M26

Project Number: W16076

Project Year: 2015

Estimated Cost: $564,185

(i) Objective

Replace the direct buried, underground loop at Mayall Drive with new TR-XLPE cable in concrete encased ducts. W16076 will combine the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 263: SCOPE OF WORK DETAILS

District Neighborhood	York West
Station(s):	Finch TS
Feeder(s):	55M26

TABLE 264: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	484.3m
Underground Transformers	2
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

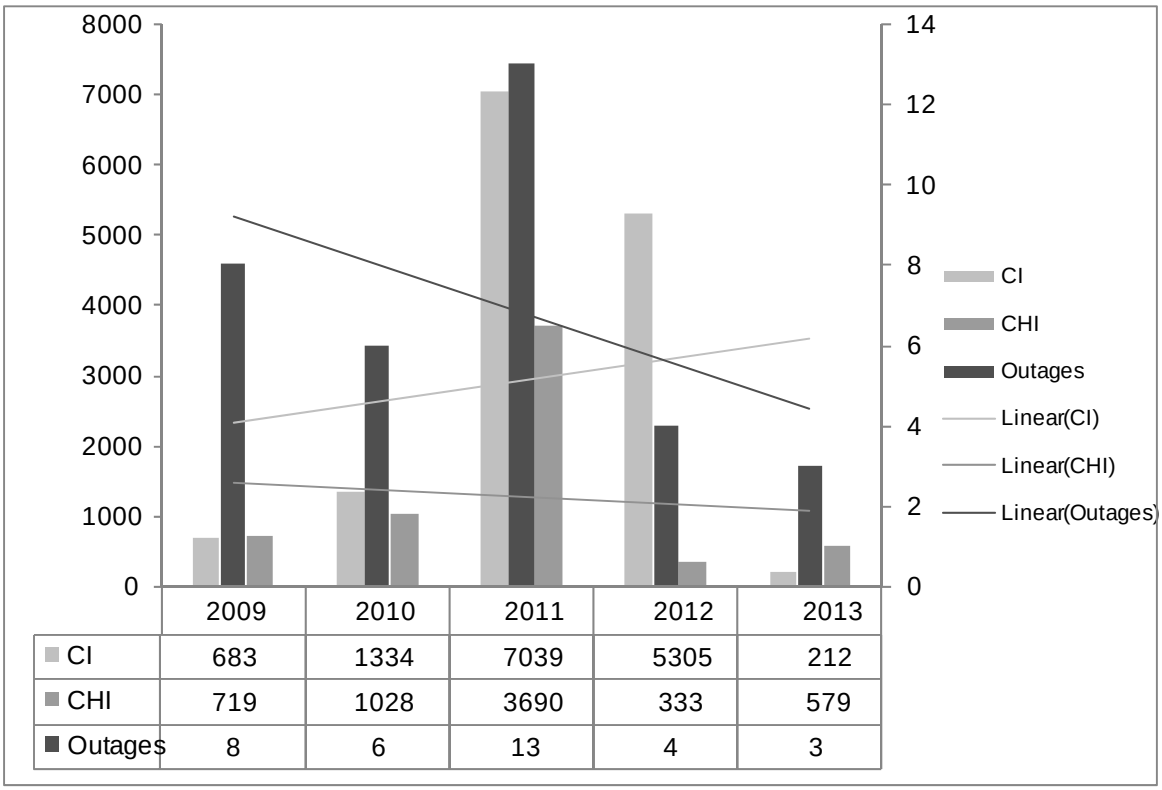
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 265: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried (solid #1) cable ƒ Installed 1970 (44 years old)
Reliability	ƒ The project area has experienced one outage due to direct buried cable fault ƒ Feeder has experienced several interruptions due to poor underground assets
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 146.



	2009	2010	2011	2012	2013
CI	683	1334	7039	5305	212
CHI	719	1028	3690	333	579
Outages	8	6	13	4	3

FIGURE 146: HISTORICAL RELIABILITY DETAILS FOR NY55M26

X12138 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: X12138 Larksong Crt Feeder DB Cable Replace (53M8)

Project Number: X12138

Project Year: 2015

Estimated Cost: $240,187

(i) Objective

Remove all direct buried cable from feeder NY53M8 to improve the reliability of the feeder. X12138 combines the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 266: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley East
Station(s):	Bermondsey TS (27.6kV)
Feeder(s):	NY53M8

TABLE 267: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	354.53m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

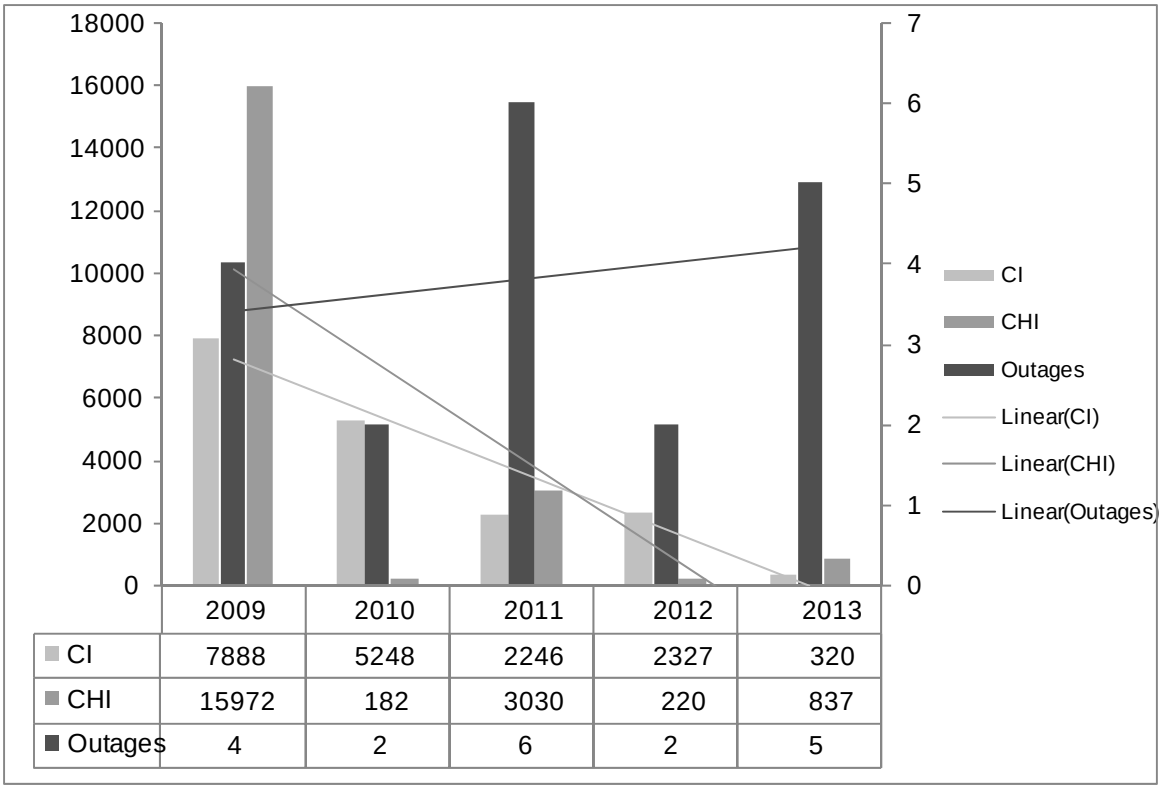
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 268: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	ƒ Direct buried cables ƒ Installed 1982 (32 years old)
Reliability	ƒ Feeder has experienced poor reliability with 7 outages in last 2 years
Other (i.e. road moratoriums, etc)	ƒ N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 147.



	2009	2010	2011	2012	2013
CI	7888	5248	2246	2327	320
CHI	15972	182	3030	220	837
Outages	4	2	6	2	5

FIGURE 147: HISTORICAL RELIABILITY DETAILS FOR NY53M8

X12497 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: X12497 - Lotherton Parkway UG reconfiguration NY35M12

Project Number: X12497

Project Year: 2015

Estimated Cost: $880,289

(i) Objective

Replace direct buried XLPE cable supplying Lotherton Pathway and change the configuration of the loop to improve reliability and service to the customer. X12497 will combine the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 269: SCOPE OF WORK DETAILS

District Neighborhood	Eglinton Lawrence
Station(s):	Fairbanks TS (27.6kV)
Feeder(s):	NY35M12

TABLE 270: ASSETS REPLACED

Assets to be Replaced	
Primary Cable	0 m
Underground Transformers	5
Underground Switchgear	8
Poles	0
Overhead Transformer	0
Overhead Switch	0

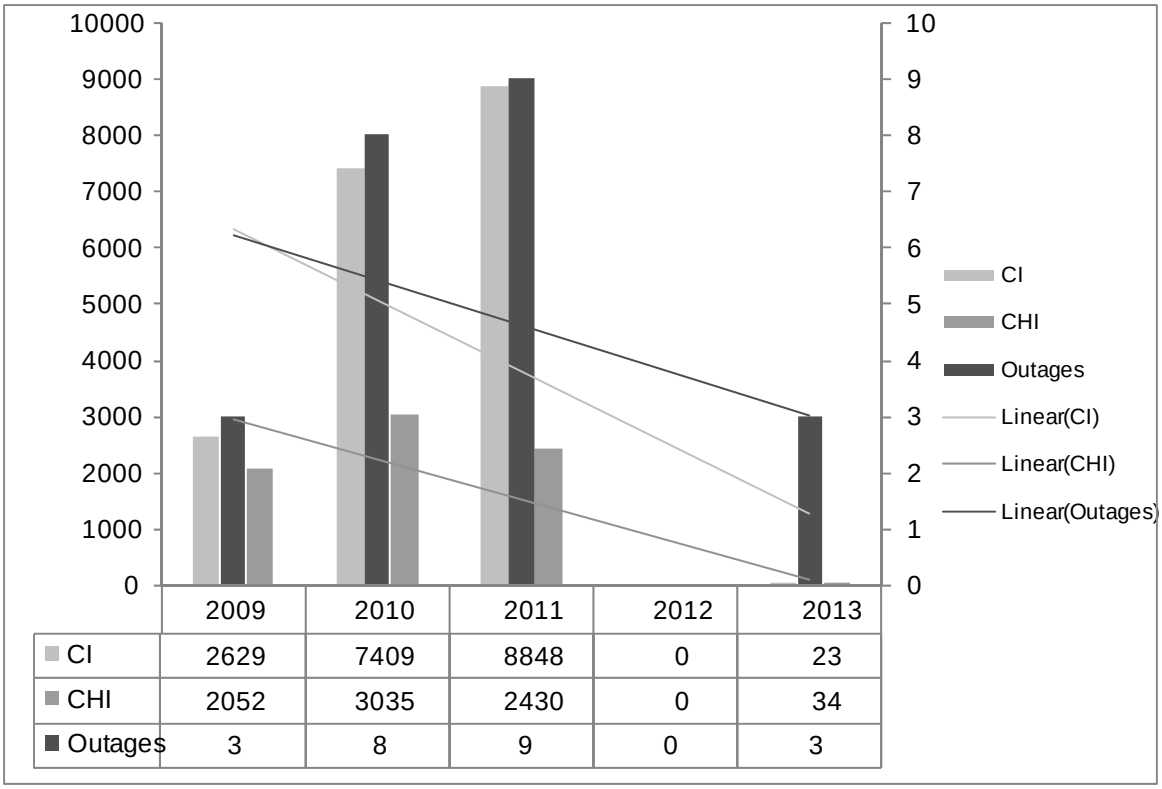
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 271: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	• Transformers, direct buried (solid #1) cable and end of life cable in duct • Assets installed 1970 (44 years old)
Reliability	• Overall reliability of the feeder is improving • Feeder has experienced two underground outage in 2014 • Assets within the underground distribution of feeder 35M12 are at end of life posing a failure risk to the feeder
Other (i.e. road moratoriums, etc)	• N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 148.



	2009	2010	2011	2012	2013
CI	2629	7409	8848	0	23
CHI	2052	3035	2430	0	34
Outages	3	8	9	0	3

FIGURE 148: HISTORICAL RELIABILITY DETAILS FOR NY35M12

X15590 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Electrical Work for the Replacement of A60CS and A61CS

Project Number: X15590

Project Year: 2015

Estimated Cost: $72,565

(i) Objective

Replace existing A60CS and A61CS which are currently suspended underneath the first segment of the Prince Edward Viaduct, over Rosedale Valley Rd, via messenger cable. X15590 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 272: SCOPE OF WORK DETAILS

District Neighborhood	Toronto Centre-Rosedale
Station(s):	Charles (13.8kV)
Feeder(s):	TOA60CS, TOA61CS

TABLE 273: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	342.28m
Underground Transformers	0
Underground Switchgear	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

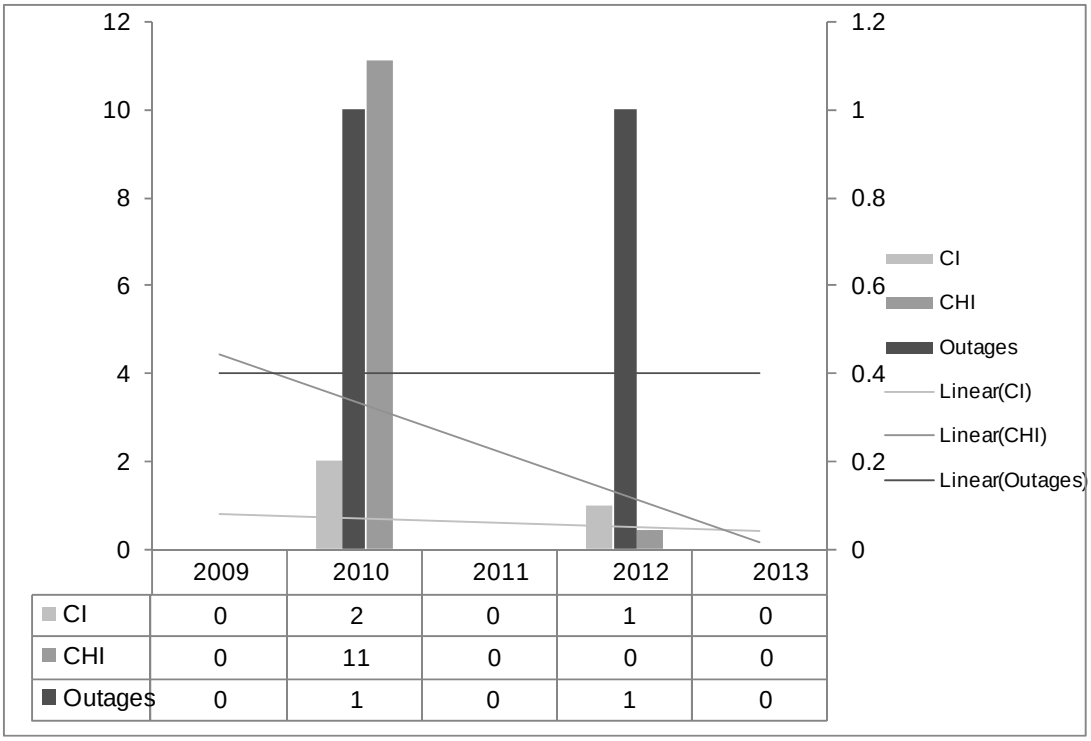
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 274: SUPPLEMENTAL DETAILS

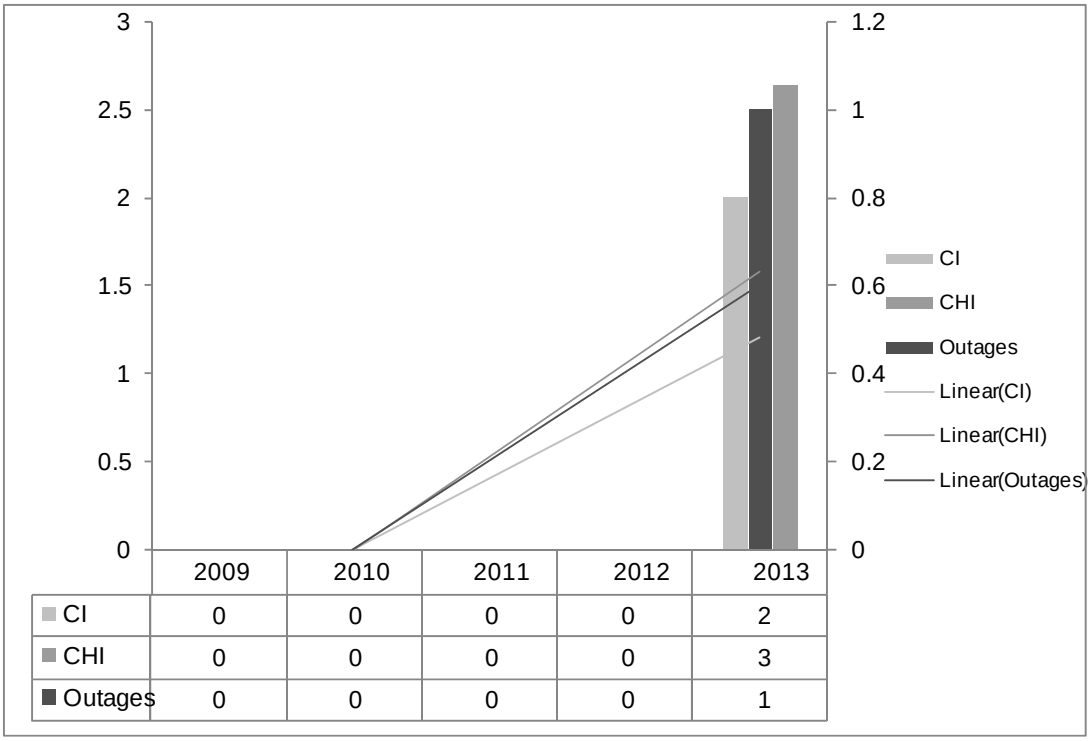
Supplemental Details	Description
Age/Condition	• Cable located under bridge (not in duct) – suspended via messenger cable • Installed 1962 (52 years old)
Reliability	• Historical failures in the project area have occurred on segments adjacent to the bridge crossing • Reactive crews indicate that if the cable fails again it will need to be completely replaced • Cables are network/dual radial configured therefore a large outage impact is not shown in figures XYZ and XYZ • All three incidents recorded here were cable faults which tripped the station breaker, taking out the entire feeder placing the network under a first contingency
Other (i.e. road moratoriums, etc)	• There is no resupply option on the other side of the bridge suitable to supply the TTC station • Replacement of the infrastructure under the bridge is the most prudent option to maintain reliability to customers fed from these feeders • Other options would require significant new civil infrastructure to be built

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 149 and 150.



	2009	2010	2011	2012	2013
CI	0	2	0	1	0
CHI	0	11	0	0	0
Outages	0	1	0	1	0

FIGURE 149: HISTORICAL RELIABILITY DETAILS FOR TOA60CS



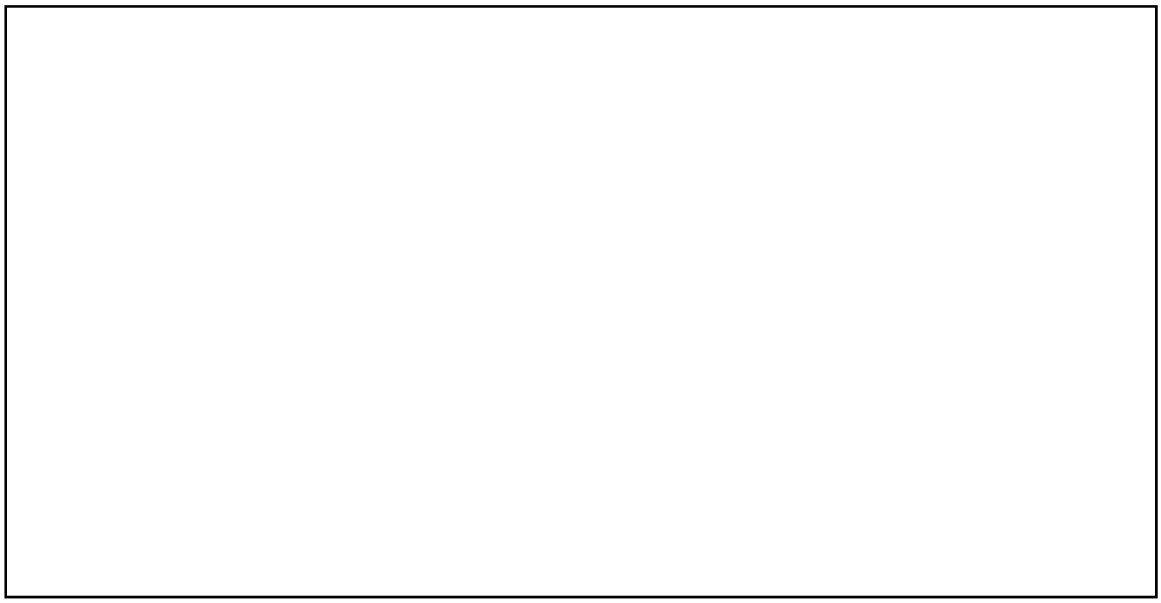
	2009	2010	2011	2012	2013
CI	0	0	0	0	2
CHI	0	0	0	0	3
Outages	0	0	0	0	1

FIGURE 150: HISTORICAL RELIABILITY DETAILS FOR TOA61CS

Works Cited

1. Majdi, Emily. Cable Diagnostic Testing (An internal study of available field testing techniques). Toronto, Ontario, Canada: Toronto Hydro, August 8, 2013.

E6.2 Paper-Insulated Lead-Covered Leakers & Cable Piece-Outs



SUSPENDED PILC CABLES

E6.2.1 Summary

Program Description

The Paper-Insulated Lead-Covered (PILC) Leakers & Cable Piece-Outs program is a continuation of the activities previously described in the Ontario Energy Board (OEB) approved PILC Cable – Piece Outs and Leakers segment of Toronto Hydro's 2012-2014 rate application[1].

The objective of this ongoing program is to replace and repair leaking PILC cables and to piece-out and properly rack any cable in congested chambers. As outlined in Toronto Hydro's previous rate filing, the PILC Piece-Out and Leakers program involves three activities that address three distinct issues with existing PILC cable:

- Repair/Replacement of leaking PILC cables
- Replacement of PILC cables on the High Level TS – Bridgman TS (B-HL) express feeder
- "Piecing out" of PILC cable in congested cable chambers[2]

[1] EB-2012-0064, Tab 4, Schedule B2.

The anticipated benefits of the Paper-Insulated Lead-Covered (PILC) Leakers and Cable Piece-Out program are as follows:

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Reduced risk of prolonged outages for Toronto Hydro customers
Reliability	ƒ Reduced repair time on underground feeders in cable chambers with leaking PILC cables
Safety	ƒ Improved working conditions in cable chambers for Toronto Hydro employees ƒ Improved public safety: reduced risk of faults in cable chambers mitigates the risk of cable chamber lids dislodging.
Efficiency	ƒ Improved operational flexibility during contingency events ƒ Enhanced efficiency of underground crews during service restoration efforts ƒ Reduced resource time on leaking PILC cable enables crews to perform additional planned capital or maintenance work
Environment	ƒ Mitigates possible negative impacts on the environment

Program Drivers

As established in Toronto Hydro's 2012-2014 rate application, the PILC Leakers and Cable Piece-Outs program is required to manage the substantial asset failure risks associated with leaking cables and to mitigate safety hazards that have caused injuries and near misses to underground workers in the past.

The trigger and secondary drivers for the PILC Leakers and Cable Piece-Outs program are as follows.

TABLE B: PROGRAM DRIVERS

	Drivers	Reasoning
Trigger Driver	Failure Risk	ƒ Water ingress in corroded cables leads to higher failure risk ƒ Cable cannot predictably perform at an acceptable standard as it deteriorates ƒ Cracked and leaking cables have reduced insulation,

[2] As discussed more fully in Section E6.2.2.3, "piecing out" refers to the process of extending a cable in a chamber, usually by adding an additional piece of cable, such that it has the correct length to allow placement on cable racks, thereby permitting ample clearance for personnel entering a cable chamber, and also providing proper support to prevent damage to the cable.

	Drivers	Reasoning
		reducing dielectric strength and increasing the risk of failure and potential flashover ƒ Increased mechanical stresses due to cable being suspended in congested chambers
Secondary Drivers	Safety	ƒ Compromised insulation can lead to electrical contact hazards ƒ Reduced dielectric strength can lead to faults or arc flashes ƒ Congested chambers often contain trip hazards ƒ Congested chambers lack proper clearance to handle cable
	Reliability	ƒ Requirement to de-energize and repair all feeders with leakers prior to crews' entry into the cable chambers prolongs outage duration ƒ Operating in congested cable chambers slows power restoration efforts.

Preferred Alternative

The PILC Leakers and Cable Piece-Out program analyzed and evaluated the following options

(1) Do nothing and replace on a reactive basis only

(2) To mitigate safety risks, de-energize all of the PILC primary cables in a given cable chamber prior to entry of a worker

(3) Repair leading cables and perform piece outs on an emergency basis

(4) Proactive repair of leakers and piece out of cable chambers

Option IV is the preferred alternative, as it allows work to proceed in a planned and cost-efficient way, focusing on the highest priority areas. Feeders with multiple leakers and chambers requiring piecing out can be scheduled for isolation and all of the associated hazards and defects can be addressed at the same time while the feeder is out of service.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $3.89 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets. Accounting for capital program costs, the first year's activities deliver a positive NPV of $0.44 million, confirming the economic prudence of the investments.

Timing and Pacing

Toronto Hydro is committed to substantially reducing the backlog of known leakers and congested chambers within a reasonably short timeframe in order to mitigate associated failure and safety risks. With the exception of the 2012 and 2013 budget years (which are lower due to the timing of the decision for Phase 1 of Toronto Hydro's 2012-2014 rate filing), historical expenditures reflect the urgency of the work required and the emphasis Toronto Hydro has placed on removing leaking cable.

Table C provides a summary of the five year historical spend on the Underground Circuit Renewal program or its equivalent as well as projected spending from 2015 to 2019.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	-	5.47	1.47	2.44	4.73	3.45	1.38	0.73	0.81	0.51

Once the B-HL tie-feeder replacement project and the majority of the known piece out and leaker issues are rectified, Toronto Hydro anticipates a reduction in capital spending required in the latter years of the 2015-2019 planning horizon, as PILC cable is gradually replaced throughout the system through other capital projects and customer connections.

The estimated total capital budget for this program is $6.9 million for the 2015-2019 forecast period.

E6.2.2 Program Description

The objective of Toronto Hydro's ongoing Paper-Insulated Lead-Covered (PILC) Leakers and Cable Piece-Outs program is to replace and repair leaking PILC cables and to piece-out and properly rack any cable in congested chambers.

PILC cable is a type of underground cable that has supplied Toronto's downtown core since the early 1900s. The cable consists of a conductor that is insulated by oil-impregnated paper and protected by an outer lead sheath that prevents exposure of the cable to environmental and mechanical elements. There is approximately 12,946 km of underground cable in Toronto Hydro's distribution system and of that, approximately 3,969 km is PILC. The remaining cable supplies several commercial and industrial customers on the 13.8 kV and 4.16 kV distribution systems and in some instances used on the "express" feeders that link one substation to another.

As outlined in Toronto Hydro's previous rate filing, the PILC Piece-Outs and Leakers program involves three activities that address three distinct issues with existing PILC cable:

- Repair/Replacement of leaking PILC cables
- Replacement of PILC cables on the High Level TS – Bridgman TS (B-HL) express feeder
- "Piecing out" of PILC cable in congested cable chambers[3]

Each of these activities is described in detail in the following subsections. Toronto Hydro estimates that the total cost of this program will be approximately $6.89 million over the 2015-2019 planning horizon.

In total, the PILC Leakers and Piece-Outs program will be replacing approximately 15 km of PILC cable over the five-year period as illustrated in Table 1. Approximately 4 km of this is associated directly with the B-HL tie feeder replacement project in 2014 and the remaining amount is for the leaking cable replacement and cable piece out projects as described in E6.2.2.1 and E6.2.2.3 respectively.

TABLE 1 : ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
PILC Cable (km)	5.39	3.66	2.59	2.66	0.70	15.00

[3] As discussed more fully in Section E6.2.2.3; "piecing out" refers to the process of extending a cable in a chamber, usually by adding an additional piece of cable, such that it has the correct length to allow placement on cable racks, thereby permitting ample clearance for personnel entering a cable chamber, and also providing proper support to prevent damage to the cable.

E6.2.2.1 Repair/Replacement of PILC Leaker Cables

Over time, due to load fluctuations and physical stresses on feeder cables, the outer covers of PILC cables can develop cracks, causing oil from the paper insulation to leak from the cable and pool on the cable chamber floor. Figure 1 shows PILC cables that have oil leaking from the cable and from the splice.

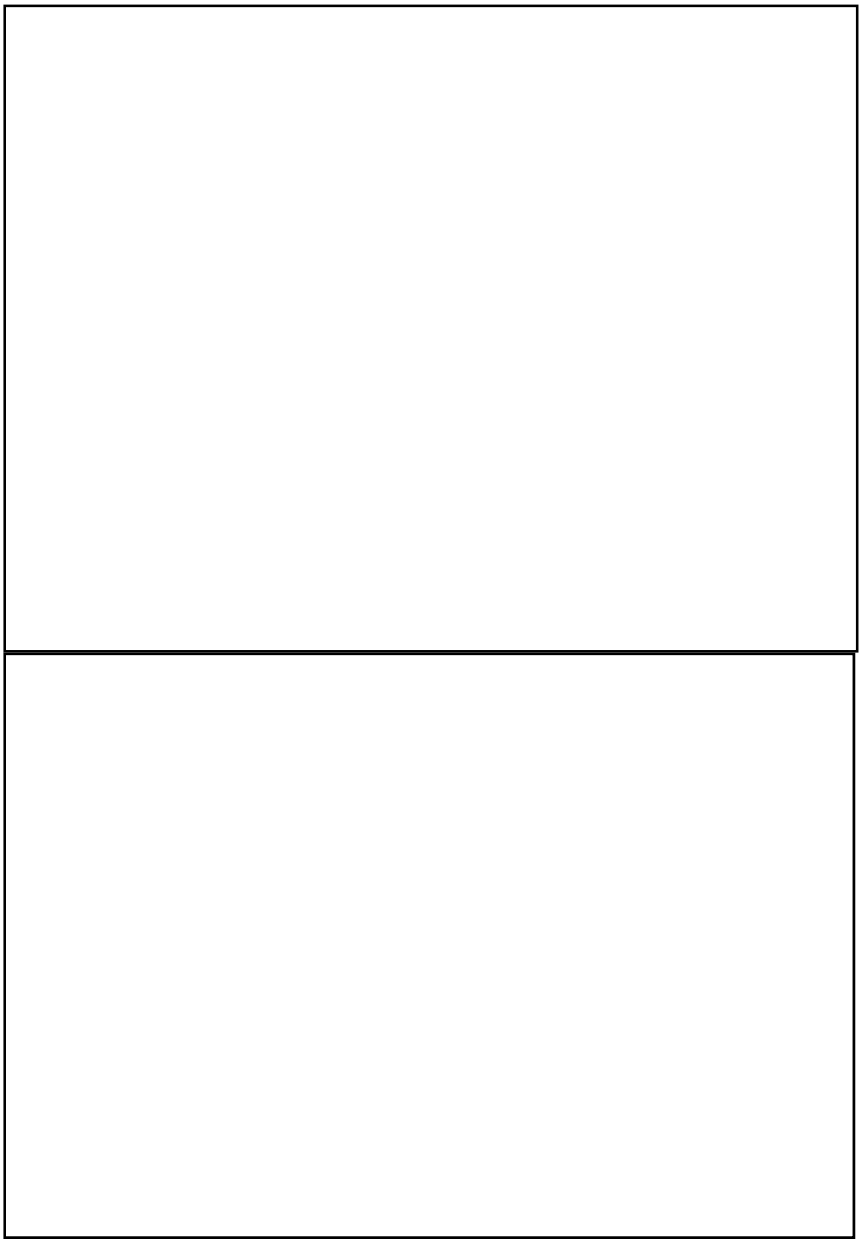


FIGURE 1: LEAKING PILC CABLE WITH OIL POOLED ON FLOOR OF CHAMBER

Leaking PILC cables can present risks to crew safety, system reliability and environmental integrity (these risks and impacts are detailed and further discussed in section E6.2.3). Toronto Hydro maintains a list of all known locations with leaking PILC cables and continues to address these cables through discrete, geographically-based repair and replacement projects that are established using several prioritization criteria (refer to section E6.2.4.1 for details). Prior to designing and executing a repair/replacement project, crews typically inspect the identified leaker sites in the defined area and identify any new leaks that have occurred since the last inspection. For each leaking splice or segment of cable, the designer and crews determine whether (a) the use of a heat shrink splice repair (Raychem) kit, (b) installation of a new sleeve, or (c) installing a new segment of cable is the best course of action.

E6.2.2.2 B-HL Express Feeder Leaker Replacement

The express feeders supplying Toronto Hydro's High Level Transformer Station (TS) from the Hydro One Networks Inc. (HONI) power transformers at Bridgman Transformer Station (TS) are a unique case of PILC leakers. Collectively known as the B-HL feeders, these station ties contain leakers in several cable chambers along the route, to the extent that existing cable segments are beyond repair (Figure 2). The leaking B-HL cables have been the primary cause of over 20 feeder faults since 2011, with all of these faults subsequently tripping HONI's station protection schemes. These faults have a large impact on the reliability of Toronto Hydro's supply to High Level TS, which serves approximately 13,600 customers in the St. Paul's area of Toronto. To prevent further issues along this critical supply path, Toronto Hydro will continue replacing the damaged cables along the feeder route.

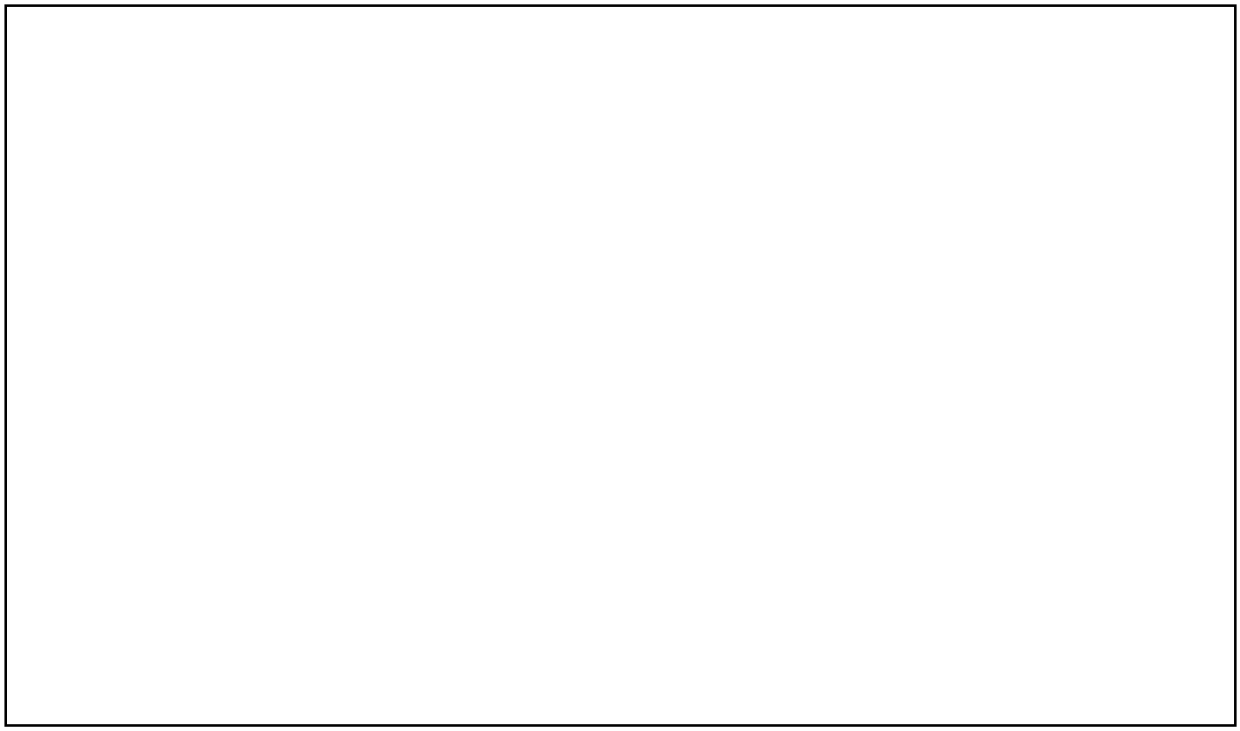


FIGURE 2: AREA OF WORK FOR B-HL TIE FEEDERS PROPOSED FOR REPLACEMENT

This is a larger scale project that Toronto Hydro is addressing in several phases over a planned multi year period that began in 2013 and has continued through 2014. The first three phases of the project, which included the installation of new civil infrastructure to enable the replacement of the B-HL tie feeders, were included in the OEB approved PILC Leakers and Piece-Outs segment in the May 2012 ICM Phase 1 application and the 2014 Phase 2 update. Table 2 below shows the actual capital spending for each phase of the previous filing (as of April 2014).

TABLE 2: HISTORICAL SPENDING FOR B-HL CABLE REPLACEMENT

Year	Actuals ($M)
2012-2013 (Total)	1.27
2014 (YTD as of April)	1.04
2014 (Total Forecast)	3.48

Due to the magnitude and the complexity of this project, Toronto Hydro expects to complete the replacement of the identified B-HL tie feeders by 2017. (Remaining proposed forecasted spending is detailed in section E6.2.4.)

E6.2.2.3 Piecing Out PILC in Congested Cable Chambers

In addition to rectifying the instances of leaking PILC cables, Toronto Hydro continues to address the congestion and cluttering of cables that is common in downtown cable chambers. As the system has grown, many cable chambers have become congested with the addition of new customers and services in the downtown core. With new connections and increasing loads, the addition of primary and secondary cables in old and small legacy "football" shaped cable chambers as led to congestion and cluttered work spaces. In some instances, cable chambers were rebuilt to provide additional space, however existing cables were left suspended or hanging.

The process of extending and racking the existing cable is termed "piecing out" the cables and entails adding sufficient length to the existing cable to allow for its placement on cable racks. Toronto Hydro's practice is now to piece out cables to allow crews safe access and egress after a chamber rebuild is complete. As seen in Figure 3, the cables in the chamber are not racked and are instead tied and bundled in an arrangement that leads to congestion and difficult work spaces.

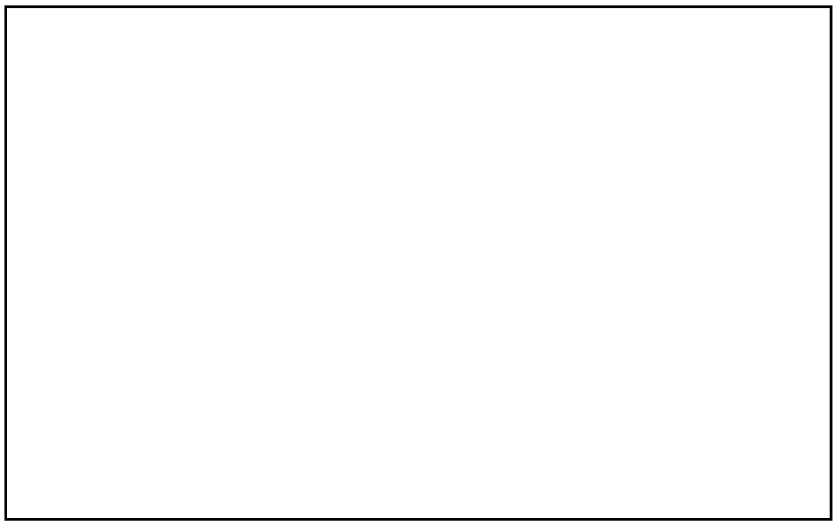


FIGURE 3: CABLE CHAMBER WITH CABLES THAT REQUIRE PIECING OUT

Toronto Hydro plans to continue to address the issue of congested chambers by inspecting each identified chamber and formulating a detailed work plan to restore the chambers to a proper arrangement as per Toronto Hydro standards. In addition, this work will also ensure that Toronto Hydro is in compliance with Electrical Utilities Safety Rules (EUSR) provision 141 (7) which requires cables to be properly supported. Figure 4 shows a chamber with properly racked cable after a piece out.

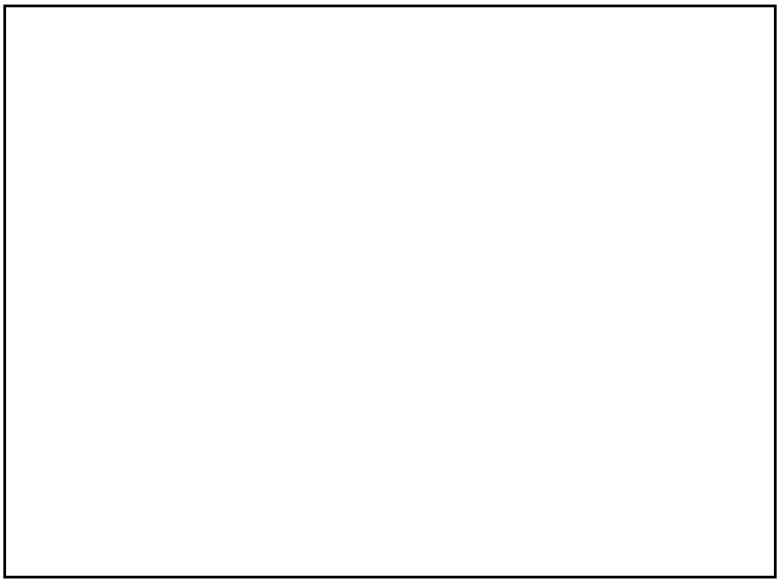


FIGURE 4: CABLE CHAMBER WITH PROPERLY RACKED CABLES

Figure 5 illustrates all proposed locations of work for this program over the 2015-2019 period across the Toronto Hydro system.

FIGURE 5: MAP OF CABLE CHAMBER LOCATIONS REQUIRING PIECING OUT OR LEAKERS REPAIR

As detailed in the three activities outlined above, Toronto Hydro anticipates that the PILC Leakers and Cable Piece Outs program will deliver several program benefits. These are summarized in Table 3 below.

TABLE 3: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Reduced risk of prolonged outages for Toronto Hydro customers ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $3.89 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.2.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $0.44 million, confirming the economic prudence of the investments (see Section E6.2.7).
Reliability	ƒ Reduced repair time on underground feeders in cable chambers with leaking PILC cables. ƒ Reduced risk of prolonged outages for Toronto Hydro customers
Safety	ƒ Improved working conditions in cable chambers for Toronto Hydro employees ƒ Improved public safety: reduced risk of faults in cable chambers mitigates the risk of cable chamber lids dislodging.
Efficiency	ƒ Improved operational flexibility during contingency events ƒ Enhanced efficiency of underground crews during service restoration efforts ƒ Reduced resource time on leaking PILC cable enables crews to perform additional planned capital or maintenance work
Environment	ƒ Mitigates possible negative impacts on the environment

E6.2.3 Why the Program is Needed

As established in Toronto Hydro's previous rate filing, the PILC Leakers and Cable Piece-Outs program is required to manage the substantial asset failure risks associated with leaking cables and to mitigate safety hazards that have caused injuries and near misses to underground workers in the past.

Until about 1990, Toronto Hydro did not consider cracked and leaking cables to be defective and confined space work practices had not yet matured. It was normal operating practice to work in and around the energized leaking PILC cable and move the energized cable out of the way to make enough room to enter, work in and exit chambers. Over the past 20 years, work practices have matured and, today, leaking PILC cables like the one shown in Figure 6 below are

considered defective and a source of potential safety hazards to workers, environmental concerns and remediation requirements.

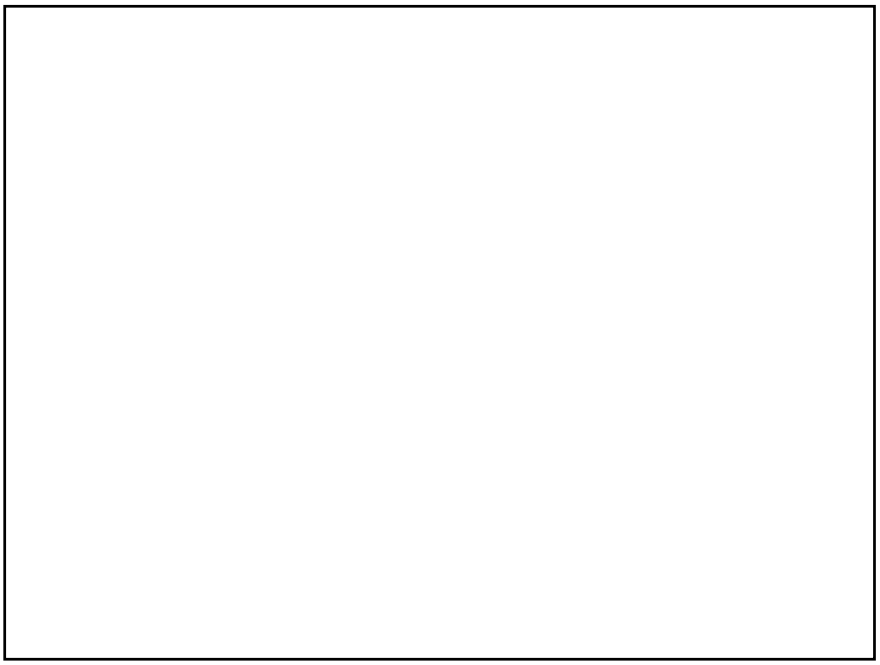


FIGURE 6: OIL LEAKING FROM PILC CABLE

The chambers that require piecing out are also safety hazards, as the crews cannot generally enter them without exposing themselves to trip hazards and work space limitations. Moreover, by piecing out and properly racking the cables in the newly rebuilt chambers, Toronto Hydro ensures that crews can quickly and safely access all cables in a chamber in the event of a fault. As discussed in section E6.2.3.2, this can reduce the likelihood of prolonged outages on the underground system, which can occur if crews are required to operate in congested cable chambers or cable chambers containing leaking PILC cables.

E6.2.3.1 Program Drivers

Table 4 presents the primary and secondary drivers for the PILC Leakers and Cable Piece-Outs program. This program is a System Renewal initiative because the primary driver is Failure Risk.

TABLE 4: PROGRAM DRIVERS

	Drivers	Reasoning
Primary Driver	Failure Risk	ƒ Water ingress in corroded cables leads to higher failure risk ƒ Cable cannot predictably perform at an acceptable standard ƒ Reduced insulation to cable, reducing dielectric strength ƒ Increased mechanical stresses due to cable being suspended
Secondary Drivers	Safety	ƒ Compromised insulation can lead to electrical contact hazards ƒ Reduced dielectric strength can lead to faults or arc flashes ƒ Congested chambers may contain trip hazards ƒ Congested chambers lack proper clearance to handle cable
	Reliability	ƒ Requirement to de-energize and repair all feeders with leakers prior to crews' entry into the cable chambers prolongs outage duration ƒ Operating in cluttered cable chambers slows down the crews' power restoration efforts.

Failure risk is the primary driver for the PILC piece out and leakers program. The compromised state of leaking PILC cable prevents it from performing at its rated capacity and standard. This is because the insulation of the leaking cable is now reduced due to the continuous water ingress as a result of the cables being submerged under water in flooded cable chambers. This reduced insulation results in an increased probability of failure. In addition, the escaping oil from the leaking cable compromises the dielectric strength of the cable. This increases the cable's potential to fault or cause an arc flash. The resulting failures can have substantial cascading impacts on customer outages, safety and reliability.

Similarly, failure risk is an issue for hanging cable and congested cable chambers. Over time, when a cable is left hanging or suspended in a position similar to the one identified in Figure 3 shown in section E6.2.2.3, a mechanical stress is exerted on the cable which will weaken the cable insulation and jacket. This leads to more rapid cable deterioration and combined with increased probability of movement and physical contact due to the congestion, the failure risk for these cables is higher.

While the risk of cable failure is itself a reliability and potential safety risk, leaking and hanging cable further impacts reliability because of the need to de-energize the cable and repair all defects prior to performing additional work in a chamber. These required work practice

procedures can prolong contingency situations where customers are at risk of extended outages. These scenarios and their resulting impacts are discussed in detail in the Asset Failures Impact subsection in the following Asset Details section.

Safety is also a critical secondary driver of this program. Being an inherently weak point on the feeder as described above, leaking PILC cable introduces the risk of sudden feeder faults, arc flashes, and electrical contact hazards to workers. Congested chambers and hanging cable also create potentially hazardous working conditions for crews when performing work in the chamber. Cluttered cables result in tripping hazards as well less working space for crews to handle cable. By removing these risks from the system, risks to worker as well as public safety can be mitigated. Limiting crew exposure to faulty and cluttered cable will reduce the likelihood of the types of injuries and near misses described below:

Arc Flash Hazards – In December 2011, a PILC cable on the B-HL tie feeders faulted and resulted in a near-miss arc flash while the crews were working in the chambers. Upon investigation of the incident, crews discovered numerous leaking PILC cables in the cable chambers along the feeder route. Crews have now flagged these chambers as hazardous and can potentially refuse entry for work.

Flash Burns from an Improperly Racked PILC Splice – In April 2007, while descending into a cable chamber, a worker made contact with a PILC cable splice that required piecing out. The cable in question was not properly racked, but running unsupported and directly beneath the cable chamber opening. The worker received flash burns to his face, neck and shins, and sustained further fall-related injuries.

Cable Splice Fault – In May 2013, an incident occurred resulting in damage to five feeders and a catastrophic failure that propelled the chamber lid off the roof and onto the road. The crews investigating the incident reported that the cable chamber contained a PILC splice that was extremely damaged, which likely led to improper insulation and possible leaking. A cable splice in this condition may not be able to withstand fault current passing through it and the result could be enough heat and force to propel the chamber lid in the air. Figure 7 below shows the splice after the incident occurred.

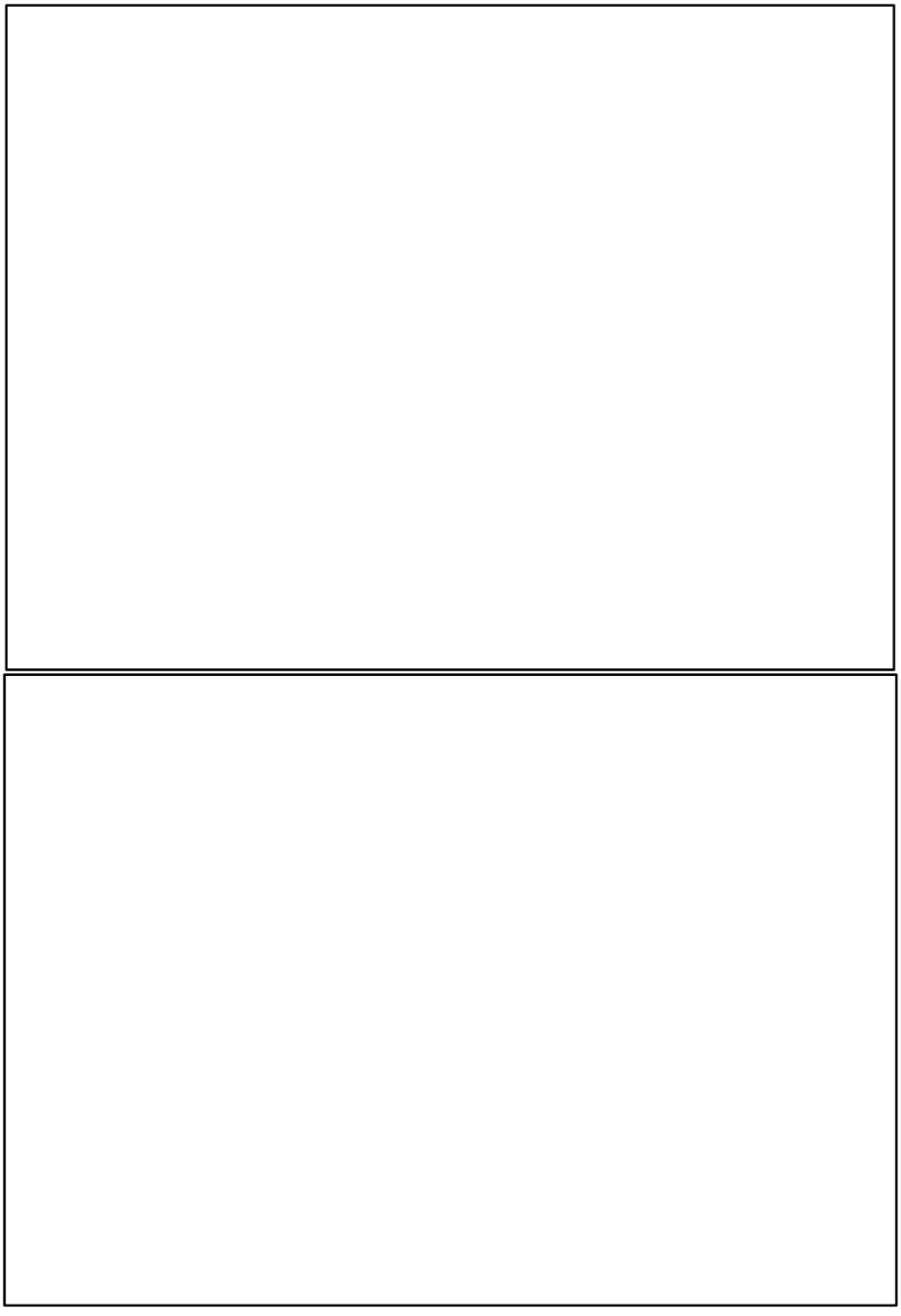


FIGURE 7: PILC SPLICES FROM MAY 2013 INCIDENT

E6.2.3.2 Asset Details

(i) Asset Lifecycle

The majority of cable to be replaced or repaired under this program is over 25 years old. While PILC cable can be reliable and operational for over 75 years, the cable being targeted in the PILC Leakers portion of the program are all segments of cable that have reduced reliability and increased failure risk due to the presence of pinhole leaks on the cable or at the splice due to cracking or stress fractures. The need for intervention stems from these deficiencies that significantly reduce the reliability of the asset.

If the cable surface is damaged, moisture can penetrate into the insulation, causing rapid degradation of the insulation itself and the expulsion of oil that helps maintain the cable's dielectric properties. These deficiencies compromise the cable's insulation properties and increase the electrical stress on the conductor, thereby reducing cable reliability.

An illustrative example of PILC cables with reduced useful life is the aforementioned B-HL tie feeders scenario. On average, the cables comprising the feeder are 60 years old, which is within the normal 75-year lifecycle. However, control room reports and outage data indicate that there have been approximately 22 cable-related faults on the B-HL feeders during the 36 month period between January 2011 and December 2013. (Moreover, during the week of November 24 to November 30, 2012, the same tie feeders reportedly tripped 5 times.) Figure 8 illustrates these outages on the B-HL tie feeders which all lasted over 12 hours.

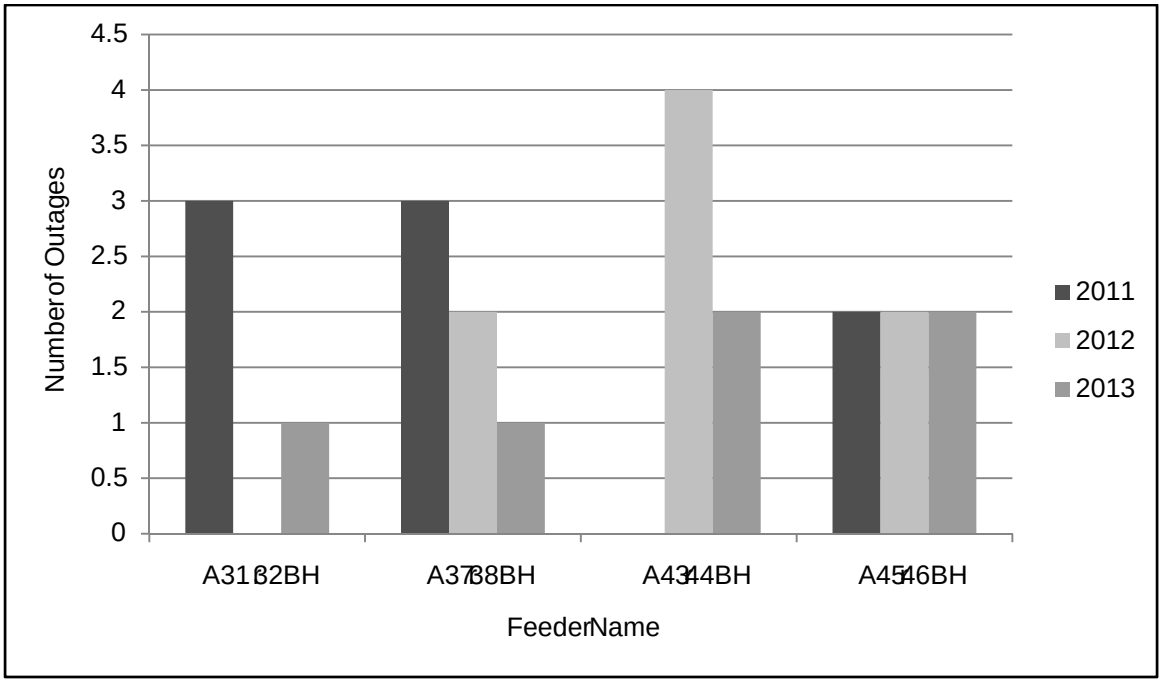


FIGURE 8: HISTORICAL FEEDER OUTAGES FOR B-HL TIE FEEDERS

By replacing these leaking cables in this program, Toronto Hydro can eliminate these unnecessary outages and improve reliability for customers in the St. Paul's area.

(ii) Asset Failure Impacts

PILC Leakers

Cable chambers in Toronto are treated as confined spaces. Due to the possibility of electrical contact and other hazards related to defective PILC cable, Toronto Hydro operating procedures require that cables with identified leakers be de-energized prior to crews entering the cable chamber. In addition, Toronto Hydro work practices dictate that all leaking PILC cables replaced or repaired before the crews leave the site. While this requirement improves the safety of Toronto Hydro employees, it can prolong the duration of outages and put an increased stress on the system.

When a downtown feeder suffers a cable fault, standard operating procedures dictate that all customers on the feeder should be transferred to their respective standby feeders. Downtown feeders have an average of 12 customers per feeder and it typically takes 45 minutes to restore the first customer and 15 minutes for every subsequent customer. Therefore, Toronto Hydro's average time to restore all customers on a faulted downtown feeder is approximately 3.5 hours.

This translates to an average outage duration of 1.5 hours for the affected customers. To avoid further customer interruptions and enable the crews to safely enter the chamber, Toronto Hydro must perform additional switching until all leaking feeders are de-energized. Doing so can take an additional 3.5 hours per feeder (based on the same averages described above), thus further prolonging the time that the system operates under an N-1 contingency[4]. Along with rectifying the source(s) of the fault, Toronto Hydro operating procedures dictate that the crews must address the cable leaks in the chamber. Given that each PILC leaker takes about four hours to repair, the presence of leaking PILC cables extends the duration of the N-1 event to a minimum of eight hours (longer if multiple PILC leaks are present in the cable chamber).

While the design of Toronto Hydro's system allows it to operate acceptably without damaging any assets during an N-1 contingency, doing so for a prolonged period of time is violates good utility practice, as it limits the utility's ability to perform switching to enable planned maintenance work or capital project execution.

In addition, while under N-1 contingency, the entire system and its customers face a greater prolonged outage risk and lower reliability as a second fault or outage may result in feeders and customers that cannot be restored quickly. The minimum typical outage duration from a second fault during N-1 contingency is 12 hours – over three times the outage duration of a "normal" outage – due to the fact that existing feeders are already out of service for fault locating or repair because of the presence of leaking cable.

The impact of PILC cable failure on the B-HL tie feeders is even more pronounced. Apart from compromising the security of supply for Toronto Hydro's customers in the St Paul's area, the cable faults can have a significant failure impact on the upstream HONI assets. Each incident that causes HONI's transformers at Bridgman TS to trip requires a thorough investigation and, as a result, requires HONI to take remedial action to verify the health of their transformers following each incident. Given the number of incidents affecting HONI's equipment in the recent past, Toronto Hydro must address the situation with the B-HL tie feeders in a timely and sustainable manner.

Cable Piece Outs

Similar to leaking cable, congested chambers with improperly racked cables can negatively impact Toronto Hydro crews and customers alike. Suspended or hanging cable has a higher failure risk as described earlier in Section E6.2.3.1 and a congested chamber also creates an

[4] The system under normal operation with all feeders energized is in an N-0 state. An N-1 contingency is a scenario where the system is operating with one asset failed or out of service.

unsafe working environment for Toronto Hydro crews due to tripping hazards and restricted space for labour intensive activities like the pulling of new cable and installation of cable joints and splices.

Moreover, chamber congestion can prolong underground outages and extend the duration of N-1 contingency events. When cable faults occur in congested cable chambers, crews require significantly more time to access and repair the faulty equipment, as cluttered cables restrict their movements and require significant efforts to move them aside. In situations where a piece-out is required to address a congested chamber, the cable will require an outage for as long as it takes to install and splice new cable. Similar to a leaker issue as detailed above, the additional switching and cable replacement repair time in these scenarios extends the amount of time the system is under N-1 contingency to a minimum of eight hours for every piece of cluttered cable present. The longer the Toronto Hydro system is under N-1 contingency, the surrounding distribution system and its customers face a greater prolonged outage risk and lower reliability as a second fault or outage may result in feeders and customers that cannot be restored quickly. The minimum typical outage duration from a second fault during N-1 contingency is 12 hours, over three times the outage duration of a "normal" outage.

E6.2.4 Timing & Pacing of the Program

Table 5 shows the estimated costs for the PILC Leakers and Piece-Outs program over the 2015 to 2019 period and the historical costs from 2010 to 2014.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	-	5.47	1.47	2.44	4.73	3.45	1.38	0.73	0.81	0.51

Toronto Hydro is committed to substantially reducing the backlog of known leakers and congested chambers within a reasonably short timeframe in order to mitigate associated failure and safety risks. With the exception of the 2012 and 2013 budget years (which are lower due to the timing of the decision for Phase 1 of Toronto Hydro's 2012-2014 rate filing), historical expenditures reflect the urgency of the work required and the emphasis Toronto Hydro has placed on removing leaking cable. As illustrated in Table 5, the majority of the program spending for the forecast period is concentrated in 2015 and 2016. This pace of spending is partly attributable to ongoing replacement of the leaking B-HL feeder tie cables. Due to the complexity of the project and the civil construction and coordination required, the costs associated with the

replacement of these feeders form a significant portion of the spending in the first two forecast years.

Toronto Hydro expects that deferral of the forecasted work beyond the planning horizon will result in the worsening of identified problems. Old and defective cables on the system will continue to leak oil, increasing the risks of cable faults, prolonging repair and restoration time, reducing system reliability and potentially increasing the safety risk to Toronto Hydro workers. Also, the ongoing work to rectify the leaking cables for the B-HL feeder ties has already begun and cannot be deferred without incurring operational risks. Approximately $4.73 million has already been invested into this project, which was notionally approved by the OEB as part segment B2 in Toronto Hydro's May 2012 ICM Phase 1 filing and the subsequent 2014 Phase 2 update. This spending was to construct approximately 500 metres of new civil infrastructure in order to install new 1500 kcmil cable for the B-HL tie feeders. Any delays or deferrals to replace the feeders will put the system at risk and crews will no longer be able to enter any of the impacted cable chambers to perform work. The new civil infrastructure already constructed will also not be utilized and will remain empty until such time that the remainder of the project is executed.

Once the B-HL tie-feeder replacement project and the majority of the known piece out and leaker issues are rectified, Toronto Hydro anticipates a reduction in capital spending required in the latter years of the 2015-2019 planning horizon, as PILC cable is gradually replaced throughout the system through other capital projects and customer connections.

E6.2.4.1 Ranking & Prioritization

As discussed in Section E6.2.2, Toronto Hydro has compiled a "Deficiencies List" of all known PILC leaker and congested cable chamber locations. When determining the sequencing of work execution from among the identified deficiencies, the utility considers several factors. These include:

Magnitude of the Problem – Areas with a concentrated number of reported cable leaks and congested chambers receive priority over those with isolated and scattered incidents.

Surrounding Work in the Area – surrounding work in the same geographical area is considered in the prioritization in order to avoid possible conflicts with other Toronto Hydro capital work and City of Toronto projects.

Feeder Outage Availability – The availability for the control room to schedule feeder outages is also given consideration. If numerous projects or a major project is being executed in the same area as a piece-out and leaker project, feeder outages may not be granted by the control room

due to system restraints and other feeders already out of service. This impact is considered as well in the prioritization to avoid conflict in feeder and resource scheduling.

The B-HL feeder performance issue is high-priority due to the magnitude of the associated failure impacts on Toronto Hydro's system and workers and the operation of upstream HONI transmission equipment. A detailed discussion of the impact of the leaking cable on the B-HL circuits is provided in Sections E6.2.2.2 and E6.2.3.2.

E6.2.5 Program Execution

As described in Section E6.2.2, this program will address all existing and known leaking PILC cables. Toronto Hydro will inspect each chamber on the deficiencies list and formulate a work plan to address any identified leaking cable. Field crew workers, in collaboration with planning and control room staff, will arrange the necessary feeder outage schedule and ensure that all work coordination is in place. For each leaking splice or segment of cable, the designer and crews will determine if the leak can be fixed using one of three methods:

A splice repair – Performing a splice repair is ideal for minor leaks as the repairs meet all requirements of cable test specifications and its internal moisture seals protect the cable from water ingress. Crews complete a splice repair using a heat-shrink adhesive polymeric sleeve called a Raychem kit. The Raychem kit is fast and pre-engineered for installations that reduce time and repair costs.

A new sleeve – Where the damage is too extensive to repair with a Raychem kit, the crews will remove the existing sleeve and break down the insulating material used to fill the splice. Once the crews clean and re-tape the cable, they install a new lead sleeve and fill it with the new insulating material prior to sealing the sleeve through the process known as "wiping."

A new segment of cable – If neither the Raychem kit nor a new sleeve can adequately address the damage, the crews will remove the existing cable and/or splice and will pull a new segment of cable from the adjacent cable chamber, prior to installing a new splice.

For congested cable chambers, crews will move the cable and properly rack it on chamber walls. If segments of cables are too short or too long to allow for proper racking, crews will install (or remove) a new segment of cable and complete the proper splicing. In certain cases the crews will also have to install new cable racks along the chamber walls and/or make other modifications to the chamber itself.

E6.2.5.1 Proposed Work Plan

Table 6 outlines Toronto Hydro's forecasted work plan for the 2015-2019 period by feeder and station .

TABLE 6: 2015-2019 LONG TERM PLAN

Year	Feeder	Station
2015-2016	A31/32HB, A37/38HB	Bridgman – High Level
2015	Various	Charles
2015	Various	Bridgman
2015-6	Various	Windsor
2016-2017	A43/44HB, A45/46HB	Bridgman – High Level
2016	Various	Dufferin
2017	Various	Strachan
2017	Various	Various 4 kV MS
2018	Various	High Level
2019	Various	Various Downtown 13.8 kV TS

E6.2.5.2 Program Risks

The following are risks to program completion that Toronto Hydro considers when planning and executing the PILC leaker repairs and piecing out work.

Civil Asset Obstacles : Due to the age of the surrounding civil assets, the original ducts may have shifted or collapsed, trapping the cable inside. The existing cable may also be bent within the ducts, making it difficult to pull out. These obstacles are difficult to foresee until the projects are underway. Project delays and cost increases can also occur where significant rebuild of civil infrastructure is required. To best anticipate this risk, Toronto Hydro will consider and review the age and type of ducts in the area for each project in order to assess the probability of collapsed ducts and trapped cable, and this risk assessment will inform the scheduling and cost estimation for each individual project.

Resource Availability : Working with PILC cable and performing the lead splice replacement requires specialized training and experience. While Toronto Hydro has a number of crews with the required expertise, these crews are typically in high demand to perform other planned or reactive work on the utility's underground system. Toronto Hydro is mitigating this risk through its comprehensive staffing strategy, which features a multi-faceted approach to meeting the utility's

resource requirements. To mitigate this risk, Toronto Hydro has begun working with external contractors to increase resources available to work on PILC cable.

Managing Feeder Outages : Prior to rectifying PILC leaks, Toronto Hydro must de-energize the damaged feeders. This requires switching crews to be available to transfer all affected customers to a standby feeder. Given that switching crews may be at any time deployed to higher-priority projects, the execution of the Leakers and Piece-Outs program depends on their availability. To mitigate this risk, Toronto Hydro has begun a feeder scheduling planning review to optimize and better coordinate the work on de-energized feeders.

Summer Outage Restrictions : Some feeders containing PILC leakers may be on Toronto Hydro's Summer Switching Restriction List, which identifies the feeders with high loading that are not available for planned outages during the summer peak conditions. Inability to obtain outages on necessary feeders can result in project delays. In order to reduce the number of feeders on the Summer Switching Restriction List, Toronto Hydro has initiated projects to relieve demand from heavily loaded feeders which in turn will allow them to be removed from the restrictions list. These projects are referenced in the Load Demand narrative (Section E5.4).

E6.2.6 Evaluation of Alternatives

Toronto Hydro has evaluated three alternative approaches for addressing the issues identified in this program. These options are detailed below.

(i) Status Quo

Deferring the work in this program is essentially a run-to-failure option. This approach does not address the existing risks to workers associated with working in confined spaces where defective primary cable is in service. This option also exposes customers to the risk of extensive outages from collateral cable damage in a chamber should a cable fail. Finally, it reduces the choices for routing new underground cable, as the chambers will remain congested. For all these reasons, this option is not preferred.

(ii) De-energizing all of the PILC primary cables in the chamber prior to entry

This option would eliminate many of the associated hazards for workers and would comply with work practices. However, in the downtown core, the service and standby cables often run in the same chambers and de-energizing both of them would create outages. With up to ten primary cables in a single downtown chamber, each with a capacity of 10 MVA, this option would create multiple outages for a significant number of customers on a regular basis. As a result, this option is not feasible.

(iii) Repair leaking cables and perform piece outs on an emergency basis

In many cases, workers are dispatched to cable chambers to investigate an event only to find that there are leakers or piece-out requirements that prevent them from addressing the situation that originally caused them to be there. If the original task was to restore power because of a cable failure, or some other urgent need, the leaking cables or piecing out work must be completed first. These operating restrictions become unmanageable as the backlog of leakers and feeders requiring piecing out increases. This situation also adds to the control room's switching and operating workload. Selecting this option for dealing with leakers and piece out requirements would mean that the work was unplanned. The result of unplanned work is often failure to complete all aspects of the job, or a requirement for substantial overtime. This option is not preferred because it prolongs the time to complete the original task and its cost.

(iv) Proactive repair of leakers and piece out of chambers

This option allows work to proceed in a planned way, focusing on the highest priority areas. Feeders with multiple leakers and chambers requiring piecing out can be scheduled for isolation and all of the associated hazards and defects can be addressed at the same time while the feeder is out of service. This approach is the most efficient and preferred approach.

The cost of ownership (ûCOO) and program net benefit (NPV) associated with the PILC Leakers and Cable Piece-Outs program is further detailed in Table 8. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities in this program. The cost of ownership reflects the risk of asset failure for a given state, including both direct and indirect costs. These costs include customer interruptions, emergency repairs, and asset replacements associated with the given design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first year of activities, the PILC Leakers and Cable Piece-Outs program produces a net benefit (NPV) value of $0.44 million, as shown in Tables 8 and 9.

TABLE 7: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	$5.06
Non Asset Risk [NAR_E]	0
Maintenance Cost [MC_E]	0
Additional Quantifiable Benefits [AQB_E]	0
Cost of Ownership of Existing Assets [COO_E]	$5.06

TABLE 8: BOX CONSTRUCTION CONVERSI ON BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 1: Conversion to Standardized Equipments	
Asset Risk [AR_N]	$1.17
Non Asset Risk [NAR_N]	0
Maintenance Cost [MC_N]	0
Additional Quantifiable Benefits [AQB_N]	0
Cost of Ownership of New Assets [COO_N]	$1.17
Option 1: Program Net Benefit (NPV)	
Difference in Cost of Ownership [$\Delta COO_2 = (COO_E - COO_N)$]	$3.89
Program Cost [PC_2]	$3.45
Program Net Benefit [NPV = ($\Delta COO_2 - PC_2$)]	$0.44

E6.2.7 2015 Projects

Table 10 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

- previously filed projects that appeared as jobs in the OEB approved PILC Cable – Piece Outs and Leakers segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and
- projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 9: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Projects	CIR Projects
$1.79	$1.66

Table 11 lists all projects that are planned for partial or complete execution as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 10: 2015 PROJECTS

Project Number	Project Name	Total Project Cost ($M)	Start Date	Project Type (ICM or CIR)
29776	X15039 - Bridgman High Level Tie Feeder Replacement Phase 4: Electrical Part 1 (A31,32HB & A37,38HB)	0.78	2015	CIR
30620	X15585 Charles Station Piece Out and Leakers Phase 1: Civil	0.39	2015	CIR
30621	X15586 Charles Station Piece Out and Leakers Phase 2: Electrical	0.49	2015	CIR
28037	X14362 – Bridgman Station Piece out and Leakers	0.35	2015	ICM
19798	X12160 Windsor Station Piece Out and Leakers	1.44	2015	ICM

E6.2.7.1 X15039 Project Description

Portfolio: U/G Grid System

Program: Paper Insulated Lead Covered (PILC) Piece-Outs and Leakers

Project Title: Bridgman High Level Tie Feeder Replacement Phase 4: Electrical Part 1 (A31, 32HB & A37, 38HB)

Project Number: X15039

Project Year: 2015

Estimated Cost: $778,599

(i) Objective

Objective of this project is to replace cable for four of the Bridgman High Level tie feeders. The four feeders to be replaced are A31,32HB and A37,38HB. This project is phase four of five.

(ii) Scope of Work

Replace tie feeders A31,32HB and A37,38HB from T12X and T13X at Bridgman Station to A7-8H switchgear at High Level Station by pulling four new circuits (12 cables total) of 1500 kcmil TRXLPE cable through the new civil infrastructure built in Phase 1-3 of this project.

TABLE 11: X15039 SCOPE OF WORK DETAILS

District Neighborhood	ST PAUL'S
Station(s)	BRIDGMAN, HIGH LEVEL
Feeder(s)	A31BH, A21BH, A37BH, A38BH

TABLE 12: X15039 ASSETS REPLACED

Assets (Units)	2015
1500 kcmil PILC cable (km)	1.95

(iii) Justification & Benefits

The Bridgman High Level tie feeders have been identified as leaking and have been the primary cause of several cable faults over the past three years. These faults have a large impact on not only the distribution system and the customers in the St Paul's area of Toronto, but also the upstream HONI transmission protection schemes.

By replacing these feeders, Toronto Hydro expects there to be a significant improvement in reliability.

E6.2.7.2 X15585 Project Description

Portfolio: U/G Grid System

Program: Paper Insulated Lead Covered (PILC) Piece-Outs and Leakers

Project Title: Charles Station Pi ece Out and Leakers Phase 1: Civil

Project Number: X15585

Project Year: 2015

Estimated Cost: $390,090

(i) Objective

Objective of this project is to repair the leaking PILC cable and piece out any required feeders to rectify any chamber congestion in the Charles Station egress area. This project is phase one of two and focuses on the civil work to rebuild and construct new cable chambers and ducts.

(ii) Scope of Work

- Breakout of east side of CC7002 and run a duct structure to the existing duct run which runs from the station to CC9880
- Breakout of both the north side of CC7002 and the east station wall and run duct to a new chamber south of CC6995 and CC9880 (referred to as New Chamber #1)
- Run duct from the north wall of New Chamber #1 to another new chamber (New Chamber #2) to the east of CC6999.
- Run duct from the east wall of New Chamber #2 and break into the adjacent duct structure running to CC5550.

TABLE 13: E12345 SCOPE OF WORK DETAILS

District Neighborhood	ROSEDALE
Station(s)	CHARLES
Feeder(s)	NONE

TABLE 14: X15585 ASSETS REPLACED

Assets (Units)	2015
Cable Chambers (EA)	2

(iii) Justification & Benefits

The egress chambers for the Charles Station area were reported by crews to be congested. New civil infrastructure is required so the feeders can be rerouted out of congested chambers creating additional space for cable to be properly installed and racked. This scope focuses on civil work required on the east side of the station.

By completing this work, Toronto Hydro will remove numerous tripping hazards and create safer working conditions within the chamber for crews. The work is also expected to allow for quicker restoration time and improved reliability when repairing faulted cable for a feeder that runs through these chambers outside Charles TS.

E6.2.7.3 X15586 Project Description

Portfolio: U/G Grid System

Program: Paper Insulated Lead Covered (PILC) Piece-Outs and Leakers

Project Title: Charles Station Piece Out and Leakers Phase 2: Electrical

Project Number: X15586

Project Year: 2015

Estimated Cost: $489,247

(i) Objective

Objective of this project is to repair the leaking PILC cable and piece out any required feeders to rectify any chamber congestion in the Charles Station egress area. This project is phase two of two and focuses on the electrical work to repair leaking cable and piece out cluttered cable.

(ii) Scope of Work

- Relocate feeders A60CS, A61CS and A65CS from the ducts from CC6996 to CC6995 on the south side of Charles St to the ducts from CC6996 and CC6880 also on the south side of Charles St.
- Transfer Network Locations N1023 and N1077 from A50CS, A53CS and A55CS to A91CS, A92CS and A93CS and remove congested cables through chambers outside Charles Station.
- Relocate feeder A8CS from the ducts on the south side of Charles St from CC9880 to CC6996 to the ducts south of Charles TS from CC7002 to CC6996.
- Relocate feeders A7CS, A9CS, A52CS and A54CS from the ducts from Charles TS to CC6995 on the North East side of the station to the new cable chambers built in Project X15585.

TABLE 15: X15586 SCOPE OF WORK DETAILS

District Neighborhood	ROSEDALE
Station(s)	CHARLES
Feeder(s)	A60CS, A61CS, A65CS, A50CS, A53CS, A55CS, A91CS, A92CS, A93CS, A8CS,

TABLE 16: X15586 ASSETS REPLACED

Assets (Units)	2015
500 kcmil PILC Cable (km)	1.4

(iii) Justification & Benefits

The egress chambers for the Charles Station area were reported by crews to be congested. This electrical work is required so the feeders can be rerouted out of congested chambers creating additional space for cable to be properly installed and racked.

By completing this work, Toronto Hydro will remove numerous tripping hazards and create safer working conditions within the chamber for crews. The work is also expected to allow for quicker restoration time and improved reliability when repairing faulted cable for a feeder that runs through these chambers outside Charles TS.

E6.2.7.4 X14362 Project Description

Portfolio: U/G Grid System

Program: Paper Insulated Lead Covered (PILC) Piece-Outs and Leakers

Project Title: Bridgman Station Piece Out and Leakers

Project Number: X14362

Project Year: 2015

Estimated Cost: $348,480

(i) Objective

Objective of this project is to piece out cables as well as repair any leaking cable within cable chambers with feeders that originate from Bridgman Station.

(ii) Scope of Work

In the following identified cable chambers and vaults, inspect and confirm all feeders requiring piece out or feeders that are leaking. If a leaker is identified, repair cable by; installing a heat shrink splice repair, installing a new sleeve or installing a new segment of cable. If a piece out is identified install a new segment of cable and properly rack new cable.

- CC4233, CC4227, CCN440, CCN441, CC4971, CC4769, CC8753, CC6096, CC8233, CC6478, CC4234.

- LOC4882SV, LOC N1066.

TABLE 17: X14362 SCOPE OF WORK DETAILS

District Neighborhood	ST PAUL'S
Station(s)	BRIDGMAN
Feeder(s)	A52B, A54B, A91B, A92B, A93B, A94B, A6B

TABLE 18: X14362 ASSETS REPLACED

Assets (Units)	2015
500 kcmil PILC cable (km)	1.19

(iii) Justification & Benefits

The identified chambers have been reported to contain leaking PILC cable or unracked and cluttered feeders. This work is required to repair all leaking cable as leaking cable does not perform at its rated capacity and standard and is more susceptible to a fault or flashover.

By completing this work, Toronto Hydro will remove numerous tripping hazards and create safer working conditions within the chamber for crews. The work is also expected to allow for quicker restoration time and improved reliability when repairing faulted cable.

E6.2.7.5 X12160 Project Description

Portfolio: U/G Grid System

Program: Paper Insulated Lead Covered (PILC) Piece-Outs and Leakers

Project Title: Windsor Station Piece Out and Leakers

Project Number: X12160

Project Year: 2015

Estimated Cost: $1,444,417

(i) Objective

Objective of this project is to install new civil assets and perform the required electrical work in order to piece out congested and cluttered cable chambers that were created by a number of new connections and installations over the past decade in the growing business area of York and Front.

(ii) Scope of Work

- On Front St between Simcoe St and York St break out and install new ducts from CC9672 to CC3009 on the north side of Front St.
- Relocate feeders A58WR, A54WR and A50WR from the south side of Front St to the north side of Front St using the new civil infrastructure installed in previous step above.
- At the corner of Simcoe St and Bremner Blvd break out and install new ducts from CC10863 to CC10865.
- At the corner of York St and Bremner Blvd rebuild existing CC3275 and install new ducts to CC10913.
- Replace and new install new cable for feeders A71WR and A72WR along Bremner Blvd from CC10863 to CC3275 in the new civil infrastructure installed in previous two steps as described above.

TABLE 19: X12160 SCOPE OF WORK DETAILS

District Neighborhood	TRINITY-SPADINA
Station(s)	WINDSOR
Feeder(s)	A50WR, A54WR, A58WR, A71WR, A72WR

TABLE 20: X12160 ASSETS REPLACED

Assets (Units)	2015
500 kcmil PILC cable (km)	0.85
Cable Chambers (EA)	1

(iii) Justification & Benefits

The identified chambers were reported by crews to be congested due to several new services and feeders being installed in the area in order to accommodate new buildings being constructed and energized in the early 2000s. During that time, the work was completed without proper rebuilding of chambers or racking or cables. This project is required so the feeders can be rerouted out of congested chambers creating additional space for cable to be properly installed and racked.

By completing this work, Toronto Hydro will remove numerous tripping hazards and create safer working conditions within the chamber for crews. The work is also expected to allow for quicker restoration time and improved reliability when repairing faulted cable for a feeder that runs through these chambers.

E6.3 Underground Legacy Infrastructure

POWERLITE SWITCH INSTALLED IN A VAULT

E6.3.1 Summary

Program Description

Underground legacy infrastructure (ULI) refers to non-standard underground equipment and configurations throughout Toronto Hydro's distribution system. The ULI program addresses specific groups of legacy assets that are reaching the end of their useful lives and that lack suitable like-for-like replacements due to functional obsolescence.

(1) Sachsenwerk switch and fuse units are reaching end-of-life, no longer manufactured, and at risk of catastrophic failure since they are known to flashover during operation. Toronto Hydro plans to replace all 48 remaining units by 2018.

(2) Distribution equipment in the Thorncliffe Park distribution area is of a unique legacy design that has a number of issues, including the condition of the equipment, the availability of replacements and the lengthy duration of outages that are required to replace certain equipment. Toronto Hydro plans to reconfigure the distribution system by removing all submersible five-way and six-way switches and replacing them with a combination of pad-mounted and submersible four-way and three-way switches within the 2015-2019 period.

(3) Transclosures are a style of transformer that was installed in Toronto Hydro's system prior to the mid-1980s. Many of these units are in poor condition and are at or approaching end-of-life, with the newest units having been installed over 30 years ago.

Performing maintenance and reactive work on these units is difficult for field crews since their poor condition poses a potential safety hazards in the form of arc flashes. Toronto Hydro plans to replace approximately a quarter (42 units) of the total known transclosure population by the end of the 2015-2019 period.

(4) Powerlite switches , a type of secondary transfer switch, were originally installed in the mid-1960s, and are no longer manufactured. In the late 1980s, due to large overloads at locations on the Danforth (greater than 100%) and the abnormal configuration, Toronto Hydro undertook conversion projects to remove many of these units. However, there are still 10 remaining locations that need to be partially or completely replaced. Toronto Hydro plans to replace all of remaining units in the 2015-2019 period, and, in 2018-2019, will revisit locations that had been partially replaced reactively (due to safety concerns) to complete the conversion.

(5) Vault step transformers were installed at various times from the late 1950s through the early 1980s to provide customers with multiple service voltages. These transformers are legacy assets because Toronto Hydro no longer provides multiple service voltages in this manner. Toronto Hydro has identified seven sets of step-transformers that will be targeted by this replacement program during the 2015 to 2019 period. The replacement option for these units differs from location to location depending on the equipment and supply voltages that are installed in the vicinity. The ideal replacement option, if available, is to extend a secondary service of the required voltage from a nearby location. An alternative is to install a new primary transformer to distribute the required secondary voltage.

(6) In the past seven years, Toronto Hydro has recorded twenty-four incidents of cable chamber covers not being property seated on the chamber neck, i.e. ejected. Fortunately, none of these incidents have resulted in injury. However, incidents resulting in injuries and death have occurred in other jurisdictions. An ejected lid results from an eruption occurring inside a cable chamber. This eruption is caused by deteriorated cables heating up, arcing, and igniting gases, which can create a powerful shock wave. Toronto Hydro plans to address the cable chamber cover problem proactively by replacing 1,500 of the highest risk existing cable chamber covers with a new design that allows gas pressure to be released safely.

The anticipated benefits of the Underground legacy infrastructure (ULI) program are as follows:

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Reduces lengthy outages that can severely inconvenience customers. ƒ Improves public safety by replacing assets such as cable chamber lids and transclosures. ƒ Improves the aesthetic of neighborhoods, particularly in the case of transclosures, which are rusted, corroded and are often in highly visible locations.
Reliability	ƒ Mitigates outages caused by failed underground equipment (28% of total system outages). ƒ Removes certain operating restrictions posed by some legacy assets.
Safety	ƒ Mitigates the risk of current cable chamber lids being ejected into the air, which poses potential safety risks for pedestrians. ƒ Minimizes safety issues associated with crews being exposed to equipment flashover when operating switch and fuse units, as well as hazardous work environment in Powerlite locations
Efficiency	ƒ The use of engineering resources to deal with asset failure on a reactive basis is avoided, improving organizational efficiency. ƒ Installing a current standard asset, opposed to using a like-for-like legacy asset (if available) is more efficient from a cost/procurement/standards perspective (i.e. wanting to maintain few stock coded items and critical spares).
Other	ƒ New equipment being installed (CRD/CLD switches and pad-mount switches) have the ability to be retrofitted to be remote operable.

Program Drivers

The trigger and secondary drivers for the Underground legacy infrastructure (ULI) program are:

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Most of the equipment targeted by this program is no longer manufactured and therefore difficult to acquire replacements when needed ƒ Vastly improved assets have become available since the infrastructure targeted by this program was originally installed. The modern assets have additional functionality and safety measures when compared to the currently installed legacy equipment. ƒ There are no longer any construction standards which can be used by Toronto Hydro for replacing/maintaining these assets in a like-for-like manner.
Secondary Drivers	ƒ Reasoning
Safety	ƒ Degradation of assets can pose safety hazards for field crews when operating and/or maintaining the equipment.

Reliability	ƒ Often a like-for-like replacement option is not available for equipment targeted by this program. As a result, when this equipment fails, the system can be left in a contingency situation for long durations while a solution is developed and executed. Until the solution is implemented and the system resumes normal operation, customers are exposed to additional outage risk. ƒ Assets are at or near the end of their useful life and/or prone to failure, presenting an outage risk.
Failure Risk	ƒ Assets are at or near the end of their useful life. As a result, they are more likely to fail and will require reactive replacement.

Preferred Alternative

Toronto Hydro evaluated the following options for addressing the assets in this program:

(1) Do nothing and replace on a reactive basis only, incurring the risk of equipment failures and potential safety concerns.

(2) Proactively replace these assets with current standard equipment to eliminate the safety and reliability risks.

Option II is the preferred alternative as it will enable Toronto Hydro to mitigate the risks posed by the currently installed assets in the most cost effective manner.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $3.52 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets. Accounting for capital program costs, the first year's activities deliver a positive NPV of $1.46 million, confirming the economic prudence of the investments.

Timing and Pacing

The pace of replacement for the different asset types was determined based on the risk of failure of the assets as determined by age and condition, the expected impact of asset failure and the overall number of units.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	-	-	-	-	-	2.06	6.69	6.64	6.48	5.52

E6.3.2 Program Description

Underground legacy infrastructure (ULI) refers to non-standard underground equipment and configurations throughout Toronto Hydro's distribution system. The ULI program addresses specific groups of legacy assets that are reaching the end of their useful lives, including:

- Sachsenwerk switch and fuse units,
- specific equipment in the Thorncliffe Park distribution area,
- transclosures,
- Powerlite switches,
- vault step transformers, and
- cable chamber covers.

These assets and asset types are functionally obsolete because they can no longer perform their intended function to current standards; they often pose safety hazards and/or cause operating constraints. Replacement options vary from asset to asset because each has a unique function in the underground distribution system. Generally, Toronto Hydro will replace all of the ULI assets with current standard equipment and configurations.

Toronto Hydro standardizes in-service equipment as part of its efforts to make its system more efficient. As an amalgamated utility, Toronto Hydro's system contains remnants of several old standards and equipment that have become functionally obsolete. Attempting to stock like-for-like replacements for legacy equipment and performing reactive replacements is inefficient given the relatively small number of legacy assets currently in use as compared to the total number of assets in Toronto Hydro's system. As well, there is often a dearth of like-for-like replacement options for assets targeted by this program since in many cases, they are no longer manufactured because they are, or a lack of manufacturing results in them being, non-standard. Due to the difficulty and time required to settle on a suitable solution, locate a replacement and implement the corrective action when these legacy assets fail, their failure can lead to longer than average outage durations and/or lengthy contingency scenarios.

Toronto Hydro plans to spend an estimated $27.39 million on the ULI program over the 2015 to 2019 period. The locations of assets targeted by the ULI program are noted in Figure 1.

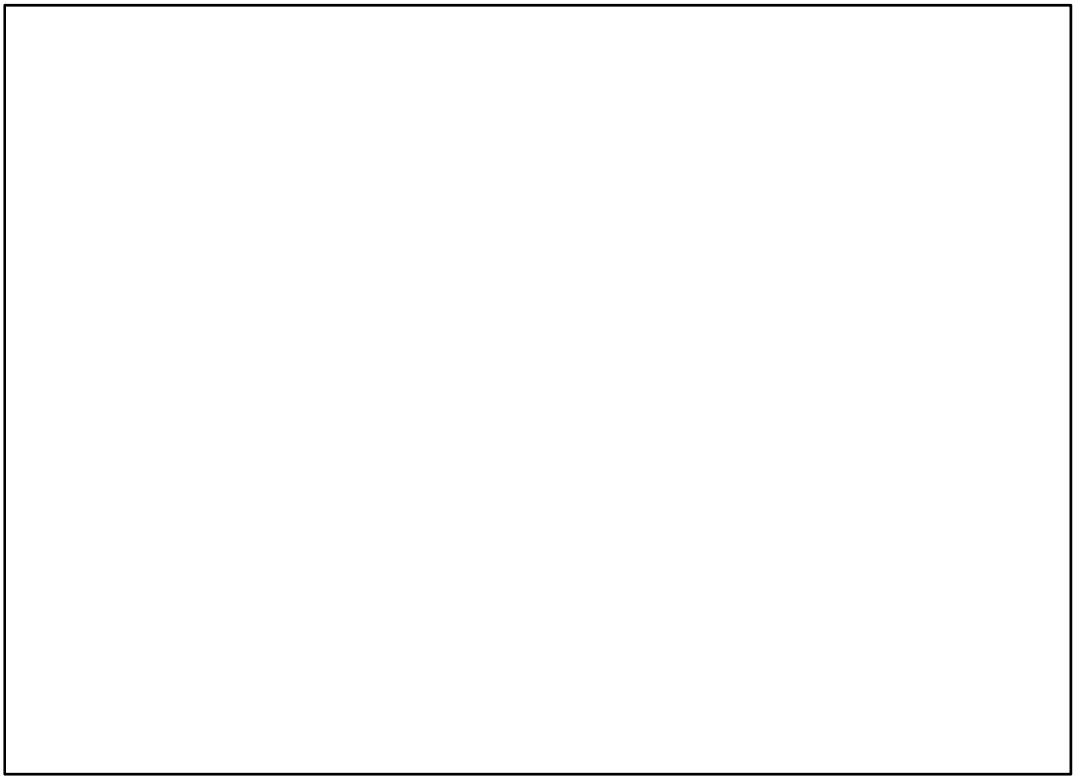


FIGURE 1: MAP OF LOCATIONS FOR ASSETS TARGETED IN THE REPLACEMENT OF UNDERGROUND LEGACY INFRASTRUCTURE PROGRAM

The following subsections discuss each of the sub-programs of the ULI program and the specific assets and asset types that are targeted.

E6.3.2.1 Replacement of Sachsenwerk Switch and Fuse Units with Compact Loop (CLD) or Compact Radial (CRD) Design

Sachsenwerk switch and fuse units were installed in Toronto Hydro's system during the mid to late 1980s. They were installed in pairs, with one switch normally open and the other normally closed, referred to as a dual radial configuration. This configuration provides a customer with the advantage of a standby power supply when normal supply experiences an outage. As well, using this configuration, the standard equipment used to replace existing units could be more easily maintained and replaced.

The switches themselves are air insulated and operate using a spring-loaded mechanism. Since the Sachsenwerk switches were originally installed, dual radial supply equipment has gone through several iterations and generations of technological improvement. Manufacturers and

standards have evolved to produce better alternatives as described below. As a result, Sachsenwerk units are no longer manufactured.

Forty-eight Sachsenwerk switch and fuse units remain in 24 locations across Toronto Hydro's system. The Sachsenwerk units in Toronto Hydro's system are at risk of catastrophic failure since they are known to flashover during operation, giving rise to serious potential safety and operational issues, described in detail in the Program Drivers and Asset Details sections. Given these risks and issues, Toronto Hydro proposes changing out Sachsenwerk units; however, these change outs would not be like-for-like replacements.

FIGURE 2: PHOTO "A" SHOWS THE SWITCH REMOVED FROM ITS CABINET, PHOTO "B" SHOWS THE SWITCH AND FUSE UNITS (NOTE SEPARATE COMPARTMENTS FOR EACH) AND THE SWITCH HANDLE BEING OPERATED. THERE IS AN ADDITIONAL EXTERNAL DOOR WHICH IS OPEN IN THIS PHOTO.

The primary replacement options for Sachsenwerk switch and fuse units are CRD or Compact Loop Design (CLD) equipment, two of Toronto Hydro's current standard switch designs. The use of either the CRD or CLD depends on the existing configuration of the switch and fuse location. Both options are submersible units insulated with SF_6 gas, as opposed to air. The CRD and CLD units are less susceptible to degradation and catastrophic flash-over when compared to existing air insulated units. In cases where the location's load can be accommodated by other means, alternative replacement options will be studied and the most efficient and practical replacement option will be implemented.

FIGURE 3: CRD EQUIPMENT INSTALLED IN AN EXISTING CRD VAULT

This sub-program is expected to remove all Sachsenwerk switch and fuse units from the system, with completion targeted for the end of 2018 due to the high priority nature of the work.

E6.3.2.2 Reconfiguring Thorncliffe Park Area Distribution Equipment

The configuration of the distribution system in the Thorncliffe Park area is a legacy design installed by the former East York Hydro. The system was installed in the early 1990s as an economical replacement for the network style system that was previously in place. The current Thorncliffe Park system was designed to mimic a spot network configuration by having five-way and six-way SF_6 switches, with multiple incoming primary feeders radially feeding the transformer vaults (Figure 12, below, is a photo of a six-way switch). These units are equipped with primary side automatic transfer switches (ATS). An ATS is a controlled motor operator that allows the switch to open or close as necessary when a feeder is taken out of service. The intended benefit of this configuration was that customers would only experience a momentary outage during a fault since the ATS operates quickly when a primary fault occurs.

There are a number of issues associated with this configuration, including the condition of the equipment, the availability of replacements and the lengthy duration of outages that are required to replace certain equipment. These issues and their reliability impact are discussed in detail in sections E6.3.3.1 and E6.3.3.2.

To remedy the situation in Thorncliffe Park, Toronto Hydro plans to reconfigure the distribution system by removing all submersible five-way and six-way switches and replacing them with a combination of pad-mounted and submersible four-way and three-way switches. Customers are currently radially fed from the five-way and six-way units. Reconfiguration will create a looped configuration between multiple three-way and four-way switches. This will allow Toronto Hydro to continue serving customers when a switch is taken out of service and will decrease outage times during reactive situations. A schematic of what the reconfiguration entails is shown in Figure 4.

FIGURE 4: EXAMPLE OF THE PLANNED RECONFIGURATION WORK FOR THE THORNCLIFFE PARK AREA

Reconfiguring Thorncliffe Park Area distribution equipment is expected to reduce outage times, since having multiple switches in place in a looped configuration will increase the ability of system operators to isolate the faulted section. The use of pad-mounted equipment in certain cases also eliminates concerns over the impacts of flooding on the currently installed equipment. Despite the

use of sump pumps, the Thorncliffe area has a history of flooded vaults that cause damage to equipment; discussed further in the Thorncliffe section of the Program Drivers section (E6.3.3.1). Toronto Hydro plans to replace all five-way and six-way switches, six switches total, in the Thorncliffe Park area over the 2015-2019 period as part of this sub-program.

E6.3.2.3 Conversion of Legacy Transclosure Equipment

Transclosures are a style of transformer that were installed in Toronto Hydro's system prior to the mid-1980s. A transclosure consists of an overhead pole-top or non-submersible vault style transformer placed on the ground inside a metal enclosure (Figures 5 and 13 are examples of typical transclosure units).

FIGURE 5: TYPICAL TRANSCLOSURE UNIT

FIGURE 6: EXAMPLE OF A PAD-MOUNTED TRANSFORMER (ONE REPLACEMENT OPTION FOR TRANSCLOSURES)

Many of these units are in poor condition and are at or approaching end-of-life, with the newest units having been installed over 30 years ago. Performing maintenance and reactive work on these units is difficult for field crews since their poor condition poses potential safety hazards in the form of arc flashes, discussed in more detail in the Program Drivers section (E6.3.3.1). Contemporary underground and pad-mounted transformers mitigate the safety issues posed by the legacy transclosure design.

Replacement options for transclosures include: (1) installing standard pad-mounted transformers, (2) installing submersible transformers in a vault, or (3) conversion to overhead using pole-mounted units. Each of these options typically requires both civil and electrical reconfiguration work. These replacement options will provide several benefits, including improved worker safety and the mitigation of long-lasting outages. In choosing a replacement option, Toronto Hydro considers the amount of load served and equipment cost. Existing transclosures supplying a service of 200 A or less will be replaced with an equivalent pole-mounted transformer. Units with a service size greater than 200 A will be replaced with a pad-mounted transformer. Submersible units are the most expensive replacement option and are not included in the current replacement plan because they would require a larger load to be economically justifiable.

In many cases, where the existing transclosure is radially fed, the replacement project will integrate the location into a looped system in order to provide more reliable service and decrease the failure impact of the new equipment going forward.

This program includes the planned replacement of six transclosure units in 2015 and is paced such that approximately a quarter (42 units) of the total known transclosure population are planned to be replaced by the end of the 2015 to 2019 period. Some units that are not included in this program may be replaced under the underground rebuild work in the Underground Circuit Renewal program as described in Section E6.1 in order to gain efficiency by incorporating the transclosure replacement within a larger feeder rebuild project, where appropriate.

E6.3.2.4 Conversion of Power-lite Switches to Network and CRD

Powerlite switches, a type of secondary transfer switch, are installed in single-phase radial vaults, typically found servicing shops along the Bloor/Danforth corridor. These switches have two incoming supply feeders and a tie in between, designed to auto transfer if one feeder experiences an outage. These units were originally installed in the mid 1960s. In the late 1980s, due to large overloads at locations on the Danforth (greater than 100%) and the abnormal configuration, Toronto Hydro undertook conversion projects to remove many of these units. However, there are still 10 remaining locations that need to be partially or completely replaced. Most of these locations are on Bloor St., since the previous conversion projects targeted the Danforth locations. This program is intended to remove all remaining Powerlite switches from the system.

FIGURE 7: POWERLITE SWITCH INSTALLED IN A VAULT. NOTE THE THREE CABINETS – ONE FOR EACH SWITCH. LOCKS ON THE FRONT ARE ON THE SWITCH OPERATING MECHANISM.

Powerlite, the original manufacturer, no longer produces these switches and there is no like-for-like replacement option available. These locations are also atypical because they are single-phase underground locations fed off of feeders that normally only service three-phase locations.

During the original conversion of these locations, customers had their secondary voltage converted from 120/240 V (single phase) to a 120/208 V (three phase) service. The conversion was required since a 120/240V service cannot be supplied from a three-phase supply. This type of secondary voltage conversion requires communication with affected customers and, in some cases, replacement or modification of customer equipment. These requirements make this work difficult to execute properly in a reactive situation.

Recently there have been reported safety hazards associated with Powerlite locations due to hazardous work environments, described in detail in the Program Drivers section (E6.3.3.1). These safety hazards were addressed reactively by replacing the failed Powerlite switches with three phase switches (CRD type), but with only one phase being utilized. In the later years of this program, 2018-2019, the locations that were originally addressed reactively will be revisited for conversion to three-phase supply. The CRD switches that were initially installed will be reused because they are three phase switches. Toronto Hydro plans to add a three-phase transformer and re-cabling services to the customers from 120/240 V to 120/208 V as part of this work.

By replacing the remaining Powerlite switches, Toronto Hydro can supply customers using standard configurations that are suitable for the long-term. Vaults with Powerlite switches will either be converted to three-phase network locations (network is an underground distribution configuration used in dense downtown areas) or to CRD locations. The selected conversion option will depend on the load at the location and the amount of space available in the existing vault. In some cases the vault size may necessitate rebuilding the vault in order to install either type of equipment. Secondary voltage conversion is required under either replacement option.

E6.3.2.5 Decommissioning of Vault Step Transformers

Step-up or step-down transformers exist in some underground vaults to provide customers with multiple service voltages. These step transformers take the secondary voltage from a distribution transformer and step it up or down. For example, the 13.8 kV distribution transformer provides a 120/208 V supply, but the customer may also require 347/600 V supply. In this example, the vault may have a step transformer to take part of the 120/208 V supply and step it up to 347/600 V. These units are usually small, dry type transformers (see Figure 8) or small submersible units (see Figure 9). Dry type transformers use air as their insulating medium instead of traditional oil insulation. Toronto Hydro has identified seven sets of step-transformers that will be targeted by this replacement program during the 2015 to 2019 period.

Toronto Hydro installed these units throughout the system at various times from the late 1950s through the early 1980s. These transformers are legacy assets because Toronto Hydro no longer provides multiple service voltages in this manner. Due to the small number of these transformer units installed and the wide array of sizes (both kVA and voltage) found among the in-service units, Toronto Hydro does not stock these units.

FIGURE 8: DRY TYPE STEP TRANSFORMERS IN VAULT LOCATION 1808 ON MERTON ST

FIGURE 9: SUBMERSIBLE OIL FILLED STEP UP TRANSFORMERS

The replacement option for these units differs from location to location depending on the equipment and supply voltages that are installed in the vicinity. The ideal replacement option, if available, is to extend a secondary service of the required voltage from a nearby location. An alternative is to install a new primary transformer to distribute the required secondary voltage.

E6.3.2.6 Replacement of Cable Chamber Covers

Cable chambers are underground structures where crews can access the cables running through the concrete duct banks in the underground system. Cable chamber covers are used to cover up cable chamber entrances on city streets. Figure 10 shows a typical cable chamber installation in the City of Toronto.

FIGURE 10: STANDARD CABLE CHAMBER COVERS INSTALLED IN TORONTO

In the past seven years, Toronto Hydro has recorded twenty-four incidents of cable chamber covers not being property seated on the chamber neck, i.e. ejected. Fortunately, none of these incidents have resulted in injury. However, incidents resulting in injuries and death have occurred in other jurisdictions, discussed in detail in the Program Drivers section (E6.3.3.1).

As described in more detail in section E6.3.3.1, an ejected lid results from an eruption occurring inside a cable chamber. This eruption is caused by deteriorated cables heating up, arcing, and igniting gases, which can create a powerful shock wave. Toronto Hydro plans to address the cable chamber cover problem proactively by replacing the existing cable chamber covers with a new design that allows gas pressure to be released safely. The design of the replacement covers allows the gases to vent (possibly preventing the eruption) and the covers themselves are able to

withstand the force of the possible shock wave without being launched into the air. Two examples of replacement options can be seen in Figure 11.

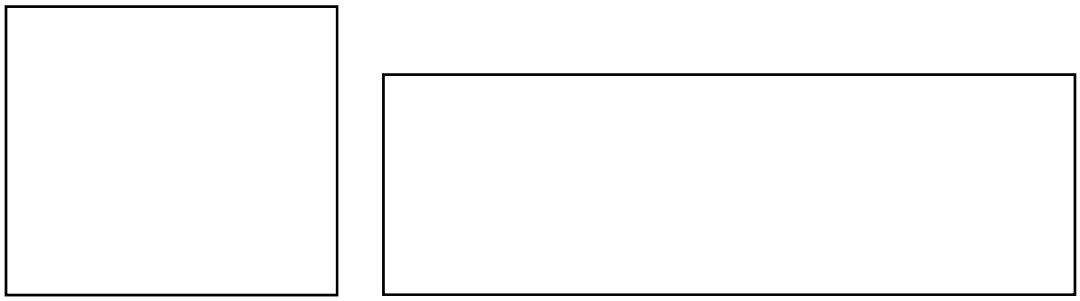


FIGURE 11: TWO OF THE REPLACEMENT OPTIONS BEING EVALUATED FOR CABLE CHAMBER COVERS. BOTH PROVIDE A MECHANISM FOR EXPLOSIVE GASES TO BE VENTED.

There are 10,572 cable chambers in the city of Toronto. Table 1 provides a breakdown of the number of cable chambers in each former utility.

TABLE 1: INVENTORY OF CABLE CHAMBERS BY FORMER UTILITY

Cable Chambers Location	Number of cable chambers
East York	355
Etobicoke	918
North York	848
Scarborough	221
Toronto	8,112
York	118
Total	10,572

In the first year of this sub-program, Toronto Hydro plans to replace 25 cable chamber lids with the new design. Toronto Hydro plans to replace a limited number in the first year because the new cable chamber lid must be tested for proper functionality in both the winter and summer months to ensure they operate in the multitude of conditions that they will be exposed to. If the new lid design passes the necessary testing, Toronto Hydro plans to replace a total of 1,475 cable chambers in the remaining four years of the program.

The three variables that impact the risk and consequences of an eruption are (1) the number primary conductors in the cable chamber, (2) the age of the conductors in the cable chamber and (3) the number of pedestrians in the area. Toronto Hydro has taken into consideration the most

vulnerable cable chambers based on these identified variables, and will execute the replacement program to address the highest risk cable chambers. A portion of the cable chamber lids that have not been identified in this program for immediate replacement may be replaced in future proactive programs; however the majority of cable chamber lids that do not pose a risk will only be replaced when the chamber is rebuilt or the lid reaches its end-of-life.

E6.3.2.7 Summary of Program Benefits

Table 2 summarizes the anticipated benefits generated by the ULI program.

TABLE 2: PROGRAM BENEFITS

Customer Value	ƒ Reduces lengthy outages that can severely inconvenience customers. ƒ Improves public safety by replacing assets such as cable chamber lids and transclosures. ƒ Improves the aesthetic of neighborhoods, particularly in the case of transclosures, which are rusted, corroded and are often located in high visibility areas. ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $3.52 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.3.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $1.46 million, confirming the economic prudence of the investments (see Section E6.3.7).
Reliability	ƒ Mitigates outages caused by failed underground equipment (28% of total system outages). ƒ Decreases the duration of outages. ƒ Removes certain operating restrictions posed by some legacy assets.
Safety	ƒ Mitigates the risk of current cable chamber lids being ejected into the air, which poses risks for both pedestrians and property. ƒ Minimizes safety issues associated with crews being exposed to: o equipment flashover when operating switch and fuse units, o a potentially hazardous work environment in Powerlite locations, and o arc-flash.

Efficiency	ƒ The use of engineering resources to deal with asset failure on a reactive basis is avoided, improving organizational efficiency. ƒ Installing a current standard asset, opposed to using a like-for-like legacy asset (if available) is more efficient from a cost/procurement/standards perspective (i.e. wanting to maintain few stock coded items and critical spares). ƒ Limiting the number of different types of assets in the system results in maintenance related savings as fewer equipment types with varying maintenance needs are used.
Other	ƒ New equipment being installed (CRD/CLD switches and pad-mount switches) have the ability to be retrofitted to be remote operable.

E6.3.3 Why the Program is Needed

The ULI program is needed to address non-standard equipment and configurations located throughout Toronto Hydro's underground system. These asset types and configurations are functionally obsolete and many of the legacy assets are at a high risk of failure due to their age and/or design defects. As previously discussed, because the assets are non-standard, failure could have a significant impact on reliability due to the lack of like-for-like replacements available. In many cases this equipment also poses potential safety risks to the public and/or Toronto Hydro crews.

E6.3.3.1 Program Drivers

Table 3 summarizes the trigger and secondary drivers for replacing ULI. This program is a System Renewal initiative with a trigger driver of functional obsolescence.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Most of the equipment targeted by this program is no longer manufactured and, therefore, it is difficult to acquire replacements when needed. These assets are becoming more likely to fail as many are near end-of-life. ƒ Vastly improved assets have become available since the infrastructure targeted by this program was originally installed. The modern assets have additional functionality and safety measures when compared to the currently installed legacy equipment. ƒ There are no longer any construction standards which can be used by Toronto Hydro for replacing/maintaining these assets in a like-for-like manner.
Secondary Drivers	Reasoning

Safety	ƒ Degradation of assets can pose safety hazards for field crews when operating and/or maintaining the equipment. ƒ Certain assets (i.e. cable chamber lids) create public safety issues.
Reliability	ƒ Often a like-for-like replacement option is not available for equipment targeted by this program. As a result, when this equipment fails, the system can be left in a contingency situation for long durations while a solution is developed and executed. Until the solution is implemented and the system resumes normal operation, customers are exposed to additional outage risk. ƒ Assets are at or near the end of their useful life and/or prone to failure, presenting an outage risk.
Failure Risk	ƒ Assets are at or near the end of their useful life. As a result, they are more likely to fail and will require reactive replacement.

The various assets and installations addressed by this program share functional obsolescence as the trigger driver for proactive replacement. If and when these assets require reactive replacement (i.e. if they are allowed to fail while in service), the lack of like-for-like replacement options or alternative equipment may result in prolonged outages for customers. Custom engineered solutions are regularly needed to fully resolve issues across all assets targeted with this program, with the exception of cable chamber covers. The time it takes to develop these solutions often means that the system must be left in a contingency situation for an extended period of time until an appropriate solution can be implemented.

Many of these assets have reached, or are approaching, end-of-life and/or are at risk of failure due to design defects, which raises the urgency to proactively replace these obsolete assets. Proactively replacing these assets is expected to help minimize operational, reliability and safety risks and will allow for more efficient use of resources.

The following sub-sections provide additional detail on the investment drivers for the specific asset types and configurations addressed in this program.

(i) Sachsenwerk Switch and Fuse Units

Toronto Hydro must proactively replace Sachsenwerk switch and fuse units in order to ensure worker safety, maintain operability of the system and to mitigate the risk of unplanned outages. As describe in section E6.3.2.1, Sachsenwerk switch and fuse units are used in dual radial configurations. The switches have been deemed unsafe because they have drawn a dangerous arc current (i.e. the unit “flashed over”) in multiple cases due to a consistent failure mode explained below. Two examples of recent failures of the Sachsenwerk switch and fuse units are the November 2012 failure at 30-40 Holly St (location MDH in the discussion below) and the April

2011 failure at 66 Walpole Ave (location GWD in the discussion below). Figure 12 shows photos of the switch compartments post-failure. Scorching on the top of the phase barriers/dividers is visible in both cases.

FIGURE 12: PHOTOS OF SWITCH COMPARTMENT (DOOR OPEN) FROM MDH (LEFT) AND GWD (RIGHT) AFTER THEIR FLASH-OVER INCIDENTS

The failure at MDH resulted in a near miss incident (i.e. injury could have occurred but did not). The Sachsenwerk unit flashed over (i.e. discharged electricity in a high current arc) while being manually operated to transfer a customer to its standby supply. The unit failure occurred because the spring-loaded mechanism, which enables the fast movement of the switch blades on opening and closing, did not engage. This caused the switch blades to move in time with the operating handle, drawing an electrical arc, which caused the fault.

The incident at MDH caused the customer to go without power supply for over 40 hours (during a portion of this time they were supplied via generator). Since the outage resulted in two primary feeders being put out of service, the customer's normal and standby supply, a total of seven customers were affected by the outage including a public library, a school, a retirement residence, an office building and two apartment buildings, with the shortest outage time being just over 100 minutes. The total customer minutes out (CMO) for this outage was 1,398 and the total Customers Interrupted (CI) was seven. The relatively low CI figure is explained by the fact that the customers affected were bulk metered customers.

Safety concerns with these units have limited the ability of system operators to use the equipment as originally intended, negatively impacting reliability. A safety bulletin was issued by Toronto Hydro to its employees, specifying special instructions for switching these units following the November 2012 incident. The bulletin indicated that before operating a Sachsenwerk switch and

fuse unit to make or break full load, crews must contact their supervisor so that a collaborative onsite assessment and evaluation can be undertaken. This evaluation includes an inspection of the switch to determine if the switch can be operated. If operation of the switch proceeds and the initial operation is unsuccessful (the switch does not operate properly), a second attempt is not made; instead, the system operator must be notified immediately.

As discussed, in certain circumstances it may be unsafe for crews to operate these switches as load break/make switches. This means that the switches can only be used in paralleled operations because otherwise, the primary feeder that supplies the switch would need to be taken out of service before switching could occur in an outage restoration situation.

Due to the failure history of these units, and the risk posed to crews operating the switches, Toronto Hydro plans to remove all Sachsenwerk switch and fuse units from the system. Prior to this failure mode being identified, Toronto Hydro was in the process of replacing existing switch and fuse units at end-of-life with retrofitted units.

(ii) Thorncliffe Park Area Distribution Equipment

Toronto Hydro plans to proactively reconfigure and replace equipment in the Thorncliffe Park area in order to mitigate the risk of prolonged outages. The distribution system in the Thorncliffe Park area is a legacy design of the former East York Hydro, as described in section E6.3.2.2.

The main issues with the existing configuration are (1) corrosive and flooded vault environments causing the ATSs to malfunction, (2) the fact that no six-way SF_6 switches are currently stocked due to the limited number in the system and since the supplier no longer manufacturers them, and (3) radial customers supplied by the five-way and six-way switches cannot remain energized if the switch is taken out of service for replacement (i.e., when a switch is scheduled for replacement, customers will experience a planned outage of up to four hours until the replacement is complete).

These inherent problems in the design of the Thorncliffe Park area directly contributed to a 29-hour long outage on March 10, 2013. The event was caused by a six-way submersible switch failing. Finding the fault proved difficult since the configuration requires complex switching procedures to determine on what segment of the feeder the failed equipment is located on. Once the fault was found, customers supplied directly from the six-way switch had to wait for the switch to be replaced before their power could be restored.

As an alternative solution, Toronto Hydro arranged for one of the three primary feeders to bypass the switch and a five-way switch was installed in place of the failed six-way switch. The

customers fed from this switch were out of power until this five-way switch could be installed. The entire process of finding the fault, performing switching to isolate the fault, determining a replacement option and completing the work took over 29 hours. The total CMO for this outage was 50,083 and the total number of CI was 70. Many of the customers were bulk metered apartment buildings, so the actual number of people affected by the outage was much greater than the CI figure indicates. The outage was so severe that it attracted extensive public and media interest.[1]

Figure 13 shows a photograph of the six-way switch in vault V4488 that failed on March 10, 2013.

FIGURE 13: THE 6-WAY SF6 SWITCH WHICH FLASHED-OVER IN THE OUTAGE IN MARCH OF 2013. THIS PHOTO WAS TAKEN AFTER THE FAULT HAD OCCURRED; FAULT WAS INTERNAL TO THE SWITCH. NOTICE THE RED TAG ON SWITCH POSITION VS216 INDICATING THE ATS FOR THAT POSITION WAS NOT FUNCTIONAL.

As noted above in Section E6.3.2.2, the ATS installed on the five-way and six-way switches in this area are associated with reliability issues. Under normal circumstances, the ATS is supposed to transfer over to a backup feeder when the normal primary supply is lost. However, many of these ATS are no longer functional due to flooding in the vaults, despite sump pumps being installed. The excessive flooding in this area is due to an underground river. This has damaged the circuitry controlling the ATS, resulting in additional maintenance costs and resources to continuously fix and inspect the ATS units. An outage in the area on April 23, 2008 had an extended impact due to an ATS failing to transfer.

[1] Please refer to:
City TV: http://www.citynews.ca/2013/03/09/power-back-on-for-hundreds-in-thorncliffe-park/,
680 News: http://www.680news.com/2013/03/10/power-outage-in-east-york-expected-to-end-by-late-saturday-afternoon/).

(iii) Legacy Transclosure Equipment

Toronto Hydro must proactively replace transclosures in order to mitigate the risk of lengthy outages and to maintain a safe working environment. As described above in section E6.3.2.3, transclosures are pole-mounted or non-submersible vault style transformers within a metal enclosure (vault style shown in Figure 14). Pole-top and non-submersible vault style transformers are not intended for use in the corrosive and dirty environment of enclosures located at ground level. The primary connection to this transformer is not performed through an elbow connector, which is the standard for most underground or pad-mounted transformers. Instead, the connection terminates directly at the primary bushing of the transformer. This means that these units are "live-front" (exposed terminations/bushings are energized), making them potentially unsafe for crews since the primary termination is more easily exposed to dirt and debris and thus more prone to tracking (i.e. the gradual breakdown of the insulator under electrical field stress) and flashovers.

FIGURE 14: VAULT STYLE TRANSFORMER IN AN ENCLOSURE

FIGURE 15: CORRODED AND DAMAGED TRANSCLOSURE ENCLOSURES

The majority of the transclosures in the system are nearing end-of-life and are in poor condition, with enclosures that have rusted through (Figure 15). The poor physical condition of the transclosures is a potential safety hazard to both the public and Toronto Hydro crews. Since transclosures are a legacy design and have no like-for-like replacement option, they are difficult to address in the event of an outage, which leads to long restoration times. In August 2013, a worker was exposed to an arc flash hazard when working on the primary termination at a transclosure location. Fortunately the worker was not harmed but this "near miss" incident could potentially have resulted in serious injury.

(iv) Powerlite Switches

Powerlite switches should be replaced in order to mitigate risk of failure and address potential worker safety concerns. Powerlite switches are secondary switches located in single-phase radial vaults. The switch is designed to auto-transfer when a primary feeder goes out. This auto-transfer mechanism has become increasingly likely to fail due, in part, to the age of the equipment. In 2013, two switches failed to operate autonomously.

The switch itself is not a stock coded item (since it is no longer manufactured) and no like-for-like replacement can be obtained. In addition, manual switching can be a safety hazard due to the poor condition of these switches (spring mechanism does not engage) and the limited space in the vault for manual operation. Each replacement requires an engineered solution dependent upon the location's load and the amount of space in the existing vault structure.

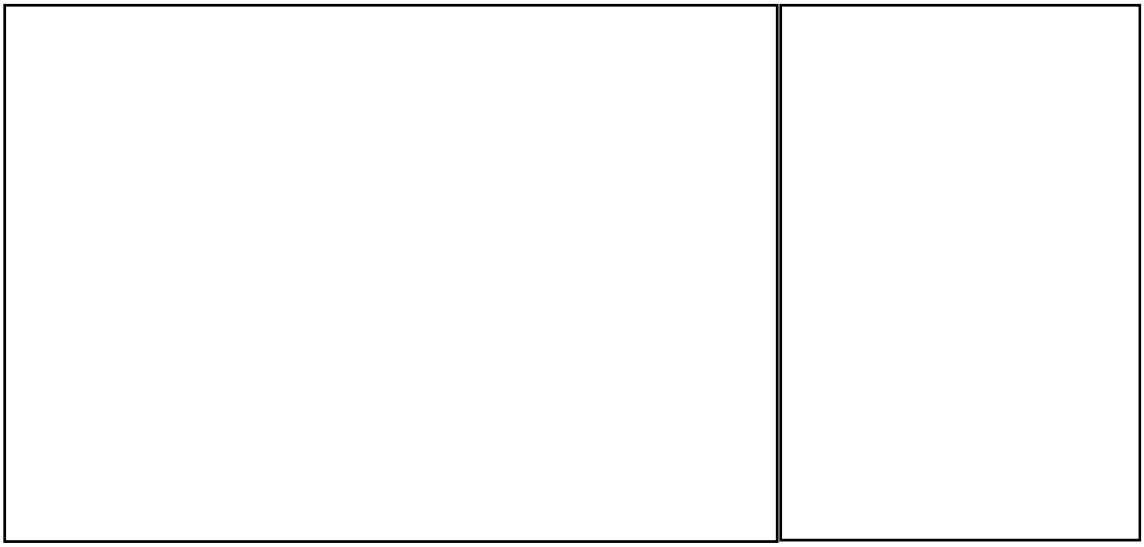


FIGURE 16: POWERLITE SWITCH AND SINGLE-PHASE TRANSFORMER

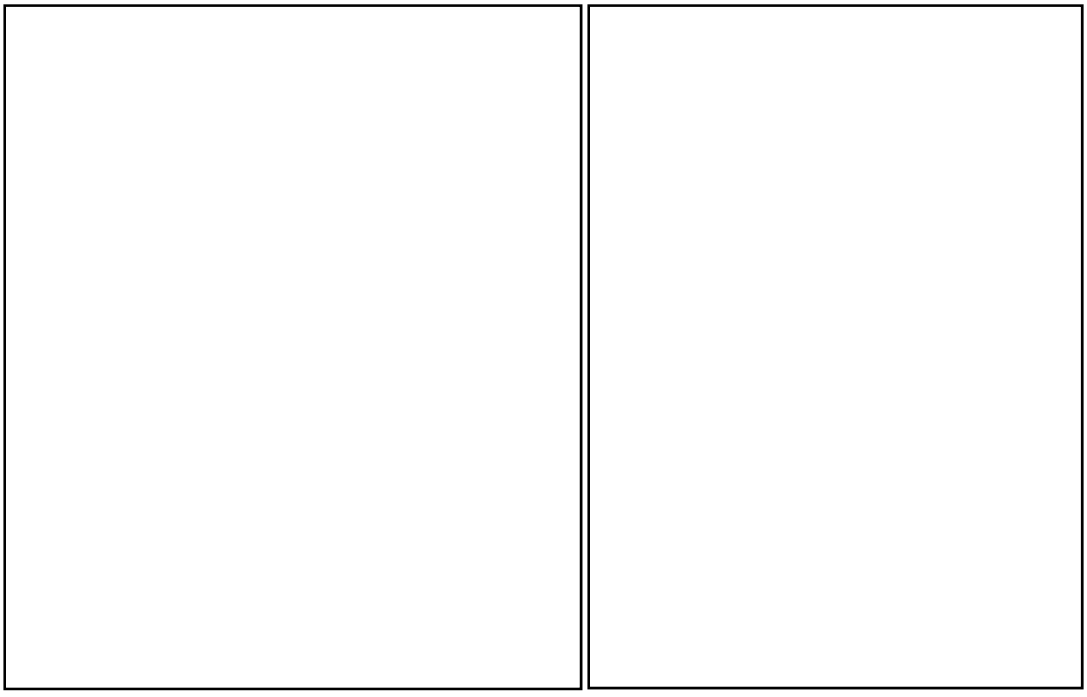


FIGURE 17: INTERNAL SWITCH MECHANISM OF THE POWERLITE SWITCH (DOOR OPEN)

In the spring of 2013, one Powerlite location on the Danforth was deemed too hazardous to continue to operate. As a result, the switch at this location had to be proactively changed out to ensure that customers could be restored in the case of an outage. The response was not able to match the urgency of the situation due to the lead times associated with a planned solution engineered specifically for this site.

The Powerlite switch in this situation had to be reactively replaced with CRD switches. However, the conversion to a CRD set-up was incomplete since there is still a single phase primary supply. This is not a preferred solution going forward since (1) the location becomes atypical relative to the distribution system as a whole, which could cause crew or operator confusion, (2) single phase loads could cause imbalance (excessive neutral currents) and subsequent inadvertent tripping of the station relay, and (3) there is the potential to get an 8 kV voltage on the system neutral while conducting work if proper precautions are not followed.

(v) Vault Step Transformers

Toronto Hydro must replace existing vault step transformers (described in section E6.3.2.5) in order to mitigate the anticipated negative reliability impacts should this obsolete and non-standard equipment fail while in service. Toronto Hydro no longer stocks step transformers for the reasons discussed above in section E6.3.2.5. As such, the lack of a like-for-like replacement option would lead to an extended outage for customers if a unit were to fail.

The majority of the step transformer units are of a dry type, meaning that the windings are insulated using air (described in section E6.3.2.5). This design exposes the transformers to failure from vault flooding. One such incident occurred in late 2013, interrupting the 600 V service to a local school. Solutions to allow for removal of these units could involve customers being fed from additional secondary circuits in the area, although each location may require a unique approach.

(vi) Cable Chamber Covers

There are 10,572 cable chambers in the City of Toronto. Toronto Hydro must replace cable chamber covers in order to mitigate the safety hazard associated with flying lids caused by eruptions in the chamber. As shown in Figure 18, there have been 24 incidents of flying lids in the past seven years; while this failure mode is not overly common, it can result in harm to people and property. Other utilities have also experienced cable chamber eruptions with some causing serious injuries[2].

[2] Some incidents from the past year have been included for reference –
Woodhaven, New York - http://theforumnewsgroup.com/2013/08/29/woodhaven-manhole-fires-send-five-to-hospital-2/
Columbus, Ohio – http://www.dispatch.com/content/stories/local/2014/03/01/manhole-explosions-tied-to-aep-vault.html
New York City – http://nypost.com/2014/01/03/fire-at-radio-city-music-hall-forces-evacuation/
Detroit – http://www.wxyz.com/news/region/detroit/underground-explosions-rock-downtown-detroit
Albany, New York – http://www.cbs6albany.com/template/cgi-bin/archived.pl?type=basic&file=/news/features/top-story/stories/archive/2013/06/YxtyahWa.xml



	2006	2007	2008	2009	2010	2011	2013
# of incidents	2	6	7	2	3	2	2

FIGURE 18: NUMBER OF EJECTED CHAMBER COVER INCIDENTS AT TORONTO HYDRO BY YEAR

Cable chamber covers in Toronto Hydro's current infrastructure are made of cast iron and have a minimum mass of 150 kg. Shock waves caused by an eruption inside the cable chamber can send the cable chamber cover into the air, posing safety risks to people and property nearby. Explosions can occur when overloaded or compromised cables generate excess heat that causes their insulation to begin to melt. The insulation then smolders and catches fire, releasing gases that then build up inside the cable chamber. With the insulation compromised, the conductor may then arc and ignite the built-up gases, causing a powerful explosion. This explosion can then eject the cable chamber cover, as shown in Figure 19

FIGURE 19: CAUSE OF EJECTED CABLE CHAMBER COVER [3]

Depending on the amount of gas-pressure built up inside the cable chamber the force of the eruption generated may cause the cover to flip over or be launched several feet in the air. Toronto Hydro estimates that the potential explosive force of the shock waves which can be generated is sufficient to send a cover up to 65 feet high at a speed of up 20 meters per second. Current cable chambers covers cannot withstand or dissipate cable chamber eruptions.

The current lid design may also be contributing to the severity of some outages. Since the current cover design does not allow for ventilation of gas, there is an increased the likelihood of an eruptions occurring due to gases being present in the chamber when a fault is experienced. These eruptions cause the chamber covers to be launched into the air and also cause damage to the cables surrounding the faulted cable. If more than one cable becomes damaged, the system is placed into a multiple contingency situation.

The new cable chamber covers that will be installed have ventilation capabilities for gases and can withstand the force of the potential shock waves. This allows them to address the potential an

[3] How Stuff Works: How Exploding Manholes Work, Kevin Bonsor: http://science.howstuffworks.com/environmental/energy/exploding-manhole1.htm

eruption inside the cable chamber in a controlled and safe manner. As well, by installing a cable chamber cover design that vents gases, Toronto Hydro plans to reduce the possibility of an eruption so that cable fault damage may be more easily contained to one feeder.

E6.3.3.2 Asset Details

(i) Asset Lifecycle This program targets the replacement of underground legacy assets and assets in non-standard configurations at, or nearing, the end of their useful lives. Due to the age of these assets, the probability of failure is high.

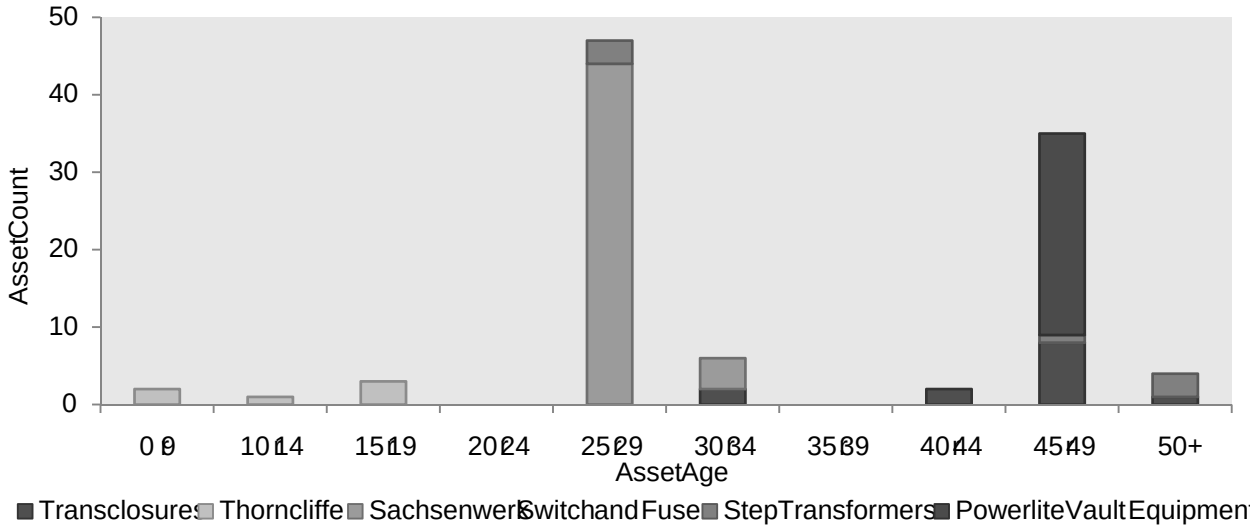


FIGURE 20: ASSET AGES FOR EXISTING IDENTIFIED LEGACY ASSETS TARGETED BY THIS PROGRAM (NOTE: SACHSENWERK AGE DATA INCLUDES UNITS BEING REPLACED IN NETWORK CIRCUIT RECONFIGURATION PROGRAM)

Figure 20 provides the age of assets to be replaced as part of this program. The 48 Sachsenwerk units planned for replacement (eight of which are being replaced in the Network Circuit Reconfiguration program) are no longer manufactured and are all 25 years and older, with four units being more than 30 years old. The transclosure units being replaced in 2015 to 2016 are at their end-of-life (or will be by their scheduled replacement dates) and are not currently stocked by Toronto Hydro as they are a legacy asset (end of life for pad or vault style transformers is 35 years). In many cases, these units show corrosion (see Figure 15) and are generally in poor condition. As their condition deteriorates, they also pose an arc flash hazard, described in further detail in the transclosure segment of section E6.3.3.1.

As can be seen in Figure 20, all of the Powerlite units are 45 years or older. This switch type is no longer manufactured. These units have past the end of their useful lives (end of life for ATS switches – a similar asset – is 40 years) and no longer operate as intended, often requiring manual switching in ways that could pose risks to operating crews. Assets included in the Powerlite vault equipment represented in Figure 20 include the Powerlite switches and single phase transformer units that will be changed out at the same time as the switches. Two of these locations have had CRD equipment installed reactively but still have single-phase transformers that will require replacement.

There are seven sets of step transformers being replaced in this program, all of which are nearing end-of-life (30 years for submersible transformers, 35 years for vault transformers) and are therefore at risk of failure. Asset age is taken into account during prioritization so that older units are replaced in the earlier years of the program. More detailed information regarding prioritization data can be found in section E6.3.4.1.

The switches in the Thorncliffe Park distribution area are the newest legacy assets being replaced through this program. The replacement of this equipment is driven primarily by an obsolete configuration that could lead to long outage durations. The SF_6 switches (SF_6 is the insulating medium for switches in the Thorncliffe Park area) are considered sealed for life by their manufacturer. Typically this life guaranteed by the manufacturer of the submersible SF_6 switches in Toronto Hydro's system is 20 years, which is shorter than that of more traditional assets. Once a switch has leaked to the point where it cannot be operated safely, it has, for all intents and purposes, failed. In the case of the outage experienced at Thorncliffe Park in the spring of 2013, a switch had leaked to the point where a fault was able to occur within the switch without any switching action taking place. The switch that failed was of the same vintage (late 1990s) as most of the other switches in Thorncliffe Park that this programs targets for replacement. Two of the switches are newer because they are the result of reactive replacements (one replaced in 2008 and one in spring 2013). For more details on the outage in March 2013 please refer to section E6.3.5.2.

(ii) Asset Failure Impacts

The ULI program improves reliability by helping mitigate equipment failures, which are one of the most common causes of outages on Toronto Hydro's system. Approximately 50% of the outages on Toronto Hydro's system during the last five years (2008-2013) were attributable to failed (i.e. defective) equipment, with 28% due to failed underground equipment. Failed underground equipment can be further broken out into cable assets (i.e. cables and splices) and other assets (e.g. transformers, switches). Failure of underground assets excluding cable related assets

represents 11% of all forced outages throughout the entire system as per Figure 21 below. Legacy assets targeted by this program have an increased failure risk because they are at, or nearing, the end of their expected useful lives.

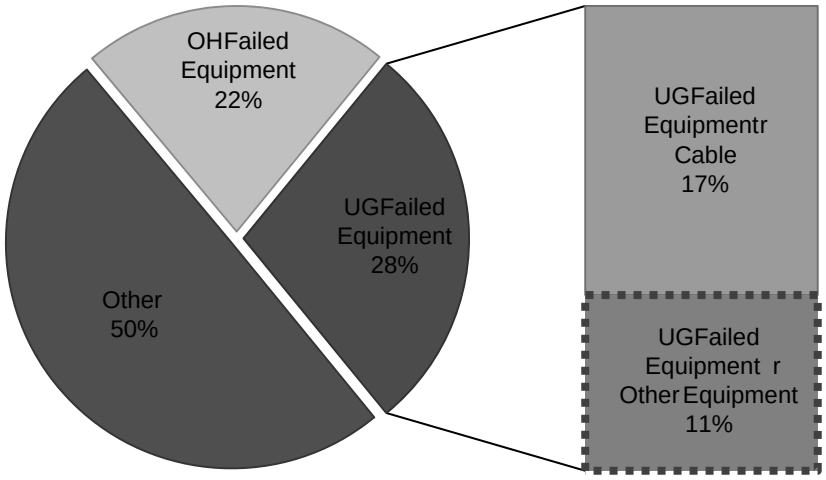


FIGURE 21: BREAKDOWN OF SYSTEM OUTAGES OVER THE PAST FIVE YEARS (2008-2013) BY OUTAGE CAUSE

If an underground equipment failure is caused by a legacy asset, outage restoration times will be lengthened due to a lack of like-for-like replacement options and/or difficulties that crews may have restoring non-standard configurations. The solution is typically dependent on site-specific conditions (e.g., vault size and customer load). As a result, legacy asset failures tend to result in relatively lengthy outages.

Failure Causing Secondary/Local Outage

The failure mode that would impact the least number of customers would be an outage that only affects customers downstream of a distribution transformer or on a segment of a feeder. This is referred to as a secondary or localized outage. While the system is designed to handle a first contingency, a contingency plan does not always exist at this level due to the relatively low number of customers impacted; therefore, restoration requires that the equipment be replaced or some other form of resupply is done.

If a failure of a transclosure feeding a commercial site occurs, all customers fed by the unit would experience an outage. If the transformer was damaged beyond repair, the outage could last up to 16 hours, since there is no standard replacement option.

In a reactive scenario, the goal is to restore power as quickly as possible. In order to accomplish this goal, Toronto Hydro must reconnect the customer to the new transformer in a delta configuration (the three phase wiring of the failed transclosure unit) in order to match their service, even though this new transformer's secondary side will be a three phase wye configuration, which has a fourth grounding wire and is the current standard. At a later date, an electrician would need to make the necessary changes to the customer's electrical supply and meter base, requiring a second (planned) outage to bring in the fourth wire (ground) to the customer. This would be the case with the failure of any delta transformer in the system, since delta transformers themselves are a legacy design.

When a residential transclosure fails, the unplanned outage would de-energize the entire residential loop so that field crews could safely work on the non-standard unit. This process results in long outages to other customers who are fed from healthy assets in the loop.

When replacements are performed proactively for these units, the outage experienced by the customer is reduced from approximately 16 hours to around six to eight hours. The proactive approach allows the necessary preparatory work to be completed in advance (i.e., civil work and electrician services) so that the customer will only be de-energized while the connections are made.

The step transformers present a similar failure scenario. While the units service small loads, if they fail, it could take a substantial amount of time to restore service if there is no nearby supply of the required voltage. Many of the step transformer units service schools; accordingly, lengthy outage durations would cause considerable difficulties and inconvenience to the public.

Failure Causing a First Contingency Feeder Outage

The failure mode that has a more severe impact on customers is an outage that takes out an entire primary feeder, referred to as a first contingency feeder outage. The system is designed to handle a first contingency, so while customers on a feeder will still be interrupted by a failure, they can be restored before the source of the failure is completely resolved. Outage restoration time will depend on the number of customers on a feeder.

Sachsenwerk switch and fuse units are prone to flashing over (faulting to ground) when operated. When this occurs, the station breaker will open and all dual radial customers on that feeder will

lose power. A flash-over of a switch and fuse unit will always cause a primary feeder outage, resulting in customers being interrupted with the number of customers affected dependent on the feeder.

Powerlite vaults provide a second example of this failure mode. The transformers in Powerlite locations are of the same vintage as the switches (mid 1960s) and have no upstream protection. If these transformers fail, the entire primary feeder will fault to ground and all customers that are supplied by the feeder will lose service.

Failure Causing a Second/Multiple Contingency Feeder Outage

The failure mode that would have the most severe impact on customers is an outage that takes out multiple primary feeders, referred to as a second or multiple contingency feeder outage. Since the system is not designed to handle a multiple contingency, customers on the interrupted feeders may not be restored until the source of the failure is resolved. Outage restoration time will depend on the severity of the damage on each feeder.

The non-standard system configuration in Thorncliffe Park features transformer vaults that are fed radially from five-way and six-way switches. When a failure of the five-way or six-way switch occurs it can take out all the primary feeders which terminate on the switch. This means a large number of customers are affected by the outage and fault locating and restoration become more difficult, lengthening outage duration. Refer to Figure 22 for a diagram showing the current configuration of a six-way switch in the Thorncliffe Park area.



FIGURE 22: VAULT V4488 CONTAINS A 6-WAY SWITCH THAT HAS THREE INCOMING PRIMARY FEEDERS AND SUPPLIES THREE TRANSFORMER VAULTS (V4478, V4616, AND V4465). IN THE EVENT OF EQUIPMENT FAILURE WITH THE 6-WAY SWITCH, THERE IS NO WAY TO SUPPLY THE THREE RADIALLY FED TRANSFORMER VAULTS AND ALL THREE PRIMARY FEEDERS WOULD EXPERIENCE AN OUTAGE.

Failure Causing System Operating Constraints

A final failure mode that would impact customers is a failure causing an operating constraint. This type of failure refers to a situation when equipment can no longer be operated as intended. When this happens, forced feeder outages may be required in order to operate the system. The impact of these outages varies based on the equipment involved and could affect multiple primary feeders. Most outages incurred due to operating constraints are momentary outages.

The Powerlite switch is an example of this type of failure. Powerlite switches can fail to automatically transfer feeders during an outage. When this type of failure occurs, customers will see an outage to half of their service (since customers have half their panel supplied by each transformer in this arrangement, see Figure 23). Crews must go to the site and manually operate the switch to fully restore customers. This can result in an outage lasting up to an hour while the crew is dispatched.

FIGURE 23: INTERNAL SET-UP OF A POWERLITE VAULT (NOTE: EACH SWITCH IS SERVICING HALF OF EACH 120/240V SUPPLY)

The spring mechanism inside the Powerlite switch does not always engage properly. In these situations, crews are forced to operate the switches by alternate means in order to restore the customer. These operations can represent a potential safety hazard for Toronto Hydro crews. Typically, vault environments are cramped, making it difficult and relatively unsafe to operate the switch by alternate means. If crews cannot operate the switch safely while it is live, the controller would need to drop an additional feeder in order to switch with both feeders de-energized. In this situation, additional customers supplied by both those feeders would experience an outage.

A similar situation presents itself with the switch and fuse units. If they are deemed unsafe to switch, a multiple contingency situation could arise when additional feeders need to be de-energized in order to restore customers (explained in more detail in section E6.3.5.2).

A final example would be a low gas switch, like those found in the Thorncliffe area. If the switch needs to be operated on low gas, all the incoming primary feeders must be de-energized before that operation could proceed. This de-energization could result in two to three primary feeders experiencing momentary outages.

E6.3.4 Timing & Pacing of the Program

Table 4 details the number of assets that Toronto Hydro plans to replace in each year of the 2015 to 2019 planning period.

TABLE 4: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Sachsenwerk Switch and Fuse Units	6	12	12	10	0	40*
Powerlite Switches	0	2	2	2	2	8
Single Phase Submersible Transformers	0	4	4	4	4	16
Step Transformers	0	2	2	2	1	7
Transclosures	6	9	9	9	9	42
SF_6 Switches	2	1	2	1	0	6
Cable Chamber Covers	25	375	375	375	350	1,500

* Note: 8 remaining switch and fuse units are planned to be removed within the Network Circuit Reconfiguration Program

The pace of replacement for the different asset types was determined based on the risk of failure of the assets as determined by age and condition, the expected impact of asset failure and the overall number of units.

Table 5 provides projected program spending from 2015-2019. After the initial year, the aggregate yearly budget for the program is relatively consistent, with only small fluctuations year over year until 2019. Spending in 2015 is planned to be lower than in subsequent years due to resource constraints.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	2.06	6.69	6.64	6.48	5.52

Some assets, such as the Sachsenwerk switch and fuse units, are of relatively higher priority. These units must be removed as soon as possible to mitigate the increased safety and operational risks that they present. The program costs are forecasted to drop in 2018 and 2019 following the planned removal of higher-risk assets by 2017.

Toronto Hydro established yearly replacement rates for Sachsenwerk switches by taking the current rate of replacement for change-outs being undertaken reactively by Toronto Hydro crews (seven locations in 2013 and 10 in 2014) and adjusting for some additional units that could be

completed given the advantages of planning out the work (3 locations for 2015, 6 locations in 2016, and an additional four in the Network Circuit Reconfiguration Program, 6 locations in 2017 and 5 locations in 2018).

A small number of cable chamber covers are planned for replacement in 2015, followed by a steady replacement rate throughout the remainder of the five year period. Toronto Hydro plans to only replace a relatively small number of units in 2015 to allow for the proper testing of the new equipment design. In 2016 to 2019, Toronto Hydro plans to replace 350-375 cable chamber covers a year. This more aggressive pace was chosen in order to minimize safety risks, considering the number of chamber covers located in busy pedestrian traffic locations, while taking into account resource constraints.

Toronto Hydro plans to also replace Powerlite switches, step transformers and transclosures at a steady pace beginning in 2016, which corresponds to the increase in spending from 2015 to 2016. Toronto Hydro created a plan to address all units within the five year period while accommodating the needs of other programs. The work on these units relies on resources that are used in the switch and fuse change outs; accordingly, the replacement rate for these assets is reflective of the high-priority given to switch and fuse units due to safety concerns.

Toronto Hydro plans to execute the Thorncliffe Park area work by grouping locations fed by sets of two five-way or six-way switches so that looping between the replacement pad-mounted switches can be achieved (see section E6.3.2.2 for more information on the switch replacement).

E6.3.4.1 Ranking & Prioritization

Toronto Hydro prioritized the sub-projects of the ULI program based on the failure risk of the asset, such as the age and condition, potential safety risks, as well as how many customers that equipment supplies or would be impacted by its failure.

Maintenance inspection data, when available, is the main source of asset condition data. For the Sachsenwerk units, additional inspections were conducted following the switch failure that occurred in November 2012 (see section E6.3.5.2 for more detail). These inspections rated the units on a scale of one to four, where a one rating required immediate action and a four rating could be addressed at a later date. This information was used to select units for crews to change out in 2013 and 2014 and to prioritize the remaining units for future replacement.

In the Thorncliffe area, locations were prioritized based on which ATS switches do not operate properly, which switching vaults have flooding history, and the historical reliability of specific

locations. The two locations planned for replacement in 2015 will help prevent a recurrence of the incident that occurred in March 2013. See section E6.3.5.2 for more details of this incident.

Loading information was also used to prioritize work. If the equipment is serving a large load, or if the equipment's failure would affect customers upstream, like in the case of the Sachsenwerk switch and fuse units, then that equipment is considered to be of a higher priority.

Projects are also prioritized in order to coordinate them with work in other programs, which may be addressing either nearby equipment or the same primary feeder. Efforts are made to group work so that it can be executed as efficiently as possible and avoid situations where conflicts between projects could negatively affect project execution.

E6.3.5 Program Execution

A large majority of the assets that Toronto Hydro plans to address in the ULI program are located on the 13.8 kV underground system (Sachsenwerk switch and fuse units, Powerlite switches and equipment in the Thorncliffe area), while some, like transclosures, are found on the underground 27.6 kV and 4.16 kV systems. Toronto Hydro plans to address these assets through a series of discrete projects from 2015 through 2019. The planned order of execution for 2015 projects is outlined in section E6.3.8. For a more general outline of the execution in the 2015-2019 period see section E6.3.6.1 below.

E6.3.5.1 Proposed Work Plan

As discussed previously, the work to be performed pursuant to the ULI program is scattered throughout the city. For many of the assets in this program (transclosures, step transformers, switch and fuse units) the year of execution is determined based on the unit's priority relative to the other units in the same asset class (prioritization discussed in section E6.3.4.1). There is often little overlap between the feeders these assets are on, so feeders do not provide a mechanism for organizing work into execution years. When possible, however, assets on the same feeder will be grouped so that they are addressed in the same execution year in order to minimize the required feeder scheduling. The work plan ensures the assets outlined for replacement in Table 5 are replaced by the end of the 2015 to 2019 period.

Some asset replacements, like cable chamber lids, Powerlite vaults and Thorncliffe reconfigurations can be organized and executed by geographic area. This approach creates efficiencies for these projects because, in the case of Thorncliffe and Powerlites, the reconfigurations/conversions can build off one another as the program progresses year-over-year. The first three years of Powerlite replacements is planned to target the Bloor St W/Dufferin

St areas, with the final year targeting the remaining Danforth Ave. locations. Reconfiguration in the Thorncliffe area will address pairs of switches in each year, building off the looped configuration built by the previous pair's replacement. The cable chamber lids replacement plan is projected to address one to two areas of high pedestrian traffic each year by targeting all the lids in those areas, specifically targeting areas with the most foot traffic.

TABLE 6: 2017-2019 LONG TERM PLAN

Year	Targeted Asset
2015	3 Switch and Fuse Replacement Projects (6 units)
2015	Phase 1 of Thorncliffe Park Reconfiguration
2015	Cable Chamber Lid Test Installation
2015	2 Transclosure Replacement Projects (6 units)
2016	6 Switch and Fuse Replacement Projects (12 units)
2016	Phase 2 of Thorncliffe Park Reconfiguration
2016	Cable Chamber Lid Installation Phase 1
2016	9 Transclosure Replacement Projects
2016	2 Powerlite Replacement Projects (Bloor St W)
2016	2 Step Transformer Replacement Projects
2017	6 Switch and Fuse Replacements Projects (12 units)
2017	Phase 3 of Thorncliffe Park Reconfiguration
2017	Cable Chamber Lid Replacement Phase 2
2017	9 Transclosure Replacement Projects
2017	2 Powerlite Replacement Projects (Bloor St W)
2017	2 Step Transformer Replacement Projects
2018	5 Switch and Fuse Replacement Projects (10 units) – Final year
2018	Phase 4 of Thorncliffe Park Reconfiguration
2018	Cable Chamber Lid Replacement Phase 3
2018	9 Transclosure Replacement Projects
2018	2 Powerlite Replacement Projects (Bloor St W)
2018	2 Step Transformer Replacement Projects
2019	Phase 5 of Thorncliffe Park Reconfiguration
2019	Cable Chamber Lid Replacement Phase 4
2019	9 Transclosure Replacement Projects
2019	2 Powerlite Replacement Projects (Danforth Ave) 1 Powerlite Replacement Project (Bloor St W)

E6.3.5.2 Program Risks

(i) Summer Switching Restrictions

Legacy underground infrastructure is often found in the downtown area on feeders that may be subject to summer switching restrictions. That operational constraint is further explained within the Load Demand program (Section E5.4). If an asset is being replaced on one of these feeders, the time available for the executing the work will be limited. This risk is mitigated by the work proposed in the Load Demand program and by accounting for the switching restrictions during the scheduling of work early in the year.

(ii) Premature Asset Failure

The assets in the ULI program are often nearing end-of-life and could require reactive replacement due to failure or worsening condition before the planned work is executed. This would necessitate changes to the planned work program. To mitigate the risk of changing the planned work program, asset condition is used as an important factor during project prioritization (see section E6.3.4.1).

(iii) Inaccurate Records

Specifically with respect to the Thorncliffe Park distribution area, limitations of the existing design records lead to a higher probability of conflicts between what is planned and what is executable during the detailed design and construction phase. This limited information may result in a need for re-design, or cause the delay of certain aspects of projects. This risk exists to some degree with most projects, but has been identified as more likely in this area due to past experience involving inaccurate records in this service area. To mitigate this risk, efforts have been undertaken and are ongoing to update and confirm these records. If delays were to arise, scheduling flexibility over the 2015-2019 period would allow the work to be completed.

(iv) Condition of Customer Owned Locations

Finally, some of these legacy infrastructure assets may be in customer owned locations. Since this infrastructure has been in place for a long time, there may be unforeseen issues with craning space and vault access or the vault condition. These issues may require the customer to perform civil work before Toronto Hydro can continue with certain projects, resulting in project delays. This risk is mitigated by the use of inspection records when planning work. Toronto Hydro built scheduling flexibility into the 2015-2019 planning period so that work can still be completed within the planning period if delays arise.

E6.3.6 Evaluation of Alternatives

E6.3.6.1 Quantification/Evaluation of Options

(i) Status Quo

Deferring the work in the ULI program would be equivalent to a run-to-failure scenario. This approach would not recognize that the equipment is at or nearing end of life and is at risk of failure. Customers would be exposed to excessively long outage durations because there is no like-for-like replacement option for many legacy assets when failure does occur. It also would not address the worker and public safety concerns associated with certain pieces of legacy equipment.

(ii) Replacement with Standard Equipment

This approach addresses the equipment obsolescence, failure risk and safety concerns. As described in E6.3.2, this option entails replacing legacy assets with current technical and economical standard solutions available for each distinct asset.

The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities within this program. The cost of ownership (COO) of a state reflects the risk of asset failure including both direct and indirect costs; these costs include customer interruptions, emergency repairs, and asset replacements associated with a given design. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NAR_E) and proposed (NAR_N) state. Non-asset risks are further explained in Section D3.3.

Any additional benefit that is associated with the program that is external to the asset and non-asset related risk evaluation is quantified for both the existing state (AQB_E) and new state (AQB_N); in the case of this program the AQB_N is associated with the scrap value recovered during cable chamber lid replacements. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first of activities, the Underground Legacy Infrastructure program produces a net benefit (NPV) value of $1.46 million, as shown in Table 7.

TABLE 7: UNDERGROUND LEGACY INFRASTRUCTURE BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 1: Replacement with Standard Equipment (N1)	
Asset Risk [AR_N]	10.31
Non Asset Risk [NAR_N]	0
Maintenance Cost [MC_N]	0
Additional Quantifiable Benefits [AQB_N]	-0.001
Cost of Ownership of New Assets [COO_N]	10.31
Option 1: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_N)$]	3.52
Program Cost [PC_1]	2.06
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	1.46

E6.3.7 2015 Projects

Table 8 is a list of Underground Legacy Infrastructure projects that are planned for execution in 2015. Details on projects for 2015 are provided in the following sections.

TABLE 8: 2015 PROJECTS

Project Number	Project Name	Total Project Cost ($ Millions)	Start Date
X15405	Replacement of Switch and Fuse Gear at TGC (U9001)	0.13	2015
X15412	Replacement of Switch and Fuse Gear at ODR (U8033)	0.13	2015
X15428	Replacement of Switch and Fuse Gear at EPU (U8026)	0.13	2015
E15403	Replace transclosure pad transformers on feeders of EJ and ZE SCEJF1	0.77	2015
E15435	Ellendale-Kennedy Transclosure Replacement Civ-Elec SCFBF4	0.09	2015
X15352	Thorncliffe Rebuild (Phase 1)	0.69	2015
X15544	Replacement of Cable Chamber Lids (Test)	0.11	2015

E6.3.7.1 X15405 Project Description

Investment Category: System Renewal

Program: Underground Legacy Infrastructure

Project Title: Replacement of Switch and Fuse Gear at TGC (U9001)

Project Number: X15405

Project Year: 2015

Estimated Cost: $133,436

(i) Objective

To replace the Saschenwerk switch and fuse gear at location TCG (U9001). The switch and fuse gear present a known hazard to crews switching (when making and breaking load). This hazard is described above in section E6.3.3.1. Toronto Hydro plans to replace the equipment with submersible CRD 2-way SF_6 switches, a replacement option which is described in section E6.3.2.1. The existing distribution transformer will be maintained.

(ii) Scope of Work

TABLE 9: X15301 SCOPE OF WORK DETAILS

District Neighborhood	YONGE & COLLEGE
Station(s)	WINDSOR
Feeder(s)	A7CE, A5CE

TABLE 10: X15301 ASSETS REPLACED

Assets (Units)	2015
Switch and Fuse Unit	2

(iii) Justification & Benefits

Saschenwerk switch and fuse units pose a hazard to the switching crews for load make or break operations. This hazard is described earlier in section E6.3.3.1. Due to this hazard, operational constraints have been placed on the system where Saschenwerk switch and fuse gear is present (can only be operated when paralleled). These units are being replaced with CRD two-way SF_6 switches, in order to relieve this operating constraint and safety hazard.

The location of TGC (U9001) has been inspected by crews and has sufficient space for CRD equipment. The replacement of the switch and fuse units with new CRD equipment will resolve the arc flash hazard that currently exists at this location. This unit is 27 years old.

E6.3.7.2 X15412 Project Description

Investment Category: System Renewal

Program: Underground Legacy Infrastructure

Project Title: Replacement of Switch and Fuse Gear at ODR (U8033)

Project Number: X15412

Project Year: 2015

Estimated Cost: $133,193

(i) Objective

To replace the Saschenwerk switch and fuse gear at location ODR (U8033). The switch and fuse gear presents a known hazard to crews switching (when making and breaking load). This hazard is described above in section E6.3.3.1. The equipment will be replaced with submersible CRD two-way SF_6 switches. The existing distribution transformer will be maintained.

(ii) Scope of Work

TABLE 11: X15301 SCOPE OF WORK DETAILS

District Neighborhood	FINANCIAL DISTRICT - TRICHMOND & SHEPPARD
Station(s)	WINDSOR
Feeder(s)	A51WR, A55WR

TABLE 12: X15301 ASSETS REPLACED

Assets (Units)	2015
Switch and Fuse Unit	2

(iii) Justification & Benefits

Saschenwerk switch and fuse units pose a hazard to the switching crews for load make or break operations. This hazard is described in section E6.3.3.1 above. Due to this hazard, operational constraints have been placed on the system where Saschenwerk switch and fuse gear is present (can only be operated when paralleled). These units are being replaced with CRD two-way SF_6 switches, in order to relieve this operating constraint and safety hazard.

The location of ORD (U8033) has been inspected by crews and has sufficient space for CRD equipment. The feeders supplying this location are network feeders and were placed in high

priority because if a double contingency (described previously in section E6.3.3.2) were to arise on the network system, the entire network for that bus may need to be dropped. The replacement of the switch and fuse units with new CRD equipment will resolve the arc flash hazard that currently exists at this location. This unit is 26 years old.

E6.3.7.3 X15428 Project Description

Investment Category: System Renewal

Program: Underground Legacy Infrastructure

Project Title: Replacement of Switch and Fuse Gear at EPU (U8026)

Project Number: X15428

Project Year: 2015

Estimated Cost: $133,193

(i) Objective

To replace the Saschenwerk switch and fuse gear at location EPU (U8026). The switch and fuse gear presents a known hazard to crews switching (when making and breaking load). This hazard is described above in section E6.3.3.1. The equipment will be replaced with submersible CRD two-way SF_6 switches. The existing distribution transformer will be maintained.

(ii) Scope of Work

TABLE 13: X15301 SCOPE OF WORK DETAILS

District Neighborhood	FINANCIAL DISTRICT, FRONT & UNIVERSITY
Station(s)	WINDSOR
Feeder(s)	A51WR, A55WR

TABLE 14: X15301 ASSETS REPLACED

Assets (Units)	2015
Switch and Fuse Unit	2

(iii) Justification & Benefits

Saschenwerk switch and fuse units pose a hazard to the switching crews for load make or break operations. This hazard is described in section E6.3.3.1 above. Due to this hazard, operational constraints have been placed on the system where Saschenwerk switch and fuse gear is present (can only be operated when paralleled). These units are being replaced with CRD two-way SF_6 switches, in order to relieve this operating constraint and safety hazard.

The location of EPU (U8026) has been inspected by crews and has sufficient space for CRD equipment. The feeders supplying this location are network feeders and were placed in high

priority because if a double contingency (described previously in section E6.3.3.2) were to arise on the network system, the entire network for that bus may need to be dropped. The replacement of the switch and fuse units with new CRD equipment will resolve the arc flash hazard that currently exists at this location. This unit is 26 years old.

E6.3.7.4 E15403 Project Description

Investment Category: System Renewal

Program: Underground Legacy Infrastructure

Project Title: Replace transclosure pad transformers on feeders of EJ and ZE SCEJF1

Project Number: E15403

Project Year: 2015

Estimated Cost: $766,519

(i) Objective

The objective of this project is to replace old, rusted, and non-standard transclosures at five different locations supplied by feeders of FJ and ZE since they are a failure risk. They also pose a safety concern to both Toronto Hydro crews and the public, as described previously in E6.3.2.3 and the transclosure section of E6.3.3.1.

Location 1: PT47621 (SCEJF2)

Existing transformer is a 3 phase - 225kVA 600V Delta transclosure unit and it is 47 years old. Proposed work is to install a new standard pad-mounted 300kVA 600/347V transformer beside the existing transclosure pad, followed bythe new cables and terminations including the secondary connections (converted to 4 wires Y) to the customer.

Location 2: PT56550 (SCEJF1)

Existing transformer is a 3 phase - 112kVA 600V Delta transclosure unit and it is 47 years old. Proposed work is to install a new standard pad-mounted 150kVA 600/347V transformer beside the existing transclosure pad, followed by the new cables and terminations including the secondary connections (converted to 4 wires Y) to the customer.

Location 3: PT27773 (SCZEF3)

Existing transformer is a 3 phase - 225kVA 208/120V transclosure unit and it is 33 years old. Proposed work is to convert the 4.16 kV OH lateral which supplies the UG cable to PT27773, as well as pole top transformer OT38614. A new standard pad-mounted 300kVA 208/120V transformer will be installed beside the existing transclosure pad, followed by the new cabling and terminations. This includes the secondary connections to the customer.

Location 4: PT47412 (SCEJF2)

Existing transformer is a 3 phase - 112kVA 600/347V transclosure unit and it is 50 years old. Proposed work is to install a new standard pad-mounted 150kVA 600/347V transformer beside the existing transclosure pad, followd by the new cables and. This includes the secondary connections to the customer. Location 5: PT5650 (SCEJF1)

Existing transformer is a 3 phase - 150kVA 600V Delta transclosure unit and it is 44 years old. Proposed work is to install a new standard pad-mounted 150 or 300kVA 600/347V transformer beside the existing transclosure pad, followed by the new cables and terminations including the secondary connections (converted to 4 wire Y) to the customer.

(ii) Scope of Work

TABLE 15: E15403 SCOPE OF WORK DETAILS

District Neighborhood	HWY401 & KENNEDY
Station(s)	CANADIEN, MIDLAND (4.16 KV), MIDLAND, LAWRENCE (4.16 KV)
Feeder(s)	SCEJF1, SCEJF2, SCZEF3

TABLE 16: E15403 ASSETS REPLACED

Assets (Units)	2015
Transclosures	5

(iii) Justification & Benefits

All five of these locations are transclosures. The low quality of the metal used to construct the enclosures around the transformers has caused rusting, making the transformers unsafe to operate and maintain. This is described in greater detail in E6.3.2.3 and the transclosure section of E6.3.3.1.

For these five locations, a standard pad transformer will replace the existing transclosures. The new pad transformer will be installed beside the existing transclosure and, when ready, with minimum outage, the new cables and terminations can be carried out. This work includes the secondary connections to the customer's panel. This pad unit will provide additional safety for both the public and Toronto Hydro crews since it will be "dead-front".

Inspections show the units are in poor condition and require replacement. Additionally, the units being replaced in this scope are all at or nearing end of life (oldest unit is 50 years old, newest unit is 33 years old). Replacement will mitigate the impact of failure, improve worker safety and improve the overall neighborhood aesthetic.

E6.3.7.3 E15435 Project Description

Investment Category: System Renewal

Program: Underground Legacy Infrastructure

Project Title: Ellendale-Kennedy Transclosure Replacement Civ-Elec SCFBF4

Project Number: E15435

Project Year: 2015

Estimated Cost: $88,413

(i) Objective

The objective of this project is to replace the old, rusted, and non-standard transclosure PT44494, proactively bringing it up to standard.

Currently the existing transformer is fed from FB-F4 (13.8kV) and is a wye-wye configured transformer. Replacing the transclosure will require converting the customer line from 13.8kV to 27.6kV (i.e., the customer will not be fed from FB-F4 but rather from E5-M30).

Proposed work includes the installation of a three phase 208/120V (1x150kVA) pad-mounted transformer that will be supplied from a dip from the adjacent 27.6kV line. A new switch will need to be installed on the overhead pole to facilitate this. Following this, existing 13.8 kV cables will be dead-ended and the transclosure pad will be completely removed from the customer's site

(ii) Scope of Work

TABLE 17: E15435 SCOPE OF WORK DETAILS

District Neighborhood	ELLENDALE & KENNEDY
Station(s)	CANADIEN, MIDLAND (4.16 KV), MIDLAND LAWRENCE (4.16 KV)
Feeder(s)	SCARBOROUGH

TABLE 18: E15435 ASSETS REPLACED

Assets (Units)	2015
Transclosures	1

(iii) Justification & Benefits

PT44494 is a transclosure, a non-standard transformer with an enclosure build around it as described above in sections E6.3.2.3 and E6.3.3.1. The enclosure was not made of standard grade steel and is showing signs of decay, posing a potential safety hazard to public.

As well, due to the non-standard internal configuration (i.e., "live-front"), this transclosure poses a potential safety hazard to field crews. Inspections show the unit is in poor condition and needs replacement. Replacement will mitigate the impact of failure, improve worker safety and improve overall neighborhood aesthetic.

Doing this work should mean that the customer will see a significantly shorter outage since the customer's power will be maintained while all connections are set up and only disconnected when crews are ready to transfer power.

Since the secondary service is roughly 600A the customer requires a pad-mounted transformer. The transformer cannot be replaced with an OH bank-type transformer. As well, since the customer is already wye-wye connected it does not require a new meter-base or secondary ancillary (as was required for multiple units in E15403).

E6.3.7.4 X15352 Project Description

Investment Category: System Renewal

Program: Underground Legacy Infrastructure

Project Title: Thorncliffe Rebuild (Phase 1)

Project Number: X15352

Project Year: 2015

Estimated Cost: $691,775

(i) Objective

The existing distribution system in the Thorncliffe Park area is ULI (non-standard), and is susceptible to flooding (high water table area). It is also vulnerable to extended outages when there is equipment failure on the five-way and six-way switches, as experienced on March 10, 2013 (29-hour outage). These issues are described in detail earlier on in sections E6.3.2.2 and E6.3.3.1.

This project is the first of Toronto Hydro's planned five phases to remove five and six-way switches from this area and to reconfigure the system into a standard looped system. Figure E6.3-4 in section E6.3.2.2 shows the proposed reconfiguration/replacement of the 5-way and 6-way switches, V4488 and V4489, respectively.

(ii) Scope of Work

TABLE 19: X15352 SCOPE OF WORK DETAILS

District Neighborhood	THORNCLIFFE PARK (OVERLEA BLVD)
Station(s)	LEASIDE
Feeder(s)	EYA10L, EYA5L, EYA6L

TABLE 20: X15352 ASSETS REPLACED

Assets (Units)	2015
5 way and 6 way Submersible SF6 Switches	2

(iii) Justification & Benefits

On March 10, 2013, the Thorncliffe Park area experienced an extended 29 hour outage after a six-way switch failed. This outage is described in greater detail in the Thorncliffe section of E6.3.3.1.

The new configuration for this area requires pad-mounted switches, instead of the existing underground 5-way and 6-way switches, to alleviate flooding issues. It also requires a looped system using 3-way switches in the transformer vaults rather than the existing single radial feeds from the switches to transformer vaults.

This new configuration will mitigate the impact of future equipment failures or planned work.

E6.3.7.5 X15544 Project Description

Investment Category: System Renewal

Program: Underground Legacy Infrastructure

Project Title: Replacement of Cable Chamber Lids (Test)

Project Number: X15544

Project Year: 2015

Estimated Cost: $114,030

(i) Objective

The objective of this project is to replace 25 existing cable chamber lids with the new lid design that will be able to vent pent up gases from the chamber and withstand the force of shock waves that would be generated if an eruption occurred.

(ii) Scope of Work

TABLE 21: X15544 SCOPE OF WORK DETAILS

District Neighborhood	HIGH PEDESTRIAN AREAS DOWNTOWN
Station(s)	N/A
Feeder(s)	N/A

TABLE 22: X15544 ASSETS REPLACED

Assets (Units)	2015
Cable chamber lids	25

(iii) Justification & Benefits

This project replaces 25 lids with the new lid design. The reason for the limited number of replacements in the first year is because the lids need to go through standard testing procedures for new equipment, including testing operations in both the summer and winter months.

The replacements target areas of high pedestrian traffic and chambers that have a greater number of feeders passing through them, since these are at greater risk of experiencing an explosion.

E6.4 Overhead Circuit Renewal

NEW INLINE DISCONNECT SWITCH

E6.4.1 Summary

Program Description

Toronto Hydro's Overhead Circuit Renewal program is a continuation of activities previously described in the Ontario Energy Board (OEB) approved Overhead Infrastructure segment as part of the 2012-2014 IRM/ICM rate-setting application. This program replaces assets that have aged, are in poor condition and that are functionally obsolete. These assets contribute to the overall failure risk of the utility's overhead distribution system. The program's investments are focused on the replacement of poles, switches, transformers and overhead accessories. This program also includes former street lighting assets that were found to be distribution assets by the Ontario Energy Board (OEB) in the Transfer Decision ("former street lighting assets").[1]

End-of-life and/or obsolete assets that are replaced in this program include: wood poles, concrete poles, overhead switches, end-of-life transformers (including obsolete completely self-protected ("CSP") transformers), and porcelain and non-standard accessories (including non-standard animal guards). The Overhead Circuit Renewal program consists primarily of projects that are considered complete rebuilds, where a substantial number of assets in a geographical area are at a high risk of failure and are therefore replaced simultaneously on a 'like-for-like' basis. The like-for-like approach means that the aged assets are replaced with new and standardized assets that

[1] EB-2009-0180,0182,0183, Decision and Order (February 11, 2010) at page 8. For additional information, please refer to Exhibit 2A, Tab 5.

have the same essential specifications and functions. Standardizing overhead assets that are at risk of failure will mitigate costs that would otherwise be incurred during repair and restoration efforts.

The anticipated benefits of the Overhead Circuit Renewal program are as follows.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Improves service reliability for customers on the targeted feeders; the trunk-related outages to be mitigated can affect up to 7,000 customers and can cause adverse power quality issues for large industrial facilities on the same station bus.
Reliability	ƒ Improves system reliability by mitigating failure risk and limiting the frequency and impact of overhead defective equipment outages through the timeline like-for-like replacement of end-of-life overhead assets
Safety	ƒ Polymeric insulating material has less destructive failure modes than currently used porcelain material. ƒ Prevents poles from falling due to rotting bases. ƒ Standardized transformers have a longer working distance compared to CSP transformers. ƒ Avoids sub-optimal illumination for drivers and pedestrians caused by defective street light pole outages.
Efficiency	ƒ Avoids unnecessary costs that are incurred for repair and restoration efforts on defective overhead equipment.

Program Drivers

The trigger and secondary drivers for the Overhead Circuit Renewal program are summarized in the following table.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ Aged and deteriorating wood and concrete poles ƒ Overhead transformer deterioration ƒ Aging and obsolete switches and controls ƒ Deteriorating and obsolete ancillary equipment
Secondary Drivers	**Reasoning**
Safety	ƒ Pole deterioration weakens structures ƒ Porcelain insulating material is susceptible to contamination build-up and electrical tracking, which can cause cracking, rupture and catastrophic failures

Functional Obsolescence	ƒ Obsolete animal guards ƒ Obsolete remote switching communication systems

Preferred Alternative

Toronto Hydro considered the following alternatives for addressing the assets in this program:

(1) Do nothing and replace on a reactive basis only, incurring the risk of equipment failures and potential safety concerns.

(2) Short term mitigation or rehabilitation of deteriorated assets, such as replacement of only the porcelain insulators or switches, leaving other assets in place (e.g., an aged pole).

(3) Proactively replace end-of-life overhead equipment, which includes aged, poor condition, and functionally obsolete equipment that is at the highest risk of failure over the next five years in a coordinated fashion.

Option III is the preferred alternative as it is expected to enable Toronto Hydro to most effectively mitigate the risks posed by the currently installed assets in the most cost-efficient manner. Option I is likely to result in deterioration of overhead system reliability performance and high costs associated with reactive equipment replacement. Option II may provide short-term performance stability, similar to the Worst Performing Feeder program (E6.21) but would ultimately result in unnecessary costs due to the inefficiency of rebuilding overhead feeders in a piecemeal fashion.

The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $39.94 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.4.7).

Timing and Pacing

The Overhead Circuit Renewal program will ensure that Toronto Hydro is replenishing aged and deteriorating infrastructure at an appropriate pace in order to mitigate failure and safety risk.

Table C summarizes historical and projected program spending. A high number of overhead defective equipment outages occurred between 2008 and 2010, prompting an increase in spending levels from 2010 and onwards. Outages began to rise again from 2012 to 2013, prompting another increase in proactive renewal spending to address the growing backlog of

aging overhead assets. Future spending levels are somewhat reduced compared to the ICM period (2012-2014) expenditures; this is made possible due to the fact that the overall DSP contains an expanded suite of programs that includes complementary renewal and modernization efforts that will enable more cost-effective management of overhead system performance (e.g. Overhead Infrastructure Relocation, E6.5; Feeder Automation, E7.3).

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	$25.8	$28.3	$23.2	$49.0	$53.3	$44.0	$23.0	$24.9	$25.3	$30.3

E6.4.2 Program Description

Toronto Hydro's Overhead Circuit Renewal program replaces assets that have aged, are in poor condition and that are functionally obsolete; these assets contribute to the overall failure risk of the utility's overhead distribution system. The program's investments are focused on the replacement of poles, switches, transformers, overhead accessories.

This program also includes former street lighting assets that were found to be distribution assets by the Ontario Energy Board (OEB) in the Transfer Decision ("former street lighting assets").[2]

The Overhead Circuit Renewal program consists primarily of projects that are considered complete rebuilds, where a substantial number of assets in a geographical area are at high failure risk and are therefore replaced simultaneously on a "like-for-like" basis. In some cases, abnormally high failure risk may warrant stand-alone replacements of assets in multiple locations. The like-for-like approach means that the aged assets are replaced with new and standardized assets that have the same essential specifications and functions. Also as part of this program, voltage conversions will target 4.16 kV or 13.8 kV equipment that is aged and in poor condition, replacing the existing assets with new assets at higher voltage levels.

Standardizing overhead assets that are at risk of failure is expected to mitigate costs that would otherwise be incurred in connection with repair and restoration efforts. Typically, outages related to defective overhead equipment necessitate the replacement of a major asset. In these scenarios, Toronto Hydro crew members must transport new assets to the location of the outage and conduct on-site installation to restore power.

The Overhead Circuit Renewal program will cost an estimated $147.4 million over the 2015 to 2019 period and is expected to deliver $39.94 million in avoided risk costs. The following subsections describe the various assets that are being renewed through the Overhead Circuit Renewal program.

E6.4.2.1 Replacement of Aging Poles

Toronto Hydro uses two types of poles in its overhead system: wood poles and concrete poles which are typically former street lighting assets. Poles act as support structures to route power distribution lines and accommodate other electrical distribution assets. The Overhead Circuit Renewal program includes proactive replacement of deteriorating poles that are unfit for

[2] EB-2009-0180,0182,0183, Decision and Order (February 11, 2010) at page 8. For more information, please refer to Exhibit 2A, Tab 5.

continued use. These replacements will mitigate failure and safety risks associated with aged and poor condition poles, as detailed in section E6.4.3.

(i) Wood Poles

The wood poles used throughout Toronto Hydro's overhead system have an expected useful life of 45 years. Approximately 31% of existing poles are at or near end-of-life and will require proactive replacement during the 2015-2019 period. Toronto Hydro plans to replace these poles with new butt-treated Western Red Cedar poles. Pole heights range from 30 feet to 55 feet depending on the area (e.g., residential, industrial/commercial or arterial roadway) and the mix of assets attached to the pole (e.g. number of primary and secondary circuits, the presence of third party attachments, transformers, underground terminations, switches, etc.).

Wood pole replacements include the replacement of ancillary support structures, like fiberglass cross arms and new brackets, and new accessories, like insulators and arrestors. These ancillary support structures are usually the same vintage as the wood pole itself since they are typically installed during the construction of the pole. Replacing the ancillary structures at the same time as the poles allows Toronto Hydro to utilize its resources more efficiently.

Figure 1 illustrates a standard wood pole with new ancillary support structures.

FIGURE 1: NEW WOOD POLE

(ii) Concrete Poles

In addition to distribution wood poles, the Overhead Circuit Renewal program intends to replace aged and poor condition concrete poles that have an expected useful life of 60 years. Approximately 4-5% of existing concrete poles are at or near end-of-life and will require proactive replacement during the 2015-2019 period. These are typically former street lighting poles, which accommodate brackets, luminaries, and service wires inside brackets. They are mostly concrete with reinforced rods (rebar) or, in some cases, aluminum.

The new poles range in height from 28 feet to 35 feet and selection will vary depending on the application. Figure 2 below illustrates a standard concrete pole with a bracket and luminaries attachment.

FIGURE 2: NEW CONCRETE STREET LIGHT POLE

E6.4.2.2 Replacement of Aging Switches

Overhead switches used throughout Toronto Hydro's overhead system have an expected useful life of 45 years. Approximately 33% of existing switches are at or near their end-of-life and will require proactive replacement during the 2015-2019 period. Overhead switches allow Toronto Hydro to isolate feeder sections or equipment for maintenance, or to interrupt load for load shifting and other operating requirements on three-phase systems. They also allow workers to work safely by isolating feeder sections and creating zones that are free of energized equipment.

Toronto Hydro uses three types of switches in its overhead system: in-line disconnect switches, manual load break switches and SCADA-mate switches. The consequence of aging switches is natural deterioration due to wear as parts move against one another, resulting in the binding of moving components and eventually, the inability to operate. Also, environmental conditions can

lead to corrosion and rust. The Overhead Circuit Renewal program includes a like-for-like replacement of these assets with new standard switches in order to reduce the failure risk of these assets.

(i) In-line Disconnect Switches

Toronto Hydro uses in-line disconnect switches as isolation points on portions of feeders. The switches are operated manually and are opened one electrical phase at a time. They are used to electrically isolate sections of overhead when performing maintenance or asset replacement tasks. In-line disconnect switches that have reached their end of life will be replaced with updated assets.

(ii) Manual Loadbreak Switches

Manual loadbreak switches are designed to manually open and close all three electrical phases simultaneously (i.e. a "gang-operated" switch) using an operating handle or motor-driven operating rod. These switches are used to sectionalize circuits to reduce the size of outages during fault conditions. Under this program, old obsolete switches will be replaced with new manual load break switches that have solid blades mounted in a three-phase switchgear. These loadbreak switches use load interrupters and an air gap to provide isolation.

(iii) SCADA-Mate Switches

SCADA-Mate load break switches are gang-operated switches that can be operated using an electric motor. This type of switch is meant to be operated remotely, though it can also be manually operated if required. The supervisory control and data acquisition (SCADA) system enables remote operation and provides sensors for three-phase monitoring of line current and line-to-neutral voltages. Remote operability allows for faster restoration of customers during an outage as compared to manually operated switches. As an ancillary benefit, it mitigates safety risks associated with manual switching such as potential for flashover during operation.

Components of SCADA-Mate switches are prone to corrosion, including the housing and internal moving parts, and can experience mechanical deterioration of bearings, loose connections, motor winding deterioration, contamination of the circuitry, or the failure of electronic equipment as they age. Furthermore, particular SCADA-Mate switch locations in the Etobicoke area use the Motorola radio communication system (DARCOM radio system and MOSCAD Terminals). This technology has reached the end of its useful life and the equipment is obsolete.

The replacement of aged SCADA-Mate switches will be done as part of rebuild projects. In some cases, obsolete SCADA-Mate MOSCAD RTUs and DARCOM radios in Etobicoke will be targeted for replacement as part of self-contained projects due to the high failure risk associated with these aged and obsolete assets. This program targets non-R1 SCADA-Mate switches that are end-of-life or utilize MOSCAD RTUs and DARCOM radios in Etobicoke. Defective SCADA-Mate R1 switches are being proactively placed at a more accelerated pace in the SCADA-Mate R1 Renewal program (refer to section E6.8 of the Distribution System Plan).

E6.4.2.3 Replacement of Legacy Overhead & CSP Transformers with Standardized Pole-Top Transformers

Overhead transformers used throughout Toronto Hydro's overhead system have an expected useful life of 40 years. Approximately 24% of existing overhead transformers are at or near end-of-life and will require proactive replacement during the 2015-2019 period to reduce failure risk.

Pole-mounted transformers are an important component of the 27.6 kV overhead system. Age, condition, and loading contribute to the increasing failure risk of overhead transformers over time. All pole-mounted transformers are single phase units rated at 16.0 kV for the 27.6 kV system and can be mounted as one single-phase unit or a cluster of three single-phase transformers forming a three-phase unit.

Under this program, pole mounted transformers that have reached their end of life will be replaced. The three standard sizes of pole-mounted transformers are 50 kVA, 100 kVA, and 167 kVA. The size of the transformer used in a particular circumstance generally correlates to the anticipated load and is located near the load centre to maximize bus utilization and reduce voltage drop. Figure 3 shows a new overhead transformer.

FIGURE 3: NEW OVERHEAD TRANSFORMER

E6.4.2.4 Replacement of Porcelain & Non-Standard Accessories with Standardized Accessories

The replacement of overhead accessories as part of this program includes animal guards and porcelain hardware. These assets are located on transformers, poles and switches that are proposed for replacement as part of this program.

(i) Porcelain Hardware

In Toronto Hydro's overhead plant, porcelain material was used as insulation for switches, lightning arrestors, terminators, and line post insulators. The porcelain material tends to carry a higher risk of failure due to its tendency for contamination build up that leads to electrical tracking (i.e. the breakdown of insulation materials, which can lead to faults). The new standard technology to be installed under this program uses polymeric material that is less susceptible to contamination in high corrosion areas, minimizing the leakage current that can cause tracking.

(ii) Animal Guards

Existing legacy wildlife protection on Toronto Hydro's overhead distribution system consists of "Guthrie" guard animal protectors. The Guthrie guard creates a physical barrier that attaches to the bushings of overhead transformers, repelling animal contact with a mild shock that prevents

them from contacting the energized transformer bushing. However, animal contacts with energized components of the transformer still occur. The new standard animal guards to be installed through this program use a cone shaped guard on the bushing, with an accompanying insulated drop wire. This design provides improved physical non-conductive barriers to deter animals.

FIGURE 4: MAP OF OVERHEAD CIRCUIT RENEWAL AREAS FOR 2015

The following table summarizes the anticipated benefits Overhead Circuit Renewal program.

TABLE 1: PROGRAM BENEFITS

Customer Value	***f*** Improves service reliability for customers on the targeted feeders; the trunk-related outages to be mitigated can affect up to 7,000 customers and can cause adverse power quality issues for large industrial facilities on the same station bus. *f* The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $39.94 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.4.7).
Reliability	*f* Improves system reliability by mitigating failure risk and limiting the frequency and impact of Overhead defective outages through the like-for-life replacement of end-of-life overhead assets
Safety	*f* Polymeric insulating material has less destructive failure modes than currently used porcelain material. *f* Prevents poles from falling due to rotting bases. *f* Standardized transformers have an external disconnect switch to provide a visible positive affirmation of an “open” or “close” state and longer working distances, as opposed to CSP transformers. *f* Avoids sub-optimal illumination for drivers and pedestrians caused by defective street light pole outages.
Efficiency	*f* Reduces unexpected costs that are incurred for repair and restoration efforts as part of overhead defective equipment.

Table 2 below provides details of the estimated number of assets forecasted for replacement from 2015 to 2019.

TABLE 2: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Poles	2,838	1,735	1,900	1,934	2,313	11,214
Overhead Switches	218	160	166	154	207	981
Overhead Transformers	937	511	478	598	673	3,232

/C

E6.4.3 Why the Program is Needed

Toronto Hydro’s Overhead Circuit Renewal program targets assets that are aged and deteriorated, leading to a high risk of failure. The failure of these assets will negatively impact service reliability to customers on the overhead system and could pose safety concerns for employees and the general public. As discussed in Section E6.4.5.2, defective overhead equipment is a significant source of outages.

Figure 5 shows historical trending of outages due to overhead defective equipment in terms of customers interrupted (CI), customer hours interrupted (CHI), and frequency of outages. Sustained interruptions on Toronto Hydro's overhead system stabilized over the 2011 to 2013 period, as shown in Figure 5, due to increased overhead renewal spending levels from 2010 and onwards (refer to Table 6). There was an increase in outages due to overhead defective equipment from 2012 to 2013.

FIGURE 5: OVERHEAD DEFECTIVE EQUIPMENT HISTORICAL RELIABILITY

As per Figure 6, overhead equipment continues to be a major contributor to sustained interruptions every year, over the past five years, compared to other major failure types.

FIGURE 6: SYSTEM WIDE OUTAGE FREQUENCY 2008-2013

The overhead system is a significant contributor to SAIDI and SAIFI. On average, overhead defective equipment contributes to about 22% of all system wide outages every year.

Figure 7 breaks down the frequency of overhead system outages.

FIGURE 7: OVERHEAD CORE ASSETS OUTAGE FREQUENCY

The figure above demonstrates that overhead transformers and animal contacts contribute most to the frequency of overhead type outages.

E6.4.3.1 Program Drivers

Table 3 presents the trigger and secondary drivers for the Overhead Circuit Renewal program.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ Aged and deteriorating wood and concrete poles. ƒ Overhead transformers deterioration. ƒ Aging and obsolete switches and controls. ƒ Deteriorating and obsolete ancillary equipment.
Secondary Drivers	**Reasoning**
Safety	ƒ Pole deterioration weakens structures ƒ Porcelain insulating material is susceptible to contamination build-up and electrical tracking, which can cause cracking, rupture and catastrophic failures ƒ Older pole mount transformers lack visible disconnect switch for positive confirmation of being open or closed
Functional Obsolescence	ƒ Obsolete animal guards. ƒ Obsolete communication systems. ƒ Pole mount transformers lack of external fuses, as required by new standards.

(i) Aging Poles

Aging & Deteriorating Wood Poles

The risk of failure for wood poles is related to both their age and condition. Given that wood is a natural material, the degradation process is somewhat different from those that affect other distribution system assets. For example, pole rot is caused by naturally-occurring fungi that attack and degrade wood, resulting in decay. Birds and insects can also damage poles. The nature and severity of the resulting degradation depends both on the type of wood and the environmental conditions. Certain fungi will attack the external surfaces of the pole, while others will target the internal heartwood. Degradation may occur internally, externally, or both. Depending on the

particular pole, a number of degradation modes such as feathering, internal rot, decay at the ground line, shell rot and infestation may combine to reduce pole strength.

Figures 8 and 9 demonstrate pole-top feathering. The top portion of the pole is critical because it contains the necessary attachments for insulators, brackets and other hardware used to secure the overhead conductors to the line.

FIGURE 8: POLE-TOP FEATHERING

FIGURE 9: POLE-TOP FEATHERING

Figures 10 and 11 show internal base rot. This type of deterioration weakens the pole base, which can cause the pole to fall.

FIGURE 10: INTERNAL BASE ROT

FIGURE 11: INTERNAL BASE ROT

Figures 12, 13 and 14 show major cracks, holes, and evidence of rot.

FIGURE 12: AND FIGURE 13: MAJOR POLE CRACKS, HOLES, AND ROT

FIGURE 14: MAJOR POLE CRACKS, HOLES, AND ROT

The expected useful life of a wooden pole is 45 years. The Overhead Circuit Renewal program will address all poles that have reached end-of-life and that are in poor and very poor condition according to Toronto Hydro's Asset Condition Assessment (ACA) program (see section E6.4.3.2 (i) for additional details). Toronto Hydro expects to address all of these poles during the 2015-2019 period. This work is required to mitigate the reliability and safety concerns associated with the risk of pole failure. The failure impacts of wooden poles are discussed in more detail in section E6.4.3.2 (ii).

Concrete Poles

The majority of concrete poles are mostly made of concrete with metal reinforced rods (rebar), and in some cases, aluminum. These poles degrade in the same manner as other concrete structures. Initially, moisture enters cracks or voids inside the concrete material and accumulates. Freezing temperatures cause moisture to expand and enlarge the crack in the concrete resulting in the exposure of internal metal rebar. As well, road salt can enter the cracks and, over time, corrode the metal rebar, reducing pole strength and ultimately reducing the useful service life of the pole. Aluminum poles degrade from corrosion due to road salt and moisture exposure. The failure of these assets can potentially mean an outage to the street lighting system in the area which in turn can lead to customer complaints and potential safety issues. Figure 15 shows a deteriorated concrete pole.

FIGURE 15: CONCRETE POLE DETERIORATION

The Overhead Circuit Renewal program will address all concrete poles that have reached end-of-life of 60 years and that are in poor and very poor condition. Toronto Hydro plans to address all of these poles during the 2015-2019 period. This work is required mitigate the reliability and safety concerns associated with the risk of pole failure.

(ii) End-of-Life & CSP Overhead Transformers

Age, condition, and loading contribute to the failure risk of overhead transformers. A transformer's useful life is heavily dependent on the state of the transformer winding insulation system. The insulation media is comprised of paper wrapped around the conductors in the transformer's coils, and the paper and coils are submerged in insulating oil. Over time, the normal operation of a distribution transformer naturally degrades the paper insulation within the transformer oil. As this occurs, the oil gradually turns to sludge, and its own insulating properties are reduced. The combined loss of dielectric strength from both the paper and oil insulation can result in an internal failure of the transformer and an outage to connected customers.

The application of a voltage over a long period of time induces electromagnetic stresses that lead to insulation breakdown and the loss of dielectric strength. Therefore, loading profiles and the length of time in service are key determinants of an in-service transformer's useful life. Also, when any transformer exceeds its loading capacity, the increased heat travelling through the winding coil can accelerate the degradation of both the winding paper insulation as well as the dielectric transformer oil.

Some of Toronto Hydro's older units are known as completely self-protected (CSP) transformers because they are of a legacy design that features primary fusing contained inside the transformer tank. Once a CSP transformer fails in the field or the primary fuse has operated, the transformer must be replaced. In contrast, Toronto Hydro's current standard for overhead, pole-mounted transformers requires the fuse to be externally-located, providing a visible isolation point and the ability to re-fuse the transformer. The visible isolation point provides crews positive affirmation that the transformer is disconnected from the primary line, whereas a defective CSP transformer would have the open fuse hidden inside the transformer tank. In about 50% of the outages related to standard non-CSP transformers, transformer replacement is not required because the external fuse can be replaced while leaving the transformer in place.

Most CSP transformers are located in north-central Toronto, with a smaller number located in Etobicoke and Scarborough. Since amalgamation, CSP transformers have been replaced by standard non-CSP pole-mounted transformers. CSP transformers are typically installed on 35-foot poles. The additional external hardware above the transformer for the non-CSP transformers requires these assets to be installed on taller poles. Figure 16 and Figure 17 show a typical overhead CSP transformer.

FIGURE 16: CSP TRANSFORMER

FIGURE 17: TYPICAL CSP TRANSFORMER POLE INSTALLATION

CSP transformers create potential safety risks for Toronto Hydro crews because they lack the external fuse and visible disconnect switch that can be used as an isolation point when restoring standardized non-CSP transformers. An external and visible disconnect switch provides a positive affirmation of an "open" or "close" state. In addition, CSP transformer restoration requires that crew members be closer to the transformer when working on it. In contrast, the use of longer equipment for standard non-CSP transformers increases the distance between the crew worker and the transformer during operation, thereby minimizing any potential safety risks that may arise.

The expected useful life of a transformer is 40 years. The Overhead Circuit Renewal program will address all transformers that have reached end-of-life and severe loading issues. Toronto Hydro plans to address all of these transformers during the 2015-2019 period. This work is required mitigate the reliability and safety concerns associated with the transformers. The failure impacts of transformers are discussed in more detail in section E6.4.3.2 (ii).

(iii) Aging Legacy Overhead Switches

All switches are susceptible to corrosion and rust, and can cause seizing of moving parts.. This can render the switch inoperable. Environmental conditions can corrode the blades in a switch, which results in the loss of the material's mechanical strength. Figure 18 below shows a severely corroded switch blade.

FIGURE 18: SEVERELY CORRODED SWITCH BLADE.

Manual overhead gang-operated switches use air as an insulation medium to extinguish the arc created by interrupting normal load current. Any contaminants present on the switch blade during a load break operation may cause the electrical arc to elongate, which can lead to excessive and premature damage to the blade itself. Furthermore, age results in operating mechanism to seize, making the disconnect switch inoperable. When blades fall out of alignment, excessive arcing may result. Air pollution, which typically occurs in heavy industrial areas or where road salt is used, can also affect support insulators reducing the useful lifespan of the switch.

Many components of non-R1 SCADA-Mate switches are prone to corrosion, including the housing and moving parts, and can experience mechanical deterioration of bearings, loose connections, motor winding deterioration, contamination of the circuitry, or the failure of electronic equipment.

In addition to failures during manual operation, switches also fail while in service. The safest way to remedy this situation is generally to open the next upstream isolation device so that a Toronto Hydro crew can replace the broken switch. The resulting outage may impact a large number of customers for an extended time.

MOSCAD Upgrades

Particular non-R1 SCADA-Mate switch locations in the Etobicoke area use the Motorola radio communication system (DARCOM radio system and MOSCAD Terminals). This technology has reached the end of its useful life and the equipment is obsolete. As a result, when the communication of the SCADA infrastructure fails, control for switching restoration is unavailable, increasing the risk of longer customer outages.

This technology has not been supported by the manufacturer for over ten years and Toronto Hydro has exhausted all methods of acquiring components in third party markets. The concern is the backup master radio units; it is anticipated that their reliability may be compromised because of the age of the spares. If replacement of these master radios exceeds these spares, the SCADA-based communication could be interrupted in Etobicoke as more than half of the SCADA switches in Etobicoke operate on the MOSCAD/DARCOM system.

SCADA-Mate switches offer remote control capability to restore load in the event of sustained trunk outages. The loss of remote operability of MOSCAD controlled SCADA switches, as a result of the failure of two aged Master Radios, will result in increased restoration time among Etobicoke feeders due to a lack of spare parts. Furthermore, it will complicate the restoration of sustained trunk outages since fault detection will need to done manually and manual switches will need to be operated.

Figure 19 below shows that existing SCADA infrastructure is helping to improve restoration time. However, MOSCAD obsolete equipment has significant failure risk that will compromise this existing stable state.

FIGURE 19: HISTORICAL RELIABILITY OF FEEDERS WITH MOSCAD-CONTROLLED SCADA SWITCHES

The expected useful life of an overhead switch is 45 years. The Overhead Circuit Renewal program will address all overhead switches that have reached end-of-life and that are in poor and very poor condition according to Toronto Hydro's ACA program (see section E6.4.3.2 (i) for additional details). Toronto Hydro expects to address all of these overhead switches during the 2015-2019 period. This work is required mitigate the reliability and safety concerns associated with the risk of switch failure. The failure of switches is discussed in section E6.4.3.2 (ii).

(iv) Legacy Porcelain Accessories & Non-Standard Animal Guards

Legacy Porcelain Accessories

Porcelain insulation material is used in overhead assets such as line post insulators, switches, lightning arrestors, and terminators. Over the last decade, porcelain has been phased out in favour of polymer-based materials because of safety and system performance issues. Porcelain is susceptible to:

- hairline cracks that can lead to failure;

- potential catastrophic failure caused by electrical tracking;
- higher tracking, leakage current, and system losses; and
- incompatibility with tree-proof conductors, which are essential for improving feeder reliability in heavily treed areas.

Historically, porcelain was used for insulating electrical overhead hardware mainly because of its sound electrical insulation characteristics. However, porcelain is susceptible to contamination build-up and electrical tracking, which can cause cracking, rupture and potential catastrophic failure. Electrical tracking is a leakage of electric current from one point to another, separated by an insulating material, and is caused by dirt, carbon particles, moisture, etc. It leads to a semi-conductive track that, over time, further weakens the insulator.

This also presents an injury risk to Toronto Hydro employees or members of the public who are in close proximity to the switch at the time of failure, as failure could result in debris falling from the overhead distribution system. Toronto Hydro no longer installs switches containing porcelain insulation.

Figures 20 and 21 illustrate instances of failed porcelain insulators.

FIGURE 20: BROKEN PORCELAIN INSULATOR

FIGURE 21: BROKEN PORCELAIN INSULATOR

Figures 22 and 23 below show an example of damage to the porcelain insulator of a manual load break switch, caused by electrical tracking over time along the surface.

FIGURE 22: BROKEN INSULATOR OF MANUAL LOAD BREAK SWITCH DUE TO TRACKING

FIGURE 23: BROKEN INSULATOR OF MANUAL LOAD BREAK SWITCH DUE TO TRACKING

See Figure 24 below for example of typical line post porcelain insulator installation.

FIGURE 24: TYPICAL PORCELAIN INSULATOR INSTALLATION

The majority of the failure modes for assets with porcelain insulating material are typically cracking and falling apart, posing a safety risk to operating line personnel and members of the public in proximity to the failure. In some cases, discharge of fragments due to weakening structural integrity of the material could occur as a result of a failure. Tracking causes the switch to fail, either by cracking the insulation and rendering the switch inoperable. The structural integrity of the switch has been reduced to a point that prevents the switch from safely withstanding the force required to open or close it, causing a potential flashover.

With regards to porcelain SMD-20s, in order to maintain safe clearance from the switch during operation, a hot stick is used to operate the switch from a distance. Operation from a distance means that a switch could be severely cracked which can result in significantly reduced structural integrity, without these cracks being noticeable. This can create a potential safety risk for the crew when a switch breaks during operation.

Animal Guards

The currently used Guthrie guard is a type of wildlife protection that attaches to the bushings of overhead transformers to repel animal contact. It is electrostatic and acts as a physical barrier between the transformer and the animal. Animals receive a non-lethal, mild shock that prevents them from contacting the energized transformer bushing. However, animal contact with energized components of the transformer still occurs with this guard.

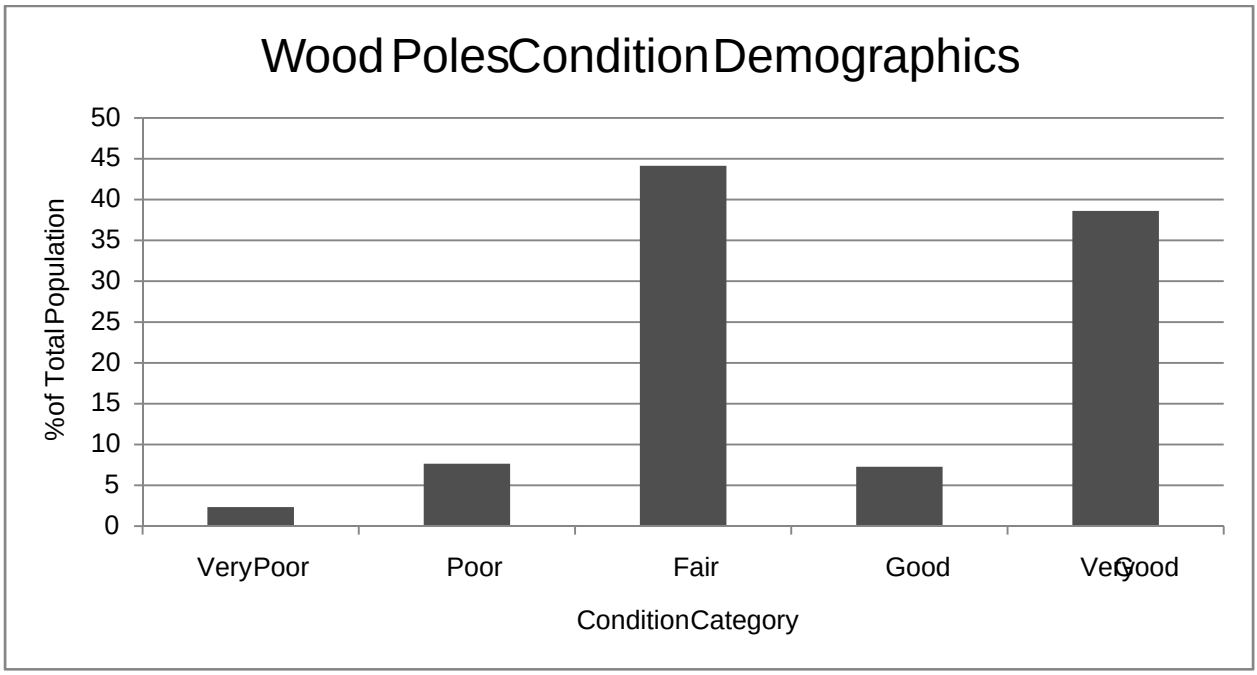
The new standard uses a cone shaped guard on the bushing with an accompanying insulated drop wire. It could curtail the number of outages related to animal contact which has a discernable trend as shown in Figure 7.

E6.4.3.2 Asset Details

In this section, the lifecycle and failure impacts of assets that will be replaced through this program are discussed in greater detail.

(i) Asset Lifecycle

As detailed in D3.1 Asset Replacement & Refurbishment Policies, Toronto Hydro utilizes an ACA program to monitor the condition of various key asset classes within its system and produce a health index score to support project planning. Figure 25 shows available condition demographics of wood poles. From a population of 123, 280 wood poles in the system, 37.66% of poles were sampled.



1 FIGURE 25: CONDITION DEMOGRAPHICS OF WOOD POLES

2 All electrical equipment inevitably ages during its service life and gradually deteriorates. This
3 deterioration can be further exacerbated by abnormal environmental and loading conditions.
4 Aging and its impact on overhead asset conditions, are detailed E6.4.3.1.

5 Table 4 shows the average useful life for the core overhead assets addressed in this program.

6 TABLE 4 : AVERAGE USEFUL LIFE

Asset	Average Useful Life (Years)
Wood Pole	45
Concrete Pole	60
Overhead Transformer	40
Overhead Switch	45

7 Figure 26 shows the age distribution of overhead major assets being targeted as part of this
8 program. Many of these assets, including 42,043 wooden poles, 2,685 overhead switches, and
9 7,252 overhead transformers, are past their useful lives.

FIGURE 26: AGE DISTRIBUTION OF OVERHEAD CORE ASSETS

The Overhead Circuit Renewal program focuses on replacing overhead assets that have the highest probability of failure, based on a combination of having reached its average useful life and being in poor and very poor conditions. In some cases, assets that have not have reached, or just approaching their useful life, may display deteriorated conditions that warrant an earlier replacement. This will ensure the mitigation of failure risk and safety concerns associated with end-of-life overhead equipment.

(ii) Asset Failure Impacts

Figures 27 and 28 show the number of CI and CHI, respectively, to depict historical impact trends of the overhead assets being addressed through the Overhead Circuit Renewal program.

FIGURE 27: OVERHEAD CORE ASSETS CI CONTRIBUTION

FIGURE 28: OVERHEAD CORE ASSETS CHI CONTRIBUTION

The figures above demonstrate that switches, porcelain equipment, and animal contact have the greatest impact on CI and CHI.

The following incidents portray the type and severity of impact due to the failure of overhead equipment being addressed in this program. The Overhead Circuit Renewal program alleviates these types of failure impacts through like-for-like replacement of end of life and poor condition equipment.

Poles

A catastrophic failure was reported on Midland Avenue in June 2011, where 13 poles fell during a windstorm. After inspection, these poles had signs of shell rot (refer to Figure 29), which led to the deterioration of their bases, causing them to fall during the storm.

FIGURE 29: MIDLAND AVE, JUNE 2011 – POLE SHELL ROT

As a result of the windstorm, a cascading failure took place shortly after the first pole failed and fell to the ground. This failure caused the rest of the poles in the line to fall as well (refer to Figures 30 and 31). Investigation of this incident also found evidence of an ant infestation, as shown in Figure 32. This type of infestation cannot be completely eliminated and can affect any pole, independent of age. Fortunately, this incident resulted in no injuries and did not require the payment of any property damage claims; however, it had the potential to cause significant injury and property damage.

FIGURE 30: MIDLAND AVE, JUNE 2011 - POLE COLLAPSE

FIGURE 31: MIDLAND AVE, JUNE 2011 - POLE COLLAPSE

FIGURE 32: MIDLAND AVE, JUNE 2011 – ANT INFESTATION

A pole failure took place at Fairbanks TS, where field staff reported a broken pole on Glencairn Avenue, affecting about 2,000 customers. The resulting outage lasted more than 11 hours. Similarly, in another incident at Manby TS, field staff reported a rotten pole on Riverbank Drive affecting 27 customers, and resulting in an outage lasting more than ten hours. It is evident from these cases that pole related outages lead to long outage durations. This is mainly due to complexities associated with installing a new pole such as new framing depending on number of circuits, poor condition of assets on pole that may no longer be reusable, and specialized equipment such as sucker trucks.

The degradation of poles can lead to irreversible damage including loss of pole strength, cross-arm rot, woodpecker or carpenter ant damage, surface rot at various levels of the pole, pole top feathering, wood loss and mechanical fire damage. Extreme deterioration and weakness, combined with external environmental forces, can cause poles to topple and create safety hazards for the public. Also, a fallen pole with a transformer could potentially result in adverse environmental repercussions.

Another incident involving wood poles occurred on Pape Avenue during a voltage conversion project. Once the crew had completed the approved procedures for the project, they cut the conductor in order to remove it. After so doing, one of the wood poles began to lean over. As shown in Figure 33 and Figure 34, this pole fell on a fence and porch roof with the conductors still attached.

The incident was caused by an aging pole with a rotten base (illustrated in Figures 33 and 34 below) and resulted in a property damage claim against Toronto Hydro.

FIGURE 33: PAPE AVE POLE FAILURE

FIGURE 34: PAPE AVE POLE FAILURE

A more serious incident occurred on Acacia Road. In this incident, a pole fell onto a residence causing it substantial damage, as illustrated in Figures 35, 36 and 37. This incident was a result of the poor condition of the pole, which had a rotten base at ground level. The pole, and the transformer attached to it, fell onto the residence, striking the second floor, roof, eaves, rafters, and front door, and damaging personal property belonging to the tenant. The resulting oil leak from the damaged transformer spread across the interior of the home. Fortunately, no one was injured, but the incident had the potential to cause injuries to individuals in the residence or standing in the front yard.

1

2 FIGURE 35: ACADIA ROAD POLE FAILURE

FIGURE 36: ACADIA ROAD POLE FAILURE

3 FIGURE 37: ACADIA ROAD POLE FAILURE

CSP

On CSP transformers, the internal fuse is designed to coordinate with the current limiting fuse (CLF) outside the transformer, but the effectiveness of this coordination depends on the nature of the internal fault. For example, a CLF was burning at CSP Transformer T13102 on feeder 85M23 on July 5, 2004 and became a potential safety risk for crews at the scene since the fire could have spread to the pole and other equipment. As another example, on March 18, 2010, a crew arrived to find a lid blown off at CSP Transformer T8040 on feeder SS58-F1 that could have caused injury to the public.

Overhead Switches

The failure of a gang-operated overhead switch can result in entire trunk portions of feeders experiencing an outage. Furthermore, the communication system upgrades in Etobicoke ensure that remote operation of SCADA switches in this part of the system is available during a trunk outage and contingency scenarios. If the master radios fail, there is no method of communication between old MOSCAD-controlled SCADA switches and the control room; this will result in Etobicoke losing remote functionality through SCADA switches and having adverse restoration times in the event of a trunk outage.

Porcelain

Porcelain pothead terminations also have the potential to fail in a catastrophic manner, releasing porcelain shards and dispersing oil; this can damage other nearby electrical equipment and public property. In addition, the dispersion of oil from the damaged terminations may result in a fire or an environmental hazard.

In 2009, Toronto Hydro received a Public Safety Concern from the ESA as a result of a porcelain pothead failure sending shards of porcelain onto the balcony of a nearby home, shattering the window of the family room and causing damage to the windshield of a nearby police car. The effects of the failure are seen in Figure 38. Toronto Hydro replaced the failed porcelain pothead with a new polymer termination.

FIGURE 38: PORCELAIN POTHEAD FAILURE IMPACT

Figure 39 below shows a situation where one of the center-phase porcelain insulators had broken and fallen off on a manual load break switch. The porcelain components of these switches are susceptible to contamination, which leads to tracking across the insulator and eventually failure.

FIGURE 39: PORCELAIN INSULATOR FAILURE ON MANUAL LOAD BREAK SWITCH

Figure 40 below illustrates an in-line disconnect switch where part of the porcelain insulation has broken off. This is a potential safety risk as large pieces of porcelain could fall to the ground from switches mounted up to 50 feet 1 (15.24 metres) high, could injure someone or damage nearby property.

FIGURE 40: BROKEN PORCELAIN INSULATOR FROM IN-LINE DISCONNECT SWITCH

Figure 41 below shows a broken porcelain insulator on a pole to string conductor. In addition to the safety concerns about falling debris, porcelain fragments could also potentially trigger pole fires.

FIGURE 41: BROKEN PORCELAIN INSULATOR ON POLE

The program addresses overhead assets at risk of failure. Because these assets are located on both trunk and lateral portions of feeders, the extent of outages can vary from a localized group of customers downstream of a fuse to all customers on a feeder. The customers impacted by these types of outages range from low-volume residential to large industrial power consumers.

Replacing overhead equipment near or past its end of life in a proactive fashion is expected to curtail the frequency of outages caused by defective overhead equipment, reducing customer interruptions and mitigating safety risks as discussed earlier in this exhibit.

E6.4.4 Timing & Pacing of the Program

As per the table below, the total cost of the Overhead Circuit Renewal program over the 2015-2019 period is $147.4 M.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	$25.8	$28.3	$23.2	$49.0	$53.3	$44.0	$23.0	$24.9	$25.3	$30.3

The Overhead Circuit Renewal program will help ensure that Toronto Hydro is replenishing its aged and deteriorating infrastructure at a strategic pace in order to mitigate failure and safety risks. The deferral of the projects in this program will result in the excess accumulation of an aged and poor conditioned overhead distribution plant. If Toronto Hydro does not replace these assets between 2015 and 2019, assets operating beyond useful life and in deteriorating conditions will be compounded and renewal efforts will likely be insufficient to maintain existing levels of system reliability.

The table above provides historical spending figures as well. A significantly high number of overhead defective equipment outages occurred from 2008–2010, which prompted an increase in spending levels from 2010 and onwards. Outages began to rise again from 2012-2013, prompting a large spending increase to address the issue. Future spending levels are lower than past ICM expenditures due to the fact that the overall DSP contains core renewal work that will be supplemented by modernization efforts in order to better manage the overhead system.

E6.4.4.1 Ranking & Prioritization

Individual projects under this program are prioritized based on criteria such as age, asset condition, and historic performance.

Age and asset condition are the primary drivers of asset failure. Therefore, as is the case for the majority of System Renewal programs, older and poorer condition assets will generally be replaced first. In addition, the number of customers that an asset could interrupt in the case of a failure is also factored into the timing of individual projects. Finally, consideration is given to assets that pose specific reliability concerns or other risks based on their past reliability performance.

Generally, overhead assets on lower primary voltages of 4.16 kV or 13.8 kV are at their end of useful life. The transformers, switches and other equipment at this voltage level are at or close to end of their useful life. Municipal Stations (MS) that supply the 4.16 kV and 13.8 kV distribution systems are 50 or 60 years old and slated for decommissioning. Overhead circuit renewal of 4.16 kV and 13.8 kV feeders, via voltage conversion, also provides the ancillary benefit of decommissioning MS stations that have aged/obsolete equipment. By converting these feeders necessary to decommission the MS, Toronto Hydro aims not only to decrease failure risk of the aged 4.16 kV and 13.8 kV systems, but also to avoid the need to maintain the aged and obsolete equipment in the MS. Thus, voltage conversion jobs were also considered in prioritizing overhead circuit renewal jobs and in complementing necessary station work.

E6.4.6 Program Execution

Toronto Hydro's approach is to identify common geographical areas that contain a significant number of at-risk assets and execute full overhead rebuilds. Overhead rebuilds involve the replacement of an entire group of assets, which includes pole line replacements, re-stringing new conductor, installing new overhead transformers, new switches, and upgrading all associated overhead accessories. In some cases, abnormally high failure risk may warrant stand-alone replacements of assets in multiple locations.

Voltage Conversions target aged and poor condition 4.16 kV or 13.8 kV equipment that have high failure risk, and replace it with new assets at higher voltage levels. Voltage conversions eventually allow Toronto Hydro to decommission aged Municipal Substations (MS) that are 50-60 years old once all of the feeders emanating from them have been converted.

Large overhead circuit renewal projects are broken into smaller phases for better manageability and coordination, providing greater flexibility for scheduling and assigning resources. Staging also reduces the number of scheduled outages and disruptions that customers will experience. Customer notifications are communicated prior to scheduled power outages to minimize the inconvenience they cause. Efforts are also made to coordinate overhead circuit renewal work with other capital projects wherever practical.

E6.4.6.1 Program Risks

Large overhead rebuild projects can be complicated by work undertaken by other utilities operating in the area. This can result in conflicts leading to incremental costs and delays. In some cases, overhead work that involves poles on sidewalks may be in conflict with existing sidewalk moratoriums. The Toronto Public Utilities Coordinating Committee (TPUCC) is a consortium that aims to resolve such conflicts and sidewalk moratoriums between multiple utilities by establishing schedules in a sequential manner that mutually benefits all parties involved. Toronto Hydro participates in this forum to mitigate the conflict risks with other utilities and the City.

The program also entails entire overhead plant rebuilds that may present easement issues. Existing third-party attachments must be contacted to explore other options and may delay execution timeline. Delays in obtaining permits from the City of Toronto, Ministry of Transportation, or even CN railways may require extra design time. In some areas of Toronto, arborist consultation may be required to comply with Toronto and Region Conservation Authority requirements and obtain permits. Identifying and making efforts to accommodate these issues during planning stages can mitigate much of this risk.

E6.4.6.2 Standard & Regulation Adherence

Toronto Hydro plans, designs and construct the current distribution system assets in accordance with approved standards, which are developed to achieve the objectives of public and employee safety in compliance with the requirements of Ontario Regulation 22/04. This program has been established to upgrade legacy assets to bring them into compliance with current construction standards.

E6.4.7 Evaluation of Alternatives

In addition to the reasons and benefits outlined in E6.4.3 and E6.4.5, the preferred option of proactively replacing overhead equipment has a lower cost of ownership than keeping the

existing configuration. This is primarily due to avoided annualized risk costs and maintenance costs that are otherwise incurred on an annual basis.

E6.4.7.1 Quantification/Evaluation of Options

(i) Option 1: Status Quo

The 'Status Quo' option involves deferring the activities in the Overhead Circuit Renewal program past the five-year planning horizon of 2015 to 2019. Under this scenario, Toronto Hydro can expect to continue experiencing a large number of overhead-caused outages. Defective overhead equipment contributed to approximately 22% of all system-wide outages. Assets would continue to deteriorate and fail, likely requiring an increasing amount of reactive replacement work while generating operational issues as a result. This option would also fail to mitigate the safety concerns discussed earlier.

(ii) Option 2: Rehabilitation of Assets

Another option considered was to provide short term mitigation rehabilitation in the form of upgrading overhead accessories (insulators, switches, transformers, etc.) only. This method is similar to a Worst Performing Feeder approach where, at the minimum, it provides a means to curtail an abnormal amount of particular outages with minimal work until a complete replacement rebuild is scheduled.

This option is not recommended because it does not address the underlying issue of system-wide overhead equipment failures that are primarily caused by asset aging and deterioration. Another disadvantage is that most aged core assets (poles) do not easily accommodate the new standard accessories. New polymeric insulators would be bolted on feathered pole tops where its mechanical strength has deteriorated. New animal guard installations on aged CSP transformers require modifications to the guards.

(iii) Option 3: Replacement of Assets

The preferred option is to replace end-of-life overhead equipment, which includes aged, poor conditioned, and functionally obsolete equipment that is at the highest risk of failure over the next five years in a coordinated fashion. This alternative will generate all of the benefits discussed throughout the narrative.

The anticipated execution strategy is to address these issues by identifying and rebuilding assets together in the same area that has a significant accumulated risk of failure. This also includes voltage conversions that help aid the removal of 4.16 kV and 13.8 kV MS stations.

Executing the first year of planned activities in the Overhead Circuit Renewal program in the first year as opposed to deferring these activities until 2020 is anticipated to result in an avoided estimated risk cost (ARC) of approximately $39.94 million. The ARC takes into account the probability of failure of the assets and multiplies this figure by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement. For further details on the ARC approach is provided in Section D3.3.

TABLE 6: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Asset Renewal	
Present Value of Net Cost in 2020 [PV(NET_COST(2020)]	$70.09
Net Cost for the First Year of Activity [NET_COST(First Year of Activity)]	$30.14
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - (NET_COST(First Year of Activity))]	$39.94

E6.6.9 2015 Project Details

Table 7 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

(a) Previously filed projects that appeared as jobs in the OEB approved in the Overhead Infrastructure segment, as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 7: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	CIR Projects
10.78	33.20

Table 8 lists all projects that will be partially or fully executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 8: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
W14344	Voltage Conversion Westmount MS	$ 573,68931	2015	CIR
W14345	Voltage Conversion RB-F2 Westmount MS	$ 231,43652	2014	ICM
X12196	FESI Bathurst Lawrence OH Rebuild Ph3 35M5	$ 2,594,99876	2015	ICM
X11732	35M11 Marlee Ave Primary Detailing	$ 44,14708	2015	CIR
W15277	West of Kipling Ave, OH Voltage Conversion of AHF2, AHF5	$ 1,358,09902	2015	CIR
W12491	FESI Rebuild and CSP replacement PH#3	$ 1,531,15265	2015	CIR
W14176	OH Feeder Rehab-Alexdon, Chesswood, Champagne	$ 521,23566	2015	CIR
W14216	OH Rehab & VC Burnhamthorpe - Mill to Triburnham 88M46	$ 554,74122	2015	CIR
W14220	UG Rehab & VC of two Townhouse Complexes ETKKF2	$ 576,38281	2015	CIR
W14351	Drewry & Cactus OH Area Rebuild Fairchild TS 80M2	$ 744,13409	2015	CIR
W14353	Peckham & Pleasant OH Area Rebuild Fairchild TS 80M2	$ 569,19852	2015	CIR
E15036	P05 Voltage Conversion Phase 2 SCREF3 Shep-Ken MS	$ 221,63308	2015	CIR
E15037	P05 Voltage Conversion Phase 3 SCREF3 Shep-Ken MS	$ 221,64235	2015	CIR
X12179	Replacement of CSP transformers YK35M10	$ 1,050,71140	2014	ICM

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
X13191	35M11 - Lawrence and Brucewood Cres Rebuild	$ 1,796,532.68	2015	CIR
W13206	Refurbish Feeder Laterals - Phase 1 of 2	$ 1,272,900.88	2014	ICM
W14658	P05-Conversion of West Islington feeder AF1	$ 578,591.31	2014	ICM
W14661	P05-Conversion of West Islington feeder AF6	$ 173,577.39	2014	ICM
W14659	P05-VC of West Islington feeder AF2, Electrical	$ 231,436.52	2014	ICM
W14073	Overhead Rebuild at Steels Ave W and Weston Road 55M31	$ 768,158.43	2015	CIR
W14174	Lambton MS VC PH#1	$ 1,073,344.35	2015	CIR
W14175	Lambton MS VC PH#2	$ 565,315.47	2015	CIR
W13054	FESI Refurbish OH feeder PH#1	$ 1,106,903.50	2015	CIR
W13055	FESI Refurbish OH feeder PH#2	$ 661,455.75	2015	CIR
W13056	FESI Refurbush OH feeder PH#3	$ 679,337.72	2015	CIR
W13057	FESI Refurbish OH feeder PH#4	$ 728,886.04	2015	CIR
W15492	P05 - MOSCAD/DARCOM Controller Replacement PH1 - Richview TS	$ 414,520.22	2015	CIR
W15494	P05 MOSCAD/DARCOM Replacement Ph2 - Rexdale TS, Woodbridge TS	$ 345,383.83	2015	CIR
E12891	Voltage Conversion of SS38 F1 F2 from Burbank MS - Install Poles	$ 182,991.63	2015	CIR
E15099	Mountland OH Voltage Conversion YGF1 SCYGF1	$ 561,836.03	2015	CIR
E15368	Brimley-Finch OH Rehab SCNT63M8	$ 795,652.93	2015	CIR
E14117	OH Rebuild R43M28 Aylesworth Kennedy	$ 713,196.11	2015	CIR
W14276	OH Feeder Rehab - Signet, Weston, Fenmar	$ 901,659.10	2014	ICM
W13115	FESI Feeder Rehab and Change out Phase 2	$ 431,678.87	2014	ICM
W14289	OH Rebuild off Gary Avenue	$ 773,556.93	2015	ICM
W12265	Overhead Rebuild on 55M26 Phase 1	$ 967,904.70	2015	CIR
W12269	Overhead Rebuild on 55M26 Phase 2	$ 1,410,229.08	2015	CIR

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
W10461	FESI Scarlett-St. Clair OH Rebuild (YK11M7)	$ 1,677,149	33 2015	CIR
W15264	P05 Queenslea Avenue Overhead Rebuild 55M23	$ 1,214,416	90 2015	CIR
W15335	Ranee and Ameer OH Area Circuit Renewal PH1 NY85M26	$ 514,853	21 2015	CIR
W15336	Ranee and Ameer Area OH Circuit Renewal PH2 NY85M26	$ 928,302	92 2015	CIR
W15338	Ranee and Ameer Area OH Circuit Renewal PH3 NY85M26	$ 1,078,063	62 2015	CIR
W15169	East mall/Dundas OH Renewal 38M10	$ 535,631	24 2015	CIR
E14097	Voltage Conversion of SS63F1 to 80M4 - Between Yonge & Bayview	$ 1,217,582	02 2015	CIR
X12318	1.1.2 34M1 SCADAmate install	$ 109,932	35 2014	ICM
E14286	OH Rebuild 64F2 Ruddington MS VC	$ 980,460	58 2014	ICM
W13634	P05 Extension of 30M12 eastwards along Evans Ave into 30M1 and 30M8	$ 867,886	96 2014	ICM
W14677	P05 - Manby Richview Load Cascades, Part 2	$ 578,591	31 2015	ICM
E14734	P05 Comstock Faulklands MS Decommission Feeders	$ 206,764	29 2015	CIR
E15348	Warden-Lowcrest UG Voltage Conversion Civ (Part 1)	$ 1,327,482	31 2015	CIR
W13238	Brenthall MS to Fairchild TS VC Mascot and Kingsbridge	$ 426,176	32 2015	CIR
E12326	E123246 Voltage Conversion of NYSS38F1 and NYSS38F2 from Burbank MS	$ 870,487	47 2015	CIR
E15102	E15102 Huronia Harley OH Voltage Conversion QGF3 SCQGF3	$ 771,593	79 2015	CIR

W14344, W14345 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Voltage Conversion Westmount MS – Phase 1 to 4

Project Number: W14344, W14345

Project Year: 2015

Estimated Cost: $805,125.83

(i) Objective

The objective of these projects is to renew the distribution system along Dixon Road (between Islington Avenue and Scarlett Road) by replacing the deteriorating 4.16kV distribution assets and converting the area to 27.6kV in order to prepare the substation for decommissioning.

(ii) Scope of Work

TABLE 9

District Neighbourhood:	Etobicoke North
Station(s):	Westmount MS (4.16kV)
Feeder(s):	ETRBF1, ETRBF2, ETRBF3

TABLE 10

Asset	Count
Pole	49
Transformer	13
Manual Switch	5
SCADA Switch	2
Fuse	4
Switchgear	0
*Conductor Length (m)	1,350
*Cable Length (m)	1,000

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 11

Supplemental Details	Description
Age/Condition	• Most of the equipment is over 40 years of age or older • Majority of the equipment is in poor condition
Reliability	• Failure risk due to age
Other (i.e. moratorium, etc)	• Station equipment reaching end of life and proposing decommissioning

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figures 42 to 44.

FIGURE 42: HISTORICAL RELIABILITY DETAILS FOR RBF1

FIGURE 43: HISTORICAL RELIABILITY DETAILS FOR RBF2

FIGURE 44: HISTORICAL RELIABILITY DETAILS FOR RBF3

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

X12196 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: FESI Bathurst Lawrence OH Rebuild Ph3 NY35M5

Project Number: X12196

Project Year: 2015

Estimated Cost: $2,594,998.76

(i) Objective

The objective of this project is to address failure modes related to defective overhead equipment outages by rebuilding the overhead infrastructure on feeder 35M5 as well as replacing undersized and de-rated conductor within the project area.

(ii) Scope of Work

TABLE 12

District Neighbourhood:	Eglinton-Lawrence
Station(s):	Fairbanks TS (27.6kV)
Feeder(s):	NY35M5

TABLE 13

Asset	Count
Pole	55
Transformer	55
Manual Switch	0
SCADA Switch	0
Fuse	0
Switchgear	0

Asset	Count
*Conductor Length (m)	2,000
*Cable Length (m)	0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 14

Supplemental Details	Description
Age/Condition	ƒ The project involves a rebuild of the overhead primary distribution system in the area of Lawrence Avenue West, Bathurst Street, Coldstream Avenue and Edgecombe Avenue ƒ Field inspections have shown that the overhead infrastructure along the feeder is in deteriorating conditions as well as portions of the overhead conductors to be undersized
Reliability	ƒ 27% of the outages on the feeder are due to defective overhead equipment ƒ Feeder has an increase trend over the five years with nine outages in 2013
Other (i.e. local failures, etc)	ƒ This project hopes to mitigate the risk presented by deteriorating assets and non-standard equipment in the area through a proactive rebuild of feeder NY35M5

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 45.

FIGURE 45: HISTORICAL RELIABILITY DETAILS FOR 35M5

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

X11732 Project Descriptions

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: NY35M11 Marlee Ave Primary Detailing

Project Number: X11732

Project Year: 2015

Estimated Cost: $44,147.08

(i) Objective

The objective of this project is to install new standard animal guards on feeder NY35M11 in the area of Lawrence Avenue West and Allen Road.

(ii) Scope of Work

TABLE 15

District Neighbourhood:	York South-Weston
Station(s):	Fairbanks TS (27.6kV)
Feeder(s):	NY35M11

TABLE 16

Asset	Count
Pole	0
Transformer	0
Manual Switch	0
SCADA Switch	0
Fuse	0
Switchgear	0
*Conductor Length (m)	0

Asset	Count
*Cable Length (m)	0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 17

Supplemental Details	Description
Age/Condition	ƒ Feeder NY35M11 from Fairbanks TS experienced a number of forced interruptions due to animal interference ƒ The overhead transformers on the feeder have no standards animals guards installed
Reliability	ƒ Feeder has experienced 12 outages due to animal contact within five years, this accounts for 40% of the interruptions of the feeder
Other (i.e. local failures, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 46.

FIGURE 46: HISTORICAL RELIABILITY DETAILS FOR 35M11

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W15277 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: West of Kipling Avenue Overhead Voltage Conversion of AHF2, AHF5

Project Number: W15277

Project Year: 2015

Estimated Cost: $1,358,099.02

(i) Objective

The objective of this project is to rebuild parts of Fieldway MS feeders that are aging as confirmed by feeder patrol of the area in the summer of 2013.

(ii) Scope of Work

TABLE 18

District Neighbourhood:	Etobicoke Lakeshore
Station(s):	Fieldway MS
Feeder(s):	AHF2, AHF5

TABLE 19

Asset	Count
Pole	80
Transformer	20
Manual Switch	5
SCADA Switch	0
Fuse	2
Switchgear	0
*Conductor Length (m)	7,900

*Cable Length (m)	0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 20

Supplemental Details	Description
Age/Condition	• The scope through the voltage conversion, will replace aged 4kV feeder assets of feeder AHF2 and AHF5 that are already in deteriorated condition as confirmed by feeder patrol of the area in the summer of 2013, with brand new 27.6kV equipment.
Reliability	• The renewal OH and UG infrastructure in the scope addresses and stems the increasing number of outage incidents due to feeder equipment defects and failures. • A total of 3 forced outages, 368 CI and 509 CHI on feeder AHF2 since 2009 • A total of 5 forced outages, 390 CI and 137 CHI on feeder AHF5 since 2009 • 81% of the CI and 99% of the CHI occurred in the last two years while 96% of the CI and 65% of the CHI occurred in the last year showing an increasingly dire reliability situation in the area.
Other (i.e. moratorium, etc)	• Feeders in the area, from West Islington MS, Cloverdale MS and Shaver MS will all be completely converted to 27kV by the end of 2015 leaving parts of the feeders AHF2 and AHF5 west of Kipling Avenue with no back-up. For this reason it is critical to complete this voltage conversion job in 2015.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figures 47 and 48.

FIGURE 47: HISTORICAL RELIABILITY DETAILS FOR AHF2

FIGURE 48: HISTORICAL RELIABILITY DETAILS FOR AHF5

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W12491 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: FESI Rebuild and CSP replacement PH#3

Project Number: W12491

Project Year: 2015

Estimated Cost: $1,531,152.65

(i) Objective

The objective of this project is to rebuild the overhead infrastructure on feeder NY85M1 due to poor reliability. The scope is intended to replace Completely-Self-Protected (CSP) transformers, glass insulators and arrestors as well as installing primary distribution with tree proof conductor.

(ii) Scope of Work

TABLE 21

District Neighbourhood:	York Centre
Station(s):	Bathurst TS (27.6kV)
Feeder(s):	NY85M1

TABLE 22

Asset	Count
Pole	145
Transformer	50
Manual Switch	10
SCADA Switch	0
Fuse	10
Switchgear	0

Asset	Count
*Conductor Length (m)	5,055
*Cable Length (m)	0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 23

Supplemental Details	Description
Age/Condition	ƒ The assets in the Wilson and Faywood area are aged and in poor condition ƒ Assets being replaced include aged poles, transformers, and porcelain equipment
Reliability	ƒ Outages on 85M10 have been increasing for the last 5 years ƒ There was a significant increase from 5 to 10 outages from 2012 to 2013
Other (i.e. moratorium, etc)	ƒ This project is intended to mitigate failure risk of these assets and improve reliability

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 49.

FIGURE 49: HISTORICAL RELIABILITY DETAILS FOR 85M1

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W14176 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: OH Feeder Rehab-Alexdon, Chesswood, Champagne

Project Number: W14176

Project Year: 2015

Estimated Cost: $521,235.66

(i) Objective

The objective of this project is to rebuild/replace the aging and non-standard primary overhead distribution equipment on feeder NY85M4 in order to improve reliability.

(ii) Scope of Work

TABLE 24

District Neighbourhood:	York West
Station(s):	Bathurst TS (27.6kV)
Feeder(s):	NY85M4

TABLE 25

Asset	Count
Pole	30
Transformer	18
Manual Switch	9
SCADA Switch	0
Fuse	0
Switchgear	0
*Conductor Length (m)	0

Asset	Count
*Cable Length (m)	0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 26

Supplemental Details	Description
Age/Condition	• To refurbish the OH distribution system by replacing old and poor condition poles and non-standard equipment of feeder 85M4 along Alexdon, Chesswood, Champagne, Toro, etc.
Reliability	• 85M4 has had an average of 4 outages a year during 2009-2013
Other (i.e. moratorium, etc)	• This project is intended to mitigate failure risk of these assets and improve reliability

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 50.

FIGURE 50: HISTORICAL RELIABILITY DETAILS FOR 85M4

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W14216, W14220 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Rehab & VC of ETKKF2 Phase 1 to 3

Project Number: W14216 and W14220

Project Year: 2015

Estimated Cost: $1,131,124.03

(i) Objective

The objective of these projects is to convert the distribution system in the Burnhamthorpe – Mill area by replacing the deteriorating 4.16kV system and converting the area to 27.6kV.

(ii) Scope of Work

TABLE 27

District Neighbourhood:	Etobicoke Centre
Station(s):	Burnhamthorpe MS (4.16kV)
Feeder(s):	ETKKF2

TABLE 28

Asset	Count
Pole	30
Transformer	8
Manual Switch	3
SCADA Switch	0
Fuse	14
Switchgear	0
*Conductor Length (m)	750.0

*Cable Length (m)	2,900.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 29

Supplemental Details	Description
Age/Condition	• Most of the equipment is over 40 years of age or older • Majority of the equipment is in poor condition
Reliability	• Failure risk due to age
Other (i.e. moratorium, etc)	• Station equipment reaching end of life and proposing decommissioning

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 51.

FIGURE 51: HISTORICAL RELIABILITY DETAILS FOR KKF2

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W14351, W14353 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Drewry, Cactus, Peckham and Pleasant OH Area Rebuild Fairchild TS NY80M2

Project Number: W14351 and W14353

Project Year: 2015

Estimated Cost: $1,313,332.61

(i) Objective

The objective of these projects is to refurbish the overhead laterals of feeder NY80M2 in the area of Cactus Avenue, Drewry Avenue, Peckham Avenue and Pleasant Avenue.

(ii) Scope of Work

TABLE 30:

District Neighbourhood:	York Centre
Station(s):	Fairbanks TS (27.6kV)
Feeder(s):	NY80M2

TABLE 31

Asset	Count
Pole	110
Transformer	35
Manual Switch	14
SCADA Switch	0
Fuse	14
Switchgear	0

Asset	Count
*Conductor Length (m)	3,600
*Cable Length (m)	0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 32

Supplemental Details	Description
Age/Condition	ƒ The assets in the general area of Drewry and Cactus supplied from 80M2 are in poor condition, aged, and functionally obsolete ƒ Spot condition assessments shows may poles have a score of below 50 in the ACA assessment.
Reliability	ƒ There have been a significant amount of outages from 2009 - 2012
Other (i.e. moratorium, etc)	ƒ This project is intended to mitigate failure risk of these assets and improve reliability

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 52.

FIGURE 52: HISTORICAL RELIABILITY DETAILS FOR 80M2

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15036, E15037 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Voltage Conversion of Shep-Ken MS SCREF3 Phase 2 and 3

Project Number: E15036, E15037

Project Year: 2015

Estimated Cost: $443,275.43

(i) Objective

The objective of these projects is to convert feeder SCREF3 due to the poor asset condition.

(ii) Scope of Work

TABLE 33:

District Neighbourhood:	Scarborough Agincourt
Station(s):	Shepherd Kennedy MS (4.16kV)
Feeder(s):	SCREF3

TABLE 34

Asset	Count
Pole	2
Transformer	1
Manual Switch	4
SCADA Switch	0
Fuse	3
Switchgear	0
*Conductor Length (m)	60
*Cable Length (m)	90

(iii) Justification & Benefits

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 53.

FIGURE 53: HISTORICAL RELIABILITY DETAILS FOR REF3

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

X12179 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Replacement of CSP transformers YK35M10

Project Number: X12179

Project Year: 2015

Estimated Cost: $1,050,711.40

(i) Objective

The objective of this project is to rebuild the overhead infrastructure on feeder YK35M10 from Fairbanks TS due to poor reliability and to replace end-of-life infrastructure.

(ii) Scope of Work

TABLE 35:

District Neighbourhood:	York South-Weston
Station(s):	Fairbanks TS (27.6kV)
Feeder(s):	YK35M10

TABLE 36

Asset	Count
Pole	55
Transformer	24
Manual Switch	20
SCADA Switch	0
Fuse	0
Switchgear	0
*Conductor Length (m)	8,400.0

*Cable Length (m)	640.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 37

Supplemental Details	Description
Age/Condition	ƒ Feeder YK35M10 has experienced many overhead reliability issues within the boundaries of this project ƒ This project was initiated due to the poor overhead infrastructure condition and poor reliability of the assets on feeder ƒ As determined by a feeder patrol, the majority of the assets along this feeder are past their useful service life and will be replaced
Reliability	ƒ Feeder YK35M10 is one of the worst performing feeders in the system with a total of 11 outages in 2011, 11 outages in 2012 and 16 outages in 2013. ƒ Due to the number of interruptions the feeder has experienced, the area is to be rebuilt with standard equipment to minimize the outages caused by defective equipment. ƒ The feeder has experienced at least six failures per year ƒ The major failure mode for this feeder is overhead equipment.
Other (i.e. local failures, etc)	ƒ In addition to the overhead infrastructure renewal, the project covers an underground section of the feeders and involves replacing underground transformers and underground cable as well as incorporating civil infrastructure for the installation of new underground cable

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 54.

FIGURE 54: HISTORICAL RELIABILITY DETAILS FOR 35M10

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

X13191 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: NY35M11 - Lawrence and Brucewood Crescent Rebuild

Project Number: X13191

Project Year: 2015

Estimated Cost: $1,796,532.68

(i) Objective

The objective of this project is to rebuild the overhead infrastructure on feeder NY35M11 on Lawrence Avenue West from W.R. Allen Rd to Brucewood Crescent.

(ii) Scope of Work

TABLE 38:

District Neighbourhood:	Eglinton-Lawrence
Station(s):	Fairbanks TS (27.6kV)
Feeder(s):	NY35M11

TABLE 39

Asset	Count
Pole	106
Transformer	28
Manual Switch	2
SCADA Switch	0
Fuse	2
Switchgear	0
*Conductor Length (m)	6,906.00

*Cable Length (m)	0.00

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 40

Supplemental Details	Description
Age/Condition	• The identified streets under this job, supplied by NY 35M11 require a rebuilt due to the deteriorating conditions of the overhead infrastructure. • Feeder possesses a significant count of non-standard equipment and assets past their useful life • Recent feeder patrol reports have shown that most of the poles in the job area are aged and feathered at the top
Reliability	• Feeder 35M11 has experienced a high number of interruptions due to overhead equipment • Overhead defective equipment accounts for 33% of the outages on the feeder • 30% of the outages are due to animal related contacts. This project will be installing animal guards with new overhead transformers in the area • There is an urgent need to upgrade deteriorating assets on this feeder, which have contributed the increase in the customers interrupted in 2013
Other (i.e. local failures, etc)	• This project is intended to mitigate failure risk of these assets and improve reliability.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 55.

FIGURE 55: HISTORICAL RELIABILITY DETAILS FOR 35M11

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W13206 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Refurbish Feeder Laterals - Phase 1 of 2

Project Number: W13206

Project Year: 2015

Estimated Cost: $1,272,900.88

(i) Objective

The objective of this project is to rebuild/replace the aging and non standard primary overhead distribution equipment on feeder NY85M10 in order to improve reliability and replace the XLPE lateral services with TRXLPE cable to improve reliability.

(ii) Scope of Work

TABLE 41:

District Neighbourhood:	York Centre
Station(s):	Bathurst TS (27.6kV)
Feeder(s):	NY85M10

TABLE 42

Asset	Count
Pole	110
Transformer	37
Manual Switch	11
SCADA Switch	0
Fuse	25
Switchgear	0

Asset	Count
*Conductor Length (m)	5,750.0
*Cable Length (m)	1,100.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 43

Supplemental Details	Description
Age/Condition	• To rebuild OH feeder 85M10 by replacing aging and/or non-standard distribution equipment including, but not limited to, poles, lines and transformers along (predominantly) single phase laterals. • The area is bounded by Dufferin, Whitley, Keele and Powell.
Reliability	• There has been an average of 5 outages a year during 2009-2013.
Other (i.e. moratorium, etc)	• This project is intended to mitigate failure risk of these assets and improve reliability.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 56.

FIGURE 56: HISTORICAL RELIABILITY DETAILS FOR 85M10

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W14658, W14661, W14659 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: P05-Conversion of W est Islington feeder AF1, AF2, AF6

Project Number: W14658, W14659, W14661

Project Year: 2015

Estimated Cost: $983,605.22

(i) Objective

The objective of these projects is to renew the distribution system in the area of Etobicoke-Lakeshore by rebuilding the deteriorated West Islington MS 4.16kV feeders and convert them to 27.6kV.

(ii) Scope of Work

TABLE 44:

District Neighbourhood:	Etobicoke-Lakeshore
Station(s):	West Islington MS; Wingrove MS
Feeder(s):	AF1, AF2, AF6, VNF4

TABLE 45

Asset	Count
Pole	150
Transformer	64
Manual Switch	13
SCADA Switch	0
Fuse	5
Switchgear	0

Asset	Count
Conductor Length (m)	9,200.00
Cable Length (m)	30

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

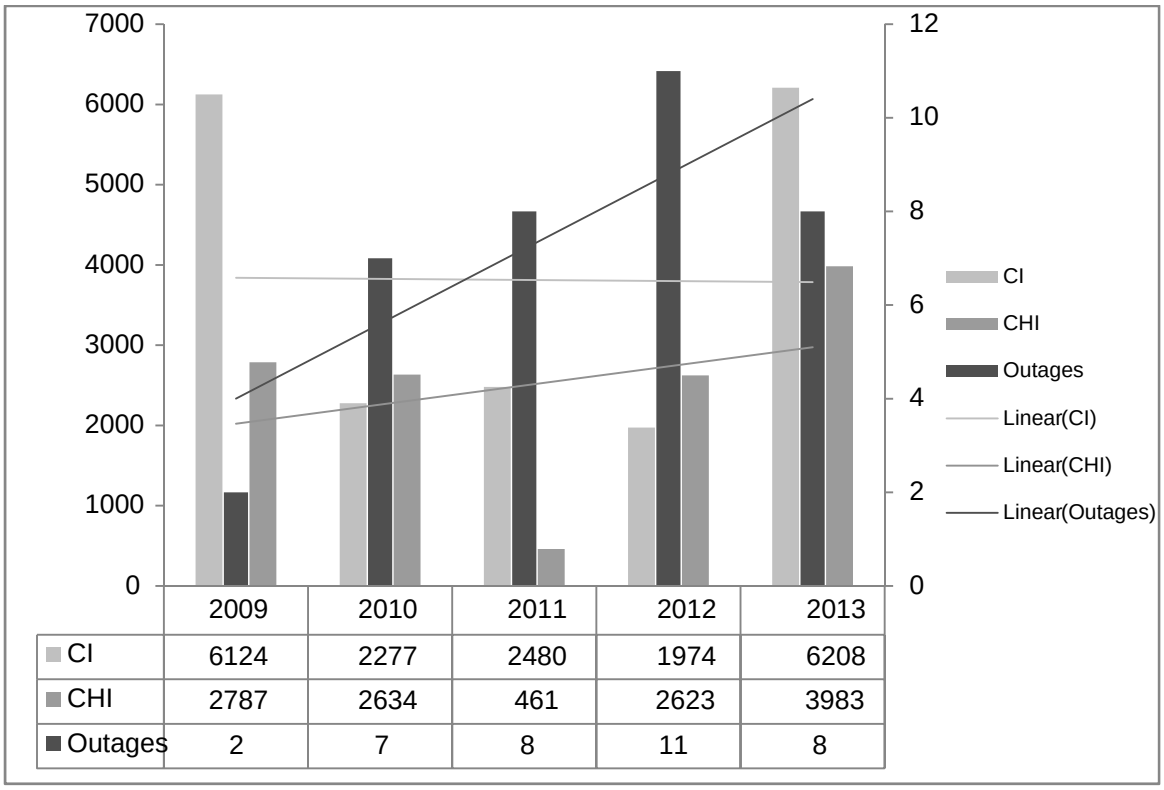
TABLE 46

Supplemental Details	Description
Age/Condition	ƒ Scope upgrades undersized feeder trunk conductors along The East Mall from 4/0 to THESI standard 556 kcmil.
Reliability	ƒ Scope upgrades distribution assets along 38M10 in the area order to stem the residents' experience of outages which was particularly high in 2013. ƒ A total of 5 forced outages, 8378 CI and 4910 CHI on feeder 38M10 since 2009 with 80% of the outages in 2013 showing an increasingly dire reliability situation along the feeder.
Other (i.e. moratorium, etc)	ƒ Customers in the area had complained of the high incidence of outages in 2013.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 57 to 59.

FIGURE 57: HISTORICAL RELIABILITY DETAILS FOR AF1

1 FIGURE 58: HISTORICAL RELIABILITY DETAILS FOR AF2



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

FIGURE 59: HISTORICAL RELIABILITY DETAILS FOR AF6

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W14073 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Overhead Rebuild at Steels Ave W and Weston Road NY55M31

Project Number: W14073

Project Year: 2015

Estimated Cost: $768,158.43

(i) Objective

The objective of this project is to rebuild feeder NY55M31, bounded by Weston Road (East), Fenmar Drive (North), Steeles Ave (West), and Kenhar Drive (South), through the replacement of poles, insulators and Completely-Self-Protected (CSP) transformers.

(ii) Scope of Work

TABLE 47:

District Neighbourhood:	York West
Station(s):	Finch II TS (27.6kV)
Feeder(s):	NY55M31

TABLE 48

Asset	Count
Pole	71
Transformer	56
Manual Switch	2
SCADA Switch	0
Fuse	2
Switchgear	0

Asset	Count
*Conductor Length (m)	0.0
*Cable Length (m)	0.0

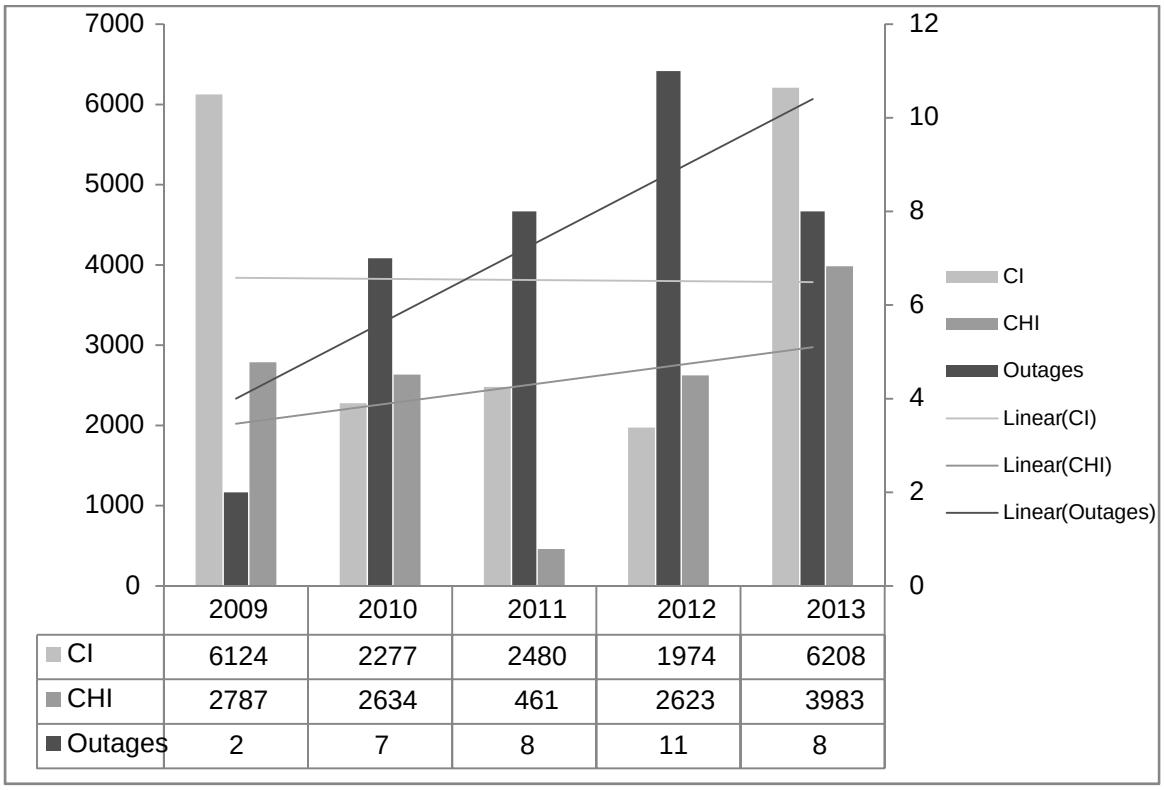
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 49

Supplemental Details	Description
Age/Condition	ƒ This project was initiated due to the poor overhead infrastructure condition and poor reliability of the assets on feeder NY55M31 ƒ As determined by a feeder patrol, the majority of the assets along this feeder are past their useful service life and will be replaced
Reliability	ƒ Feeder has experienced 10 outages due to defective overhead equipment in the past five years ƒ The major failure mode for this feeder is overhead equipment.
Other (i.e. local failures, etc)	ƒ The project will help mitigate future risk associated with asset failure and will help improve reliability and performance of NY55M31

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 60.



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

FIGURE 60: HISTORICAL RELIABILITY DETAILS FOR 55M31

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W14174, W14175 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Lambton MS VC PH#1 - PH#2

Project Number: W14174, W14175

Project Year: 2015

Estimated Cost: $1,638,659.82

(i) Objective

The objective of this project is to renew the distribution area of Etobicoke-Lakeshore by rebuilding the deteriorated Lambton 4.16kV feeders and converting them to 27.6kV in order to prepare the station for decommissioning.

(ii) Scope of Work

TABLE 50

District Neighbourhood:	Etobicoke-Lakeshore
Station(s):	Lambton MS (4.16kV), Kingsway MS (4.16kV)
Feeder(s):	ETVBF2-1, ETVBF5-1, TEF5-1, TEF1

TABLE 51

Asset	Count
Pole	128
Transformer	52
Manual Switch	18
SCADA Switch	0
Fuse	18
Switchgear	0

Asset	Count
*Conductor Length (m)	4,695.0
*Cable Length (m)	100

(iii) Justification & Benefits

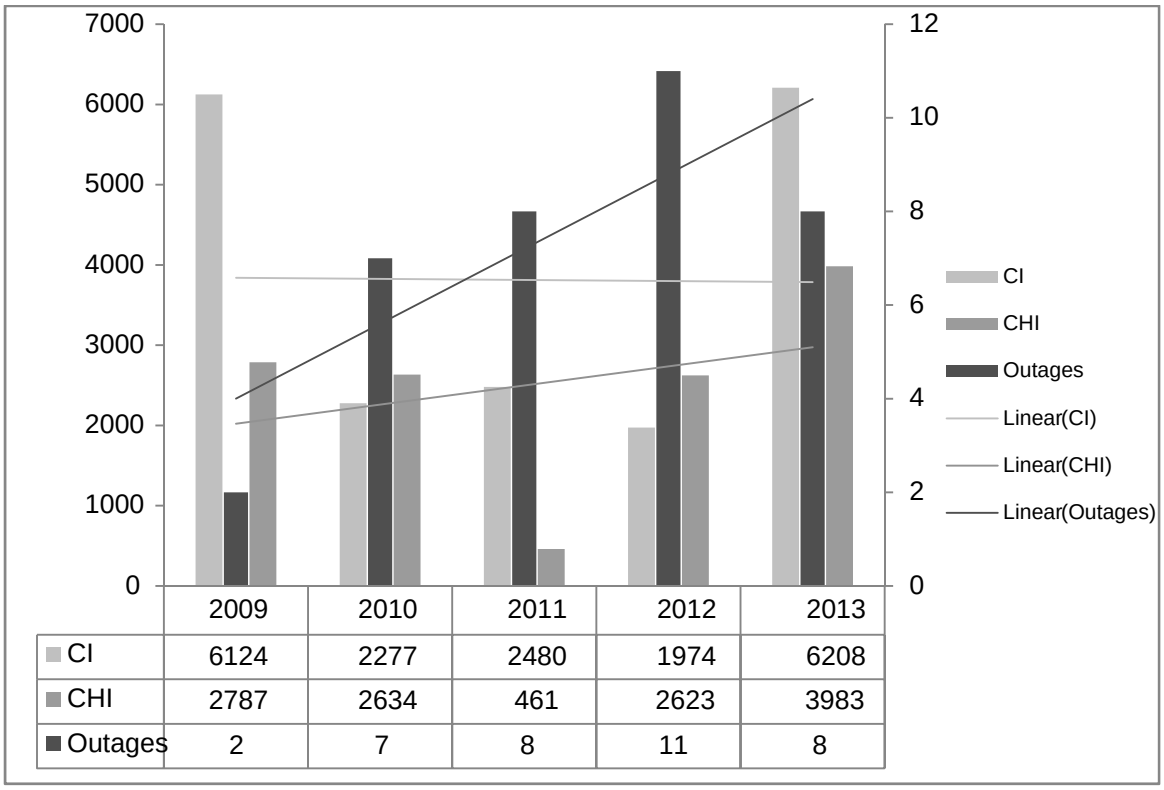
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 52

Supplemental Details	Description
Age/Condition	ƒ 60 yr old Lambton 4kV distribution assets of Lambton MS feeder VBF5 approaching end of service life to be replaced with brand new 27.6kV equipment. ƒ Replacement of deteriorated switchgear at Lambton substation withheld because of this scope
Reliability	ƒ The scope replaces overloaded transformers with bigger units and aged direct buried cables are replaced with new TRXLPE cables in concrete encased ducts stemming the probability of outage incidents and reducing restoration times. ƒ A total of 1 forced outage, 22 CI and 154 CHI on feeder VBF5 since 2009
Other (i.e. moratorium, etc)	ƒ Grid reconfiguration in the project improves operational flexibility in the area. ƒ The voltage conversion of the Lambton MS feeder VBF5 in this scope enables the decommissioning of the Lambton substation that will eliminate growing maintenance costs at the municipal station, obsolete construction standards and deteriorated plant condition.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 61 to 64.

FIGURE 61: HISTORICAL RELIABILITY DETAILS FOR VBF2



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

1 FIGURE 62: HISTORICAL RELIABILITY DETAILS FOR VBF5

1 FIGURE 63: HISTORICAL RELIABILITY DETAILS FOR EF5

FIGURE 64: HISTORICAL RELIABILITY DETAILS FOR EF1

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W13054, W13055, W13056, W13057 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: FESI Refurbish OH feeder PH#1, PH#2, PH#3, PH#4

Project Number: W13054, W13055, W13056, W13057

Project Year: 2015

Estimated Cost: $3,176,583.01

(i) Objective

The objective of these projects is to rebuild/replace all deteriorated or non-standard equipment such as poles, overhead lines, CSP transformers, glass insulators, porcelain insulators, and porcelain arrestors on feeder NY85M23.

(ii) Scope of Work

TABLE 53

District Neighbourhood:	Eglinton Lawrence
Station(s):	Bathurst II TS (27.6kV)
Feeder(s):	NY85M23

TABLE 54

Asset	Count
Pole	230
Transformer	128
Manual Switch	0
SCADA Switch	0
Fuse	0
Switchgear	0

Asset	Count
*Conductor Length (m)	6,100.0
*Cable Length (m)	0.00

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 55

Supplemental Details	Description
Age/Condition	ƒ To rebuild the entire OH plant of feeder 85M23 by replacing aging and/or non-standard distribution equipment including, but not limited to, poles, lines, transformers, porcelain equipment
Reliability	ƒ 85M23 has had an average of 7 outages a year during 2009-2013 ƒ There was a significant increase from 1 to 9 outages from 2012 to 2013
Other (i.e. moratorium, etc)	ƒ This project is intended to mitigate failure risk of these assets and improve reliability

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 65.

FIGURE 65: HISTORICAL RELIABILITY DETAILS FOR 85M23

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W15492, W15494 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: P05 - MOSCAD/DARCOM Controller Replacement - Richview TS, Manby TS, Horner TS, Rexdale TS, Woodbridge TS

Project Number: W15492, W15494

Project Year: 2015

Estimated Cost: $759,904.05

(i) Objective

The objective of these projects is to replace the obsolete MOSCAD RTU and radio SCADA system with the current standard.

(ii) Scope of Work

TABLE 56

District Neighbourhood:	Etobicoke Centre
Station(s):	Richview TS, Manby TS, Horner TS, Rexdale TS, Woodbridge TS
Feeder(s):	88M1, 88M8, 88M11, 88M13, 88M14, 88M46, 30M2, 30M5, 30M7, 30M8, 38M1, 38M10, 38M13, 38M5, 29M2, 29M3, 29M33, 29M34, 29M4, 29M5, D6M4, D6M1

TABLE 57

Asset	Count
Pole	1
Transformer	0
Manual Switch	0
SCADA Switch	1

Asset	Count
RTU	29
Fuse	0
Switchgear	0
*Conductor Length (m)	0.0
*Cable Length (m)	0.0

(iii) Justification & Benefits

The MOSCAD RTU was developed by Motorola and uses the DARCOM radio system. This technology was used as the predominate control and radio technology on many SCADA switches and MS stations in Etobicoke. This technology has not been supported by the manufacturer for over ten years and Toronto Hydro has exhausted all methods of acquiring components in third party markets. The main concern is the backup for the master radio units. Toronto Hydro currently has two spare units in its possession if there is a need to replace the existing ones in service. There is a risk that due to the age of the spares that the ability to perform reliably and the extended period of in-service time will be reduced. If replacement of these master radios exceeds these spares, Etobicoke's SCADA system will not be able to communicate and will lose all remote functionality.

E12891 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Voltage Conversion of NYSS38 F1 F2 from Burbank MS - Install Poles

Project Number: E12891

Project Year: 2015

Estimated Cost: $182,991.63

(i) Objective

The objective of this project is to convert the early fifties 4.16kV primary distribution system fed by the Burbank Municipal Substation by rebuilding and converting both outgoing feeders F1 and F2 to the 27.6kV system level.

(ii) Scope of Work

TABLE 58

District Neighbourhood:	Willowdale
Station(s):	Burbank MS, Leslie TS
Feeder(s):	NYSS38F1, SS38F2, NY51M8

TABLE 59

Asset	Count
Pole	52
Transformer	
Fuse	
Switch	
Switchgear	
Conductor Lengths (m)	

Asset	Count
Cable Lengths (m)	

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 60

Supplemental Details	Description
Age/Condition	ƒ Burbank MS was built in 1957. Station assets are aged and reached their useful service life.
Reliability	ƒ Burbank MS distribution is frail from reliability viewpoint for power restoration in the event of contingency condition
Other (i.e. moratorium, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 66 to 68.

FIGURE 66: HISTORICAL RELIABILITY DETAILS FOR SS38-F1

FIGURE 67: HISTORICAL RELIABILITY DETAILS FOR SS38-F2

FIGURE 68: HISTORICAL RELIABILITY DETAILS FOR 51M8

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15099 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Mountland overhead Voltage Conversion YGF1 SCYGF1

Project Number: E15099

Project Year: 2015

Estimated Cost: $561,836.03

(i) Objective

The objective of this project is to convert the early fifties 4.16kV primary distribution system by rebuilding and converting feeder SCYGF1 to the 27.6kV system level.

(ii) Scope of Work

TABLE 61

District Neighbourhood:	Scarborough Centre
Station(s):	Markham Pandora MS, Ellesmere TS
Feeder(s):	SCYGF1, SCNAH9M30

TABLE 62

Asset	Count
Pole	49
OH Transformer	15
Manual Switch	3
SCADA Switch	0
Fuse	5
UG Switchgear	0
*Conductor Length (m)	1,600
*Cable Length (m)	150

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 63

Supplemental Details	Description
Age/Condition	ƒ 50 year old EOL overhead system. ƒ Municipal station out of commission due to switchgear failure.
Reliability	ƒ N/A. MS Decommissioned.
Other (i.e. moratorium, etc)	ƒ N/A.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figure 69.

FIGURE 69: HISTORICAL RELIABILITY DETAILS FOR NAH9M30

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15368 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Brimley-Finch OH Rehab SCNT63M8

Project Number: E15368

Project Year: 2015

Estimated Cost: $795,652.93

(i) Objective

The objective of this project is to rebuild all assets along Finch between switches OS94753 and OSC84468.

(ii) Scope of Work

TABLE 64

District Neighbourhood:	Scarborough Centre
Station(s):	Agincourt TS
Feeder(s):	SCNT63M6, SCNT63M8

TABLE 65

Asset	Count
Pole	43
Transformer	7
Manual Switch	7
SCADA Switch	0
Fuse	17
Switchgear	0
*Conductor Length (m)	16,900

Asset	Count
*Cable Length (m)	0.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 66

Supplemental Details	Description
Age/Condition	ƒ Inspection in area found overhead assets in poor condition, replacement of these assets recommended to mitigate failure risk
Reliability	ƒ Feeder has experienced poor reliability with 5 outages in 2013. The distribution system supplying the area is reaching end of life and the asset will be subjected to significant failure risk as result of continued aging. By renewing the area future risk can be mitigated.
Other (i.e. moratorium, etc)	ƒ Brings feeder assets in project area up to latest standard

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 70 and 71.

FIGURE 70: HISTORICAL RELIABILITY DETAILS FOR NT63M6

FIGURE 71: HISTORICAL RELIABILITY DETAILS FOR NT63M8

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14117 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: OH Rebuild SC – NAR43M28 Aylesworth Kennedy

Project Number: E14117

Project Year: 2015

Estimated Cost: $713,196.11

(i) Objective

The objective of this project is to renew sections of assets along the feeder main of NAR43M28 by rebuilding and replacing the pole line.

(ii) Scope of Work

TABLE 67

District Neighbourhood:	Scarborough Southwest
Station(s):	Warden TS
Feeder(s):	SC NAR43M28

TABLE 68

Asset	Count
Pole	45
OH Transformer	9
Manual Switch	1
SCADA Switch	2
RTU	2
Fuse	13
Switchgear	0
*Conductor Length (m)	6,045

Asset	Count
*Cable Length (m)	0.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 69

Supplemental Details	Description
Age/Condition	ƒ Inspection in area found overhead assets in poor condition, replacement of these assets recommended to mitigate failure risk
Reliability	ƒ Feeder has poor reliability with 5 outages in the last 2 years
Other (i.e. moratorium, etc)	ƒ Upgrades feeder tie point from 336 kcmil aluminum conductor to standard 556 kcmil aluminum conductor ƒ Brings feeder assets in project area up to latest standard

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 72.

FIGURE 72: HISTORICAL RELIABILITY DETAILS FOR NAR43M28

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W14276 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: OH Feeder Rehab - Signet, Weston, Fenmar

Project Number: W14276

Project Year: 2015

Estimated Cost: $901,659.10

(i) Objective

The objective of this Project is to refurbish the overhead distribution system by replacing defective poles and non-standard equipment of feeder NY55M1 along Signet Drive, Weston Road, Fenmar Drive and Kenhar Drive.

(ii) Scope of Work

TABLE 70

District Neighbourhood:	York West
Station(s):	Finch TS (27.6kV)
Feeder(s):	NY55M1

TABLE 71

Asset	Count
Pole	100
Transformer	22
Manual Switch	15
SCADA Switch	5
RTU	5
Fuse	49

Asset	Count
Switchgear	0
*Conductor Length (m)	20,900
*Cable Length (m)	0.0

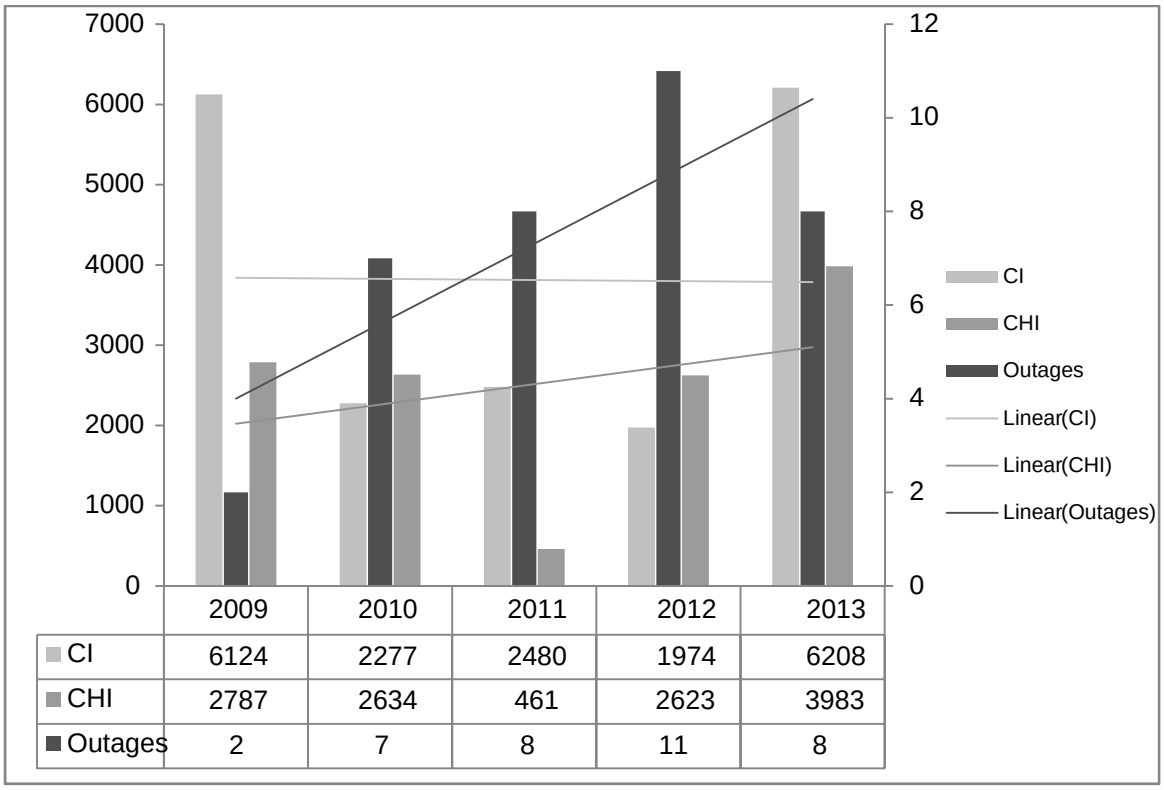
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 72

Supplemental Details	Description
Age/Condition	• Feeder patrols have identified that most poles on this feeder are in poor condition. These poles will be replaced due to high failure risk. • The feeder is primarily comprised of non-standard poor performing assets such as CSP transformers, glass insulators, arrestors, and switches.
Reliability	• Feeder has experienced 22 overhead outages since 2011, which were identified on the overhead equipment, likely to be attributed due to the poor asset condition
Other (i.e. local failures, etc)	• Rebuilding feeder NY55M1 will improve the reliability of the feeder.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 73.



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

FIGURE 73: HISTORICAL RELIABILITY DETAILS FOR 55M1

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W13115 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: FESI Feeder Rehab and Change out Phase 2

Project Number: W13115

Project Year: 2015

Estimated Cost: $431,678.87

(i) Objective

The objective if this project us to replace poles, conductor, Completely-Self-Protected (CSP) transformers, glass insulators and arrestors on feeder NY80M8 to reduce failure risk, safety issues, and functional obsolescence.

(ii) Scope of Work

TABLE 73

District Neighbourhood:	York Centre
Station(s):	Fairchild TS (27.6kV)
Feeder(s):	NY80M8

TABLE 74

Asset	Count
Pole	33
Transformer	7
Manual Switch	5
SCADA Switch	2
RTU	2
Fuse	5

Asset	Count
Switchgear	0
*Conductor Length (m)	1,870
*Cable Length (m)	0.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 75

Supplemental Details	Description
Age/Condition	• The assets in the Finch and Bathurst area are aged and in poor condition • Assets being replaced include aged poles, transformers, and porcelain equipment
Reliability	• There has been an average of 6 outages a year during 2009-2013
Other (i.e. moratorium, etc)	• This project is intended to mitigate failure risk of these assets and improve reliability

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 74.

FIGURE 74: HISTORICAL RELIABILITY DETAILS FOR 80M8

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W14289 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Overhead Rebuild off Gary Avenue

Project Number: W14289

Project Year: 2015

Estimated Cost: $773,556.93

(i) Objective

The objective of this project is to rebuild the overhead infrastructure on feeder NY55M23 to improve reliability and mitigate failure risk of obsolete equipment.

(ii) Scope of Work

TABLE 76

District Neighbourhood:	York South-Weston
Station(s):	Finch II TS (27.6kV)
Feeder(s):	NY55M23

TABLE 77

Asset	Count
Pole	60
Transformer	21
Manual Switch	5
SCADA-Switch	0
Fuse	5
Switchgear	0
*Conductor Length (m)	2,625

*Cable Length (m)	0.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 78

Supplemental Details	Description
Age/Condition	• Feeder NY55M23 is primarily comprised of non-standard poor performing assets such as CSP transformers, glass insulators, arrestors, and switches. • Feeder patrols have identified that most poles on this feeder are in poor condition • The project covers an underground section of the feeders and involves replacing underground transformers and underground cable as well as incorporating civil infrastructure for the installation of new underground cable
Reliability	• Feeder NY55M23 has shown evidence of deteriorating reliability in the past few years • The feeder has experienced at least six failures per year • The major failure mode for this feeder is overhead equipment.
Other (i.e. local failures, etc)	• The project will help mitigate future risk associated with asset failure and will help improve the reliability and performance of NY55M23.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 75.

FIGURE 75: HISTORICAL RELIABILITY DETAILS FOR 55M23

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W12265, W12269 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Overhead Rebuild on 55M26 Ph 1 and 2

Project Number: W12265, W12269

Project Year: 2015

Estimated Cost: $2,378,133.78

(i) Objective

The objective of these projects is to rebuild areas of feeder NY55M26 due to poor performance of the feeder which is related to modes related to defective overhead equipment outages.

(ii) Scope of Work

TABLE 79

District Neighbourhood:	York West
Station(s):	Finch II TS (27.6kV)
Feeder(s):	NY55M26

TABLE 80

Asset	Count
Pole	160
Transformer	39
Manual Switch	2
SCADA Switch	0
Fuse	16
Switchgear	0
*Conductor Length (m)	11,150

Asset	Count
*Cable Length (m)	0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 81

Supplemental Details	Description
Age/Condition	• The primary overhead distribution on feeder NY55M26 requires an overhead rebuild in order to address failure risk • Feeder patrol conducted show that equipment had reached its end of life, in particular aging poles
Reliability	• NY55M26 has experienced approximately 20 outages due to poor conditions of the overhead infrastructure in the project area • The major failure mode for this feeder is overhead equipment.
Other (i.e. local failures, etc)	• The project will help mitigate future risk associated with asset failure and will help improve reliability and performance of NY55M26

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 76.

FIGURE 76: HISTORICAL RELIABILITY DETAILS FOR 55M26

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W10461 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: FESI Scarlett-St.Clair Overh ead Rebuild YK11M7 Project Number: W10461

Project Year: 2015

Estimated Cost: $1,667,149.33

(i) Objective

The objective of this project is to rebuild areas of feeder YK11M7 due to poor performance of the feeder which is related to modes related to defective overhead equipment outages.

(ii) Scope of Work

TABLE 82

District Neighbourhood:	Parkdale-High Park
Station(s):	Runnymede TS (27.6kV)
Feeder(s):	YK11M7

TABLE 83

Asset	Count
Pole	167
Transformer	20
Manual Switch	0
SCADA Switch	0
Fuse	11
Switchgear	0
*Conductor Length (m)	4,100
*Cable Length (m)	0.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 84

Supplemental Details	Description
Age/Condition	ƒ Average age of the system is approximately 40 years old ƒ Non-standard equipment (ie. Porcelain)
Reliability	ƒ Heavily treed area contributing to outages ƒ Requires tree proof and animal proofing the equipment
Other (i.e. moratorium, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure XYZ.

FIGURE 77: HISTORICAL RELIABILITY DETAILS FOR 11M7

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W15264 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: P05 Queenslea Avenue Overhead Rebuild 55M23

Project Number: W15264

Project Year: 2015

Estimated Cost: $1,214,416.90

(i) Objective

The objective of this project is to rebuild the overhead distribution system on feeder NY55M23 from Finch TS by replacing end-of-life and non-standard equipment.

(ii) Scope of Work

TABLE 85

District Neighbourhood:	York South-Weston
Station(s):	Finch TS
Feeder(s):	NY55M23

TABLE 86

Asset	Count
Pole	91
Transformer	18
Manual Switch	2
SCADA Switch	0
Fuse	9
Switchgear	0
*Conductor Length (m)	5,300

*Cable Length (m)	330

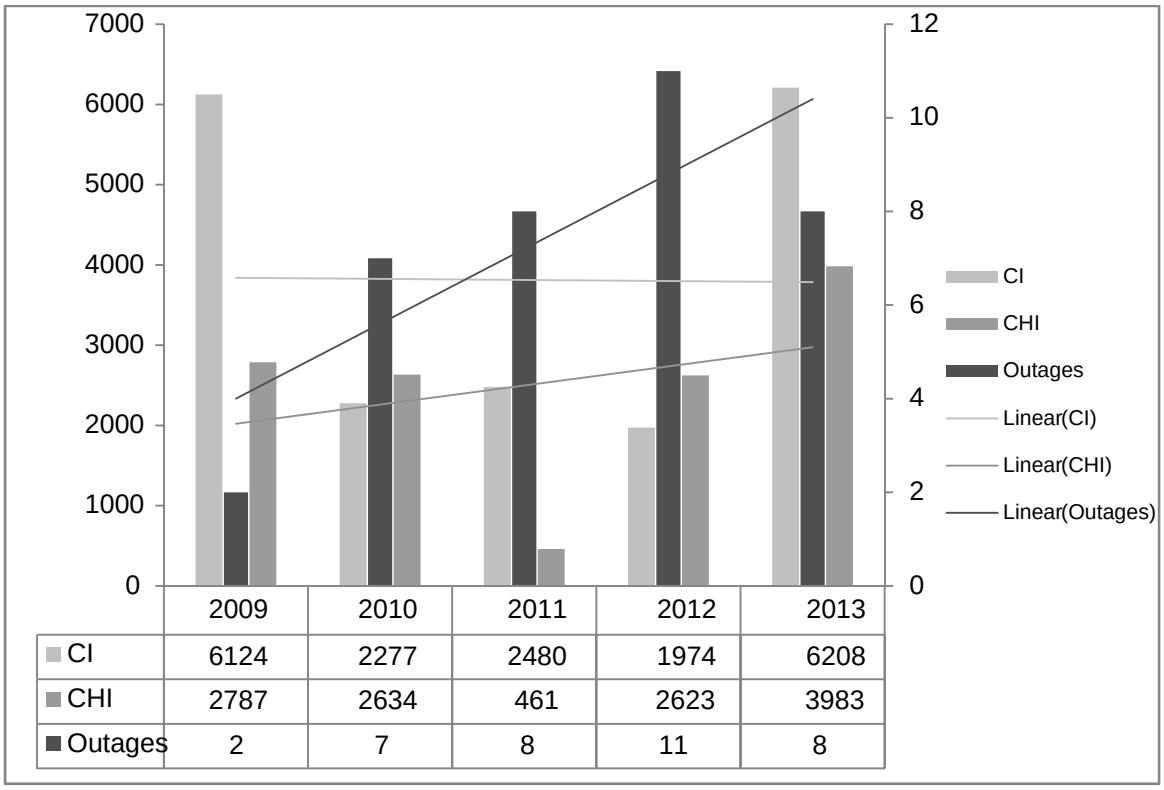
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 87

Supplemental Details	Description
Age/Condition	ƒ Feeder NY55M23 is primarily comprised of non-standard poor performing assets such as CSP transformers, glass insulators, arrestors, and switches. ƒ Feeder patrols have identified that most poles on this feeder are in poor condition ƒ The project covers an underground section of the feeders and involves replacing underground transformers and underground cable as well as incorporating civil infrastructure for the installation of new underground cable
Reliability	ƒ Feeder NY55M23 has shown evidence of deteriorating reliability in the past few years ƒ The feeder has experienced at least six failures per year ƒ The major failure mode for this feeder is overhead equipment.
Other (i.e. local failures, etc)	ƒ This project is intended to mitigate failure risk of these assets and improve reliability

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 78.



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

FIGURE 78: HISTORICAL RELIABILITY DETAILS FOR 55M23

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W15335, W15336, W15338 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Ranee and Ameer overhead Area Circuit Renewal PH1, PH2, PH3

Project Number: W15335, W15336, W15338

Project Year: 2015

Estimated Cost: $2,521,219.75

(i) Objective

The objective of these projects is to rebuild/replace the aging and non standard primary overhead distribution equipment on feeder NY85M26 in order to improve reliability.

(ii) Scope of Work

TABLE 88

District Neighbourhood:	Eglinton Lawrence, York West
Station(s):	Bathurst TS (27.6kV)
Feeder(s):	NY85M26

TABLE 89

Asset	Count
Pole	272
OH Transformer	61
Manual Switch	15
SCADA Switch	1
Fuse	12
UG Switchgear	0
*Conductor Length (m)	26,782

Asset	Count
*Cable Length (m)	0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 90

Supplemental Details	Description
Age/Condition	• The primary objective of this scope entails renewing the OH plant in the Ranee Ave. and Bathurst St. area, which is comprised of aged and poor condition OH assets
Reliability	• 85M26 has had an average of 4 outages a year during 2009-2013 • The urgency for a rebuild in the Ranee Ave and Bathurst St neighbourhood stems from 11 total outages contained in this area from 2009-2013. In 2013, 80% of all outages were due to OH defective equipment in this region alone.
Other (i.e. moratorium, etc)	• This project is intended to mitigate failure risk of these assets and improve reliability

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure XYZ.

FIGURE 79: HISTORICAL RELIABILITY DETAILS FOR 85M26

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W15169 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: East mall/Dundas Overhead Renewal ET38M10

Project Number: W15169

Project Year: 2015

Estimated Cost: $535,631.24

(i) Objective

The objective of this project is to rebuild the trunk portions of the overhead infrastructure on feeder ET38M10 in order to avoid failure risk due to aging and mal-operating infrastructure.

(ii) Scope of Work

TABLE 91

District Neighbourhood:	Etobicoke Lakeshore
Station(s):	Manby TS
Feeder(s):	ET38M10

TABLE 92

Asset	Count
Pole	40
OH Transformer	2
Manual Switch	3
SCADA Switch	2
MOSCAD RTU	2
Fuse	0
UG Switchgear	0

Asset	Count
*Conductor Length (m)	1400.0
*Cable Length (m)	0.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 93

Supplemental Details	Description
Age/Condition	Scope upgrades undersized feeder trunk conductors along The East Mall from 4/0 to THESI standard 556 kcmil.
Reliability	Scope upgrades distribution assets along 38M10 in the area order to stem outages, which were particularly high in 2013. A total of 5 forced outages, 8378 CI and 4910 CHI on feeder 38M10 since 2009 with 80% of the outages in 2013 showing an increasingly serious reliability situation along the feeder.
Other (i.e. moratorium, etc)	Customers in the area had complained of the high incidence of outages in 2013.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 80.

FIGURE 80: HISTORICAL RELIABILITY DETAILS FOR 38M10

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14097 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Voltage Conversion of SS63F1 to NY80M4 - Between Yonge & Bayview

Project Number: E14097

Project Year: 2015

Estimated Cost: $1,217,582.02

(i) Objective

The objective of this project is to rebuild the overhead aged 4.16kV primary distribution fed by the Estelle Municipal Substation by upgrading assets on the feeder route to 27.6kV rating and sourcing power to the assets directly from the adjacent feeder NY80M4.

(ii) Scope of Work

TABLE 94

District Neighbourhood:	Willowdale
Station(s):	Estelle MS
Feeder(s):	NY SS63F1, NY80M4

TABLE 95

Asset	Count
Pole	78
Transformer	28
Manual Switch	8
SCADA Switch	1
MOSCAD RTU	2
Fuse	1

Asset	Count
Switchgear	0
*Conductor Length (m)	3,535
*Cable Length (m)	0.0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 96

Supplemental Details	Description
Age/Condition	• Estelle MS was built in 1958, Station assets are aged and reached their useful service life.
Reliability	• Estelle MS has experienced power outages each year from 2009-2012 and escalated to 4 power outages in 2013.
Other (i.e. moratorium, etc)	• Result of an inspection in May 2011 confirmed the presence of Friable Asbestos, Corrosion, Dirt, Debris and Contamination as well as damaged doors in Estelle MS

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 81 and 82.

FIGURE 81: HISTORICAL RELIABILITY DETAILS FOR SS63-F1

FIGURE 82: HISTORICAL RELIABILITY DETAILS FOR 80M4

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

X12318 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Replacement of Manual Switch & Installation of SCADA Switch 34M1

Project Number: X12318

Project Year: 2015

Estimated Cost: $109,932.35

(i) Objective

The objective of this project is to replace manual switches with SCADAmate switches at two locations on feeder 34M1.

(ii) Scope of Work

TABLE 97

District Neighbourhood:	Scarborough Centre
Station(s):	Leaside TS (27.6kV)
Feeder(s):	34M1

TABLE 98

Asset	Count
Pole	0
Transformer	0
Manual Switch	0
SCADA Switch	3
Fuse	0
Switchgear	0
*Conductor Length (m)	0.0

*Cable Length (m)	0.0

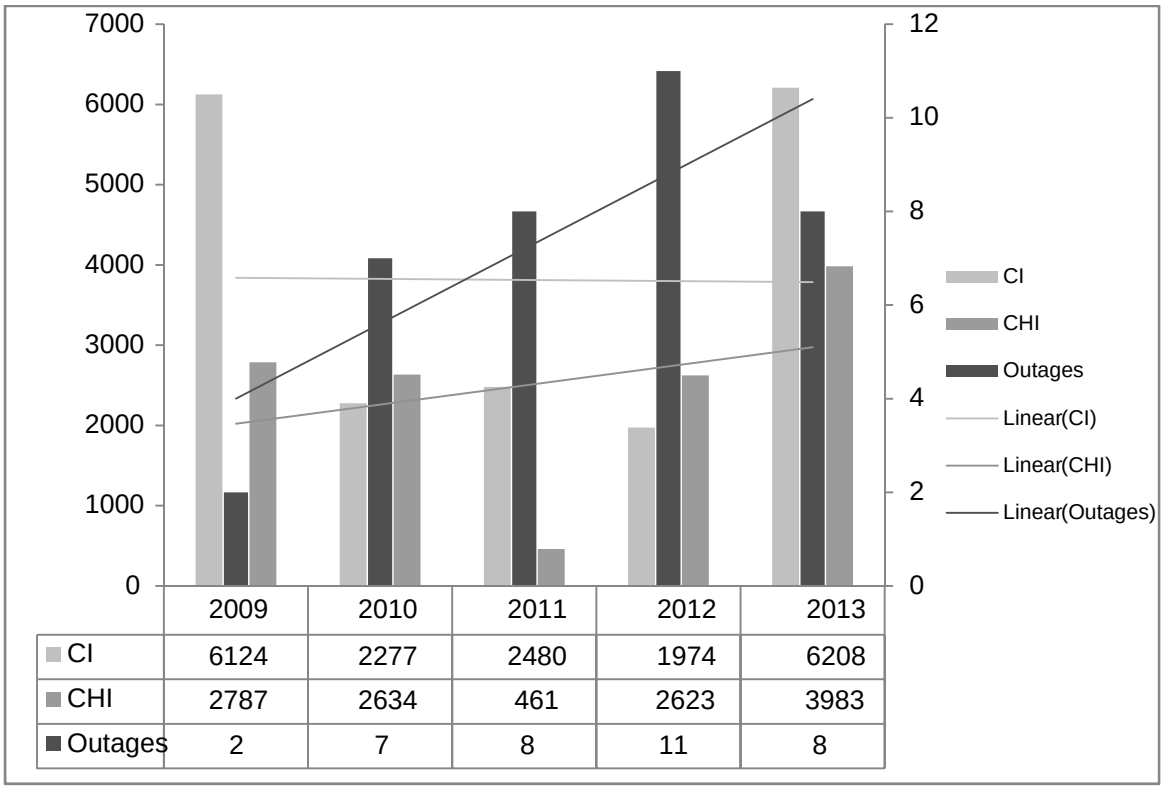
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 99

Supplemental Details	Description
Age/Condition	
Reliability	ƒ 34M1 experienced 7 power outages in 2009 and 3 or more outages each year from 2010 to 2013. Converting existing manually operated switch to SCADA-controlled type will greatly improve restoration time and reduce impact to customer under contingency condition
Other (i.e. moratorium, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure XYZ.



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

FIGURE 83: HISTORICAL RELIABILITY DETAILS FOR 34M1

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14286 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Overhead Rebuild 64F2 Ruddington MS VC

Project Number: E14286

Project Year: 2015

Estimated Cost: $980,460.58

(i) Objective

The objective of this project is to rebuild the aging 4.16kV primary distribution system fed by Ruddington Municipal Station and converting it to 27.6kV.

(ii) (ii) Scope of Work

TABLE 100

District Neighbourhood:	Scarborough Centre
Station(s):	Ruddington MS (27.6kV)
Feeder(s):	NYSS 64F2

TABLE 101

Asset	Count
Pole	75
OH Transformer	19
Manual Switch	2
SCADA Switch	1
MOSCAD RTU	1
Fuse	0
UG Switchgear	0

Asset	Count
*Conductor Length (m)	8,275
*Cable Length (m)	0.0

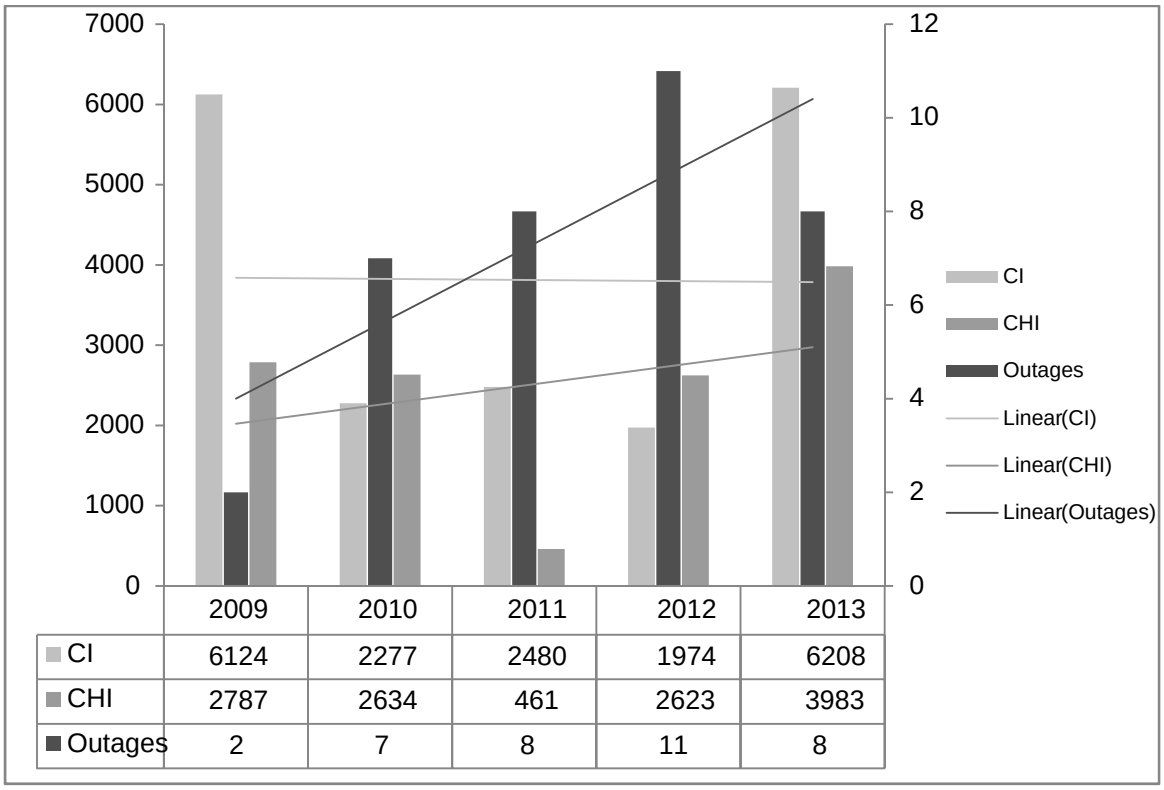
(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 102

Supplemental Details	Description
Age/Condition	Ruddington MS was built in the early sixties. Both station transformer and switchgear has reached the end of their useful service life.
Reliability	Ruddington MS had 3 power outages in 2013
Other (i.e. moratorium, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 84.



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

FIGURE 84: HISTORICAL RELIABILITY DETAILS FOR SS64-F2

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W13634 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: P05 Extension of 30M12 eastwards along Evans Ave into 30M1 and 30M8

Project Number: W13634

Project Year: 2015

Estimated Cost: $867,886.96

(i) Objective

The objective of this project is to relieve feeders R30M1 and R30M8 from the Horner TS east of Kipling Avenue by upgrading and extending the new feeder R30M12 powered out of the Horner TS and slightly modifying the configuration of the existing Horner TS feeders south of The Queensway.

(ii) Scope of Work

TABLE 103

District/Neighbourhood:	York West
Station(s):	Horner TS
Feeder(s):	R30M1; R30M8; R30M12

TABLE 104

Asset	Count
Pole	11
Transformer	16
Manual Switch	0
SCADA Switch	2
Fuse	0

Asset	Count
Switchgear	0
*Conductor Length (m)	3,000
*Cable Length (m)	750

(iii) Justification & Benefits

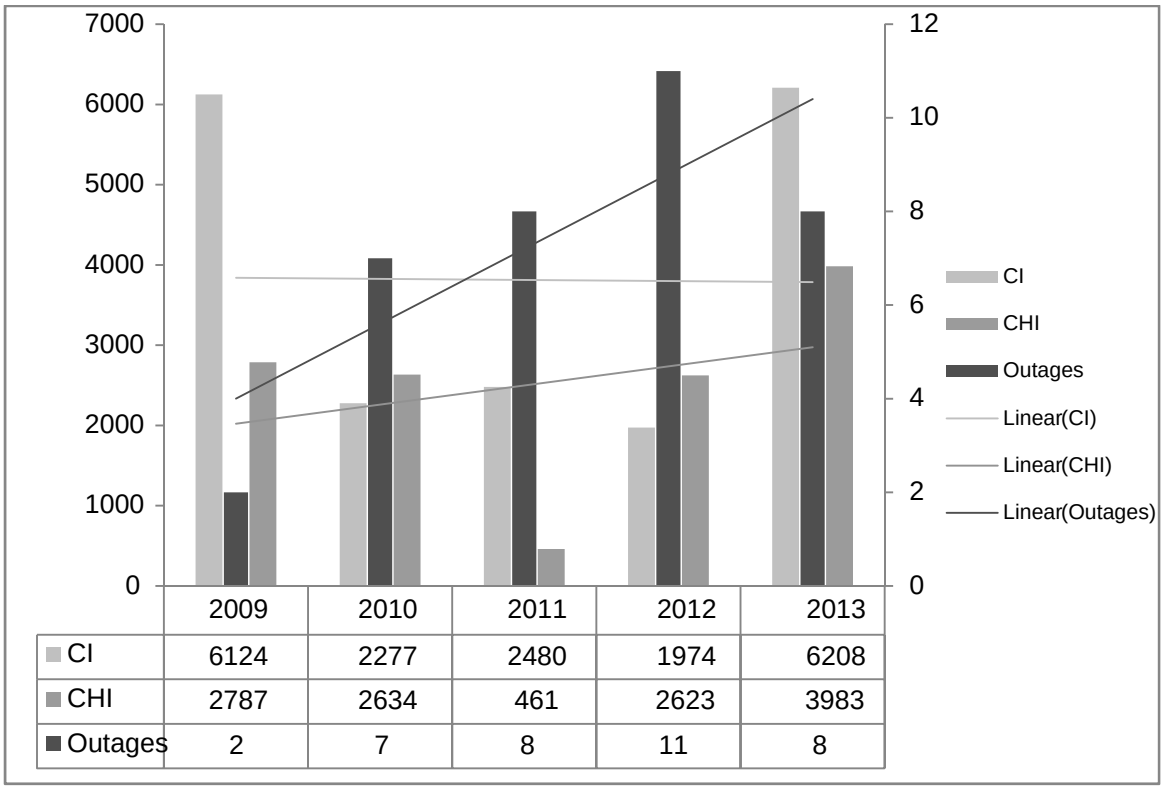
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 105

Supplemental Details	Description
Age/Condition	ƒ The scope replaces aging poles and conductors along Evans Avenue while converting the erstwhile single circuit to a double circuit
Reliability	ƒ This scope builds a new feeder that introduces capacity (of about 25 MVA) for emergency load transfers during contingencies that would reduce outage restoration times for customers in the area. ƒ R30M1 had a total of 11 forced outages, 8017 CI and 6566 CHI since 2009, ƒ R30M8 had a total of 9 forced outages, 7912 CI and 3397 CHI since 2009
Other (i.e. moratorium, etc)	ƒ The scope relieves capacity from R30M1, R30M8 and other Horner TS feeders in the distribution area immediately enabling them to accommodate the rising tide of feeder requests from new building developments. ƒ This project will rebuild feeder lines to accommodate the new circuit and provide the capacity relief required

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 85 and 86.

FIGURE 85: HISTORICAL RELIABILITY DETAILS FOR R30M1



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

FIGURE 86: HISTORICAL RELIABILITY DETAILS FOR R30M8

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W14677 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: P05 - Manby Richview Load Cascades, Part 2

Project Number: W14677

Project Year: 2015

Estimated Cost: $578,591.31

(i) Objective

The object of this project is to relieve Manby TS bus pairs Q-Z and B-Y of overload and provide capacity for system expansion by converting some 4.16 kV in the area of Burnhamthorpe Road.

(ii) Scope of Work

TABLE 106

District Neighbourhood:	Etobicoke Centre
Station(s):	Manby TS; Richview TS
Feeder(s):	38M16, 38M1

TABLE 107

Asset	Count
Pole	90
Transformer	22
Manual Switch	7
SCADA Switch	4
Fuse	2
Switchgear	0
*Conductor Length (m)	10,000

Asset	Count
*Cable Length (m)	1,500

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 108

Supplemental Details	Description
Age/Condition	• Scope includes system renewal needed to replace aging 51 yr old 4kV OH and UG assets of Islington MS that are already in poor service condition.
Reliability	• System expansion in the scope includes extending feeder lines and installing additional tie points and sectionalizers that will improve system restoration times and reduce outage impact.
Other (i.e. moratorium, etc)	• The scope transfers 8MVA load off Manby TS buses Q2Z and B1Y that are currently loaded to the extents of their capacity in order to enable new customers to access the grid.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 87 and 88.

FIGURE 87: HISTORICAL RELIABILITY DETAILS FOR 38M16

FIGURE 88: HISTORICAL RELIABILITY DETAILS FOR 38M1

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E14734 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: P05 Comstock Faulklands MS Decommission Feeders

Project Number: E14734

Project Year: 2015

Estimated Cost: $206,764.29

(i) Objective

The objective of this project to permanently remove the lines from Comstock Faulklands Municipal Station. The transformers at the station are un-reparable and are to be taken offline. The Municipal station can no longer provide backup contingency power.

(ii) Scope of Work

TABLE 109

District Neighbourhood:	
Station(s):	Comstock-Faulklands MS
Feeder(s):	SCEAF1, SCEAF2, SCEAF3

TABLE 110

Asset	Count
Pole	0
Transformer	0
Manual Switch	0
SCADA Switch	0
Fuse	0
Switchgear	0

Asset	Count
*Conductor Length (m)	15,366.8
*Cable Length (m)	877.3

(iii) Justification & Benefits

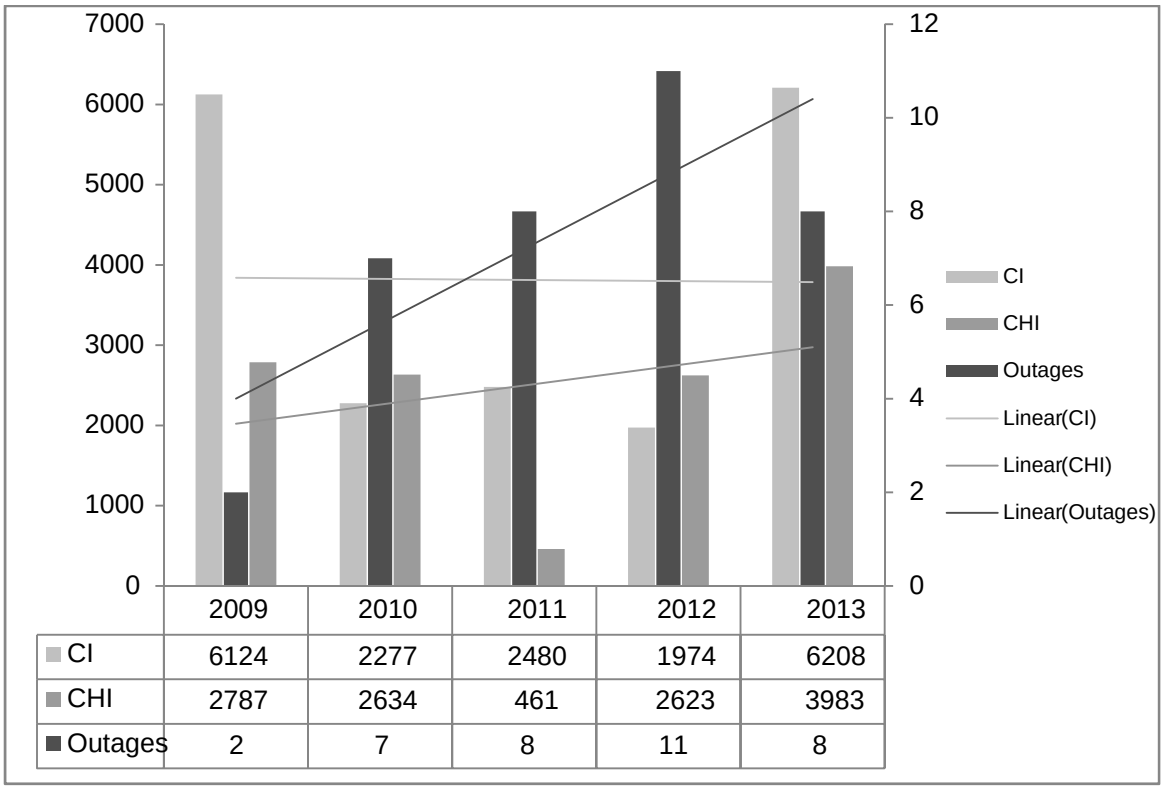
Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 111

Supplemental Details	Description
Age/Condition	ƒ Comstock-Faulklands MS constructed in 1953, station transformer removed from service due to unrepairable oil leaks
Reliability	ƒ Station utilized for contingency and backup
Other (i.e. moratorium, etc)	ƒ Project constructs new feeder tie from another adjacent station enabling completed decommissioning of Comstock-Faulklands MS

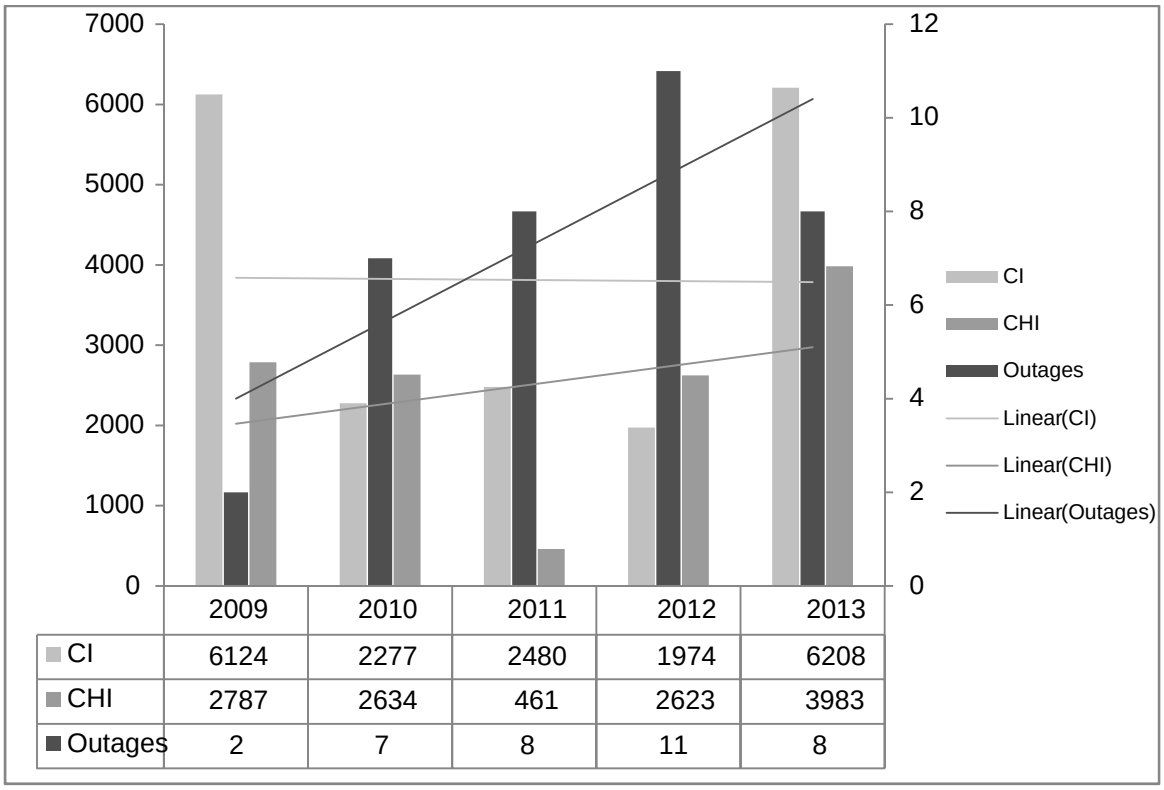
Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeders are given in Figures 89 to 91.

1 FIGURE 89: HISTORICAL RELIABILITY DETAILS FOR EAF1



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

1 FIGURE 90: HISTORICAL RELIABILITY DETAILS FOR EAF2



	2009	2010	2011	2012	2013
CI	6124	2277	2480	1974	6208
CHI	2787	2634	461	2623	3983
Outages	2	7	8	11	8

FIGURE 91: HISTORICAL RELIABILITY DETAILS FOR EAF3

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15348 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Warden - Lowcrest UG Voltage Conversion Civil (Part 1)

Project Number: E15348

Project Year: 2015

Estimated Cost: $1,327,482.31

(i) Objective

To replace assets along the remaining feeder segment of NHF3 and convert all remaining assets to 27.6kV rated voltage.

(ii) Scope of Work

TABLE 112

District Neighbourhood:	Scarborough West
Station(s):	Warden MS, Lowcrest MS
Feeder(s):	SC NHF3

TABLE 113

Asset	Count
Pole	0
Transformer	0
Manual Switch	0
SCADA Switch	0
Fuse	0
Switchgear	0
*Conductor Length (m)	0

*Cable Length (m)	0

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 114

Supplemental Details	Description
Age/Condition	Some sections of the feeder addressed under the scope are currently direct buried increasing the failure risk and deteriorating the reliability of the feeder.
Reliability	Feeder has poor reliability with 8 outages in the last 2 years.
Other (i.e. moratorium, etc)	Brings feeder assets in project area up to latest standard

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 92.

FIGURE 92: HISTORICAL RELIABILITY DETAILS FOR NHF3

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

W13238 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Brenthall MS to Fairchild TS VC Mascot and Kingsbridge

Project Number: W13238

Project Year: 2015

Estimated Cost: $426,176.32

(i) Objective

The objective of this project is to renew the 4.16kV distribution system for feeder NYSS26F1 at Benthall Municipal station by converting them to 27.6kV using Fairchild station feeder NY80M8.

(ii) Scope of Work

TABLE 115

District Neighbourhood:	North York Centre
Station(s):	Brenthall MS (4.16kV)
Feeder(s):	NYSS26F1

TABLE 116

Asset	Count
Pole	9
Transformer	2
Manual Switch	0
SCADA Switch	0
Fuse	0
Switchgear	0
*Conductor Length (m)	360

*Cable Length (m)	450

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 117

Supplemental Details	Description
Age/Condition	The area supplied by SS26 F1 is aged and in poor condition The distribution plant has been in service for about 40 years and the switchgear in Brenthall MS is also aged
Reliability	There have been 3 outages in the last 5 years
Other (i.e. moratorium, etc)	This project is intended to mitigate failure risk of these assets and improve reliability

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 93.

FIGURE 93: HISTORICAL RELIABILITY DETAILS FOR SS26-F1

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E12326 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: Voltage Conversion of NYSS38F1 and NYSS38F2 from Burbank MS

Project Number: E12326

Project Year: 2015

Estimated Cost: $870,487.47

(i) Objective

The objective of this project is to rebuild the early fifties 4.16kV primary distribution system fed by the Burbank Municipal Substation by converting both outgoing feeders to 27.6kV system.

(ii) Scope of Work

TABLE 118

District Neighbourhood:	Willowdale
Station(s):	Burbank MS; Leslie TS
Feeder(s):	NYSS38F1, NYSS38F2, NY51M8

TABLE 119

Asset	Count
Pole	43
Transformer	19
Manual Switch	0
SCADA Switch	0
Fuse	2
Switchgear	0
*Conductor Length (m)	4,000

*Cable Length (m)	300

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 120

Supplemental Details	Description
Age/Condition	Burbank MS was built in 1957, Station assets are aged and reached their useful service life.
Reliability	Burbank MS distribution is frail from reliability viewpoint for power restoration in the event of contingency condition
Other (i.e. moratorium, etc)	

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figures 94 to 96.

FIGURE 94: HISTORICAL RELIABILITY DETAILS FOR SS38-F1

FIGURE 95: HISTORICAL RELIABILITY DETAILS FOR SS38-F2

FIGURE 96: HISTORICAL RELIABILITY DETAILS FOR 51M8

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E15102 Project Description

Investment Category: System Renewal

Program: Overhead Circuit Renewal

Project Title: E15102 Huronia Harley OH Voltage Conversion QGF3 SCQGF3

Project Number: E15102

Project Year: 2015

Estimated Cost: $771,593.79

(i) Objective

The objective of this project is to rebuild, by converting to 27.6kV system, the early sixties 4.16kV primary distribution system fed by feeder F3 of MS station Sunderland Bellamy (QG).

(ii) Scope of Work

TABLE 121

District Neighbourhood:	Scarborough Centre
Station(s):	Sunderland Bellamy (4.16kV)
Feeder(s):	SCQGF3

TABLE 122

Asset	Count
Pole	68
Transformer	21
Manual Switch	1
SCADA Switch	0
Fuse	1
Switchgear	0
*Conductor Length (m)	2,550

*Cable Length (m)	210

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 123

Supplemental Details	Description
Age/Condition	49 year old EOL overhead system. Municipal station out of commission due to switchgear failure.
Reliability	N/A. MS Decommissioned. CI and CHI are 254 and 398 respectively for the feeder in 2012.
Other (i.e. moratorium, etc)	Must be complete before March 2015 due to City road resurfacing.

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 97.

FIGURE 97: HISTORICAL RELIABILITY DETAILS FOR QGF3

NOTE:

A table of assets to be replaced is not provided for the civil portion of the project since none of the existing assets are replaced in this phase.

E6.5 Overhead Infrastructure Relocation

OVERHEAD EGRESS CONGESTION

E6.5.1 Summary

Program Description

The objective of the Overhead Infrastructure Relocation program is to mitigate safety and reliability risks by targeting overhead infrastructure assets that are part of unacceptably high risk and therefore functionally obsolete feeder designs. The existing overhead infrastructure will be relocated to locations that are more accessible to Toronto Hydro crews, have a reduced safety and reliability risk in the event of a failure, and a reduced probability of failure. The program addresses various assets throughout the overhead system that have reached end-of-life and encompasses all primary voltage levels. The three main scenarios necessitating overhead infrastructure relocation are the following.

- Overhead assets that are in areas with limited or difficult access , such as heavily treed ravines. These locations can be especially vulnerable during major storm events such as heavy rainfall, floods, and ice storms. Restoration efforts following major storms can also be extremely challenging in this areas. Toronto Hydro plans to relocate these assets to more accessible and less vulnerable routes.

- Overhead station egress lines carrying three or more circuits . The congested nature of these pole lines means that there is an unacceptably high risk that a significant asset

failure along the line could interrupt three or more entire feeders, resulting in potentially long duration outages to thousands of customers. Toronto Hydro plans to separate the circuits where possible, or, if necessary, convert the egress section to underground infrastructure where it will be less susceptible to the simultaneous interruption of multiple feeders.

- Overhead assets crossing highways . Toronto Hydro plans to replace these overhead crossings with underground crossings to avoid the risk and impact of primary power lines falling onto highways.

The anticipated benefits of the Overhead Infrastructure Relocation program are as follows.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	• Improve outage restoration times • Mitigate public safety risk
Reliability	• Minimize failure impact on existing overhead egress feeders • Help minimize vegetation related outages • Mitigate the risk of momentary interruptions on feeders • Remove high risk asset configurations that are especially vulnerable to major storm events
Safety	• Improve public safety by relocating overhead wires that cross highways Improve Toronto Hydro crew member safety by improving access to assets, including poles.
Efficiency	• Improve maintenance activities by facilitating better access to critical infrastructure, including the ability to use needed equipment

Program Drivers

The trigger and secondary drivers for the Overhead Infrastructure Relocation program are summarized in the following table.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	• Obsolete system layout can complicate and extend feeder restoration efforts. • Certain assets are installed in areas where access is very limited. • There is a considerable number of assets past their useful lives
Secondary Driver	**Reasoning**
Safety	• Overhead highway crossings pose potential safety risks if the energized lines fall to the ground.

	ƒ Overhead infrastructure in areas with limited access (steep terrain or heavily treed areas with no road access) present safety hazards for field crews.
Reliability	ƒ Restoration times are impacted by assets that are difficult to access. ƒ Vegetation in difficult to access areas reduces the reliability of the overhead system. ƒ Feeders in some locations are more susceptible to a high number of momentary interruptions during adverse weather conditions.

Preferred Alternative

Toronto Hydro evaluated the following options for addressing the assets in this program:

(1) Do nothing and replace on a reactive basis only, incurring the risk of equipment failures and potential safety concerns

(2) Replace the aged assets on a like-for-like basis, temporarily reducing the probability, but not the impact, of asset failure

(3) Replacement of the aged assets and relocation of the plant to avoid safety and reliability issues associated with its current location

Option III is the preferred alternative as it provides the most value by minimizing the safety and reliability risks associated with the assets, while reducing the time and effort required when restoring power in the event of an outage.

The difference in the cost of ownership between existing and renewed assets ("COO") for the first year of the program is $1.76 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.5.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $1.02 million, confirming the economic prudence of the investments (see Section E6.5.7). For comparison, the NPV of the like-for-like replacement option is -$0.69 million.

Timing and Pacing

Table C provides historical and projected program spending. The program requires an investment of approximately $9.87 million over the five year planning horizon. Due to the large backlog of assets that have reached end-of-life, Toronto Hydro plans to increase yearly expenditures throughout the 2015-2019 period.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	0.74	1.38	1.83	2.28	3.64

By the end of the program period, it is anticipated that approximately 32% of the assets that require relocation will have been addressed. Accordingly, Toronto Hydro plans to continue relocation efforts beyond the 2015-2019 planning period.

E6.5.2 Program Description

The Overhead Infrastructure Relocation program will target overhead infrastructure assets that are part of functionally obsolete feeder designs. Similar to Toronto Hydro's larger Box Construction Conversion (Section E6.7) and Rear Lot Conversion (Section E6.6) programs, the feeder designs addressed by this program no longer align with Toronto Hydro's current planning and work practices and their failure could result in significant reliability impacts. The program is expected to mitigate safety and reliability risks associated with functionally obsolete feeder designs by relocating the existing overhead infrastructure to locations that are more accessible to Toronto Hydro crews and that lower the potential likelihood and impact of failure. The program addresses assets of all voltages throughout the overhead system and that have reached end-of-life.

There are three primary activities that constitute this program.

- Relocation of overhead assets that are in areas with limited or difficult access
- Relocation of overhead station egress assets carrying three or more circuits
- Relocation of overhead assets crossing highways

Each of these activities is described in detail in the following subsections. Toronto Hydro's estimated cost for the program is $9.87 million over the 2015 to 2019 period.

E6.5.2.1 Relocation of Difficult-to-Access Overhead Plant

Overhead assets in certain parts of the city are located in areas that are difficult or are impossible for Toronto Hydro employees to access. Figure 1 shows the location of assets that are in undesirable locations.

FIGURE 1: LOCATIONS OF ASSETS IN THE OVERHE AD SYSTEM THAT ARE DIFFICULT OR IMPOSSIBLE TO ACCESS

Toronto Hydro plans to relocate these pole lines, including primary conductors, poles, insulators, lightning arrestors, transformers and switches. The program will replace these overhead sections with new construction located in more accessible areas, e.g., overhead distribution on nearby roadways, underground distribution on boulevards, or ducts on bridges.

An example of assets that are difficult to reach is illustrated in Figure 2. The yellow line traces the path of two operational feeders and two abandoned feeders from Leaside TS that are running through a ravine where access is limited and heavy vegetation impacts reliability. As well, most of the poles and cross-arms in the ravine are in poor condition with signs of pole top "feathering" and cracks, indicating a relatively high risk of failure due to asset deterioration. The relocation of these feeders will be completed throughout different phases due to the extension of the work. Customers will have to re-supply throughout different routes in order to remove the two feeders from the ravine. The planned work for this section of Leaside TS is planned for completion within the 2015-2019 period.

FIGURE 2: LEASIDE TS FEEDERS RUNNING IN RAVINE

Toronto Hydro plans to reconfigure the feeders to relocate these assets from the ravine in order to improve accessibility for Toronto Hydro crew members and to reduce vulnerability to outages in adverse weather conditions. This relocation will reduce safety risks, such as slips, trips or fall hazards due uneven terrains and by enabling the use of bucket trucks in place of having to climb poles to perform certain activities. Currently, when climbing poles to work on energized lines, crews may not have sufficient support, increasing the risk of them coming into contact with live lines. The use a bucket trucks is the most secure way for crews to reach the assets located on poles since the crews will be working on a stable and an insulated aerial device. In general, the reconfiguration and relocation will reduce restoration times in the event of an outage.

E6.5.2.2 Relocation of Over-head Station Egress Plant

One of the most important and vulnerable aspects of a feeder is its egress portion, the initial section of the feeder that begins at the station circuit breaker at continues until the first sectionalizing switch. This initial path out of the substation is critical because it carries the entire feeder load; a fault on the egress portion of a feeder will result in an interruption to all customers on the feeder. When egress conductors are overhead, they are exposed to a variety of external

harms such as tree contact, animal and human interference, adverse weather conditions and lightning.

The Overhead Infrastructure Relocation program targets stations with a high density of overhead egress assets, i.e., three or more feeders on the same pole. Figure 3 shows the locations of stations with three or more overhead circuits on a single pole line. Under this program, the Richview Station will be addressed during the 2015-2019 period.

Toronto Hydro has determined that a single pole line carrying three or more feeder egresses represents an unacceptably high level of risk to the reliability of power due to the amount of load connected in a single physical location; should a failure occur that impacts the pole line, three or more feeders could experience an outage, resulting in an unacceptably high number of customer interruptions. In addition, risk of falling wires on city streets creates considerable safety risks to the general public. Toronto Hydro plans to reconfigure these assets such that there are no more than two feeders on a pole line. In some cases, this will involve replacing overhead egress with new underground tree-retardant cross-linked polyethylene (TR-XLPE) cable in concrete-encased conduit. The circuit will be underground from the circuit breaker to a point where it can return to overhead.

FIGURE 3: OVERHEAD EGRESS STATION

E6.5.2.3 Relocation of Overhead Plant Crossing Highways

Toronto Hydro plans to relocate overhead primary conductors that currently cross major highways in order to eliminate the risk and impact of primary power lines falling onto the highway. Figure 4 shows a map of the identified locations where primary overhead conductors currently cross major highways. The program will relocate these assets underground by building ducts and installing new underground cable.

FIGURE 4: OVERHEAD HIGHWAY CROSSINGS

The primary activities that constitute the Overhead Infrastructure Relocation program will convert obsolete and difficult to access location feeder sections to modern and efficient configurations. Toronto Hydro anticipates that these relocations will improve efficiency to maintenance activities and restoration time as well as reducing the safety risks associated with better accessibility for Toronto Hydro crews. Table 1 shows the estimated number of assets forecasted for replacement through the Infrastructure Relocation program during the 2015-2019 period.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Poles		32		27	8	
OH Conductor (mts)		5,656			3,400	
OH Switches		10		6	6	
OH Transformers		22		1		
Underground Cable Chamber	2		18			
Underground Duct (mts)	110		3,000	165	200	

In general, the Overhead Infrastructure Relocation program is expected to produce benefits related to increased reliability, outage restoration efficiency and timing, and safety. Table 2 summarizes the anticipated benefits of the program.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Improve outage restoration times by relocating assets in locations with limited accessibility, like ravines and railway tracks ƒ Mitigate public safety risk by relocating overhead wires from highway crossings x The difference in the cost of ownership between existing and renewed assets (ôCOO) for the first year of the program is $1.76 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.5.7). x Accounting for capital program costs, the first year's activities deliver a positive NPV of $1.02 million, confirming the economic prudence of the investments (see Section E6.5.7).
Reliability	ƒ Minimize failure impact on existing overhead egress feeders ƒ Help minimize vegetation related outages, such as tree contacts ƒ Mitigate the risk of momentary interruptions on feeders currently in locations susceptible such as ravines
Safety	ƒ Improve public safety by relocating overhead wires that cross highways underground ƒ Improve Toronto Hydro crew member safety by improving access to assets, including poles. Currently, limited vehicle access and the need to climb poles to make repairs create potential safety hazards
Efficiency	ƒ Improve maintenance activities by facilitating better access to critical infrastructure, including the ability to use needed equipment

E6.5.3 Why the Program is Needed

Certain portions of the overhead grid are functionally obsolete from a design perspective, as they do not align with Toronto Hydro's planning and work practices. Many of the assets on these feeders are approaching end-of-life and carry an especially high failure risk due to their current locations or configurations. These feeders have been contributing an increasing share of overall system outages during the last five years. In order to permanently address the heightened risks to reliability and crew and public safety associated with these assets, Toronto Hydro plans to rebuild these feeders to an improved design standard by either relocating overhead pole lines to a safer and more accessible location, or by moving critical sections of certain egress feeders underground as appropriate.

E6.5.3.1 Program Drivers

Table 3 presents the trigger and secondary drivers for the Overhead Infrastructure Relocation program. The program addresses functionally obsolete overhead feeder designs that do not align with Toronto Hydro's current planning and work practices, as they have a number of reliability and safety deficiencies. Compared to standard overhead feeders, these assets, by virtue of their location and configuration, carry higher reliability and safety risks, including with respect to performance during major storm events. Toronto Hydro has categorized this program as a System Renewal activity.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Obsolete system layout can complicate and extend feeder restoration efforts. ƒ Certain assets are installed in areas where access is very limited. ƒ Overhead highway crossings and high density overhead egress circuits are functionally obsolete designs. ƒ There is a considerable amount of assets in use that are past their useful lives
Secondary Drivers	**Reasoning**
Safety	ƒ Overhead highway crossings pose potential safety risks if the energized lines fall to the ground. ƒ Overhead infrastructure in areas with limited access (steep terrain or heavily treed areas with no road access) present safety hazards for field crews.
Reliability	ƒ Restoration times are impacted by assets that are difficult to access. ƒ Ever-growing vegetation reduces the reliability of the system as it affects overhead infrastructure and the egress section of the feeder. Overhead station egress can impact a large number of customers.

	ƒ Feeders in some locations (for example, ravines) are more susceptible to a high number of momentary interruptions during adverse weather conditions.

Figures 5 and 6 provide a graphical representation of the number of Customers Interrupted (CI) and Customers Hours Interrupted (CHI) over the 2009-2013 period generated by the feeders that are targeted by the Overhead Infrastructure Relocation program. The information is split out between feeder trunks (i.e., the main section of the feeder emanating from the station breaker) and laterals (i.e., the fuse protected branches off of the trunk).

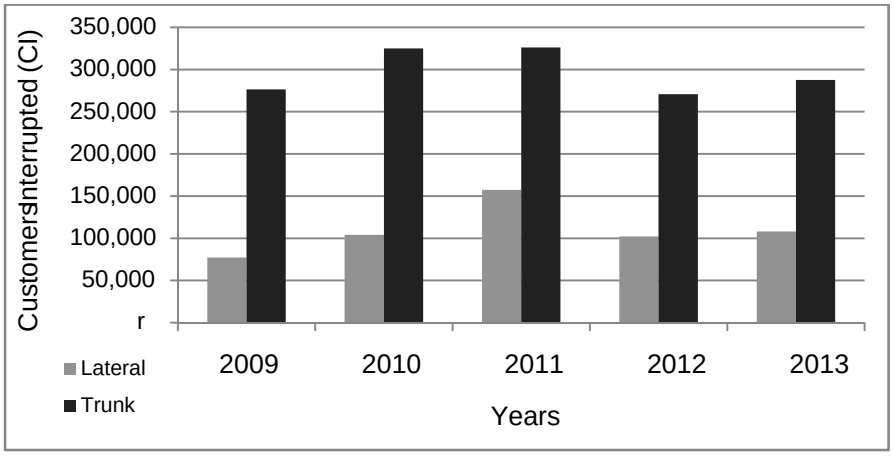


FIGURE 5: AVERAGE CUSTOMER INTERRUPTED (CI) – TRUNK VS. LATERAL

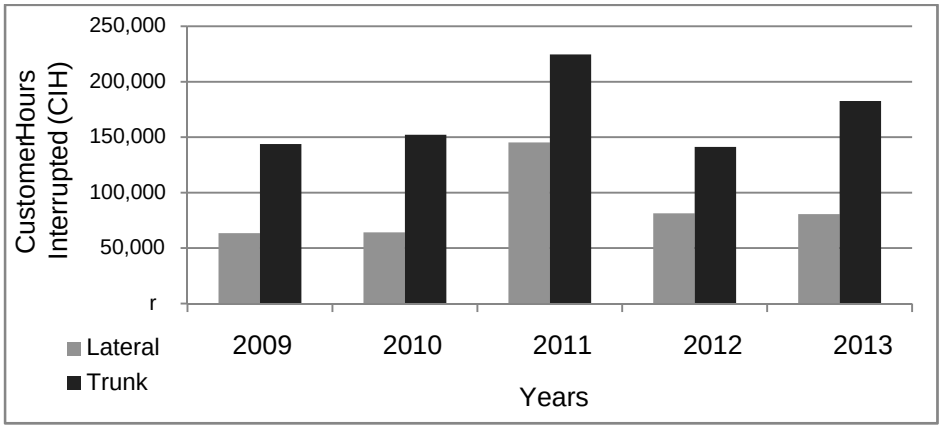


FIGURE 6: AVERAGE CUSTOMER HOURS INTERRUPTED (CHI) – TRUNK VS. LATERAL

As seen in the above two figures, the trunk portion of the circuits contribute a high number of CIs and CHIs. Prolonged outages are common, especially where the assets are located in areas that are difficult to access. In many instances, the trunk portion of the circuit is vulnerable to outages caused by coming into contact with trees, animals, and moisture.

As well, overhead feeder egress sections are exposed to outages caused by the weather, animal contacts and human impact, such as vehicles hitting poles. Moving high density egress sections underground is expected to significantly mitigate these risks. As part of these projects, a SCADA switch will be installed where the egress eventually rises into the overhead circuit (at a safe distance from the transformer station). The SCADA switch will be installed at the riser point to detect and remotely isolate any underground cable faults.

For the 2009-2013 timeframe, 30% to 40% of system-wide CIs were caused by feeders that will be addressed by the Overhead Infrastructure Relocation program, as shown in Figure 7. Figure 8 shows that, over the same time period, approximately 20% of all CHIs were related to feeders addressed by this program. As can be seen in both figures, there is a discernable upward trend in the percentage of interruptions attributable to feeders that are targeted by this program. Accordingly, the Overhead Infrastructure Relocation program is designed to address this issue and is expected to improve reliability going forward.

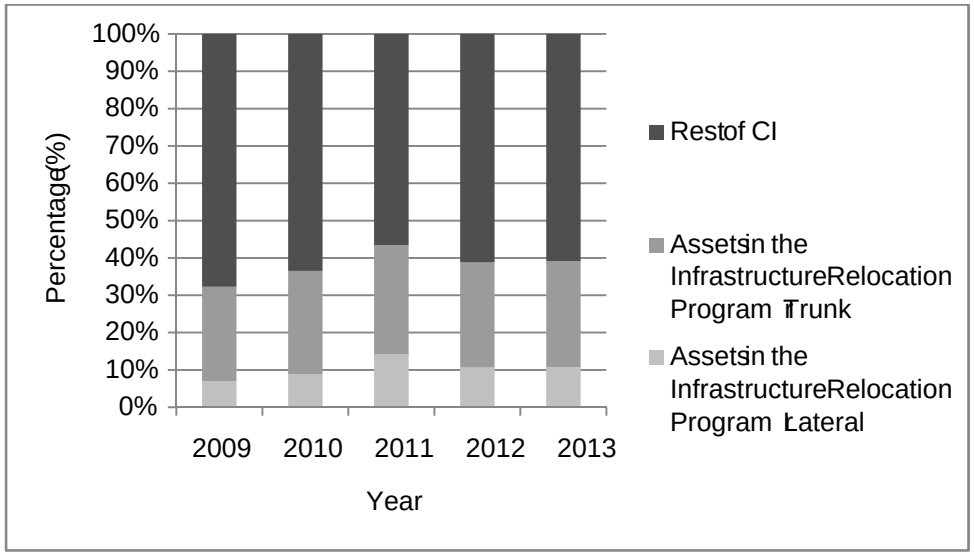


FIGURE 7: CUSTOMER INTERRUPTED PERCENTAGE COMPARED TO THE SYSTEM WIDE

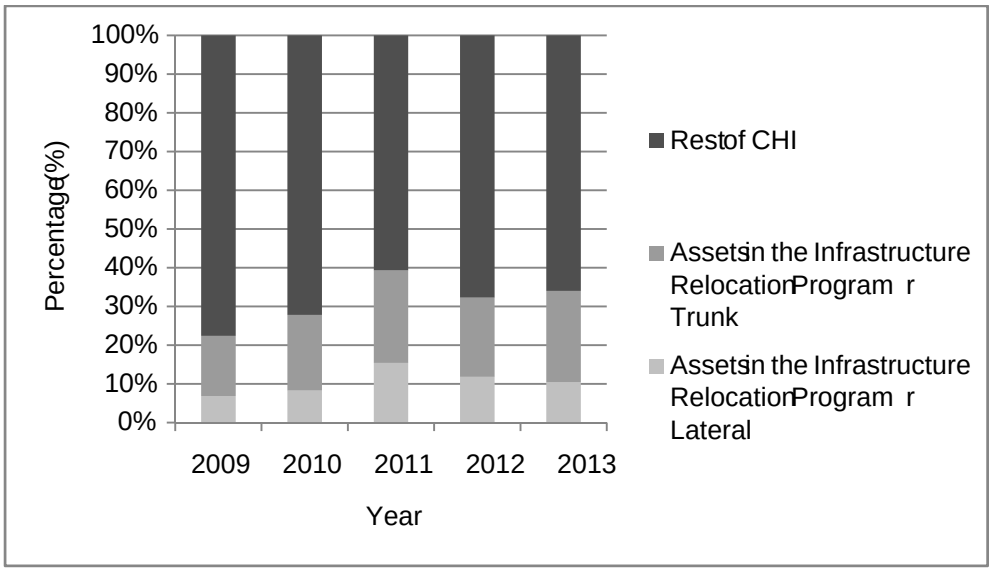


FIGURE 8: CUSTOMER HOURS INTERRUPTED PERCENTAGE COMPARED TO THE SYSTEM WIDE

As discussed in the Program Description section, the Overhead Infrastructure Relocation program will predominantly target three forms of overhead infrastructure: (i) difficult-to-access overhead plant, (ii) overhead egress plant, and (iii) overhead plant crossing highways. These issues are further described below.

(i) Difficult-to-access overhead plant

Assets located in areas with limited access were installed when multiple electrical utilities co-existed as part of the Metropolitan Toronto area. The purpose of feeders running along these areas was to use them as back-up connection points between neighboring districts (for example, between Scarborough, East York, North York, York, Etobicoke and Toronto). These utilities used the shortest and most economical routes – including ravines and railway corridors – which would have been more accessible at the time of construction than they are today. As these locations have developed and as surrounding vegetation has become increasingly dense and intrusive, it has become increasingly difficult and complex for personnel and equipment to access these locations in order to perform necessary work.

Figure 9 shows existing overhead infrastructure that passes through a ravine. To perform restoration or maintenance procedures on these assets, Toronto Hydro employees must work around trees and climb along the steep terrain, which can be saturated with ice or mud, resulting

in an elevated risk of slip, trip or fall hazard. Also, Toronto Hydro personnel are unable to make use of bucket trucks to access equipment in these locations, and instead resort to less safe options, such as climbing poles.

FIGURE 9: FEEDERS RUNNING THROUGH A RAVINE

Figure 10 shows Toronto Hydro distribution lines running along a railway track and over the Don Valley Parkway. If these poles were to fail, they could potentially fall on the railway track or on the highway. The space that crews are required to work within is limited and vehicle access is only available from the railway track or the highway. The problems associated with this work are exacerbated by the fact that the railway track is active and the highway is busy throughout the day and night, making it difficult for crews to move equipment due to highway and railway traffic. In the event that repair work is required on these assets, rail and highway traffic would need to be halted or the number of traffic lanes would need to be reduced.

FIGURE 10: LIMITED ACCESS AND NARROW PATHWAYS

Figures 11 and 12 show the steep terrains that must be traversed to access some poles. In this case, crews would be required to carry heavy assets by hand, such as poles and transformers, to perform repairs, increasing potential risks to crew members and extending repair times, particularly at night and in the winter where visibility is limited and snow, ice and muddy conditions make it more difficult to walk and carry equipment.

FIGURE 11: LIMITED ACCESS AND STEEP TERRAINS

FIGURE 12: LIMITED ACCESS AND NARROW PATHWAYS

(ii) Overhead Egress Plant

As described previously, the egress portion of a feeder trunk circuit is the initial route of power from the circuit breaker at the substation to the rest of the circuit. This initial path out of the substation plays a critical role in the distribution of power to the rest of the feeder since the entire feeder load will flow through this section. As a result, failure on the egress portion of the feeder

will translate into a circuit breaker operation that will affect all customers connected to the feeder. In multiple locations across the city, the egress portion was originally installed overhead, exposing the feeder to numerous risks that can impact the reliability of the feeder or multiple feeders.

Having three or more different circuits running on one pole line outside of the transformer station considerably increases the potential impact of failure. If this portion of the pole line experiences a significant failure, all connected customers on the feeders may experience an outage. Section E6.5.3.2 describes a historical example of such a failure on the Toronto Hydro system. The down wires also represent a safety concern to the public, since they could be electrocuted if they were to come in contact with energized wires.

The program is planned to target overhead egress sections where there are three or more different circuits installed on a pole line. The program will minimize the risk of failure on the feeders by reconfiguring and relocating the feeders to a different location or by undergrounding the circuits. Figures 13 and 14 show existing stations with overhead egress congestion.

FIGURE 13: PICTURES OF OVERHEAD EGRESS CONGESTION

FIGURE 14: PICTURES OF OVERHEAD EGRESS CONGESTION

(iii) Relocation of overhead plant crossing highways

The Overhead Infrastructure Relocation program also is also planned to target overhead infrastructure that crosses major highways. At these particular locations, there is an increased public safety risk due to the possibility of energized lines or assets falling onto oncoming traffic. Due to the high rate of speed at which vehicles travel on a major highway, falling overhead infrastructure presents a serious potential safety risk to the public. The public may not always understand the hazards associated with energized cables lying on the streets. This situation is a serious safety risk since individuals can severely injure themselves if they come in contact with energized lines.

Accessing overhead infrastructure that crosses a highway for repair work is also challenging because it may require closure of the highway and/or special equipment (due to height). Figure 15 is an example of overhead highway crossing in Toronto. Section E6.5.3.2 (ii) describes a

recent historical example of an overhead highway crossing failure on the Gardiner Expressway in Toronto.

FIGURE 15: OVERHEAD HIGHWAY CROSSINGS

E6.5.3.2 Asset Details

(i) Asset Lifecycle

Assets targeted by the Overhead Infrastructure Relocation program were evaluated based on their end-of-life criteria. Figure 16 illustrates the breakdown of the assets by age. The assets targeted by this program are overhead transformers, overhead switches and poles. Roughly 39% of assets are categorized as 30 years of age or older, surpassing their respective asset lifecycle, with an additional 23% approaching end-of-life in the next decade. These assets must be replaced in a timely manner to mitigate elevated reliability risks associated with these obsolete feeder designs.

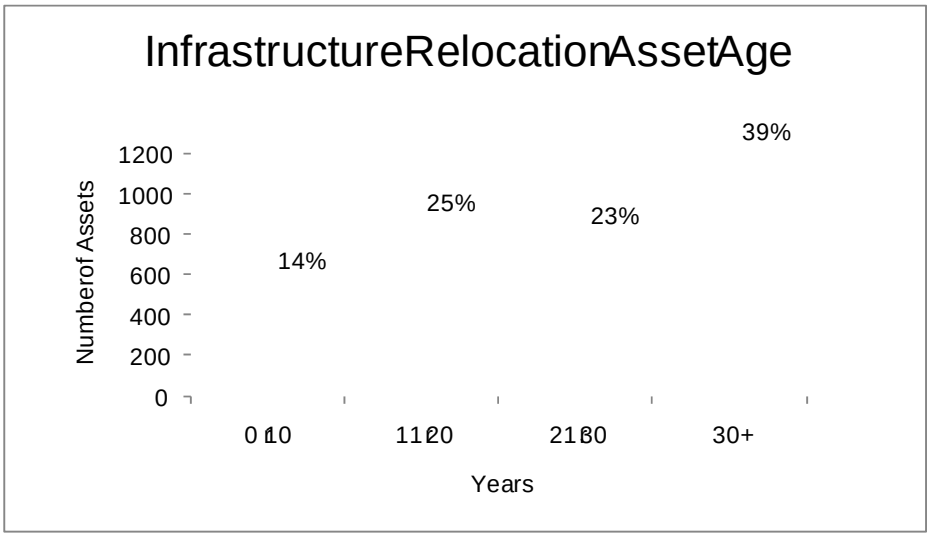


FIGURE 16: INFRASTRUCTURE RELOCATION ASSET AGE

(ii) Asset Failure Impacts

Difficult to access overhead feeders

Overhead portions of feeders that are located in areas with limited accessibility are mostly feeder trunks. Interruptions on these sections can impact more than 3,000 customers and typically take approximately two and a half times longer to restore than outages affecting assets that are more accessible. Poor accessibility also results in complications with respect to maintenance activities and poses risks of slips, trips and falls for Toronto Hydro crews.

These risks became an issue during the December 2013 ice storm on a feeder from Leaside TS in the area of Bayview Avenue and Lawrence Avenue East. Crews had to work in a ravine for two days to restore power to customers, with the prolonged duration due in part to the fact that the crew was unable to use proper machinery. Also, due to the accumulation of ice on the trees, branches frequently fell on the conductors during repair work.

Overhead highway crossings

The possibility of energized lines or other overhead highway crossing assets falling into oncoming traffic poses a significant public safety risk. The safety risk is high because of the rate of speed at which vehicles travel on highways and other major routes. In 2011, the overhead conductors

crossing the Gardiner Expressway near Royal York Road fell on the highway during a snow storm (see Figures 17 and 18). This caused significant disruption to traffic. Fortunately, the conductors had already been isolated and de-energized for removal due to an ongoing project before the incident happened. If the conductor had been energized, cars may have come into contact with live lines. It took approximately one hour to remove the cables and for the lanes to be reopened.

FIGURE 17: FALLEN OVERHEAD CONDUCTORS ON THE GARDINER EXPRESSWAY

FIGURE 18: FALLEN OVERHEAD CONDUCTORS ON THE GARDINER EXPRESSWAY

Congested overhead station egress

The egress portion of a feeder trunk circuit out of a substation plays a critical role in the distribution of power. If this portion of the feeder experiences a failure, all connected customers will experience an outage. This impact of failure can become extreme when there are three or more feeders on a single pole line. An example of an egress incident of this magnitude occurred on June 7, 2011, when thirteen poles collapsed due to a severe windstorm. The investigation of this incident also found evidence of an ant infestation. The severe wind and the weak poles resulted in a lengthy outage that took down three feeders coming out of Agincourt Station. The outage took approximate 8.5 hours to restore and affected close to 6,000 customers. Figure 19 shows the failure of the poles.

FIGURE 19: OVERHEAD EGRESS OUTAGE

E6.5.4 Timing & Pacing of the Program

Table 4 provides the estimated cost of the program for the 2015-2019 forecast period.

TABLE 4: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	0.74	1.38	1.83	2.28	3.64

Many assets within the Overhead Infrastructure Relocation program have reached end-of-life and pose a risk to the reliability of the system and the safety of customers and Toronto Hydro personnel. Rather than undertaking a costly "like-for-like" replacement of end-of-life assets, it is prudent to relocate the infrastructure to improve feeder design, reliability, efficiency and safety. The program requires an investment of approximately $9.87 million over the five year planning horizon. Due to the large backlog of assets that have reached end-of-life, Toronto Hydro plans to

increase yearly expenditures throughout the 2015-2019 period. The timing of overhead relocation also takes into account capacity constraints with respect to Toronto Hydro's workforce.

By the end of the program period, it is anticipated that approximately 32% of the assets that need to be relocated will have been addressed. Accordingly, Toronto Hydro plans on continuing relocation efforts past the 2015-2019 planning period.

E6.5.4.1 Ranking & Prioritization

Sequencing of the work in the Overhead Infrastructure Relocation program is determined based on the following factors:

Asset condition and age: Assets projected to fail will have an impact on customer service, satisfaction and reliability. Toronto Hydro's sequencing of planned work accounts for the risk of failure by considering which assets are in poor condition and past useful life.

Failure risk: As with other basic overhead and underground renewal programs, failure risk (i.e. the likelihood of failure multiplied by the potential impact of failure) is considered the primary criteria when sequencing work within this program. Assessment of failure risk includes consideration of the asset condition and age as well as the number of customers on the feeder and number of circuits per pole.

Reliability : All other factors being equal, feeders that have experienced a significant amount of sustained trunk outages in the last five years will be ranked higher.

Toronto Hydro plans on beginning with the relocations of the circuits from Leaside TS (as detailed in Section E6.5.9). The area was selected due to the poor asset condition, reliability and accessibility of the area.

E6.5.6 Program Execution

The Program Execution discussion is divided into three sections: (i) Relocation of difficult-to-access overhead plant (ii) Relocation of overhead egress plant and (iii) Relocation of overhead plant crossing highways.

(i) Relocation of locations with limited accessibility to overhead plant

In the case of difficult-to-access locations, Toronto plans to remove assets from ravines and railway tracks to locations that are accessible to vehicles and crews year-round. Depending on

the location and street limitations, the new lines might be installed overhead or underground. As well, the installation of the circuit might be relocated to bridges.

If the lines are relocated overhead, the scope of work will require a new pole line to be installed and the use of new conductor and switches to provide transfer capability. If the work is to be relocated underground, the project will cover the installation of concrete encased ducts and new underground cable with riser poles. If the line is to be transferred to a bridge, ducts will be required to be built on the bridge and new underground cable will be installed along with the riser poles and switches. An example of this can be shown on Figure 20. The overhead lines will be relocated from the ravine to the bridge. The work involved includes the installation of ducts along the bridge with new underground tree-retardant cross-linked polyethylene (TR-XLPE) cable. Similar to the highway crossings, riser poles will be installed to transition from the overhead to underground on both sides of the bridge.

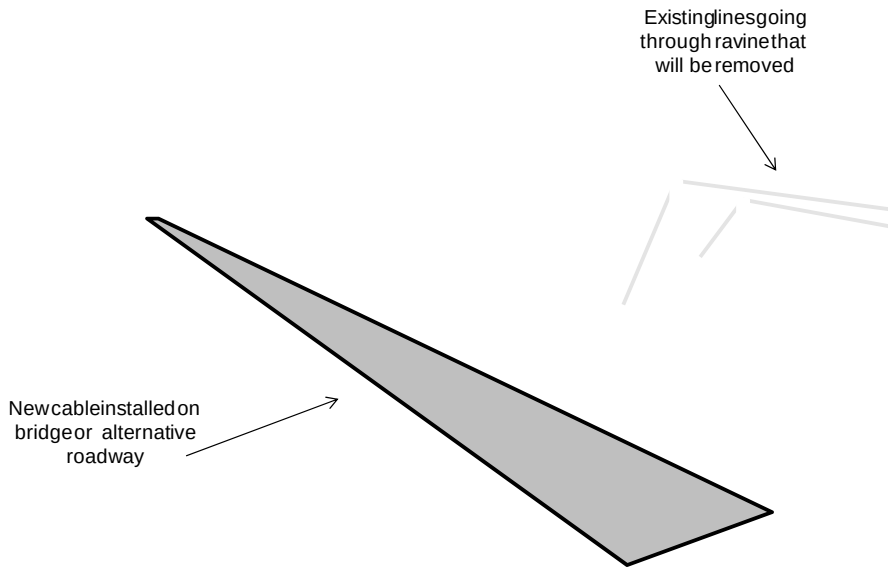


FIGURE 20: RELOCATION OF DIFFICULT ACCESS LOCATIONS

(ii) Relocation of Overhead Egress Plant

Toronto Hydro plans to relocate or move underground overhead egress circuits to reduce the failure risks associated with overhead outages. The scope of work will be limited to the relocation of feeders on pole lines with three or more circuits. Where the feeder is relocated underground, concrete encased ducts will be built with cable chambers and new underground cable. The concrete encased ducts will be built up to a point where the underground circuit will transition back to overhead. Where the feeder egress is relocated but kept overhead, work will involve the installation of poles, conductor, switches, framing hardware and other overhead accessories.

(iii) Relocation of Overhead Plant Crossing Highways

With respect to overhead highway crossings, the work will involve either tunneling, micro-, directional drilling, or jack and bore under the highway in order to build the ducts for the new underground cable. The work will involve the installation of new riser poles and switches to transition from the overhead to underground. New underground tree-retardant cross-linked polyethylene (TR-XLPE) cable will be installed. An example of this can be seen in Figure 21. A second option for the overhead highway crossing removal will is reconfiguring the feeder and routing the circuit through a different street. Each highway crossing has to be evaluated individually to determine if there is an alternative road for the new line. Undergrounding the highway crossing is typically the most effective solution as it will eliminate the risk of the circuits falling and it will great establish the civil infrastructure necessary for additional feeders to cross the highway in the future.

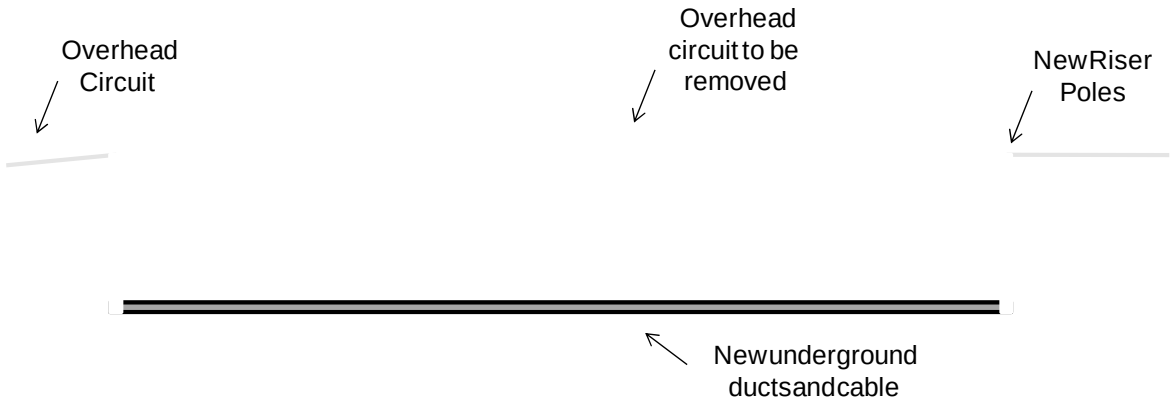


FIGURE 21: CONVERSION OF OVERHEAD HIGHWAY CROSSINGS TO UNDERGROUND

E6.5.6.1 Proposed Work Plan

The proposed work plan in the 2015-2019 period does not necessarily follow a station-by-station approach. Due to the complexity of some of these locations, projects will be scheduled by phases throughout the 2015-2019 period in order to complete the relocation of the assets. This incorporates best capability of executing and resources availability.

Table 5 represents the work plan for the program for the 2015-2019 period. Issues may arise that are specific to certain locations; however, current planning processes have not identified any major issues in years 2015-2019 other than the continued deterioration and aging of assets.

TABLE 5: 2015-2019 LONG TERM PLAN

Year	Station
2015	Leaside TS
2016	Leaside TS
2016	Belfield MS
2016	Manby TS
2017	Leaside TS
2017	Richview TS

Year	Station
2018	Leaside TS
2018	Richview TS
2018	Bermondsey TS
2019	Richview TS
2019	Finch TS

E6.5.6.2 Program Risks

Road moratoriums that follow municipal roadwork may be in place where Toronto Hydro plans to perform work under this program, which could delay some planned work within this program. To mitigate this risk, Toronto Hydro maintains communication with the City's planning staff to stay abreast of any moratoriums and to work around them and/or develop solutions in concert with the City.

A second risk relates to the need to involve provincial and municipal transportation to close highways for required work. Toronto Hydro will mitigate this risk by coordinating its work with the relevant authorities and removing the conductor at a time when traffic is low in order to minimize traffic disruption.

A third risk associated with the program is operational risk. When replacing egress cables, it is possible that several feeders will need to be de-energized in order to undertake the construction of the new design. The load of the feeder where the work is taking place will have to be transferred to adjacent feeders. Load transfers can be restricted in certain months of the year due to high usage of electricity, for example summer months. Overloading feeders can cause equipment deterioration due to heat generated by losses that can result in deterioration of the insulation material, transformers and others. Toronto Hydro will mitigate this risk by scheduling the work were lading restrictions are low.

E6.5.7 Evaluation of Alternatives

E6.5.7.1 Quantification/Evaluation of Options

In addition to the benefits outlined in section E6.5.2, the value derived from the Overhead Infrastructure Relocation program can be further quantified by examining the difference in cost of ownership between the existing infrastructure that will be replaced and the new system design

that will be installed. This difference in costs includes quantified risks, taking into account the probability of failure of the asset, and multiplying this figure by the direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement. The underlying methodology and processes associated with the business case results provided below are further explained within Section D3.

(i) Option 1: Status Quo

The status quo would have Toronto Hydro continue to maintain and repair assets targeted by the program. Due to the high number of assets at end-of-life on these feeders, maintaining the status quo will likely result in increasing maintenance costs and the continued worsening of system reliability associated with these circuits. The safety and operational issues discussed throughout this narrative would continue to arise and Toronto Hydro would have to address them in a reactive manner. The continued cost of ownership associated with the Status Quo option (COO_E) is highlighted in Table 6.

From a tree trimming perspective, foresters will be required to climb trees to perform the trimming, as opposed to working in a bucket truck. This introduces delays in execution of the work, and there is a greater risk of injury to the personnel performing the work. In some cases, due to the hazards of these locations, arrangements have to be made for a feeder outage in order to perform the trimming safely.

Additionally, the restoration time will be longer at inaccessible locations than a regular outage on a roadway. Repairing an outage for an asset in an inaccessible location can take up to two and a half times longer.

(ii) Option 2: Like-for-like Replacement

Like-for-like replacement would involve the replacement of the assets within the programs at their existing locations. Under this option, safety risks discussed earlier would remain. In addition, limited accessibility would continue to impact power restoration times. In all, the efficiency and reliability of the system would not gain the permanent improvements associated with relocation and customers would continue to experience longer than necessary outages.

The cost of ownership (COO_{N1}) and program net benefit (NPV_1) associated with like-for-like replacement is further detailed in Table 7. When the difference in cost of ownership (ΔCOO_1) is

compared to the associated program costs, the like-for-like replacement option receives a program net benefit (NPV_1) value of -$0.69 million for this option.

(iii) Option 3: Infrastructure Relocation

The Overhead Infrastructure Relocation program as described in this evidence is the preferred option. As noted, it provides the most cost effective option to increase restoration of outages, increase safety, and increase reliability.

The cost of ownership (COO_{N2}) and program net benefit (NPV_2) associated with Overhead Infrastructure Relocation program is further detailed in Figure E6.5-29. The COO is established for both the existing state (COO_E) and the proposed new state (COO_{N2}) based on the first year of activities within this program. The COO of a state reflects the risk of asset failure including both direct and indirect costs. These costs include the cost of customer interruptions, emergency repairs, and asset replacements associated with that design. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NAR_E) and proposed (NAR_{N2}) state. Non-asset risks are further explained in Section D3.3. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership (ûCOO_2) is compared to the associated program costs (PC_2) for the first of activities, the Overhead Infrastructure Relocation program produces a NPV of $1.02 million, as shown in Table 8.

TABLE 6: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	0.13
Non Asset Risk [NAR_E]	3.00
Maintenance Cost [MC_E]	0
Additional Quantifiable Benefits [AQB_E]	0
Cost of Ownership of Existing Assets [COO_E]	3.13

TABLE 7: LIKE-FOR-LIKE REPLACEMENT BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 1: Like-for-Like Replacement (N1)	
Asset Risk [AR_{N1}]	0.079
Non Asset Risk [NAR_{N1}]	3.00
Maintenance Cost [MC_{N1}]	0
Additional Quantifiable Benefits [AQB_{N1}]	0
Cost of Ownership of New Assets (Like-for-Like Replacement) [COO_{N1}]	3.079
Option 1: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\Delta COO_1 = (COO_E - COO_{N1})$]	0.051
Program Cost [PC_1]	0.74
Program Net Benefit [$NPV_1 = (\Delta COO_1 - PC_1)$]	-0.69

TABLE 8: OVERHEAD INFRASTRUCTURE RELOCATION BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 2: Infrastructure Relocation (N2)	
Asset Risk [AR_{N2}]	0.068
Non Asset Risk [NAR_{N2}]	1.30
Maintenance Cost [MC_{N2}]	0
Additional Quantifiable Benefits [AQB_{N2}]	0
Cost of Ownership of New Assets (Infrastructure Relocation) [COO_{N2}]	1.368
Option 2: Program Net Benefit (NPV_2)	
Difference in Cost of Ownership [$\Delta COO_2 = (COO_E - COO_{N2})$]	1.762
Program Cost [PC_2]	0.74
Program Net Benefit [$NPV_2 = (\Delta COO_2 - PC_2)$]	1.02

E6.5.9 Program Projects

Table 9 lists the projects that are planned for execution in 2015. Additional project details are available on the following page.

TABLE 9: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date
E14565	Beechwood DVP reconfiguration tie Point Civil 34M2 EYM2L	$743,214	2015

E14565 Project Description

Investment Category: System Renewal

Program: Overhead Infrastructure Relocation

Project Title: Beechwood DVP reconfiguration tie Point (Civil) 34M2

Project Number: E14565

Project Year: 2015

Estimated Cost: $743,214

(i) Objective

The objective of this project is to remove a section of 34M2 that is installed on a hill in the area of Leaside TS with limited access beside the Don Valley Parkway. The tie point between 34M1 and 34M2 is to be re-established via a new underground connection on Beechwood Drive. This project involves the civil portion of the project. Electrical portion will be schedule for 2016.

(ii) Scope of Work

TABLE 10: E12345 SCOPE OF WORK DETAILS

District Neighborhood	DONVALLEY WEST
Station(s)	LEASIDE TS
Feeder(s)	34M1, 34M2

TABLE 11: E12345 ASSETS REPLACED

Assets (Units)	Count
Pole	
Transformer	
Switch	
Switchgear	
Conductor Lengths (mts)	
Cable Lengths (mts)	
Underground Cable Chamber	2
Underground Duct (mts)	110

(iii) Justification & Benefits

Leaside TS feeders 34M2 and 34M3 exit the station via overhead lines across a parking lot before extending into the Don Parkland. Both of these feeders are installed on cross arms in two separate pole lines In the Don Parkland, before crossing the CN railway and Don River, both lines are mounted on poles that are installed on hills and grass field without proper road access for vehicles.

Most of the poles and cross arms in the parkland and parking lot are in poor condition with sign of pole top "feathering" and cracks. Due to their physical location, access to the lines on the north side of the Don River via trucks is difficult to impossible depending on weather conditions. Any equipment failure in the parkland or on the ravines would result in a lengthy outage and present an unsafe work environment to Toronto Hydro crews. Due to the complexity of required work, it will be divided into a number of scopes. E14565 will install the civil infrastructure required to supply the customers currently feed from the line going through the ravine.

E6.6 Rear Lot Conversion

REAR LOT MAINTENANCE BY TORONTO HYDRO CREW MEMBER

E6.6.1 Summary

Program Description

The Rear Lot Conversion program continues the activities described in the Ontario Energy Board (OEB) approved Rear Lot Construction segment of Toronto Hydro's 2012-2014 rate filing[1]. The Rear Lot Conversion program targets the replacement of assets that are currently installed in the back yard, or rear lot, of residential areas. These assets were typically installed over 40 years ago and are now either at or beyond their useful lives. The assets include wood poles, transformers, switches, and overhead and underground conductors. This program eliminates the supply of power coming from the rear lot overhead and re-distribute power to the neighbourhoods via standard front lot underground supply.

The anticipated benefits of the Rear Lot Conversion program are summarized in the following table.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Crews will no longer have to enter customer property to perform services ƒ Maintains neighbourhood aesthetics by building future state assets underground

[1] EB-2012-0064, Tab 4, Schedule B6.

Reliability	ƒ Reduces frequency and duration of outages ƒ Reduces storm, tree and animal damage ƒ Reduces vulnerabilities of the existing system to major storm events
Safety	ƒ Improves public safety ƒ Clearances are brought up to standard ƒ Reduces the risk of field crew injury with respect to over exertion, constrained work spaces, poor visibility and unstable footing
Efficiency	ƒ Enables use of standard equipment and fault location methods ƒ Improves access to distribution equipment during restoration efforts

Program Drivers

The trigger and secondary drivers for the Rear Lot Conversion program are summarized in the table below.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ The rear lot configuration is a legacy design that is associated with operational constraints (limited access and non-standard design elements) and safety risks ƒ Leads to prolonged outage durations because it is difficult to locate and repair faults
Secondary Drivers	**Reasoning**
Safety	ƒ Constrained work spaces with poor visibility and poor footing conditions potentially endanger crew members. ƒ The need to manually move and access parts and equipment can lead to overexertion.
Reliability	ƒ The need to manually locate, isolate and restore outages prolongs outage durations. Heavy vegetation can impact the reliability of the system.
Failure Risk	ƒ Equipment past its useful life and more likely to fail. ƒ The majority of rear lot underground assets are direct buried, a design that is associated with an especially high failure risk.

Preferred Alternative

Toronto Hydro considered the following alternatives for addressing the assets in this program.

(1) Do nothing and replace on a reactive basis only, incurring the risk of equipment failures and potential safety concerns

(2) Rebuild the aged rear lot assets in a like-for-like manner, temporarily reducing the probability of a power outage without reducing the potential impact of failure and the operational constraints faced as the assets approach their end of life and begin to fail

(3) Replace the rear lot distribution with a front lot, overhead distribution system that may offer improved reliability, but may not be possible to actually construct due to the harm to the aesthetic value of customer property and the need to potentially remove mature trees in the neighbourhood

(4) Replace the rear lot distribution with a front lot, underground distribution system

Option IV is the preferred alternative as it provides the most cost effective option to increase the safety and reliability of the system, while reducing the time and effort required to respond to power outages in the area and maintaining neighbourhood aesthetics, thereby maximizing customer value derived from the necessary conversion projects.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $27.02 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.6.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $5.71 million, confirming the economic prudence of the investments (see Section E6.6.7).

Timing and Pacing

Table C provides historical and projected program spending.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	6.88	16.6	17.5	23.8	22.7	17.05	8.06	10.3	10.3	13.6

Rear Lot Conversion projects are resource intensive, relatively complex and require a steady moderate pace of construction. The amounts shown in the table above represent the amount of investment required to maintain a reasonable level of service and to ensure that an excessive

backlog of work does not accumulate over the 2015-2019 period. Deferral of the program to 2020 would create a larger backlog of increasingly critical rear lot projects, since equipment will continue to age and failure risks to increase. This backlog could become difficult to manage and could contribute to the further deterioration of system performance and safety.

E6.6.2 Program Description

The Rear Lot Conversion program continues the activities described in the Rear Lot Construction segment of Toronto Hydro's 2012-2014 rate filing, which was approved by the OEB. Toronto Hydro estimates that the Rear Lot Conversion program will cost $59 million over the 2015 to 2019 period, with spending averaging approximately $12 million per year. A summary of the major assets to be replaced by asset class is shown Table 1 below and a map of the rear lot areas to be address between 2015 and 2019 can be seen in Figure 1 at the end of this section.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Asset Type	2015	2016	2017	2018	2019	Total
Pole	352	23	210	133	122	840
Transformer	99	37	64	32	51	283
Manual Switch	44	10	15	10	7	86
Fuse	48	15	27	14	29	133
Riser	32	2	27	4	25	90
Conductor (m)	18,295	2,933	9,112	6,692	9,157	46,188
Cable (m)	2,853	9,858	2,694	3,062	8,552	27,018

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Rear Lot Service History

Rear lot service was implemented in certain Toronto neighbourhoods in the 1950s and 1960s. At the time, this configuration was seen as more cost effective compared to front lot underground service and aesthetically superior to front lot overhead systems. The rear lot systems were constructed along the easements between customer properties at their rear lines. Toronto Hydro now considers rear lot service to be functionally obsolete due to a number of reliability, operational efficiency and safety issues associated with the configuration. Accordingly, Toronto Hydro no longer uses rear lot service for new projects and plans on converting rear lots to front lots. Rear lot conversion may also occasionally be driven by the need to replace 4 kV feeders that are connected to aging stations that are set to be decommissioned.

While there are some portions of rear lot distribution circuits that are underground, most rear lot service is overhead. These facilities consist of cable, poles, transformers, switches and overhead conductors. The system also features minor non-standard components, such as porcelain arrestors and insulators.

Rear Lot Conversion

Toronto Hydro's Rear Lot Conversion program began in 2007, and to date, approximately 29 feeders have been converted to front lot underground configurations. Toronto Hydro plans to continue converting rear lot plant to front lot underground plant during the 2015-2019 period. Approximately 11,000 customers currently receive power from 42 rear lot feeders emanating from 20 Toronto Hydro substations. Figure 1 shows the location of rear lots within Toronto Hydro's distribution system, most of which are located in the west end of Toronto, with a few remaining areas in the east end.

FIGURE 1: REMAINING REAR LOT MAP

The remaining rear lot configurations feature multiple feeders that provide service across the same easement, making conversion activities relatively complex. These feeders depend on one another for load transfers, especially during contingency scenarios (i.e., during outages on any of the feeders). Feeders tie with one another and can be used to resupply each other if a feeder's primary source of power from a substation is disrupted due to a fault or work being done. Therefore, it is important that alternative sources of power remain available during conversion in the event of an emergency. These interconnections necessitate the careful staging of conversion jobs over several years.

The Rear Lot Conversion program addresses the geographic areas shown in Figure 1 in red. The neighbourhoods targeted for conversion during the forecast period were chosen based on safety, equipment condition assessments, reliability concerns and city restrictions. The program will convert and resupply rear lot customers using underground front lot services. This design will supply customers through concrete-encased lateral underground 27.6 kV primary circuits along the roadways with padmount or submersible transformers. Toronto Hydro will route the customer service cables that tap off the secondary bus underground in between the homes in order to connect to the existing meter location (meterbase), located at the rear of the residences. Once customers are connected, all remaining rear lot assets will be removed to eliminate any remaining safety risks. A standard design example can be seen in Figure 2 below.

FIGURE 2: STANDARD DESIGN EXAMPLE OF REAR LOT TO UNDERGROUND FRONT LOT CONVERSION

The Rear Lot Conversion program provides customer value by improving reliability, enhancing public safety, and maintaining neighbourhood aesthetics.

In removing the electrical plant from rear lots and replacing it with standard front lots underground, Toronto Hydro anticipates that customers will experience fewer and shorter outages, as the conversion will replace an aging and non-standard rear lot system. More

specifically, outages related to storms, tree contacts, and animal contacts will be significantly reduced. When an outage does occur, Toronto Hydro will be able to more quickly locate the fault and commence restoration activities, thereby reducing outage durations.

In addition to reliability benefits, the program will also mitigate a number of safety risks faced by local residents by reducing the possibility that the energized infrastructure will come into contact with individuals or their property and improving safety clearances for equipment.

Placing the newly transferred circuits underground will also maintain the aesthetics of streetscapes in the affected communities. Since many of these communities have an existing large tree canopy along the streets, placing the circuits underground avoids the extensive arborist work that would be required if the circuits were transferred to overhead assets. Figures 3 to 4 show some of the existing streetscapes.

FIGURE 3: FRONT LOT OF MARKLAND WOODS PROJECT – TREES THAT WOULD A OBSTRUCT A FRONT LOT OVERHEAD LINE

FIGURE 4: FRONT LOT OF THORNCREST PROJECT – TREES THAT WOULD OBSTRUCT A FRONT LOT OVERHEAD LINE

Rear lot conversion will yield a number operating efficiencies for Toronto Hydro. Firstly, Toronto Hydro will be able to use standard tools to complete capital and maintenance work on feeders and improved access to work sites. As well, crews will no longer need to access multiple customer backyards to determine fault locations and perform repairs. Finally, crews will no longer need to manually carry tools and materials to work sites and/or use heavy lifting equipment to move required tools into position.

The benefits of the program are not limited to those customers whose rear lots are being converted to underground front lots. Customers who are not directly affected by the rear lot conversion but who share a feeder with customers that are having their rear lots converted will benefit from the conversion to a modern 27.6 kV system from the existing 4.16 kV system. More specifically, they will enjoy improved reliability because the reliability issues associated with old, poor conditioned 4.16 kV assets will be eliminated.

The following table summarizes the anticipated benefits of the Rear Lot Conversion program.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Improves public safety ƒ Crews will no longer have to enter customer property to perform services ƒ Maintains neighbourhood aesthetics ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $27.02 million,

	representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.6.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $5.71 million, confirming the economic prudence of the investments (see Section E6.6.7).
Reliability	ƒ Reduces frequency of outages ƒ Reduces duration of outages ƒ Reduces storm, tree and animal damage
Safety	ƒ Improves public safety ƒ Clearances are brought up to standard ƒ Reduces the risk of field crew injury with respect to over exertion, constrained work spaces, poor visibility and unstable footing
Efficiency	ƒ Enables use of standard equipment in the future (i.e. bucket trucks) ƒ Improves access to distribution equipment

E6.6.3 Why the Program is Needed

The Rear Lot Conversion program addresses an aging and functionally obsolete type of overhead construction. The proactive conversion of aging rear lot assets is needed to address the safety risks and reliability issues associated with this legacy design.

E6.6.3.1 Program Drivers

Table 3 presents the trigger and secondary drivers for the Rear Lot Conversion program. The program is designated as a System Renewal initiative, with a primary driver of functional obsolescence.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ The rear lot configuration is a legacy design that is associated with operational constraints (limited access and non-standard design elements) and safety risks ƒ Leads to prolonged outage durations because it is difficult to locate and repair faults
Secondary Drivers	Reasoning

Safety	ƒ Constrained work spaces with poor visibility and poor footing conditions endanger crew members. ƒ The need to manually move and access parts and equipment can lead to overexertion. ƒ Customer equipment and amenities such as pools are located in close proximity to energized equipment.
Reliability	ƒ The need to manually locate, isolate and restore outages prolongs outage durations. Heavy vegetation can impact the reliability of the system. ƒ Reliability (and safety) performance of the rear lot system can be especially problematic during and after major storm events, such as high winds and ice storms, due to access, fault location, vegetation and asset condition issues.
Failure Risk	ƒ Equipment past its useful life and is more likely to fail. ƒ The majority of rear lot underground assets are direct buried, a design that is associated with an especially high failure risk ƒ Replacing failed non-standard equipment and locating faults on rear lot feeders with non-standard configurations can extend the duration of outages.

Toronto Hydro considers rear lot construction to be a functionally obsolete, non-standard legacy design. This is due to a number of disadvantages and deficiencies inherent in the configuration and location of rear lot plant. These issues are captured in the secondary drivers for the program and are discussed in detail in this section. While the trigger driver for replacement is functional obsolescence, the urgent need for a steadily paced, proactive renewal program is derived from a combination of the increasing average age of rear lot assets and the complexity of rear lot conversion projects, which must be staged over multiple years.

Access and Clearance Issues

Residential backyards are difficult work environments because they pose several access and clearance issues. Figure 5 depicts common access issues with rear lot plant. Often, a number of physical obstacles are scattered throughout the backyard such as outdoor recreational equipment and are home to structures such as home extensions, sheds, patios and pools. As well, limited space often forces Toronto Hydro crews to perform rear lot work manually, with restricted use of standard tools; at times the space is too limited to carry tools into the backyard and while at times feasible, it is not always possible to move tools into the backyard using a crane when required.

An addition access issue relates to permission to enter the backyard; Toronto Hydro requires authorization from the customer before entering the backyard to perform work.

FIGURE 5: ACCESS RESTRICTIONS

Figure 6 shows an example of a rear lot lateral circuit that supplies houses on three streets. The lateral branches off of the main feeder circuit and enters the neighbourhood in between two houses. The lateral is then routed in between the rear residential property lots. The primary lateral circuit (shown in black) supplies pole top transformers. The transformers step the primary circuit voltage down to the appropriate end-use voltage for the secondary bus circuit (signified in red). From the secondary bus circuit, the service lines branch off to the meter bases that supply each residence. As seen in the figure, there is no electrical infrastructure in the front lot with the exception of the streetlights that are supplied by the secondary bus, with spans of overhead conductor being routed between the properties. All of the electrical distribution assets are in the rear lot.

FIGURE 6: LATERAL CIRCUIT CONFIGURAT ION FROM THORNCREST NEIGHBOURHOOD

In some areas, minimum clearances prescribed by safety regulations are compromised due to cluttered outdoor equipment and structures, increasing the safety risks of rear lot work. Figure 7 is a real top view of the schematic from Figure 6 of the rear lot lateral circuit, showing obstacles such as heavily treed areas and swimming pools. The minimum horizontal clearance for pools is 16'-8", and in many locations, this clearance is not met. Aside from safety clearances, pools also specifically create access issues for crews by reducing the available workspace and acting as trip hazards, especially when work is required in the evening.

FIGURE 7: OVERHEAD VIEW OF REAR LOT EXAMPLE

Figures 8 and 9 show common clearance issues encountered with existing rear lot plant.

FIGURE 8: ACCESS AND CLEARANCES ISSUES WITH SWIMMING POOL

FIGURE 9: CLEARANCES NOT MET; FENCE MAKES IT DIFFICULT TO ACCESS POLE

Overgrown Vegetation

Mature tree canopy cover and poorly landscaped brush can cause visibility issues and additional access issues in rear lots. Reduced visibility is a safety concern when executing electrical work and can contribute to extended outage durations. As well, overgrown vegetation may require trimming on site to access the equipment safely. Figure 10 shows examples of overgrown vegetation.

FIGURE 10: ACCESS RESTRICTION DUE TO OVERGROWN TREES, SHEDS, AND FENCES

Poor Reliability and Inefficient Restoration

The majority of rear lot feeders operates at 4.16 kV and therefore lack advanced fault detection and isolation technologies like SCADA-mate switches. Without these technologies, field crews are required to manually determine the location of a fault. The poor access and visibility associated with rear lot feeders exacerbates this situation, contributing to prolonged outages and inefficient use of resources during fault location and outage restoration.

Spatial constraints such as trees and fences may prevent crews from walking an uninterrupted path along the feeder to locate the fault; instead, requiring them to enter multiple residential backyards along the circuit. Once the fault is located, crews often face the difficult task of repairing the fault and restoring the service. As previously mentioned, limited access can restrict the use of standard equipment such as bucket trucks, drilling machines and other machinery and implements. This also means that heavy materials such as poles and transformers must be hand-carried to the rear lot or even hoisted over the residence by a crane. For overhead rear lot feeders, specialized reactive crews are needed to physically climb the poles to access the equipment during repairs; for underground rear lot feeders, trenches must be manually dug to repair direct buried cable, which was the typical installation practice for the rear lot when it was designed.

The additional manual effort associated with rear lot work increases the average outage time by 2.2 hours as compared to Toronto Hydro's standard overhead distribution systems. In some cases, the outage duration can last for days because detection is dependent on a customer notifying Toronto Hydro of the issue and it may be difficult to locate and repair the fault. Table 4 lists several long outages events that have occurred in the rear lot.

TABLE 4: LONG DURATION EVENTS THAT HAVE OCCURRED IN THE REAR LOT

Date	Neighbourhood	Cause	Duration (Hrs)
20-Aug-09	Markland Wood	Adverse Weather - Lightning, Extreme Wind	44.68
20-Aug-09	Thorncrest	Tree Contact	42.15
9-Aug-09	Thorncrest	Lightning	26.70
1-Jun-12	Markland Wood	Adverse Weather - Wind Extreme	23.85
16-Sep-10	Markland Wood	Defective Underground Cable	18.85
19-Oct-11	Thorncrest	Tree Contact	15.62
5-Apr-11	Markland Wood	Tree Contacts, Adverse Weather	13.80
15-Jun-08	Thorncrest	Lightning	12.47
24-Feb-09	Markland Wood	Defective Underground Cable - Primary	12.37

Table 5 compares the average outage times of rear lot configurations and other designs used in Toronto Hydro's system. As the figure demonstrates, the average outage on a rear lot lasts 2.2 hours longer than those on other feeders.

TABLE 5: AVERAGE OUTAGE STATISTICS (2008-2013) BETWEEN TORONTO HYDRO DISTRIBUTION SYSTEMS

Average Outage Statistics (2008 - 2013)			
	Duration (Hrs)	CHI	CI
Rear lot	6.07	240.42	84.88
All Feeders	3.87	488.33	430.70

Safety

Table 6 summarizes the safety issues associated with rear lots.

TABLE 6: SAFETY ISSUES AND DESCRIPTIONS

Safety Issue	Description
Toronto Hydro Crew Access	ƒ Tight work spaces ƒ Manually carry equipment, increasing risk of physical exertion ƒ Poor visibility at night and poor footing in the winter ƒ Poles require climbing, in many cases pole is rotted and requires additional stability ƒ Interference due to fences, sheds, patio's, pools, etc
Public Safety	ƒ Energized equipment close to public equipment: sheds, buildings, patios ƒ Recreational equipment in close proximity: pools, trampolines ƒ Exposed energized equipment in close proximity to customer property that is not brought to Toronto Hydro's attention ƒ Homeowners using ladders may violate electric clearances to energized equipment (Toronto Hydro standard 03-2400)

Access limitations and the age and condition of rear lot equipment present a number of potential safety risks for Toronto Hydro crew members. Front lot systems are typically situated on city property and meet standard clearances, while rear lot systems are on easements on private property. These backyards have gardens, patios, pools, and recreational and gardening equipment that can obstruct the establishment of clear and stable work area for field personnel. This risk can be more prominent at night or in the winter when there is poor visibility and poor footing. As well, heavy lifting in unstable terrain on rear lots increases the risk of injury. Furthermore, field crews must manage the presence of pets, such as dogs, located in the backyards of customers who may not be home. In addition, due to vegetation overgrowth or structural modifications that were made after the original systems were installed, there are

numerous locations where the electrical distribution equipment is in close proximity to the customer's property, such that the required minimum safety clearances are no longer met.

Besides posing risks to Toronto Hydro personnel and the public, the violation of design clearances through the presence of sheds, decks, pools, trampolines, clotheslines and house extensions can result in increased risk of contact faults and damage to Toronto Hydro equipment (Appendix A provides a discussion of Toronto Hydro's design standards for minimum clearances.) Figures 11 and 12 show additional examples of access issues with respect to rear lot plant.

FIGURE 11: ACCESS ISSUES: BEWARE OF DOG, FENCING, LOW ROOF ON PATH, VEGETATION ON CLEARING

FIGURE 12: EXAMPLE OF REAR LOT THAT IS DIFFICULT TO ACCESS

The age and condition of the equipment in rear lots poses serious safety concerns. At times, Toronto Hydro crew are required to physically climb poles that may be unstable due to cracking and rotting; poor weather conditions only serve to worsen these safety issues.The time it takes for crews to secure a safe working area will increase as the system continues to age and deteriorate and as vegetation continues to grow. Work involved in securing a site can include activities like trimming branches or stabilizing the pole to make it safe to climb. During poor weather, there is also a risk of wires coming down, which may be hazardous for Toronto Hydro crew members and the general public.

Figures 13 and 14 illustrate field crew climbing a poor condition pole to replace a failed transformer. The pole is in close proximity to trees fences and a swimming pole.

FIGURE 13: FIELD CREWS REPLACING FAILED TRANSFORMER ON POLE IN POOR CONDITION

FIGURE 14: POOR CONDITION POLE IN CLOSE PROXIMITY TO SWIMMING POOL

An additional safety concern relates to equipment that is exposed, such as riser cables, because of damaged U-guards. This type of damage is difficult to predict because of the location of the equipment. An exposed riser cable can create an electrical contact hazard for customers in the area; the overhead equipment is close to homes or backyard structures and may come into contact with individuals. Figures 15 to 17 show a number of instances where proper clearances are violated, with energized equipment in close proximity to residential structures.

FIGURE 15: ENERGIZED POLE TOO CLOSE TO HOME AND CONDUCTOR CROSSING OVER ROOF

FIGURE 16: ENERGIZED TRANSFORMER AND POLE LINE CLOSE TO HOME AND COVERED IN VEGETATION

FIGURE 17: FENCE BUILT ON EASEMENT AN D EXPOSED CABLE FROM BROKEN GUARD

FIGURE 18: PHOTO OF RECREATIONAL EQUIPMENT UNDER ENERGIZED LINES

Failure Risk

From an operational perspective, rear lot circuits are more expensive to maintain than their front lot counterparts. The access issues described above significantly prolong the duration of visual inspection or vegetation maintenance work, while deteriorating assets operating near or beyond their useful lives as well as non-standard equipment require more frequent maintenance.

Aging assets pose a risk of failure as their condition deteriorates. For example, old and poor condition poles will have diminished structural strength. Many of these pole lines run through heavily treed areas where branches can fall and take down conductors. The connecting conductors provide two counteracting forces to stabilize the pole. If a conductor goes down, there is an imbalance in forces that is pulling the pole to one side. If the pole is rotted, there is a further risk of the pole breaking or falling over. This creates a risk of safety to the public and crews when working. Crews take specific safety measures to stabilize the pole when they are working on it but the risk to the public can still exist as this failure can occur at the time of the fault. This risk is further increased when there is additional distribution equipment attached to the top of the pole.

Non-stand equipment on the overhead system, including aging porcelain insulators and arrestors, can also contribute to fault occurrences as they are prone to cracking and flashovers. For underground rear lot circuits (which are predominately direct-buried), fault identification and repair efforts are further complicated by the need to dig out the cable, often exacerbated by the encroachment of fences and other structures onto the easement. The use of T-splices to split the underground distribution circuits, as opposed to the standard switchgear and switching transformers, makes it even more difficult to assess which branch of the splice is faulted. When underground cables are split like this and are radial, the customers downstream of the fault could be out until the cable fault is repaired, where a looped system could restore the customers with a few switching operations on site while the field crew repairs the fault.

By converting the rear lot plant to an underground front lot, Toronto Hydro can effectively eliminate the access, safety, and reliability risks associated with the rear lot plant, providing a modern, safe and accessible system for the customers in these areas.

E6.6.3.2 Asset Details

(i) Asset Lifecycle

The rear lot system consists of many assets that are non-standard or have exceeded their useful lives. Approximately one-third of all critical assets comprising the rear lot infrastructure, such as transformers and switches, are beyond their useful lives and are at risk of failure. The majority of poles have feathering on their tops, indicating rot, while many also have extensive cracking, which compromises a pole's ability to support the attached distribution equipment (see Figure 19). Non-standard equipment like porcelain arrestors and insulators are prone to failure.

FIGURE 19: POLE WITH EXTENSIVE CRACKING AND FEATHERING

Figures 20 and 21 show the replacement demographics for rear lot overhead transformers and switches relative to their optimal intervention timing (also known as economic end-of-life criteria, as determined by the Feeder Investment Model (FIM), which is further explained in Section D3.1.2.1.) As seen in these figures, many of the assets should already have been replaced as they are past their economic end-of-life criteria. Figure 20 shows that there are 568 transformers

at or past their economic optimal replacement time (this asset has a typical useful life of 40 years). Figure 21 shows there are 479 switches at or past their economic optimal replacement timing (this asset has a typical useful life of 50 years).

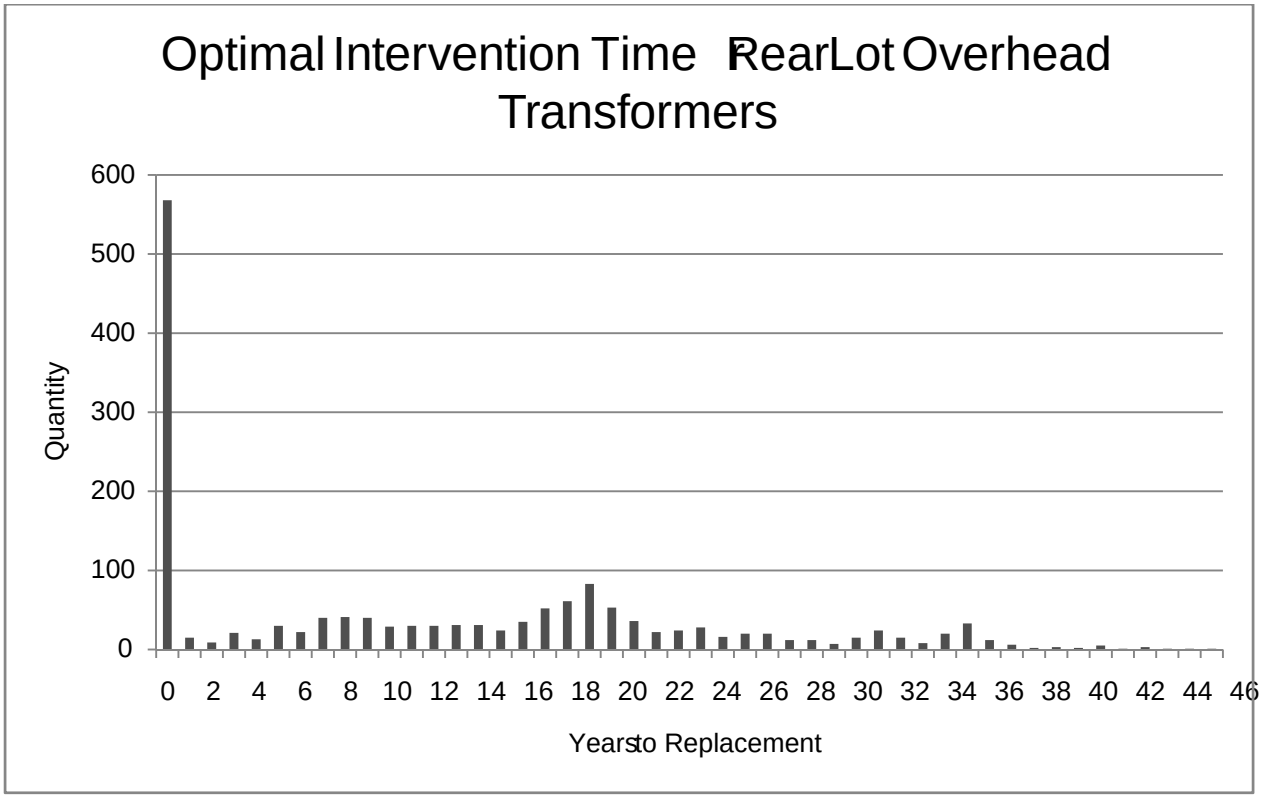


FIGURE 20: OPTIMAL INTERVENTION TIME – REAR LOT OVERHEAD TRANSFORMERS

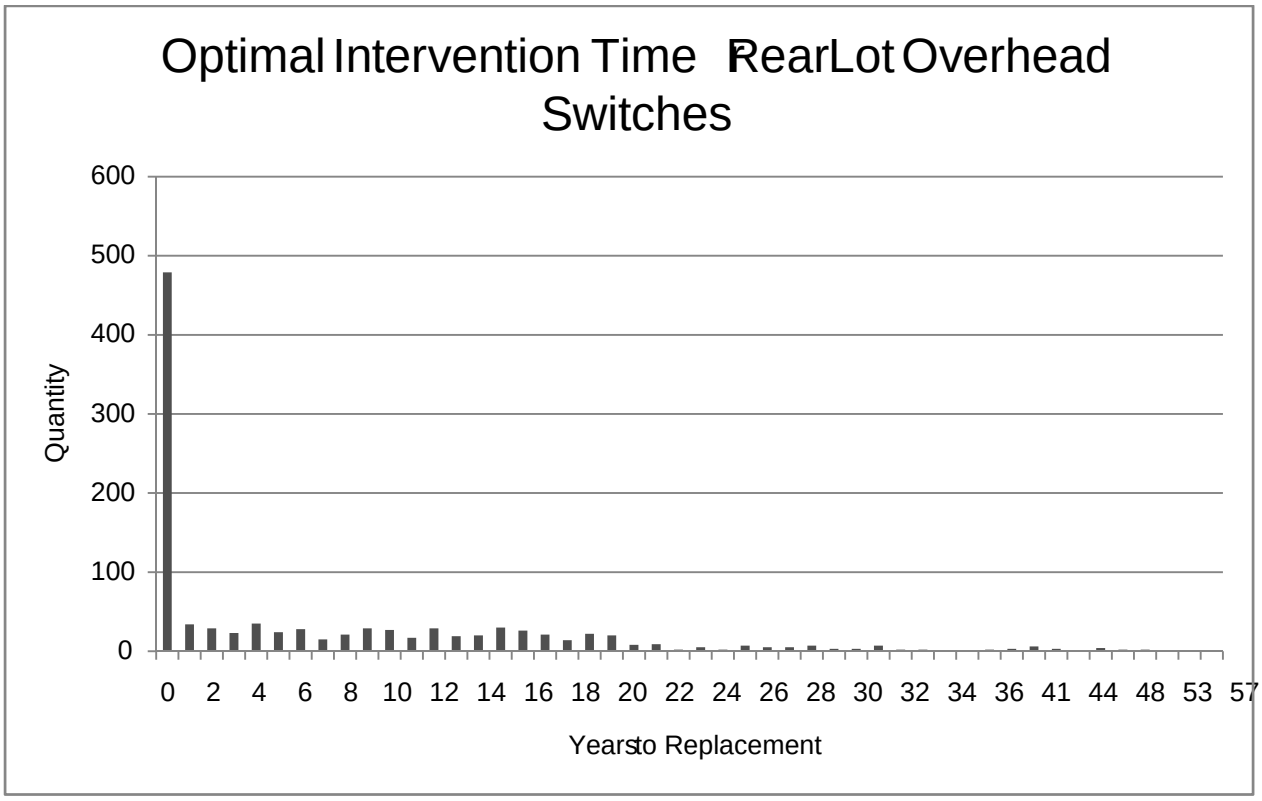


FIGURE 21: OPTIMAL INTERVENTION TIME – REAR LOT OVERHEAD SWITCHES

(ii) Asset Failure Impacts

The rear lot system targeted by this program exclusively supplies residential properties. The failure of individual rear lot assets tends to impact a small number of customers (as the feeders are small) but can result in lengthy outage durations. Rear lot system outages, on average, are almost twice as long as outages associated with other Toronto Hydro connection configurations. Most residential customers can tolerate a few short outages a year, particularly when the outages occur during non-critical times of use. However, when outages are lengthy, sometimes lasting for days, customers are understandably frustrated, particularly when faced with multiple lengthy outages in a single year. The combination of asset age, condition, and non-standard equipment provides an expected trend that failures are expected to increase in the rear lot if there is no replacement.

E6.6.4 Timing & Pacing of the Program

The Rear Lot Conversion program is a continuation of the existing rear lot program that began in 2007 and will continue beyond 2019. As per the table below, Toronto Hydro is expecting to spend an average of $12 million per year over the 2015-2019 period.

TABLE 7: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	6.88	16.6	17.5	23.8	22.7	17.05	8.06	10.3	10.3	13.6

Rear Lot Conversion projects are resource intensive, relatively complex and require a steady, moderate pace of construction. The amounts shown in the table above represent the amount of investment required to maintain a reasonable level of service and to prevent an excessive backlog of work from accumulating. Deferral of the program to 2020 would create a larger backlog of increasingly critical rear lot projects, since equipment will continue to age and failure risks to increase. This backlog could become difficult to manage and could contribute to the deterioration of system performance and safety. By undertaking this program using the schedule provided, Toronto Hydro anticipates that growing operational, reliability and safety risks will be mitigated.

E6.6.4.1 Ranking & Prioritization

The prioritization of work in the Rear Lot Conversion program is based on asset reliability, equipment condition, and coordination with planned city road work. Areas experiencing poor reliability are targeted first. As well, the condition of assets is taken into account to help determine the probability of future outages and the risks of delaying conversion work.

A critical consideration taken into account when choosing areas to target is city road work moratoriums. Once a moratorium is in place, Toronto Hydro is unable to undertake the underground work required and conversion can be delayed for five years or more. For this reason, high priority projects need to occur as soon as possible or risk being deferred for five years. A medium-priority project may also need to occur soon or risk becoming a high priority project during the five year road moratorium.

E6.6.6 Program Execution

Several of the areas that are targeted for rear lot conversion contain multiple supply feeders and, in some cases, multiple substations. This interconnection of feeders enables load shifting and the ability to resupply another area under contingency. Due to the complexity of these interconnections, the conversion of large areas can be complicated and requires dividing the area into multiple phases.

Each phase is divided into civil and electrical construction elements. Construction of the civil infrastructure to house the underground primary, secondary and service infrastructure is performed first, followed by electrical infrastructure construction.

During civil construction, concrete encased ducts are installed to protect the new underground cables. The civil work also establishes transformer pads, where the transformers will be installed, and tapboxes where connections will be made to service lines that will supply the residences. The electrical infrastructure consists of transformers, switchgear, and cable routed through the new ducts. Service lines are routed in between homes and connected to the customer's meter. The old rear lot electrical plant that previously supplied the residences is then removed from the rear lot. Once one phase of a project is completed, the next is undertaken and so on, until all phases in a particular neighbourhood are completed.

Depending on the size of the project, a project phase can be typically completed within a year for civil infrastructure installing and another year for electrical infrastructure installation along with the old electrical plant's removal.

E6.6.6.1 Proposed Work Plan

Toronto Hydro's long term plan for the 2015-2019 period is to convert the rear lots of neighbourhoods that are supplied by the stations in Table 8.

TABLE 8: 2015-2019 LONG TERM PLAN

Year	Station
2015	Mill MS
2015	Dalegrove MS
2015	Warden TS
2016	Mill MS
2016	Dalegrove MS
2016	Warden TS
2016	Chaplin MS

Year	Station
2017	Mill MS
2017	Dalegrove MS
2017	Chaplin MS
2018	Mill MS
2018	Neilson MS
2018	Longfield MS
2019	Mill MS
2019	Longfield MS
2019	Ravensbourne MS

The neighbourhood of Markland Wood is supplied by Mill MS and Neilson MS; the work in this neighbourhood is expected to take approximately five years to complete. The Thorncrest neighbourhood is large and is supplied by Dalegrove MS, Longfield MS and Ravensbourne MS. During the 2015-2019 timeframe, work in the Thorncrest neighbourhood is planned to be conducted adjacent to the work performed from 2012 to 2014. The neighbourhood of Clonmore is supplied by one feeder from Warden TS while the neighbourhood of Forest Hill is supplied by two feeders from Chaplin MS and will complete the rear lot work from this area.

The projects listed above are divided into multiple civil and electrical phases to allow for the steady staging of the project so that each phase is completed in a given year (i.e., civil completed the first year, followed by electrical installation and old electrical plant removal the next year).

E6.6.6.2 Program Risks

A risk to the program is the imposition of a minimum five-year moratorium on new road work in an area where Toronto Hydro intends on performing rear lot conversion work. Toronto Hydro will mitigate this risk by working closely with the City of Toronto on planned road work by participating in utility coordination council meetings. In the event that planned City of Toronto work puts program completion at risk, Toronto Hydro will negotiate with the city to coordinate a construction schedule that is acceptable to all parties and stakeholders involved.

Customer care is a significant aspect of risk mitigation during the planning and execution phases of rear lot projects, which by nature are relatively intrusive and involve the installation of new assets on customer properties. Toronto Hydro maintains extensive and proactive customer communication and provides an opportunity for customer's to voice their concerns and to work with the designer to determine asset locations that best align to customer preferences.

E6.6.7 Evaluation of Alternatives

E6.6.7.1 Quantification/Evaluation of Options

Option 1: Maintain status quo and make reactive replacements

This option proposes to maintain the rear lot distribution system and repair it reactively. This option will address equipment issues as a feeder fails and involves regular maintenance work to mitigate any critical risks. However, this option does not address the safety, reliability, and access issues that are inherent to the system.

Option 2: Rebuild rear lot distribution to ensure it meets current safety regulations

This option proposes to rebuild the rear lot distribution in the rear to replace the aging and non-standard equipment that is currently in use. Measures should be taken to ensure that identified safety issues are addressed. This would involve installing new poles, transformers and conductors to meet overhead requirements. For underground equipment, trenching the owners' yard for ducts and then re-sodding the yards would be required. As well, extensive tree trimming, and in some cases tree clearing, may be required in heavy vegetation areas.

This option could reduce the number of outages experienced; however, it does not address access issues and may involve potentially unsafe work environments for Toronto Hydro crew members. Furthermore, fault locating and repairing will remain a lengthy and difficult procedure, and customers will continue to experience long outages when they occur. In addition, the minimum clearance will not be met in certain areas of the system. In summary, while a renewal program in the rear lot will improve the equipment, it will not address the operational, safety and reliability issues that are associated with the rear lot. Many of the current issues would reoccur years later, making the investment's benefits temporary. In addition, since it is difficult to undertake construction in the winter months, most of the construction would have to take place in the summer, disrupting customer's enjoyment of their backyards.

Option 3: Replace rear lot distribution with overhead front lot distribution

This option involves replacing the rear lot distribution system with an overhead front lot distribution system. All 4.16 kV equipment is removed from the rear lot and the customers will be

supplied from a 27.6 kV feeder from the overhead front lot. Service conductors will have to be inserted in between property lines to access the meter base located at the back of the houses.

This option is not favourable to customers as it harms the aesthetic value of the front lots in their neighbourhoods. Also, in many areas, large trees would need to be cut down to accommodate a pole line running along the street. Furthermore, because communication lines are typically supplied through the rear, there will be an abundance of overhead lines in the neighbourhoods. Customers are often concerned about the affect this will have on their neighbourhood and their property values and could issue complaints, causing the projects to be postponed or redesigned, ultimately increasing the cost and duration of the projects.

Option 4: Replace rear lot distribution with underground front lot distribution

Under this option, the rear lot distribution would be removed and the customers would be supplied by a 27.6 kV front lot underground service. The service cables would be supplied underground between the customers' properties and connect to the meter base located at the back of the house. This would maintain the aesthetics of the customer's front lot and neighbourhood.

This option is preferred because it mitigates accessibility and safety issues and addresses aging and non-standard equipment that could degrade reliability and exacerbate other issues. Furthermore, this option improves reliability by moving the equipment underground in heavily treed areas. This will reduce interference related faults associated with tree and animal contacts and adverse weather related outages.

The cost of ownership (COO) and program net benefit (NPV) associated with the Rear Lot Conversion program is further detailed in Figure 9. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities in this program. The cost of ownership (COO) of a state reflects the risk of asset failure including both direct and indirect costs. These costs include the costs of customer interruptions, emergency repairs and asset replacements associated with current and new state designs. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NAR_E) and proposed (NAR_N) state. Non-asset risks are further explained in Section D3.3. Costs for related maintenance activities are also included for both states. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3.

The difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first year of activities. Where civil work is included in the first year activities, the cost and the benefits of the electrical phase are also included in the analysis. Rear Lot Conversion program produces an NPV of $5.71 million, as shown in Figure 10 and Figure 11.

TABLE 9: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	3.48
Non Asset Risk [NAR_E]	23.62
Maintenance Cost [MC_E]	1.85
Additional Quantifiable Benefits [AQB_E]	0
Cost of Ownership of Existing Assets [COO_E]	28.95

TABLE 10: OH REAR LOT TO UG FRONT LOT BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 4: OH Rear Lot to UG Front Lot (N)	
Asset Risk [AR_N]	1.73
Non Asset Risk [NAR_N]	0
Maintenance Cost [MC_N]	0.20
Additional Quantifiable Benefits [AQB_N]	0
Cost of Ownership of New Assets [COO_N]	1.93
Option 4: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$ûCOO_1 = (COO_E – COO_N)$]	27.02
Program Cost [PC_1]	21.30
Program Net Benefit [$NPV_1 = (ûCOO_1 – PC_1)$]	5.71

E6.6.9 2015 Project Details

Table 11 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

(a) previously filed projects that appeared as jobs in the OEB approved Rear Lot Construction segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 11: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	CIR Projects
6.25	10.80

Figure 22 is a system map of where each of the rear lot project locations is scheduled for 2015.

FIGURE 22: 2015 REAR LOT PROJECT AREAS

Table 12 lists all projects that will be partially or completely executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 12: 2015 PROJECTS

Project Number	Project Name	Total Project Cost ($M)	Start Date	Project Type (ICM or CIR)
W11726	W11726-Markland Woods Rear Lot VC phase 1 Electrical	1.93	2015	ICM
E11382	E11382 Livingston/Guild Rear Lot VC (SCGGF1) – Phase2	1.15	2015	ICM
E11382	E11382 Livingston/Guild Rear Lot VC (SCGGF1) - Phase 3	3.17	2015	ICM
W15203	W15203 P07 - Markland Wood Rear Lot Conversion PH4a Electrical - 88M46, LF-F1	1.12	2015	CIR
W15210	W15210 P07-Markland Wood Ph4b Rear Lot Conversion-Electrical ETLFF4	1.18	2015	CIR
W15211	W15211 P07-Markland Wood Rear Lot Conversion PH4c-Electrical ETLFF4	1.21	2015	CIR
W15561	W15561-System Renewal-Thorncrest RL Conversion Ph6a Civil ETBHF2	2.18	2015	CIR
W15562	W15562-System Renewal-Thorncrest RL Conversion-Ph6b-Civil	2.25	2015	CIR
E15563	E15563 Clonmore Rear Lot Conversion Phase 1 Civil SCNAR43M23	1.41	2015	CIR
E15568	E15568 Clonmore Rear Lot Conversion Phase 2 Civil SCNAR43M23	1.45	2015	CIR

E6.6.9.1 Livingston Guildwood Project Description

Investment Category: System Renewal

Program: Rear Lot Conversion

Project Title: Livingston Guildwood Rear Lot Conversion

Project Number: E11382 (ICM), E11382 (ICM)

Project Year: 2015

Estimated Cost: $4.32 Million

(i) Objective

The objective of this project is to improve the reliability in the Livingston Guildwood area by converting the rear lot distribution system to an underground front lot distribution system. This project will convert the following 4.16 kV rear lot feeders to 27.6 kV front lot underground: GGF1, and GEF2 from Livingston Guildwood MS and Galloway Dearhamwoods MS. This project will replace the overhead and underground rear lot facilities by installing new concrete-encased front lot ducts. This job will continue the work from phase 1 and will install the remaining civil and electrical infrastructure for this area. Once this work is completed the entire neighbourhood will be fully converted.

(ii) Scope of Work

TABLE 13: SCOPE OF WORK DETAILS

District Neighborhood	LIVINGSTON GUILDWOOD
Station(s)	LIVINGSTON GUILDWOOD MS, GALLOWAY DEARHAMWOODS MS
Feeder(s)	GGF1, GEF2

TABLE 14: ASSETS REPLACED

Assets (Units)	2015
Pole	126
Transformer	34
Conductor Length (m)	8,579
Cable Length (m)	1,189

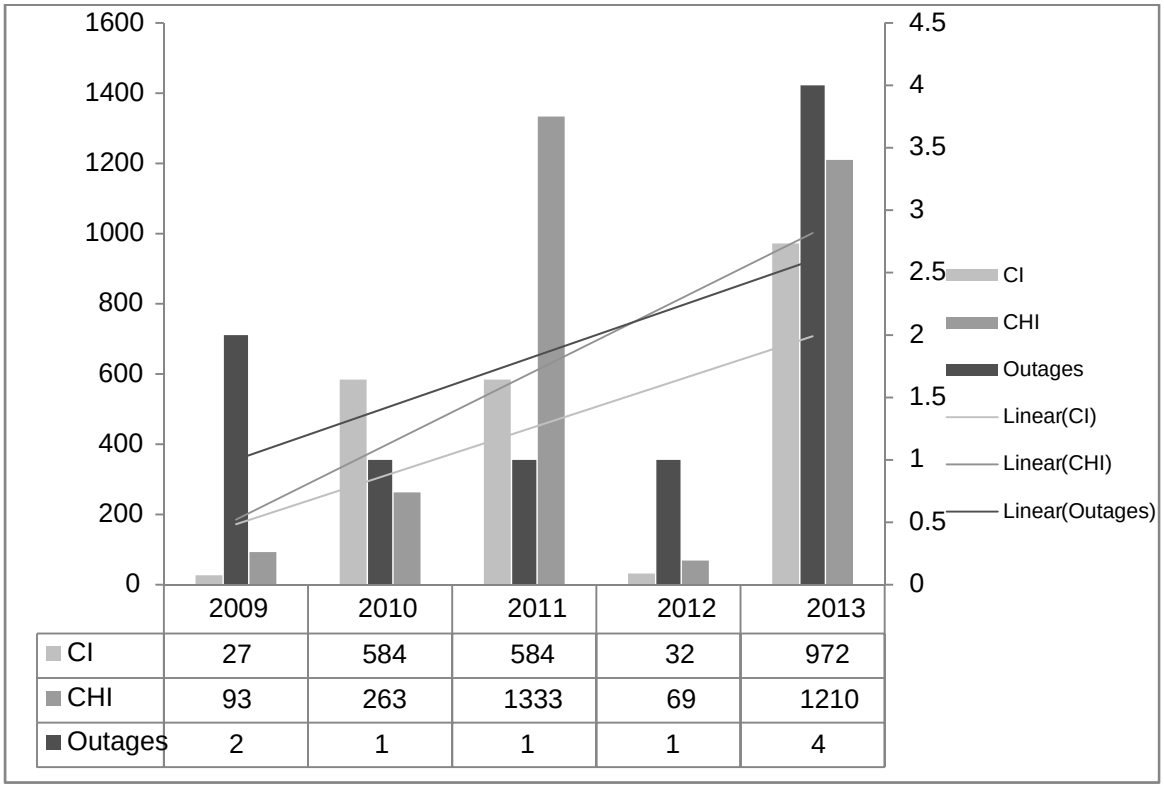
TABLE 15: SUPPLEMENTAL PROJECT DETAILS

(iii) Justification & Benefits

This area has been subjected to a number of outages over the last few years. There has been an increase in faults in the rear lot in 2013. The faults indicated in the table below are primarily

Supplemental Details	Description
Age/Condition	ƒ Average age of equipment is approximately 50 years of age ƒ Majority of the equipment is in poor condition
Reliability	ƒ Feeder consistently experiencing outages
Other (i.e., moratorium, etc.)	ƒ Aging substation proposing decommissioning

related to tree contacts and failing equipment. This work will eliminate the operational, safety and reliability risks that have been described in this narrative by resupplying the customers from an underground front lot system and removing the aging rear lot equipment.



	2009	2010	2011	2012	2013
CI	27	584	584	32	972
CHI	93	263	1333	69	1210
Outages	2	1	1	1	4

FIGURE 23: HISTORICAL RELIABILITY DETAILS FOR GGF1

E6.6.9.1 Markland Wood Project Description

Investment Category: System Renewal

Program: Rear Lot Conversion

Project Title: Markland Wood Rear Lot Conversion

Project Number: W11726 (ICM), W15203, W15210, W15211

Project Year: 2015

Estimated Cost: $5.44 Million

(i) Objective

The objective of this project is to improve the reliability in the Markland Woods area by converting the rear lot distribution system to an underground front lot distribution system. This project will convert the following 4.16 kV rear lot feeders to 27.6 kV front lot underground: ETLFF1, ETLFF2, ETLFF3, ETLF4, and ETBAF1 from Mill MS and Neilson MS. This project will replace the overhead and underground rear lot facilities by installing new concrete-encased front lot ducts. This job is continuing the work that was approved in 2014 by installing the electrical infrastructure in the civil infrastructure installed in 2014. It will continue the conversion by beginning the construction of new civil infrastructure in a new area of this neighbourhood. This work will continue in this neighbourhood to fully convert within the next five years.

(ii) Scope of Work

TABLE 16: E12345 SCOPE OF WORK DETAILS

District Neighborhood	MARKLAND WOOD
Station(s)	MILL MS
Feeder(s)	LFF-1, LFF-4

TABLE 17: ASSETS REPLACED

Assets (Units)	2015
Pole	34
Transformer	12

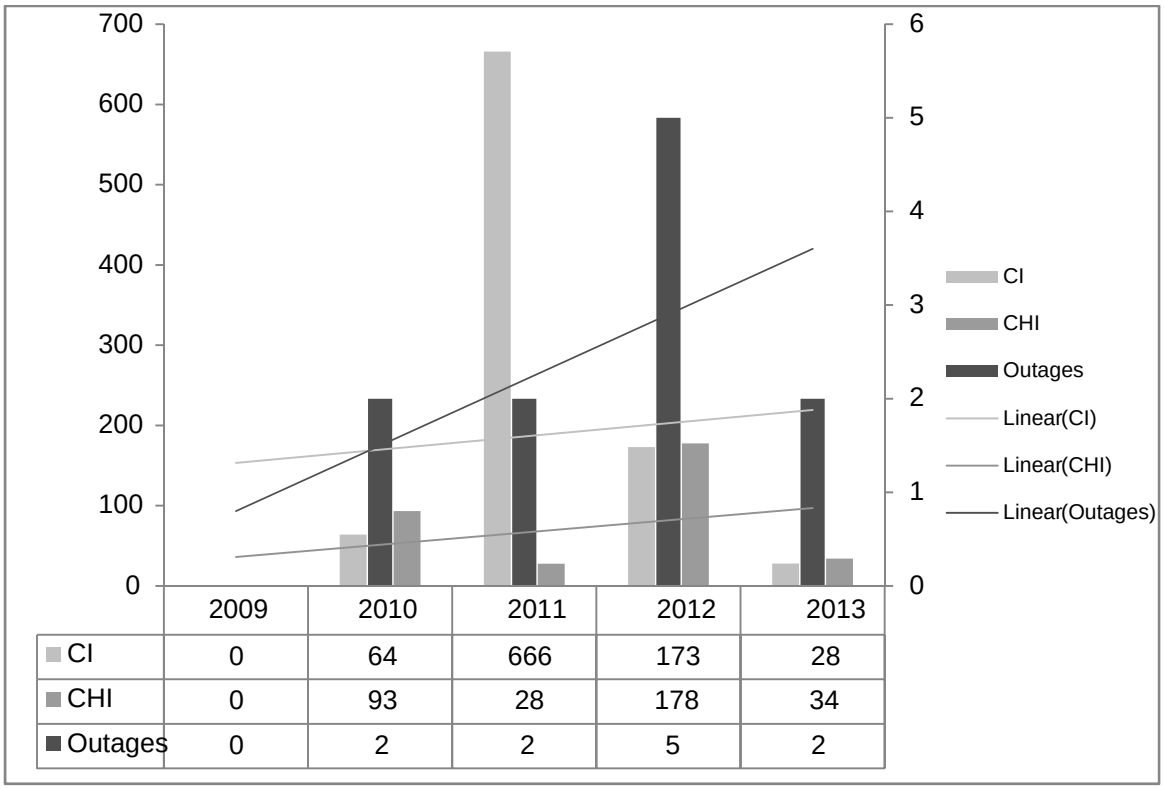
Assets (Units)	2015
Conductor Length (m)	935
Cable Length (m)	264

TABLE 18: SUPPLEMENTAL PROJECT DETAILS

Supplemental Details	Description
Age/Condition	• Average age of equipment is approximately 50 years of age • Majority of the equipment is in poor condition
Reliability	• Area experiences long duration outages • Feeder consistently experiencing outages
Other (i.e., moratorium, etc)	• Upcoming moratorium on select streets • Aging substation proposing decommissioning

(iii) Justification & Benefits

This work continues the electrical work of the approved civil work from the 2014 EDR. This area has been subjected to a number of lengthy outages. Some of the more notable outages was an underground cable fault on direct buried cable that took 18.9 hours to correct and damage caused by adverse weather that took 44.7 hours. This work will eliminate the operational, safety and reliability risks that have been described in this narrative by resupplying the customers from an underground front lot system and removing the aging rear lot equipment.

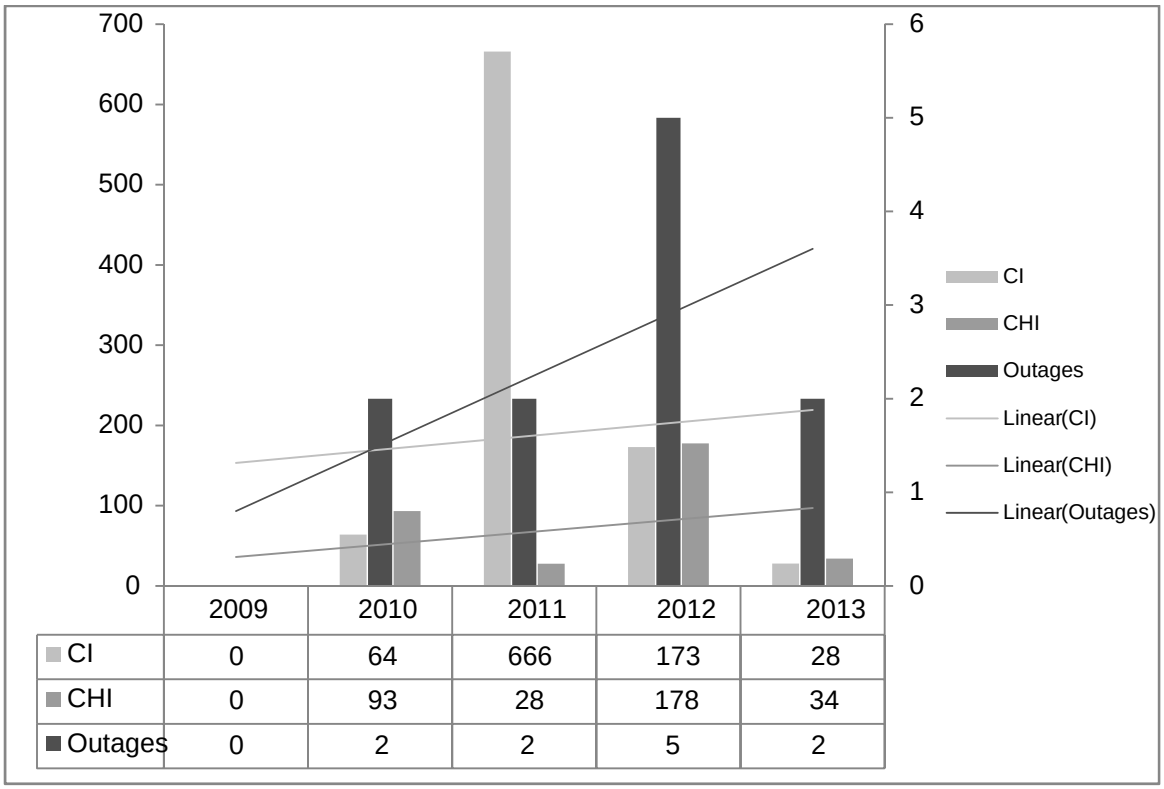


	2009	2010	2011	2012	2013
CI	0	64	666	173	28
CHI	0	93	28	178	34
Outages	0	2	2	5	2

1 FIGURE 24: HISTORICAL RELIABILITY DETAILS FOR LFF1

2 TABLE 19:

Year	2009	2010	2011	2012	2013
CI	230	152	42	0	256
CHI	15	839	204	0	307
Outages	2	2	2	0	1



	2009	2010	2011	2012	2013
CI	0	64	666	173	28
CHI	0	93	28	178	34
Outages	0	2	2	5	2

1 FIGURE 25: HISTORICAL RELIABILITY DETAILS FOR LFF4

2 TABLE 20:

Year	2009	2010	2011	2012	2013
CI	11	0	0	0	0
CHI	51	0	0	0	0
Outages	1	0	0	0	0

E6.6.9.2 Thorncrest Project Description

Investment Category: System Renewal

Program: Rear Lot Conversion

Project Title: Thorncrest Rear Lot Conversion

Project Number: W15561, W15562

Project Year: 2015

Estimated Cost: $4.42 million

(i) Objective

The objective of this project is to convert the rear lot distribution system, in the neighbourhood of Thorncrest, to an underground front lot distribution system. This project will convert the following 4.16kV rear lot feeder to 27.6kV front lot feeder: ETRAF1, ETRAF2, and ETBHF1 from Thornton MS and Longfield MS. This work will replace the overhead rear lot facilities by installing aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts and associated equipment. A new pole line will be installed along Princess Margaret Blvd to supply the adjacent rear lot neighbourhoods. This project will install new civil infrastructure this year and will install the electrical infrastructure the following year. Further conversion of this area will continue through the next five years.

(ii) Scope of Work

TABLE 21: SCOPE OF WORK DETAILS

District Neighborhood	THORNCREST ES
Station(s)	DALEGROVE MS
Feeder(s)	BHF2

TABLE 22: ASSETS REPLACED

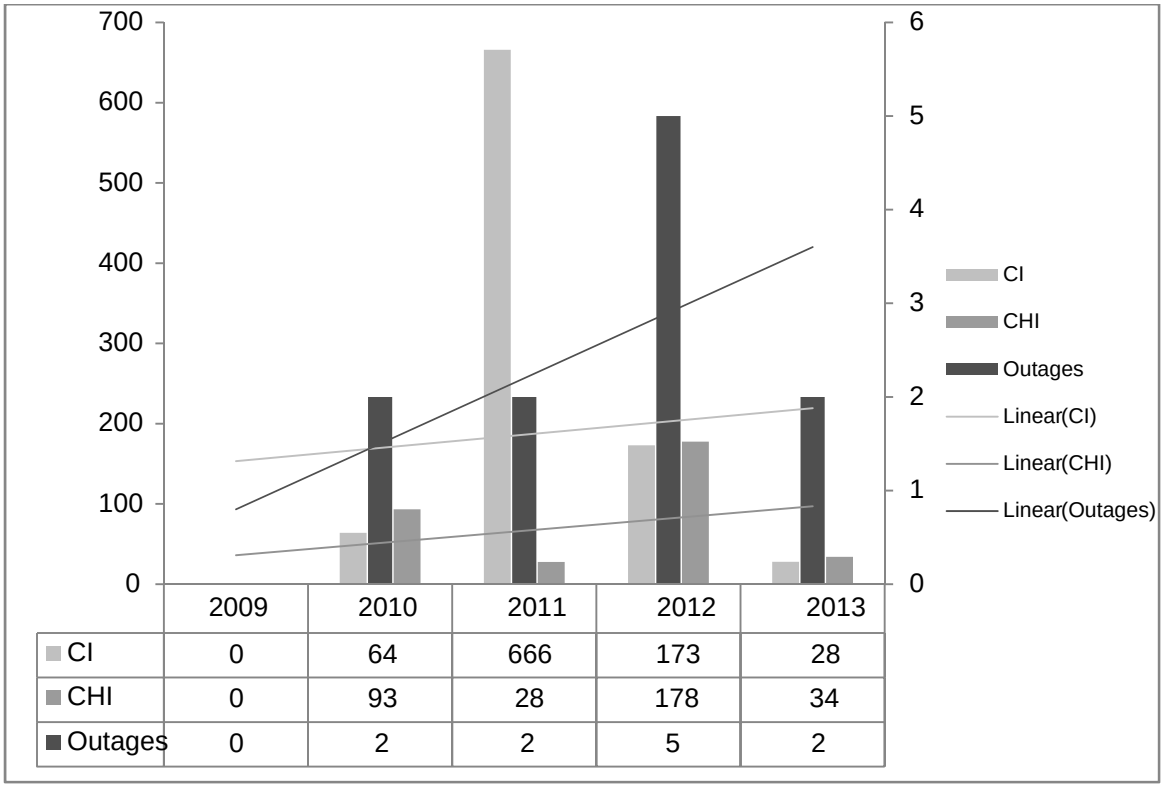
Assets (Units)	2015
Pole	134
Transformer	28
Conductor Length (m)	6,688
Cable Length (m)	1,094

TABLE 23: SUPPLEMENTAL PROJECT DETAILS

Supplemental Details	Description
Age/Condition	ƒ Average age of equipment is approximately 45 years of age ƒ Majority of the equipment is in poor condition
Reliability	ƒ Area experiences long duration outages ƒ Feeder consistently experiencing outages
Other (i.e., moratorium, etc)	ƒ Aging substation proposing decommissioning

(iii) Justification & Benefits

This work continues the expansion work from the 2014 EDR by introducing a new phase for conversion in this neighbourhood. Over the last five years there have been 11 faults in the rear lot in this part of the system. This work will eliminate the operational, safety and reliability risks that have been described in this narrative by resupplying the customers from an underground front lot system and removing the aging rear lot equipment.



	2009	2010	2011	2012	2013
CI	0	64	666	173	28
CHI	0	93	28	178	34
Outages	0	2	2	5	2

FIGURE 26: HISTORICAL RELIABILITY DETAILS FOR BHF2

E6.6.9.3 Clonmore Project Description

Investment Category: System Renewal

Program: Rear Lot Conversion

Project Title: Clonmore Rear Lot Conversion

Project Number: E15563, E15568

Project Year: 2015

Estimated Cost: $2.86 million

(i) Objective

The objective of this project is to convert the rear lot distribution system, in the neighbourhood of Clonmore, to an underground front lot distribution system. This work will replace the overhead rear lot facilities by installing aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts and associated equipment. This project will start with installing the civil infrastructure in 2015 and will complete the neighbourhood the following year, 2016, with the installation of the electrical infrastructure and removal of the rear lot plant.

(ii) Scope of Work

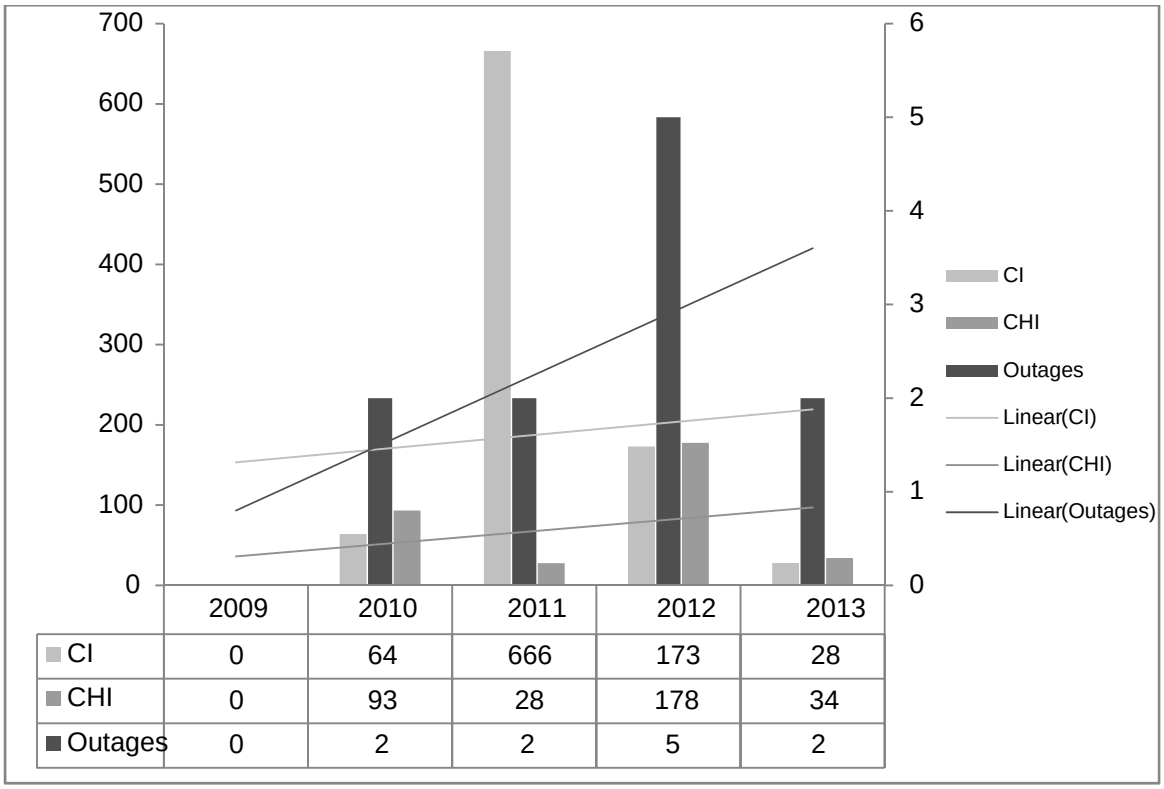
TABLE 24: E12345 SCOPE OF WORK DETAILS

District Neighborhood	CLONMORE
Station(s)	WARDEN TS
Feeder(s)	R43M23

TABLE 25: ASSETS REPLACED

Assets (Units)	2015
Pole	58
Transformer	25
Conductor Length (m)	2,093
Cable Length (m)	306

(iii) Justification & Benefits



	2009	2010	2011	2012	2013
CI	0	64	666	173	28
CHI	0	93	28	178	34
Outages	0	2	2	5	2

FIGURE 27: HISTORICAL RELIABILITY DETAILS FOR NAR43M23

TABLE 26

Year	2009	2010	2011	2012	2013
CI	532	5,295	5,047	4,817	4,362
CHI	1,302	2,366	1,149	6,781	3,591
Outages	7	7	5	7	6

APPENDIX 1: TORONTO HYDRO'S MINIMUM CLEARANCE STANDARDS

E6.7 Box Construction Conversion

TYPICAL BOX CONSTRUCTION

E6.7.1 Summary

Program Description

The Box Construction Conversion program is a continuation of activities previously described in Phase 1 and 2 of Toronto Hydro's 2012-2014 ICM application. The projects that comprise this program are identical in nature to the jobs that constituted the OEB approved Box Construction segment in EB-2012-0064[1].

Box construction is a type of legacy 4.16 kV overhead construction that was used within the former (pre-amalgamation) City of Toronto. Due to a number of reliability, safety and load capacity issues, Toronto Hydro no longer uses box construction for new capital projects. To address these issues for legacy installations, this style of construction will be replaced with 13.8 kV or 27.6 kV overhead feeders.

[1] EB-2012-0064, Tab 4, Schedule B5.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Clearance issues with new or redeveloped buildings near box construction primary feeders can result in additional costs for connecting customers. These costs will typically be unnecessary following conversion to 13.8kV/27.6kV infrastructure. ƒ 13.8kV/27.6kV feeders can better accommodate larger customer connections in the downtown area
Reliability	ƒ Average outage duration for 13.8 kV overhead feeders is lower than for 4 kV box construction feeders ƒ Impact of major storm events is less on 13.8 kV overhead feeders when compared to 4 kV box construction feeders
Safety	ƒ Less congestion at top of 13.8kV/27.6kV poles reduces risk of electrical contact ƒ Greater accessibility with bucket trucks on 13.8kV/27.6kV overhead feeders allows for safer work practices ƒ 13.8kV/27.6kV overhead feeders adhere to clearances outlined in EUSR 129 ƒ Removal of legacy equipment such as shielded primary cable and Positect switches eliminates the safety issues associated with this equipment
Efficiency	ƒ 13.8 kV overhead feeders have three times the capacity of box construction feeders ƒ Line losses are lower on 13.8 kV and 27.6 kV feeders ƒ Program projects are prioritized to avoid renewal of end-of-life legacy 4.16 kV stations equipment where possible
Other	ƒ Avoid procurement issues associated with some box construction equipment

Program Drivers

The trigger driver for this program is Functional Obsolescence, due to the safety, capacity, procurement and reliability issues associated with this legacy construction. The trigger and secondary drivers for this program are summarized in Table ii.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Legacy overhead construction standard no longer used for new capital projects ƒ High number of assets past useful life ƒ Skill set for maintaining/troubleshooting box construction is diminishing ƒ Procurement issues with legacy equipment
Secondary Drivers	**Reasoning**
Safety	ƒ System complexity (multiple circuits through same area) ƒ Accessibility issues with bucket trucks ƒ Proper working clearances are often unattainable ƒ Equipment built to legacy construction standards creates additional safety risks
Efficiency	ƒ Line losses are higher than 13.8kV/27.6kV overhead distribution, with a correspondingly higher carbon footprint.
Reliability	ƒ Average outage duration of box construction feeders is greater than that of 13.8kV feeders ƒ Impact of major storms shown to be greater on box construction feeders when compared to 13.8kV overhead feeders in downtown core

Preferred Alternative

The Box Construction Conversion program analyzed and evaluated the following options:

(1) Replace the aged, legacy box construction with new box construction

(2) Convert the aged, legacy box construction to new 13.8 kV or 27.6 kV Infrastructure

Option II is the preferred option as it allows necessary working clearances, capacity to accommodate future load requests and higher overall system reliability. Option I would likely also has the disadvantage of forcing Toronto Hydro to continue investing in and maintaining stations assets at the 4 kV municipal stations that supply existing box construction feeders. Many of these stations are lightly loaded and avoided costs could be realized by decommissioning the stations following load conversion as part of the Box Construction program.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $22.44 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.7.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $5.64 million, confirming the economic prudence of the investments (see Section E6.7.7).

Timing and Pacing

The table below provides the estimated costs of the program for the 2015-2019 period. Given the current schedule, Toronto Hydro plans to address 65% of all box construction by the end of 2019. The conversion of all box construction feeders is expected to be complete by 2026.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	5.7	7.1	0.84	13.8	23.3	16.8	20.7	21.1	21.6	22.7

Ideally, due to the age and condition of existing box construction feeders, Toronto Hydro would convert all remaining box construction in the 2015-2019 period. However, converting all remaining box construction feeders over this time period is not feasible from an engineering perspective due a number of system constraints, including limited availability of certain feeders and the need to first upgrade certain Hydro One Networks Inc. (HONI) station equipment housed in Toronto Hydro transmission stations (TS).

E6.7.2 Program Description

The Box Construction Conversion program is a continuation of activities previously described in Phase 1 and 2 of Toronto Hydro's 2012-2014 ICM application. The projects that comprise this program are identical in nature to the jobs that constituted the OEB approved Box Construction segment in EB-2012-0064.

Box construction is a type of legacy 4.16 kV overhead construction that was used within the former (pre-amalgamation) City of Toronto and still exists in some areas of the city. Figure 1 shows a typical box construction installation. Due to a number of reliability, safety and load capacity issues, Toronto Hydro no longer uses box construction for new capital projects, rendering it a functionally obsolete standard. These issues are further described in Section E6.7.5.

FIGURE 1: TYPICAL BOX CONSTRUCTION

Toronto Hydro plans to address all of the issues related to box construction described in Section E6.7.5 through a proactive program that replaces these feeders with current standard 13.8 kV or 27.6 kV overhead construction. Figure 2 shows the conversion from highly concentrated cables in box construction to the less congested 13.8 kV or 27.6 kV overhead standards. The reduction in complexity and congestion at the top of the poles is apparent. Figure 3 illustrates another variation on the current 13.8 kV overhead construction standard.

FIGURE 2: ACTUAL CONVERSION PROJECT COMPLETED IN 2013 IN THE BYRON AVE. AND DANFORTH AVE. AREA. THE PHOTOGRAPH ON THE LEFT SHOWS THE 4.16 KV BOX CONSTRUCTION FEEDER PRIOR TO CONVERSION. THE COMPLETED PROJECT IS SHOWN IN THE PHOTOGRAPH ON THE RIGHT, WHERE ALL 4 KV BOX CONSTRUCTION HAS BEEN REMOVED AND REPLACED WITH A CURRENT CONSTRUCTION STANDARD 13.8 KV OH FEEDER.

FIGURE 3: TYPICAL CURRENT CONSTRUCTION STANDARD 13.8 KV OVERHEAD FEEDER

Toronto Hydro's Box Construction Conversion program targets all 4.16 kV box construction feeders. Toronto Hydro's objective is to replace the 4.16 kV box construction infrastructure with standard 13.8 kV or 27.6 kV overhead feeders and decommission associated 4.16 kV stations by 2026. Figure 4 shows a map of all box construction feeders in Toronto.

FIGURE 4: MAP OF ALL BOX CONSTRUCTION F EEDERS SLATED FOR CONVERSION THROUGH 2026

Total costs for the Box Construction Conversion program are estimated to be $103.1 million over the period of 2015 to 2019. Figure 5 shows a map of box construction feeders that Toronto Hydro will convert over this period.

FIGURE 5: MAP OF PROPOSED FEEDER CONVERSIONS FOR 2015-2019

The following table summarizes the number of assets that Toronto Hydro plans to replace over the 2015-2019 program by asset class.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
OH Transformer	183	381	86	175	77	902
OH Switch	154	301	70	176	85	786
Poles	377	780	277	255	117	1,806
UG Switch	0	0	0	6	0	6
UG Transformer	20	27	9	52	17	125
OH Conductor (km)	23.5	46.2	11.4	24.4	11.5	117.1
UG Cable (km)	6.0	10.4	1.5	5.8	1.4	25.0

IC

Toronto Hydro evaluated the proposed program against the status-quo alternative of maintaining and replacing (on a like-for-life basis) the equipment used in box construction, and determined that proactive conversion is the best alternative. Table 2 summarizes the benefits associated with the Box Construction Conversion program.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Clearance issues with new or redeveloped buildings near box construction primary feeders can result in additional costs for connecting customers. These costs will typically be unnecessary following conversion to 13.8kV/27.6kV infrastructure. ƒ 13.8kV/27.6kV feeders can better accommodate larger customer connections in the downtown area ƒ Aesthetic improvements ƒ The difference in the cost of ownership between existing and renewed assets (ΔCOO) for the first year of the program is $22.44 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.7.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $5.64 million, confirming the economic prudence of the investments (see Section E6.7.7).
Reliability	ƒ Average outage duration for 13.8 kV overhead feeders is lower than for 4 kV box construction feeders ƒ Impact of major storm events is less on 13.8 kV overhead feeders when compared to 4 kV box construction feeders
Safety	ƒ Less congestion at top of 13.8kV/27.6kV poles reduces risk of electrical contact ƒ Greater accessibility with bucket trucks on 13.8kV/27.6kV overhead feeders allows for safer work practices ƒ 13.8kV/27.6kV overhead feeders adhere to clearances outlined in EUSR 129 ƒ Removal of legacy equipment such as shielded primary cable and Positect switches eliminates the safety issues associated with this equipment
Efficiency	ƒ 13.8 kV overhead feeders have three times the capacity of box construction feeders ƒ Line losses are lower on 13.8 kV and 27.6 kV feeders ƒ Program projects are prioritized to avoid renewal of end-of-life legacy 4.16 kV stations equipment where possible
Other	ƒ Avoid procurement issues associated with some box construction equipment

E6.7.3 Why the Program is Needed

The Box Construction Conversion program is required to eliminate the reliability, efficiency and safety risks associated with the functionally obsolete box construction feeder design.

E6.7.3.1 Program Drivers

Table 3 presents the trigger and secondary drivers for replacing box construction. Box construction replacement is a System Renewal initiative with a trigger driver of functional obsolescence.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Legacy overhead construction standard no longer used for new capital projects ƒ High number of assets past useful life ƒ Skill set for maintaining/troubleshooting box construction is diminishing ƒ Procurement issues with legacy equipment
Secondary Drivers	**Reasoning**
Safety	ƒ System complexity (multiple circuits through same area) ƒ Accessibility issues with bucket trucks ƒ Proper working clearances are often unattainable ƒ Equipment built to legacy construction standards creates additional safety risks
Efficiency	ƒ Line losses are higher than 13.8 kV/27.6 kV overhead distribution, with a correspondingly higher carbon footprint.
Reliability	ƒ Average outage duration of box construction feeders is greater than that of 13.8 kV feeders ƒ Impact of major storms shown to be greater on box construction feeders when compared to 13.8 kV overhead feeders in downtown core

Functional Obsolescence

- Box construction is a 4 kV legacy overhead construction standard that Toronto Hydro no longer uses for new capital projects. This design is considered functionally obsolete due to a number of safety, load capacity, procurement and reliability issues that render it undesirable for new projects. In addition to these design deficiencies, a high number of

box construction assets are past their useful lives (see Section E6.7.3.2 (i) for further details) and are likely to fail in the near future, leading to more frequent and extended outages on these feeders. Maintaining aging box construction could become more challenging in the future as experienced employees retire and the number of skilled resources with box construction knowledge and experience diminishes. Each of these issues is discussed in detail in the following subsections.

- Some legacy equipment associated with box construction is difficult to procure due to a limited number of suppliers or, in a few cases, no supplier. For example, only one North American supplier currently manufactures shielded primary cable. Since this cable is a 'non-stock, non-standard' item for the supplier, a lengthy 12-week lead time and a minimum quantity of 3000 metres is required for each order. Another example is Positect switches, which are no longer available from the manufacturer.

- Box construction's status as both a unique and functionally obsolete design creates additional pressures in terms of resource availability. In the past, when 4.16 kV box construction feeders were the standard design for overhead distribution, crews had continuous experience working on them. Now, because new employees work on 4.16 kV box construction feeders on an infrequent, "as-needed" basis and the older generation of employees is retiring, fewer employees have skills and experience related to this design.

Safety

- Unlike typical standard 13.8 kV/27.6 kV overhead circuits, box construction poles typically support multiple live circuits in a more congested and tightly packed configuration relative to current overhead construction standards, which increases the potential risk of electrical contact for crews.

- Some box construction circuits cannot be accessed with bucket trucks – the industry-wide practice for overhead pole maintenance – due to the physical arrangement of the feeders running through a single box pole. Power Line Workers must climb these poles, which increases the potential safety risk for Toronto Hydro employees. These additional safety risks include injury from the additional physical exertion from climbing, a more severe falling hazard when compared to the use of a bucket truck and increased risk of electrical contact due to the inability to use the insulated aerial boom and bucket liner found on bucket trucks.

- In certain box construction work scenarios, Toronto Hydro crews working in close proximity to the lines can have difficulty conforming to the working clearances defined in Electrical Utilities Safety Rules (EUSR) #129. The required 15 cm air gap between people/tools and energized conductors cannot always be achieved.

Some equipment associated with box construction was designed and installed before Toronto Hydro adopted current safe work practices. One example of this is the 'Positect' switch, an obsolete type of fused switch originally designed to be operated by hand that puts field crews in the arc flash zone of the switch. While a stick was developed to operate 'Positect' switches from a distance, operation of this switch with the stick is inefficient when compared to operating it by hand.

Efficiency

Delivering electricity at a primary voltage of 4.16 kV (as is the case with box construction) is less energy efficient when compared to 13.8 kV feeders. The line losses associated with a 4.16 kV system are approximately nine times higher than those of 13.8 kV lines. Efficiency savings can be realized from converting from 4 kV to 13.8 kV, as detailed in Section E6.7.7 Evaluation of Alternatives.

Reliability

The 4.16 kV box construction configuration has also contributed substantially to outages for Toronto Hydro's customers relative to the comparable 13.8 kV and 27.6 kV standards. Historically, outage duration on 4.16 kV box construction feeders has been significantly worse than that of other overhead configurations. Table 4 compares the historical reliability of box construction feeders to standard 13.8 kV overhead feeders in the former (pre-amalgamation) City of Toronto. Total customer hours interrupted (CHI) for box construction feeders is considerably higher (1.65 hours) than on the 13.8 kV system (1.26 hours), despite the fact that total customers interrupted (CI) is approximately equal between the two systems, (Both systems are also approximately 625 circuit kilometers in length.)

TABLE 4: AVERAGE OUTAGE DURATION (DATA 2000-2012)

	4.16 kV Overhead Box Construction	13.8 kV Overhead Construction
Total CI	142,023	149,613
Total CHI	234,491	188,813
Average Outage Duration	1.65 hours	1.26 hours

Major storm events have also been shown to have a larger impact on box construction feeders when compared to other overhead distribution configurations. On October 29th and 30th of 2012, the City of Toronto endured a powerful storm from Hurricane Sandy, causing several extended outages across the city. Figure 6 illustrates the total customer hours interrupted (CHI) and customers interrupted (CI) on overhead feeders in the downtown area during the storm:

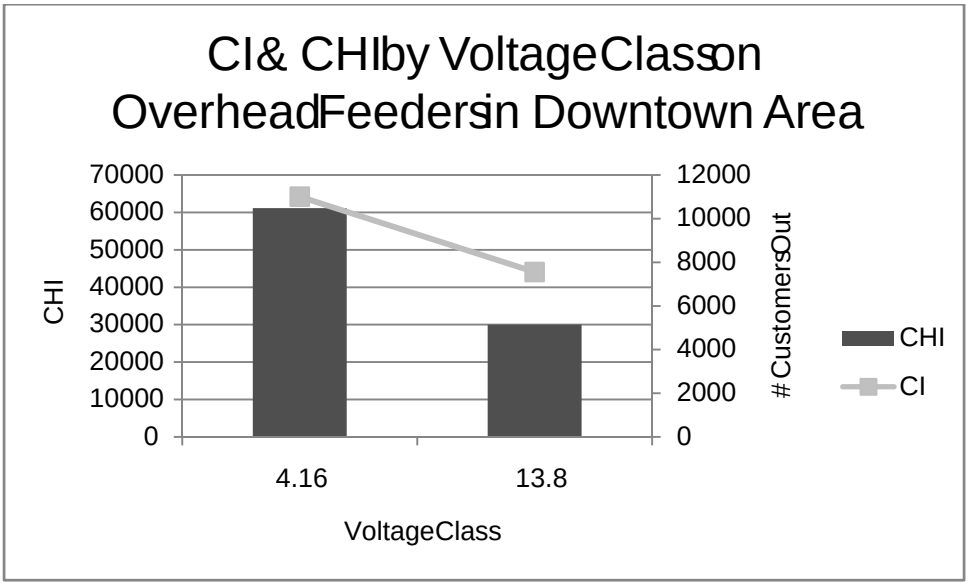


FIGURE 6: CI & CHI BY VOLTAGE CLASS ON OVERHEAD FEEDERS IN DOWNTOWN AREA DURING HURRICANE SANDY

The outage impact in terms of customer-hours interrupted was twice as high on 4.16 kV box construction circuits compared to standard 13.8 kV circuits. Factors contributing to outages and outage durations on box construction circuits include the following:

- Box construction assets are generally old and in poor condition; they are less able to withstand strong winds and contact from trees during storms compared to 13.8 kV overhead feeders in the downtown area.
- There are a limited number of field crews familiar with 4.16 kV box construction feeders, which contributes to delays in restoring power.

Figure 7 breaks down the areas impacted by the storm, sorted by station:

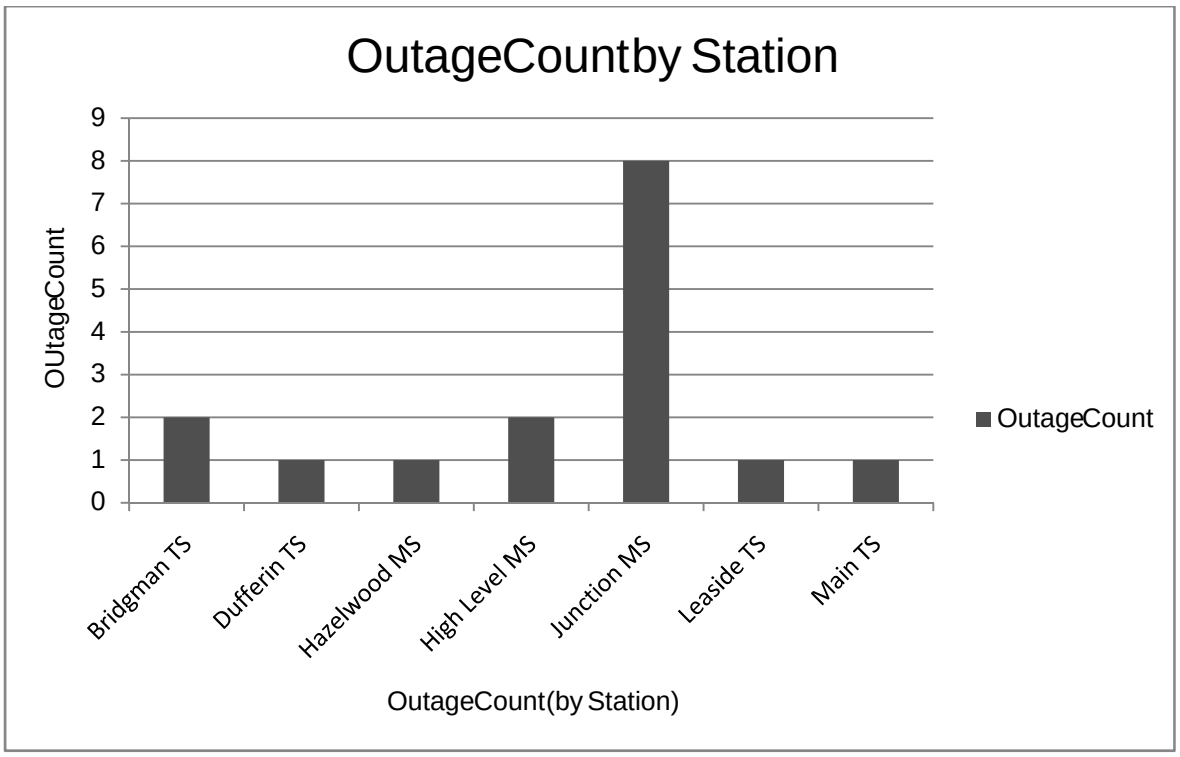


FIGURE 7: OUTAGE COUNT BY STATION IN DOWNTOWN AREA DURING HURRICANE SANDY

Junction MS, High Level MS and Hazelwood MS are stations that supply 4.16 kV box construction feeders (note: Hazelwood MS supplied only two distribution feeders at the time). The transformer stations (TS) shown serve the same areas but do not supply any box construction feeders. The figure shows that (i) Junction MS, which supplies a number of aging box construction feeders, experienced by far the most outages and (ii) 11 outages occurred on feeders from the three stations supplying box construction while only five outages occurred on feeders from the four transformer stations (TS) in the same area.

Reliability measures for box construction feeders in the 2015-2019 conversion program are summarized in Table 5.

TABLE 5: HISTORICAL RELIABILITY FOR FEEDERS PROPOSED FOR CONVERSION

	2007	2008	2009	2010	2011	2012
Customer Hours Interrupted	24,469	26,465	52,139	23,218	31,665	35,298
Customers Interrupted	31,824	29,314	37,696	22,802	21,765	19,671
Average Outage Duration (hours)	0.77	0.90	1.38	1.02	1.45	1.79

Figure 8 to Figure 11 illustrate customers interrupted (CI), customer hours interrupted (CHI), system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI) for feeders proposed for conversion.

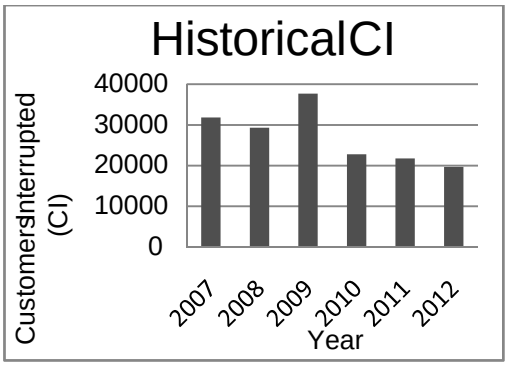


FIGURE 8: HISTORICAL CI FOR FEEDERS PROPOSED FOR CONVERSION

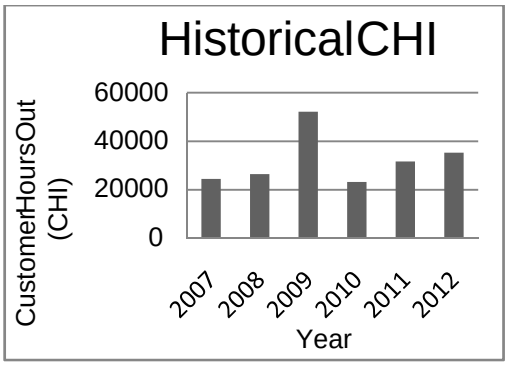


FIGURE 10: HISTORICAL CHI FOR FEEDERS PROPOSED FOR CONVERSION

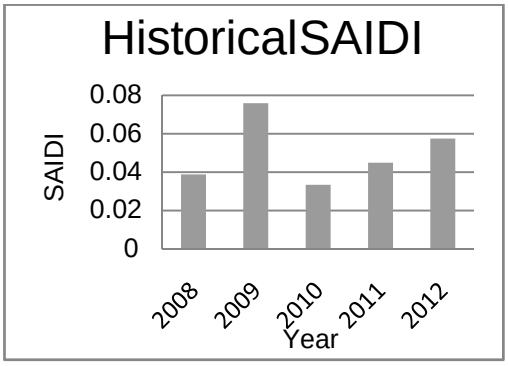


FIGURE 9: HISTORICAL SAIDI FOR FEEDERS PROPOSED FOR CONVERSION

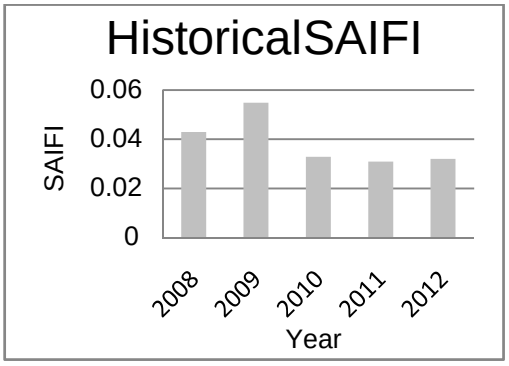


FIGURE 11: HISTORICAL SAIFI FOR FEEDERS PROPOSED FOR CONVERSION

Aging 4.16 kV Stations Assets

The 4.16 kV station assets that supply 4.16 kV box construction feeders are aging and in some cases require replacement in the near future. Rather than invest in legacy station equipment under the Station Switchgear Renewal (section E6.14), Station Power Transformer Renewal (section E6.15) or the Station Circuit Breaker Renewal (section E6.16) programs, Toronto Hydro's preferred alternative is to convert all 4.16 kV load from these stations to current standard 13.8 kV or 27.6 kV construction. This enables Toronto Hydro to eventually decommission the stations.

Load Capacity

Load capacity of 4.16 kV box construction feeders (3 MVA) is less than a third of the capacity of 13.8 kV overhead feeders (10 MVA). These feeders are not as flexible in accommodating new large customers or renewable generation suppliers. Toronto Hydro must connect these larger customers using alternative means, such as running a new feeder or extending an existing feeder to a given location, which requires additional time and Toronto Hydro resources. In these scenarios, the customer is also responsible for the additional connection costs, which are reflected in their Offer to Connect (OTC) agreement. Conversion to standard 13.8 kV or 27.6 kV feeders will help to mitigate such costs for future customers.

Clearance Issues

Clearance issues are also prevalent with 4.16 kV overhead box construction feeders. As per Canadian Standards Association (CSA) and Toronto Hydro standards, the clearance between overhead primary conductors and buildings must be greater than three meters. In many cases, as buildings are replaced, rebuilt or refurbished, they are being located closer to or even right against the lot lines, which compromises the line clearances previously achievable. Similar complications can arise from building restorations due to the temporary scaffolding required. In many instances, the three metre clearance cannot exist between the lot line and the closest primary conductor on the overhead box pole because of the large area that the box occupies at the top of the pole. In these situations, extensive planning must be done to isolate the conductors while maintaining safe and reliable supply to customers in the area. There is also a financial impact to customers, as the customer requesting the work is responsible for the cost of isolating the feeders that impede the required clearance. As standard 13.8 kV and 27.6 kV overhead feeders occupy a smaller area at the top of any given pole, the issues and costs related to the isolation of box construction feeders can ultimately be avoided in many cases with timely

conversion. Figure 12 shows some examples of recent property development activities and their interference with the existing box construction plant.

FIGURE 12: INSTANCES OF REQUIRED RECONFIGURATION

Conclusion: Need for a Proactive Replacement Program

Toronto Hydro could elect to maintain and repair box construction wherever it currently exists during the 2015-2019 period. However, due to the high number of assets past their useful lives on these feeders (as seen in Figures 13 to 16 below), the utility anticipates that this status quo option would result in worsening reliability and avoidable maintenance costs from associated 4.16 kV MS's that could otherwise be decommissioned. Also, the safety and operational issues outlined in Section E6.7.5.4 would remain.

In contrast, Toronto Hydro's preferred alternative, i.e., the planned conversion program, will convert 44 outdated 4.16 kV box construction feeders to current standard 13.8 kV or 27.6 kV feeders between 2015 and 2019.

E6.7.3.2 Asset Details

(i) Asset Lifecycle

Figures 13 to 16 illustrate the asset age profiles for overhead transformers, underground transformers, overhead switches and poles on box construction feeders. The areas highlighted in red approximate the number of assets considered past useful life. Over one-quarter of overhead transformers (Figure 14) are 35 years or older, which exceeds the useful life of this asset class. In addition, roughly another one-quarter of overhead transformers are between 25-34 years of age

and will soon be reaching the end of their 35 year lifecycle. Toronto Hydro plans to address overhead transformers reaching end-of-life within the 2015-2026 period to mitigate outage duration and frequency for customers and to improve safety and efficiency. A similar pattern is seen with underground transformers, where over half of the current assets are 35 years or older (Figure 15).

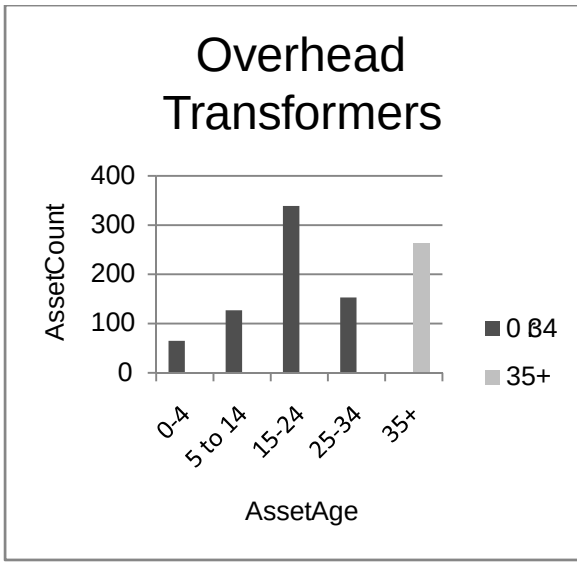


FIGURE 13: ASSET COUNT BY AGE GROUP FOR OVERHEAD TRANSFORMERS FOUND ON BOX CONSTRUCTION FEEDERS SCHEDULED FOR REPLACEMENT IN 2015-2019

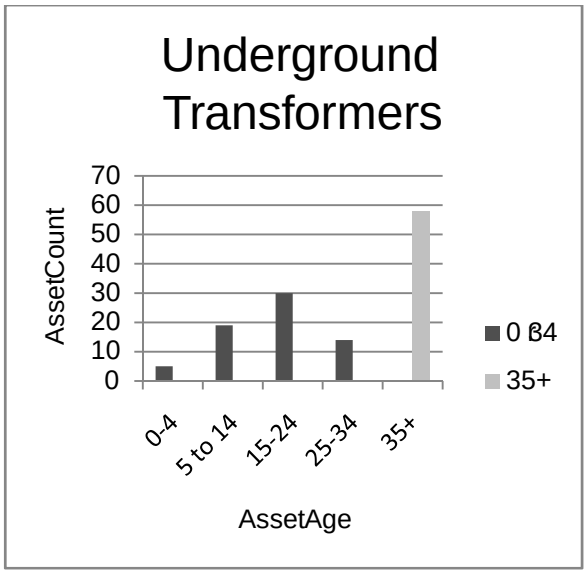


FIGURE 14: ASSET COUNT BY AGE GROUP FOR UNDERGROUND TRANSFORMERS FOUND ON BOX CONSTRUCTION FEEDERS SCHEDULED FOR REPLACEMENT IN 2015-2019

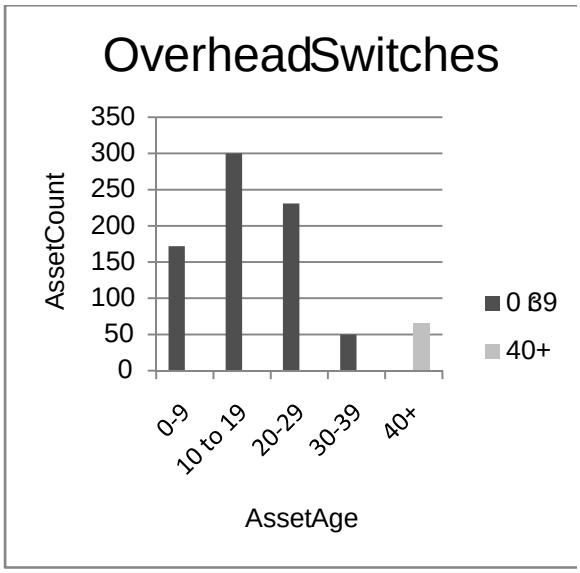


FIGURE 15: ASSET COUNT BY AGE GROUP FOR OVERHEAD SWITCHES FOUND ON BOX CONSTRUCTION FEEDERS SCHEDULED FOR REPLACEMENT IN 2015-2019

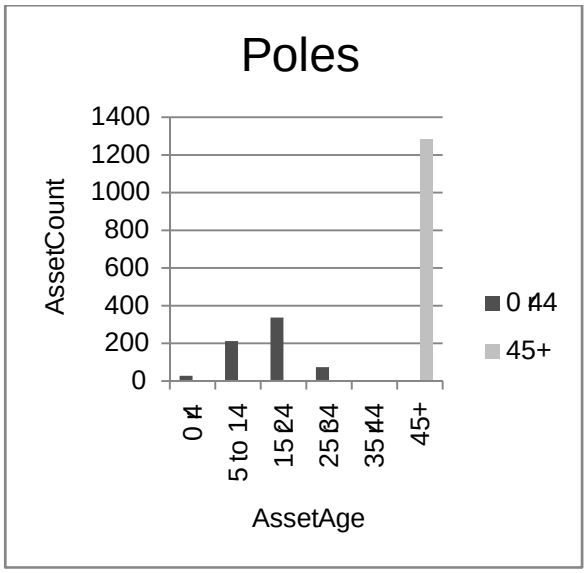


FIGURE 16: ASSET COUNT AGE GROUP FOR POLES FOUND ON BOX CONSTRUCTION FEEDERS SCHEDULED FOR REPLACEMENT IN 2015-2019

The majority of poles associated with the box construction are beyond useful life Figure 16), which raises failure risks and safety concerns for customers and crew workers. Overall, Figure 13 through Figure 16 show that approximately forty percent of box construction assets are past their useful lives and in need of replacement in order to mitigate failures, outages and safety risks.

(ii) Asset Failure Impacts

Depending on the failure mode and type of fault, there will be varying impacts on customers. However, Table 4 shows that on average, outage duration on 4.16 kV box construction feeders is considerably longer than on 13.8 kV overhead feeders. Figure 17 shows the cumulative number of customers per year who will be converted to standard 13.8 kV or 27.6 kV circuits as part of the ongoing Box Construction Conversion program. Figure 17 is a result of the criteria used to determine the order of conversion for these feeders; where possible, feeders from more lightly loaded stations are considered for conversion prior to the ones from heavily loaded stations. This approach allows those stations to be removed from service more quickly, thereby avoiding the associated future maintenance and asset replacement costs sooner.

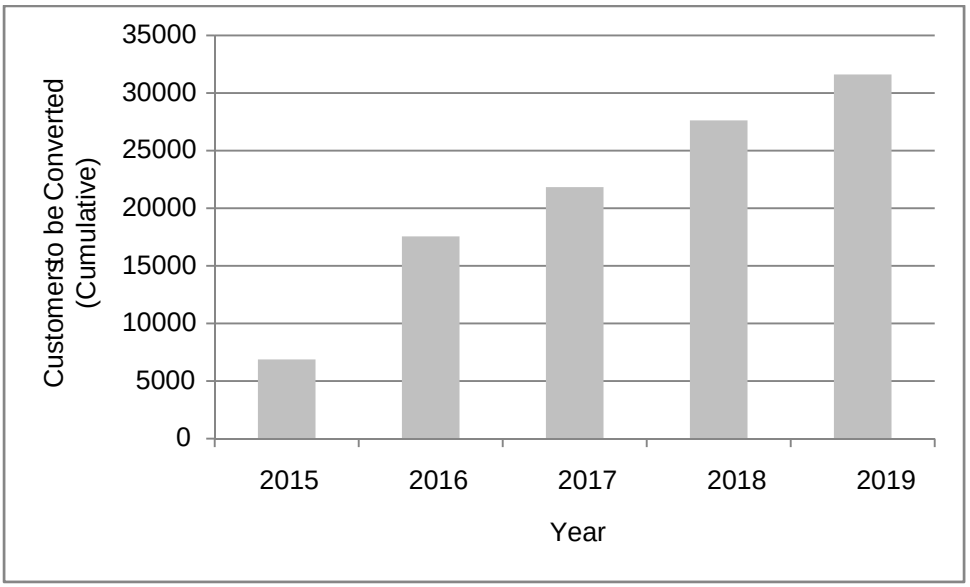


FIGURE 17: CUSTOMERS TO BE CONVERTED PER YEAR

E6.7.4 Timing & Pacing of the Program

Toronto Hydro plans to address all of the issues associated with 4.16 kV box construction feeders through a proactive program to convert these feeders to standard 13.8 kV or 27.6 kV overhead construction. The table below provides the estimated costs of the program for the 2015-2019 period. Given the current schedule, Toronto Hydro plans to address 65% of all box construction by the end of 2019. The conversion of all box construction feeders is expected to be complete by 2026.

TABLE 6: HISTORICAL AND FORECASTED SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	5.7	7.1	0.84	13.8	23.3	16.8	20.7	21.1	21.6	22.7

Ideally, Toronto Hydro would convert all remaining box construction in the 2015-2019 period. However, converting all remaining box construction feeders over this time period is not feasible from an engineering perspective due a number of system constraints, including limited availability of certain feeders and the need to first upgrade certain Hydro One Networks Inc. (HONI) station equipment housed in Toronto Hydro transmission stations (TS):

- Availability of 13.8 kV or 4-wire (with neutral) feeders: Three-phase overhead feeders require a fourth neutral cable to accommodate single-phase load (fed from a low-impedance 4-wire bus), but not all 13.8 kV feeders are '4-wire' (e.g., underground 13.8 kV feeders can be either 3-wire or 4-wire). Only those 4.16 kV box construction feeders that have either 13.8 kV 4-wire feeders or a 4-wire bus at a station in their vicinity can be converted to 13.8 kV overhead feeders. In addition, the available 13.8 kV overhead feeders must have sufficient capacity to accommodate the existing 4.16 kV load, which is not always the case.

- Some HONI-owned station equipment in Toronto Hydro transmission stations (TS) requires upgrades: Station equipment, such as transformers, switchgear and busses, must be upgraded to accommodate a future 4-wire bus for 4.16 kV box construction conversion jobs. For example, Highlevel TS must have its high-impedance 3-wire 13.8 kV bus/transformer/switchgear upgraded to a low-impedance 4-wire bus to accommodate 4.16 kV conversion jobs at Highlevel MS. Therefore, stations like Highlevel MS have not been targeted for conversion in the 2015-2019 timeframe.

E6.7.4.1 Ranking & Prioritization

Toronto Hydro considers several factors when determining the sequencing of work within the Box Construction Conversion program. These include:

- Asset condition and age – Toronto Hydro's sequencing of planned work accounts for the risk of failure by considering which assets are in poor condition and past useful life. Assets prone to failure have a higher impact on customer service, satisfaction and reliability.

- Proximity to 13.8 kV 4-wire bus with capacity – Feeders that are especially far from the nearest available 4-wire bus with available capacity can encounter significant engineering challenges requiring additional planning and coordination to develop a feasible alternative supply. High Level MS is an example of a heavily loaded MS that has no 4-wire bus in its vicinity. An upgrade of the High Level TS 13.8 kV 3-wire bus to a 4-wire bus is required accommodate conversion projects in this area.

- Avoiding replacing legacy 4.16 kV station assets – Coordination with stations investment programs is a factor when prioritizing work, specifically the switchgear, power transformer and circuit breaker replacement programs. Stations that are targeted for decommissioning within the Box Construction Conversion program can potentially be part of station renewal efforts, and coordination is done to avoid the scenario of replacing station assets in one program that are targeted for decommissioning in another. Conversely, station assets that have been recently replaced have a lower replacement priority. An example of such a station is Sherbourne MS, where a station transformer was recently replaced in 2010. Accordingly, box construction conversion for this station's feeders is not scheduled until later in the conversion period (currently 2024).

- Reliability – An important prioritization criterion for many System Renewal and System Service investments is feeder reliability. All other prioritization factors being equal, Toronto Hydro intends to address the poorest performing feeders first.

Asset condition/age, reliability and avoiding replacement of legacy 4.16 kV stations assets are all important prioritization criteria that are considered when ranking box construction projects. Proximity to a 13.8/27.6 kV 4-wire bus with capacity is a limiting factor for the order of project execution, as explained in the above points. Projects are conditional on whether there is sufficient

13.8/27.6 kV overhead infrastructure in the vicinity for conversion. Projects lacking this infrastructure will necessarily occur later in the program sequence.

The following table shows the order of forecasted decommissioning of stations that will be made possible in part by the execution of the Box Construction Conversion program.

TABLE 7: PROPOSED STATION LEVEL DECOMMISSIONING 2015-2026

Year	Station
2015	MILLWOOD MS
2016	MERTON MS
2016	QUEENSWAY MS
2017	DUFFERIN MS
2017	DUPONT MS
2017	JUNCTION MS
2017	CARLAW MS
2017	WILTSHIRE MS
2018	CHAPLIN MS
2018	HAMMERSMITH MS
2019	DEFOE MS
2020	HIGH LEVEL MS
2020	RUNNYMEDE MS
2021	DANFORTH MS
2022	STRACHAN MS
2023	SPADINA MS
2024	SHERBOURNE MS
2025	UNIVERSITY MS

Year	Station
2026	ISLAND MS

E6.7.6 Program Execution

Toronto Hydro's proposed Box Construction Conversion program consists of multiple discrete projects over the 2015 through 2019 period. Detailed projects for the year 2015 are provided in Section E6.7.8. In a typical box construction conversion project, construction crews install new framed poles for 13.8 kV/27.6 kV overhead distribution in close proximity to the existing box construction poles. Next, crews install de-energized primary and secondary cable and pole-mounted transformers. Once the new circuit is energized, customers that were initially supplied from the box construction feeder(s) are transferred to the new service. After the entire load is transferred off of the box construction circuits in the area, the circuits are de-energized and the box construction infrastructure is physically removed. Figure 19 shows an example of an actual conversion project.

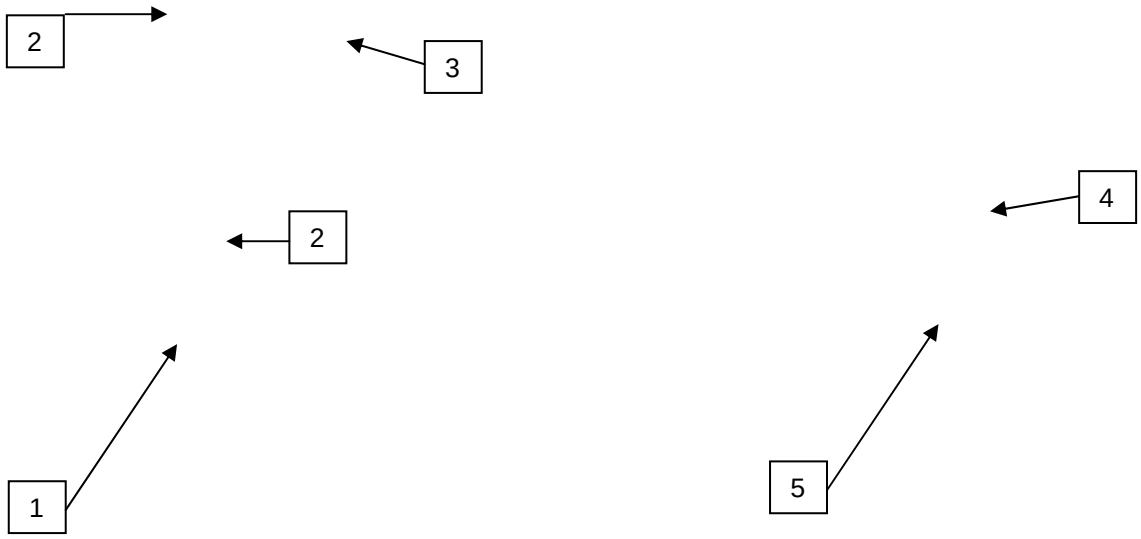


FIGURE 18: EXAMPLE OF BOX CONSTRUCTION CONVERSION JOB. (1) NEW POLES ARE INSTALLED IN CLOSE PROXIMITY TO EXISTING POLES. (2) NEW PRIMARY (TOP) AND SECONDARY CABLE (MIDDLE) INSTALLED (NOT ENERGIZED). (3) NOTE THAT CUSTOMERS STILL SUPPLIED FROM 4.16 KV BOX SERVICE, AND NOT NEW 13.8 KV/27.6 KV SERVICE. (4) CUSTOMERS ARE SWITCHED OVER TO NEW SERVICE. (5) ONCE ALL LOAD FROM CIRCUITS RUNNING THROUGH BOX POLES ARE DE-ENERGIZED, BOX CONSTRUCTION INFRASTRUCTURE (POLES, CIRCUITS, SWITCHES, TRANSFORMERS) CAN BE REMOVED.

The planned projects within the Box Construction Conversion program are occasionally broken into smaller "reactive" projects in order to make the most efficient use of Toronto Hydro resources. Toronto Hydro may proactively rebuild laterals of 4.16 kV box construction feeders in poor condition (identified by field crews) to 13.8 / 27.6 kV construction standards using reactive crew resources when they are not otherwise allocated to reactive work. Toronto Hydro would then continue to operate the lateral at 4.16 kV system voltage. When the eventual conversion of that feeder takes place, the poles and conductors on those laterals will already be prepared for the conversion, which allows the project to be completed in a more timely fashion. Another significant benefit of this approach is that the failure risks associated with poor condition 4.16 kV assets are eliminated in a more timely manner.

E6.7.6.1 Proposed Work Plan

The proposed work plan in the 2015-2019 period does not necessarily follow a station-by-station approach but rather indicates a milestone year when all load will be converted at a given station. Feeders proposed for conversion in the 2015-2019 period are summarized Table 8.

Issues may arise that are specific to certain conversions; however, current planning processes have not identified any major issues in years 2015-2019 other than the continued deterioration and aging of assets.

Ultimately, work proposed for 2016 to 2019 is of the same nature as work proposed from 2015. No major change in design standards or planning methodologies that could affect the work program are anticipated.

TABLE 8: 2015-2019 LONG TERM PLAN

Year	Feeder	Station
2015	B4KS	KEELE & ST. CLAIR MS
2015	B3MD	MILLWOOD MS
2015	B1MR	MERTON MS
2015	B2MR	MERTON MS
2015	B4E	CARLAW MS
2015	B8E	CARLAW MS
2015	B1W	WILTSHIRE MS
2015	B2W	WILTSHIRE MS
2015	B3W	WILTSHIRE MS
2015	B2HS	HAMMERSMITH MS
2016	B71DU	DUPONT MS
2016	B10J	JUNCTION MS
2016	B6DU	DUPONT MS
2016	B4DU	DUPONT MS
2016	B3MR	MERTON MS
2016	B5MR	MERTON MS
2016	B4HS	HAMMERSMITH MS
2016	B13E	CARLAW MS

/C

Year	Feeder	Station
2016	B5E	CARLAW MS
2016	B5OV	OVERDALE MS
2016	B2QU	QUEENSWAY MS
2017	B3DN	DUFFERIN MS
2017	B1DU	DUPONT MS
2017	B3J	JUNCTION MS
2017	B8J	JUNCTION MS
2017	B11J	JUNCTION MS
2017	B14J	JUNCTION MS
2017	B5W	WILTSHIRE MS
2018	B1CP	CHAPLIN MS
2018	B3CP	CHAPLIN MS
2018	B4CP	CHAPLIN MS
2018	B51CP	CHAPLIN MS
2018	B6CP	CHAPLIN MS
2018	B32HS	HAMMERSMITH MS
2018	B5HS	HAMMERSMITH MS
2018	B7HS	HAMMERSMITH MS
2019	B2DF	DEFOE MS
2019	B4DF	DEFOE MS
2019	B8DF	DEFOE MS
2019	B9DF	DEFOE MS
2019	B3DF	DEFOE MS
2019	B7DF	DEFOE MS

E6.7.6.2 Program Risks

The following are risks to program completion that Toronto Hydro considers when planning and executing box construction conversions.

- Timely third-party project completion: Some box construction conversion projects are contingent on the completion of HONI stations projects. For example, Toronto Hydro has scheduled a conversion project for Carlaw MS in 2015, but this project cannot start until a

new bus at Carlaw TS is commissioned. A significant delay of HONI's portion of the Carlaw TS expansion will necessarily lead to a delay in Toronto Hydro's box construction conversion project. To mitigate this risk, Toronto Hydro will work closely HONI to ensure that there is a mutually agreed project schedule.

E6.7.7 Evaluation of Alternatives

E6.7.7.1 Quantification/Evaluation of Options

In addition to the benefits outlined in section E6.7.3.1 , the value derived from the Box Construction Conversion program can be further quantified by examining the difference in cost of ownership between the existing box construction design that will be replaced and the new standardized 13.8 kV overhead design that will be installed. This difference in costs includes quantified risks, taking into account the probability of failure of the asset, and multiplying this by the direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement. The underlying methodology and processes associated with the business case results provided below are further explained within Section D3.1.

(i) Status Quo ("Like-for-Like" Replacement)

In the status quo scenario, Toronto Hydro would continue to maintain and repair box construction assets wherever they are currently found, and replace failed assets as needed. Due to the high number of box construction assets past their useful lives, Toronto Hydro anticipates that maintaining the status quo would result in additional avoidable maintenance costs and deteriorating reliability, as described in section E6.7.3.1. Also, the safety and operational issues outlined in Section E6.7.5.4 would remain.

The status quo options requires Toronto Hydro to manage the issues described above in a reactive and less efficient manner, delaying the decommissioning of some municipal stations (MS) or possibly preventing decommissioning of the MS altogether. The continued cost of ownership associated with the status quo option (COO_E) is highlighted in Table 9.

TABLE 9: COST OF OWNERSHIP OF EXISTING ASSETS / STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	15.38
Non Asset Risk [NAR_E]	58.22
Maintenance Cost [MC_E]	1.55
Additional Quantifiable Benefits [AQB_E]	0
Cost of Ownership of Existing Assets [COO_E]	75.15

(ii) Conversion to Standardized 13.8 kV or 27.6 kV Infrastructure

The cost of ownership (COO) and program net benefit (NPV) associated with box construction conversion is further detailed in Table 12. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities in this program. The cost of reflects the risk of asset failure for a given state, including both direct and indirect costs. These costs include customer interruptions, emergency repairs, and asset replacements associated with the given design. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NARE) and proposed (NARN) state. Non-asset risks are further explained in Section D3.3. Costs in maintenance activities are also included for both states and any additional benefit that is associated with the program that is external to the asset and non-asset related risk evaluation is quantified for both the existing state (AQBE) and new state (AQBN). Note that, for this program, AQB corresponds to savings from line losses as a result of conversion projects. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3.

When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first year of activities, the box construction conversion produces a net present value (NPV) of $5.64 million, as shown in Table 10.

TABLE 10: BOX CONSTRUCTION CONVERSION BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 2: Conversion to Standardized 13.8 kV Feeders (N)	
Asset Risk [AR_N]	3.34
Non Asset Risk [NAR_N]	52.58
Maintenance Cost [MC_N]	0
Additional Quantifiable Benefits [AQB_N]	-3.21
Cost of Ownership of New Assets (Conversion to 13.8 kV) [COO_N]	52.72
Option 2: Project Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\Delta COO_1 = (COO_E - COO_N)$]	22.44
Program Cost [PC_1]	16.80
Program Net Benefit [$NPV_1 = (\Delta COO_1 - PC_1)$]	5.64

E6.7.8 2015 Project Details

Table 13 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

(a) previously filed projects that appeared as jobs in the OEB approved Box Construction segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 11: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	CIR Projects
5.98	10.82

Table 14 lists all projects that Toronto Hydro plans to partially or completely execute as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 12: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date	Project Type
X12129	X12129 Merton / Millwood Conversion Phase 2 (B2MR, B3MD)	$1,972,609	2015	ICM
X12143	X12143 Merton / Millwood Conversion Phase 3 (B1MR, M2MR)	$1,897,845	2015	ICM
X13003	X13003 Convert 4 kV Dupont B6DU to 13.8kV	$1,419,765	2015	ICM
X13004	X13004 Convert 4 kV Dupont B4DU/B71DU to 13.8kV - Phase 3 UG Electrical	$890,496	2015	CIR
X13164	X13164 Voltage Conversion B2W/B1W PHASE 1	$1,234,184	2015	CIR
X13173	X13173 Convert 4 kV Wiltshire MS B3W to 13.8kV system	$1,317,019	2015	CIR
X13174	B2W/B1W TO 13.8kV VC PHASE II	$1,559,904	2015	CIR
X13693	X13693 (X11369) KS MS VC 4 to 13.8kV BC ph 2 (Construct only)	$690,125	2014	ICM
X14413	X14413 Convert Dupont 4 kV B4DU/B71DU / Ph 2 Decommission LOC2630	$183,815	2015	CIR
X14444	X14444 - P06 - Convert 4 kV B2HS to 13.8kV overhead feeder	$2,331,130	2015	CIR
X15017	X15017 - P06 Box conversion to 13.8kV Elec Carlaw B4E B8E Phase 1	$1,540,556	2015	CIR
X15281	X15281 P06 Box conversion to 13.8kV B4E/B8E (phase 2)	$1,759,530	2015	CIR
TOTAL		$16,796,984		

The following subsections provide additional details for all of the projects listed in the table above.

E6.7.8.10 X12129 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Merton-Millwood Conversion Phase 2 (B2MR, B3MD)

Project Number: X12129 (ICM)

Project Year: 2015

Estimated Cost: $1,972,609

(i) Objective

The objective of this job is to prepare Millwood MS feeder B3MD and Merton MS feeder B2MR for conversion from 4.16 kV to 13.8 kV for eventual decommissioning of Millwood MS and Merton MS. The main objective is to mitigate the safety concerns associated with working around energized box construction, which is found on feeders from both Millwood MS and Merton MS.

(ii) Scope of Work

TABLE 13: X12129 SCOPE OF WORK DETAILS

District Neighborhood	MOORE PARK
Station(s)	MERTON MS, MILLWOOD MS
Feeder(s)	B2MR, B3MD

Table 14 outlines the historical reliability of this feeder (Note: the majority of this project is for the conversion of B3MD).

TABLE 14: HISTORICAL RELIABILITY – B3MD

HISTORICAL RELIABILITY PERFORMANCE – B3MD			
Reliability Metric	2011	2012	2013
Feeder CI	0	0	0
Feeder CHI	0	0	0

The project is bounded by Bayview Avenue to the east, Mount Pleasant Avenue to the west, Millwood Road to the north and Merton Street to the south. Table 15 details the quantities and kilometers of assets to be replaced.

TABLE 15: X12129 ASSETS REPLACED

Assets (Units)	2015
OH Transformer	30
OH Switch	23
Poles	34
UG Switch	0
UG Transformer	5
OH Conductor (km)	3.2
UG Cable (km)	0.6

(iii) Justification & Benefits

This work will mitigate potential safety risks, improve reliability and, when conversion is complete, reduce line losses. Associated benefits of this project align to the program benefits and drivers outlined in sections E6.7.2 and E6.7.3. Furthermore, deferral of this project will likely delay plans to decommission Merton MS and Millwood MS.

E6.7.8.11 X12143 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Merton-Millwood Conversion Phase 3 (B1MR, M2MR)

Project Number: X12143 (ICM)

Project Year: 2015

Estimated Cost: $1,897,845

(i) Objective

The purpose of this project is to convert existing Merton MS feeders B1MR (complete) and B2MR (partial) load to 13.8 kV. This project is the third phase of a multi-phase project to convert the entire 4.16 kV load at Merton MS and Millwood MS to 13.8 kV with the objective of decommissioning both stations.

(ii) Scope of Work

TABLE 16: X12143 SCOPE OF WORK DETAILS

District Neighborhood	MOORE PARK
Station(s)	MERTON MS, MILLWOOD MS
Feeder(s)	B1MR, B2MR

Table 17 outlines the historical reliability of this feeder (note: the majority of this project is for the conversion of B1MR).

TABLE 17: HISTORICAL RELIABILITY – B1MR

HISTORICAL RELIABILITY PERFORMANCE – B1MR			
Reliability Metric	2011	2012	2013
Feeder CI	0	864	0
Feeder CHI	0	1468	0

The project is bounded by Mount Pleasant Road to the east, Yonge Street to the west, Manor Road to the north and Davisville Avenue to the south. Table 18 details the quantities and kilometers of assets to be replaced.

TABLE 18: X12143 ASSETS REPLACED

Assets (Units)	2015
OH Transformer	30
OH Switch	20
Poles	48
UG Switch	0
UG Transformer	2
OH Conductor (km)	3.3
UG Cable (km)	0.8

(iii) Justification & Benefits

This work will mitigate potential safety risks, improve reliability and, when conversion is complete, reduce line losses. Associated benefits of this project align to the program benefits and drivers outlined in sections E6.7.2 and E6.7.3. Furthermore, deferral of this project will likely delay plans to decommission Merton MS and Millwood MS.

E6.7.8.9 X13003 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Convert 4kV Dupont B6DU to 13.8 kV – Civil only

Project Number: X13003 (ICM)

Project Year: 2015

Estimated Cost: $1,419,765

(i) Objective

In order to accommodate the electrical conversion work for feeder B6DU, X13003 must first proceed to install new civil infrastructure for the 13.8 kV feeder that will take on B6DU feeder's load. This project is Phase 1 of 2 (civil only).

(ii) Scope of Work

TABLE 19: X13003 SCOPE OF WORK DETAILS

District Neighborhood	CRISTIE-BITTS
Station(s)	DUPONT TMS
Feeder(s)	B6DU

Table 20 the historical reliability of feeder B6DU.

TABLE 20: HISTORICAL RELIABILITY – B6DU

HISTORICAL RELIABILITY PERFORMANCE – B6DU			
Reliability Metric	2011	2012	2013
Feeder CI	0	835	1
Feeder CHI	0	529	2

The project will take place along Dufferin Street, bounded by Davenport Road to the north and Dupont Street to the south. 4 kV assets will be replaced when conversion of 4 kV B6DU load occurs in a later project in 2016. As a result, there are no asset replacements shown for this project.

(iii) Justification & Benefits

Conversion of 4 kV Dupont MS feeders to the 13.8 kV system is required due to the aging station and distribution equipment, load growth, and obsolete distribution design configuration. The conversion will also improve supply reliability to customers as well as enhance work safety for crews. Furthermore, deferral of this project will likely delay plans to decommission Dupont MS.

E6.7.8.2 X13004 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Convert 4kV Dupont B4DU/B71DU to 13.8 kV - Phase 3 UG Electrical

Project Number: X13004

Project Year: 2015

Estimated Cost: $890,496

(i) Objective

The purpose of this project is to install new underground cable to allow for the conversion of legacy 4.16 kV box construction feeders B4DU and B71DU. The new underground cable will then be utilized to connect to a new overhead 13.8 kV line to be built in future phases. This project is the third phase of a multi-phase project to convert the B4DU and B71DU feeders at Dupont MS with the eventual objective of decommissioning this station.

(ii) Scope of Work

TABLE 21: X13004 SCOPE OF WORK DETAILS

District Neighborhood	ANNEX/ST CLAIR WEST
Station(s)	DUPONT MS
Feeder(s)	B4DU/B71DU

Table 22 outlines the historical reliability of this feeder.

TABLE 22: HISTORICAL RELIABILITY – B4DU AND B71DU

HISTORICAL RELIABILITY PERFORMANCE B4DU and B71DU			
Reliability Metric	2011	2012	2013
Feeder CI	2577	0	1326
Feeder CHI	1572	0	884

The project is bounded by Christie Street to the east, Dufferin Street to the west, Davenport Road to the north and Dupont Street to the south. As this phase of the conversion plan only installs new cable, no assets are being replaced by this project.

(iii) Justification & Benefits

This project will allow for the conversion of 4.16 kV Dupont MS B-4-DU/B-71-DU feeders to 13.8 kV system in a later phase, and is the third phase of a multi-phase conversion plan which needs to take place before 4.16 kV Dupont MS can be decommissioned. Modernizing and upgrading the existing system will improve reliability and aesthetics, and reduce system losses and maintenance. Furthermore, deferral of this project will likely delay the later phases for the conversion of B4DU and B71DU feeders, as well as the eventual decommissioning of Dupont MS.

E6.7.8.3 X13164 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Voltage Conversion B2W/B1W phase 1

Project Number: X13164

Project Year: 2015

Estimated Cost: $1,234,184

(i) Objective

The purpose of this project is to convert the existing 4 kV Wiltshire MS B2W feeder and a portion of B1W feeder to the 13.8 kV system. This is the first phase of a multi-phase conversion plan to convert B2W and B1W feeders, as well as the eventual decommissioning of 4.16 kV Wiltshire MS.

(ii) Scope of Work

TABLE 23: X13164 SCOPE OF WORK DETAILS

District Neighborhood	CARLETON VILLAGE
Station(s)	WILTSHIRE MS
Feeder(s)	B2W/B1W

Table 24 outlines the historical reliability of these feeders.

TABLE 24: HISTORICAL RELIABILITY – B2W AND B1W

HISTORICAL RELIABILITY PERFORMANCE – B2W and B1W			
Reliability Metric	2011	2012	2013
Feeder CI	934	0	1231
Feeder CHI	1798	0	3272

The project is bounded by Gillespie Avenue to the east, Old Weston Road to the west, St Clair Ave. W. to the north and C.P.R to the south. Table 25 details the quantities and kilometers of assets to be replaced.

TABLE 25: X13164 ASSETS REPLACED

Assets (Units)	2015
OH Transformer	19
OH Switch	11
Poles	30
UG Switch	0
UG Transformer	3
OH Conductor (km)	1.8
UG Cable (km)	1.2

(iii) Justification & Benefits

Modernizing and upgrading the existing system will improve reliability and aesthetics, and reduce system losses and maintenance. Deferral of this project will mean that all operational efficiency, safety and reliability issues discussed earlier in Section E6.7.3 will remain.

E6.7.8.4 X13173 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Convert 4kV Wiltshire MS B3W to 13.8 kV system

Project Number: X13173

Project Year: 2015

Estimated Cost: $1,317,019

(i) Objective

The purpose of this project is to convert the existing 4 kV Wiltshire B3W feeder to the 13.8 kV system and decommission the 4.16 kV B3W feeder. This project is a part of a multi-phase plan to convert the entire 4.16 kV load at Wiltshire MS with the objective of decommissioning this station.

(ii) Scope of Work

TABLE 26: X13173 SCOPE OF WORK DETAILS

District Neighborhood	CARLETON VILLAGE
Station(s)	WILTSHIRE MS
Feeder(s)	B3W

TABLE 27: HISTORICAL RELIABILITY – B3W

HISTORICAL RELIABILITY PERFORMANCE – B3W			
Reliability Metric	2011	2012	2013
Feeder CI	1071	1128	953
Feeder CHI	210	1231	2812

The project is bounded by Wiltshire Avenue to the east, Osler Road to the west, Davenport Road to the north and Adrian Avenue to the south. Table 28 details the quantities and kilometers of assets to be replaced.

TABLE 28: X13173 ASSETS REPLACED

Assets (Units)	2015
OH Transformer	13
OH Switch	15
Poles	6
UG Switch	0
UG Transformer	0
OH Conductor (km)	1.4
UG Cable (km)	0.4

(iii) Justification & Benefits

Modernizing and upgrading the existing system will improve reliability and aesthetics, and reduce system losses and maintenance. Deferral of this project will mean that all operational efficiency, safety and reliability issues discussed earlier in Section E6.7.3 will remain.

E6.7.8.5 X13174 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Convert 4kV Wiltshire MS B2W/B1W to 13.8 kV system - Phase 2

Project Number: X13174

Project Year: 2015

Estimated Cost: $1,559,904

(i) Objective

The purpose of this project is to convert the remaining portion of existing 4 kV Wiltshire B1W feeder to 13.8 kV overhead infrastructure. This project is the second phase of a multi-phase plan to convert the entire 4.16 kV load at Wiltshire MS with the objective of decommissioning this station.

(ii) Scope of Work

TABLE 29: SCOPE OF WORK DETAILS

District Neighborhood	CARLETON VILLAGE
Station(s)	WILTSHIRE MS
Feeder(s)	B1W

Table 30 outlines the historical reliability of this feeder.

TABLE 30: HISTORICAL RELIABILITY – B2W AND B1W

HISTORICAL RELIABILITY PERFORMANCE – B2W and B1W			
Reliability Metric	2011	2012	2013
Feeder CI	934	0	1231
Feeder CHI	1798	0	3272

The project is bounded by Wiltshire Avenue to the east, Osler Street to the west, St. Clair Avenue West to the north and Adrian Avenue to the south. Table 31 details the quantities and kilometers of assets to be replaced.

TABLE 31: X13174 ASSETS REPLACED

Assets (Units)	2015
OH Transformer	25
OH Switch	15
Poles	48
UG Switch	0
UG Transformer	0
OH Conductor (km)	2.3
UG Cable (km)	0.5

(iii) Justification & Benefits

The conversion of 4.16 kV Wiltshire MS B-1-W feeder to 13.8 kV system is the second phase of a multi-phase conversion plan which needs to take place before 4.16 kV Wiltshire MS can be decommissioned. Modernizing and upgrading the existing system will improve reliability and aesthetics, and reduce system losses and maintenance. Associated benefits of this project also align to the program benefits and drivers outlined in sections E6.7.2 and E6.7.3. Furthermore, deferral of this project will likely delay the eventual decommissioning of Wiltshire MS.

E6.7.8.12 X13693 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: KS MS VC 4-13.8 kV BC ph2 (Construct only)

Project Number: X13693 (ICM)

Project Year: 2015

Estimated Cost: $690,125

(i) Objective

This project will convert and pick-up existing 4 kV loads along B4KS feeder. This project is the second phase of a multi-phase project to decommission 4 kV Keele and St. Clair MS.

(ii) Scope of Work

TABLE 32: X13691 SCOPE OF WORK DETAILS

District Neighborhood	JUNCTION (STOCKYARDS)
Station(s)	KEELE AND ST CLAIR MS
Feeder(s)	B1KS, B4KS

Table 33 summarizes the historical reliability of these feeders (note: the majority of this project is for the conversion of B4KS).

TABLE 33: HISTORICAL RELIABILITY – B1KS AND B4KS

HISTORICAL RELIABILITY PERFORMANCE – B1KS and B4KS			
Reliability Metric	2011	2012	2013
Feeder CI	1028	382	382
Feeder CHI	2512	89	598

The project is bounded by Cawthra Avenue to the east, Keele Street to the west, St. Clair Avenue to the north and Vine Avenue to the south. Table 34 details the quantities and kilometers of

assets to be replaced.

TABLE 34: X13693 ASSETS REPLACED

Assets (Units)	2015
OH Transformer	20
OH Switch	14
Poles	42
UG Switch	0
UG Transformer	6
OH Conductor (km)	2.4
UG Cable (km)	1.1

(iii) Justification & Benefits

Conversion of 4 kV Keele and St.Clair MS B-1-KS and B-4-KS feeders to 13.8kV/27.6kV systems is needed due to the current station's equipment conditions and loads, the adjacent station's loads and to maintain safe and reliable supply to customers. Deferral of this project will likely delay plans to decommission Keele and St. Clair MS.

E6.7.8.1 X14413 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Convert Dupont 4kV B4DU/B71DU- Ph 2 Decommission LOC2630

Project Number: X14413

Project Year: 2015

Estimated Cost: $183,815

(i) Objective

The purpose of this project is to resupply customer fed via LOC2630 then decommission LOC2630 fed via B4DU, including all cables and transformers. This project is the second phase of a multi-phase plan to convert feeders B4DU and B71DU, with the objective of decommissioning Dupont MS.

(ii) Scope of Work

TABLE 35: X14413 SCOPE OF WORK DETAILS

District Neighborhood	ST CLAIR-WEST/ANNEX
Station(s)	DUPONT MS
Feeder(s)	B4DU/B71DU

Table 36 outlines the historical reliability of this feeder.

TABLE 36: HISTORICAL RELIABILITY – B4DU AND B71DU

HISTORICAL RELIABILITY PERFORMANCE B4DU and B71DU			
Reliability Metric	2011	2012	2013
Feeder CI	2577	0	1326
Feeder CHI	1572	0	884

The project is on Christie Street and bounded by Davenport Avenue to the north and Dupont Street to the south.

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E6.7.8.6 X14444 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Convert 4kV B2HS to 13.8 kV overhead feeder

Project Number: X14444

Project Year: 2015

Estimated Cost: $2,331,130

(i) Objective

Convert 4 kV box construction feeder B2HS to 13.8 kV overhead infrastructure. This project is the first phase of a multi-phase conversion plan to convert the entire 4.16 kV load at Hammersmith MS with the objective of decommissioning this station.

(ii) Scope of Work

TABLE 38: X14444 SCOPE OF WORK DETAILS

District Neighborhood	BEACHES
Station(s)	HAMMERSMITH MS
Feeder(s)	B2HS

Table 39 outlines the historical reliability of this feeder.

TABLE 39: HISTORICAL RELIABILITY – B2HS

HISTORICAL RELIABILITY PERFORMANCE – B2W and B1W			
Reliability Metric	2011	2012	2013
Feeder CI	2437	0	0
Feeder CHI	6698	0	0

The project is bounded by Victoria Park Avenue to the east, Hammersmith Avenue to the west, Kingston Road to the north and Hubbard Avenue to the south. Table 40 details the quantities and kilometers of assets to be replaced.

TABLE 40: X14444 ASSETS REPLACED

Assets (Units)	2015
OH Transformer	31
OH Switch	24
Poles	92
UG Switch	0
UG Transformer	1
OH Conductor (km)	4.5
UG Cable (km)	0.1

(iii) Justification & Benefits

The conversion of 4.16 kV Hammersmith MS B-2-HS feeder to the 13.8 kV system is the first phase of a multi-phase conversion plan which must occur before 4.16 kV Hammersmith MS can be decommissioned. Furthermore, converting this feeder to 13.8 kV will reduce the load at this station enough to allow a station transformer in poor condition to be decommissioned, rather than replace it. Modernizing and upgrading the existing system will improve reliability and aesthetics, and reduce system losses and maintenance.

Deferral of this project will necessitate further maintenance of Hammersmith MS, and will also delay other conversion projects in this area that require X14444 to be completed.

E6.7.8.7 X15017 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Box conversion to 13.8 kV Elec Carlaw B4E B8E Phase 1

Project Number: X15017

Project Year: 2015

Estimated Cost: $1,540,556

(i) Objective

Convert 4 kV box construction feeder B4E and B8E to 13.8 kV overhead infrastructure. This project is the final phase of a multi-phase conversion plan to convert the entire 4.16 kV load at Carlaw MS with the objective of decommissioning this station.

(ii) Scope of Work

TABLE 41: X15017 SCOPE OF WORK DETAILS

District Neighborhood	LESLIEVILLE
Station(s)	CARLAW MS
Feeder(s)	B4E/B8E

Table 42 outlines the historical reliability of this feeder.

TABLE 42: HISTORICAL RELIABILITY – B4E AND B8E

HISTORICAL RELIABILITY PERFORMANCE – B4E and B8E			
Reliability Metric	2011	2012	2013
Feeder CI	0	0	0
Feeder CHI	0	0	0

The project is bounded by Kingston Road to the east, Booth Street to the west, Gerrard Street to the north and Queen Street East to the south. This project only installs 13.8 kV poles and overhead transformers. Assets will be replaced when conversion of 4 kV load occurs in a later project: X15281 (phase 2). As a result, there are no asset replacements shown for this project.

(iii) Justification & Benefits

The conversion of 4.16 kV Carlaw MS B-4-E/B-8-E feeder to the 13.8 kV system is the final phase of a multi-phase conversion plan that must occur before 4.16 kV Carlaw MS can be decommissioned. Furthermore, the bus supplying Carlaw MS (Carlaw TS A4-5E bus) requires replacement in 2018 and this conversion project must be executed prior the bus replacement. Deferral of this project will necessitate further maintenance of Carlaw MS, and will also delay other conversion projects in this area that require the completion of X15017. Modernizing and upgrading the existing system will improve reliability and aesthetics, and reduce system losses and maintenance.

E6.7.8.8 X15281 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Box conversion to 13.8 kV B4E/B8E (phase 2)

Project Number: X15281

Project Year: 2015

Estimated Cost: $1,759,530

(i) Objective

Convert 4 kV box construction feeder B4E and B8E to 13.8 kV overhead infrastructure. This project is the final phase of a multi-phase conversion plan to convert the entire 4.16 kV load at Carlaw MS with the objective of decommissioning this station.

(ii) Scope of Work

TABLE 43: X15281 SCOPE OF WORK DETAILS

District Neighborhood	LESLIEVILLE
Station(s)	CARLAW MS
Feeder(s)	B4E/B8E

Table 44 outlines the historical reliability of this feeder.

TABLE 44: HISTORICAL RELIABILITY – B4E AND B8E

HISTORICAL RELIABILITY PERFORMANCE – B4E and B8E			
Reliability Metric	2011	2012	2013
Feeder CI	0	0	0
Feeder CHI	0	0	0

The project is bounded by Kingston Road to the east, Booth Street to the west, Gerrard Street to the north and Queen Street East to the south. Table 45 details the quantities and kilometers of

assets to be replaced. This project utilizes the 13.8 kV poles and overhead transformers installed in project X15017 (phase 1) and takes on 4 kV load from B4E and B8E, and also removes all associated 4 kV assets.

TABLE 45: X15281 ASSETS REPLACED

Assets (Units)	2015
OH Transformer	67
OH Switch	41
Poles	77
UG Switch	0
UG Transformer	5
OH Conductor (km)	4.6
UG Cable (km)	1.4

(iii) Justification & Benefits

The conversion of 4.16 kV Carlaw MS B-4-E/B-8-E feeder to the 13.8 kV system is the final phase of a multi-phase conversion plan that must occur before 4.16 kV Carlaw MS can be decommissioned. Furthermore, the bus supplying Carlaw MS (Carlaw TS A4-5E bus) requires replacement in 2018 and this conversion project must be executed prior the bus replacement. Deferral of this project will likely delay plans to both decommission Carlaw MS and replace the aging A4-5E bus at Carlaw TS. Modernizing and upgrading the existing system will improve reliability and aesthetics, and reduce system losses and maintenance.

E6.8 SCADA-Mate R1 Switch Renewal

DEFECTIVE SCADA-MATE R1 SWITCH USED FOR INTERNAL INVESTIGATION

E6.8.1 Summary

Program Description

The SCADA-Mate R1 Switch Renewal program will complete the ongoing activities previously described in the Ontario Energy Board (OEB) approved SCADA-Mate R1 Switches segment in the Incremental Capital Module (ICM) as part of Toronto Hydro's 2012-2014 rate filing.[1]

The SCADA-Mate R1 Switch Renewal program targets the replacement of SCADA-Mate R1 switches which have proven to be defective. There have been three incidents of the switch operating unexpectedly when crews were establishing an open air-gap with the disconnect switch. In one case, this resulted in a flashover and a pole catching fire while a field worker was manually operating the disconnect switch underneath. It has been determined that corrosion of internal components, coupled with the design of the switch, caused the switch to operate unexpectedly. After determining that these switches posed a significant safety hazard (as discussed in section E6.8.3), Toronto Hydro began to replace the SCADA-Mate R1 switches in its system with new R2 switches in 2013.

[1] EB-2012-0064, Tab 4, Schedule B8.

The anticipated benefits of the SCADA-Mate R1 Switch Renewal program are as follows:

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Faster restoration of service from fully functioning SCADA-Mate switches
Reliability	ƒ Functioning SCADA-Mate switches reduce the duration of trunk related outages, helping to manage SAIDI impacts from interruptions, including during major storm events.
Safety	ƒ Eliminates the risk of switch closing on itself during air-gap disconnect ƒ Eliminates the risk of flashover during use ƒ Eliminates the status indicator malfunction discrepancy from field to control room
Efficiency	ƒ The ability to safely establish open air-gap reduces switching activities
Other	ƒ Functioning SCADA-Mate switches will play an essential role in the expansion of Toronto Hydro's Feeder Automation program (refer to section E7.3 for details) ƒ SCADA-Mate R2 switch can operate without power supply due to manual charge spring in motor mechanism.

Program Drivers

The trigger and secondary drivers for SCADA-Mate R1 Switch Renewal program are summarized in the following table.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ SCADA-Mate R1 switches do not operate as intended; therefore, the functionality in switching operations is significantly diminished. ƒ The R1 switches cannot be used as a physical open point to isolate a feeder when performing field work. ƒ Outages on feeders connected by R1 switches affect a larger number of customers, as crews have to create the open isolation point at the next load break switch.
Secondary Drivers	**Reasoning**
Safety	ƒ Due to corrosion of the internal components, the interrupter switch and interrupter indicator on the SCADA-Mate R1 have previously malfunctioned and are considered unsafe for operation due to the risk of a arcing and flashover while manually opening an energized switch. ƒ The interrupter switch has previously closed on its own, re-energizing the circuit while crews were operating the equipment, and the indicator has misrepresented the operating state to the control room.

Failure Risk	ƒ SCADA-Mate R1 switches present an increased failure risk because of the suspension of maintenance on these switches (due to the safety risks associated with working with them) and their susceptibility to corrosion build-up. ƒ Failure of this equipment results in the loss of remote functionality, which prolongs the duration of outages by making it more difficult to locate faults and restore power to customers.

Preferred Alternative

Toronto Hydro evaluated the following alternatives for addressing the assets in this program:

I. Do nothing and replace on a reactive basis only, incurring the risk of equipment failures and potential safety concerns
II. Retrofit the R1 switches with a kit provided by the manufacturer, which would necessitate the removal of each switch from the field, transport to and from the manufacturers facilities, and re-installation after the retrofit is complete
III. Replace the R1 switches with new R2 switches

Option III is the preferred alternative because it addresses the safety, reliability and operational issues associated with the SCADA-Mate R1 switches in the most cost-effective manner.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $106.82 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.8.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $100.67 million, confirming the economic prudence of the investments (see Section E6.8.7).

Timing and Pacing

Under this SCADA-Mate R1 Switch Renewal program, Toronto Hydro proposes to replace all remaining R1 switching units from 2015 to 2017, with spending levels noted in Table C below. Toronto Hydro is proposing an aggressive replacement program in order to reduce the duration of customer outages and improve safety in a timely fashion. Due to the numerous safety, reliability and operational issues associated with SCADA-Mate R1 switches, Toronto Hydro cannot defer or delay this program

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	-	-	-	1.90	2.57	6.16	4.11	2.69	-	-

E6.8.2 Program Description

The SCADA-Mate R1 Switch Renewal program will complete the ongoing activities previously described in the OEB-approved SCADA-Mate R1 Switches segment in the Incremental Capital Module (ICM) as part of Toronto Hydro's 2012-2014 rate filing[2]. Toronto Hydro expects to complete the proactive replacement of all in-service SCADA-Mate R1 switches with R2 switches by 2017.

SCADA-Mate switches are overhead load interrupting switches that have the capability of being remotely operated from the control room. The sensory, control and communication functions of these devices provide significant advantages in managing Toronto Hydro's distribution system. For example, SCADA-Mates can detect a fault on a feeder and enable the control room to rapidly isolate the faulted area and restore power to the unaffected areas of the main feeder (also known as the feeder's trunk) by opening and closing the switches remotely. In addition, SCADA-Mate switching units enable Toronto Hydro field crews to create an open isolation point when work is required on a circuit. This is a required and important safety measure to help ensure that the equipment will not become energized while field crews are working on the faulted section of the feeder when restoring a fault in order to create a zone of work protection for the field crews working on the feeder.3

Figure 1 illustrates a typical SCADA-Mate switch configuration, which consists of the switch assembly and the remote terminal unit (RTU). The switch assembly physically connects to the primary conductors to open and close the circuit. SCADA-Mate switches are equipped with SF_6 (sulfur hexafluoride) interrupters that limit and contain any electrical arcing from the interrupter switches. The interrupter indicator on the side of the switch shows whether the switch is in the open or closed position. This allows live circuit making and breaking without exposing Toronto Hydro crews and the public to the risk of arcing and flashovers.

[2] EB-2012-0064, Tab 4, Schedule B8.
[3] Infrastructure Health and Safety Association, Electrical Utility Safety Rules, (Mississauga: Infrastructure Health and Safety Association, 2014) at Rule 114 (Safe Conditions for Work), Rule 115 (Work on Isolated Circuits), and Rule 126 (Switching Operations) ["EUSR"]

FIGURE 1: SCADA-MATE R1 SWITCH CONFIGURATION

The RTU and the interrupters enable the remote operation of the switches. The RTU houses the switch controller and communication electronics that process the information necessary to activate the hardware (i.e., the disconnect operating lever) connected to the switch. It also enables Toronto Hydro field crews to operate the switch on location when they need to create an open isolation point on the circuit.

SCADA-Mate R1 switches were predominately installed between 1993 and 2000. There have been three incidents of the switch operating unexpectedly when crews were establishing an open air-gap with the disconnect switch. The worst of these incidents resulted in a flashover and a pole catching fire while a field worker was manually operating the disconnect switch underneath. An investigation determined that moisture entered the switch and caused internal components to corrode. The corrosion, along with the design of the switch, caused the switch to operate unexpectedly. After determining that these switches posed a significant safety hazard (as discussed in section E6.8.3), Toronto Hydro began to replace the SCADA-Mate R1 switches in its system with new R2 switches in 2013.

To date, Toronto Hydro has replaced 90 switches, leaving 196 switches to be replaced throughout the overhead distribution system as shown in Figure 2 below.

FIGURE 2: MAP OF THE REMAINING SCADA-MATE R1 SWITCHES

Toronto Hydro plans to continue replacing the remaining R1 units with the newer R2 switching units. As explained in section E6.8.3, the design of the SCADA-Mate R2 mitigates the safety risks to field crews and the public associated with operating the SCADA-Mate R1 switches.

Toronto Hydro plans to replace the remaining SCADA-Mate R1 switches from 2015-2017 at a total estimated cost of $12.96 million. Table 1 summarizes the assets to be replaced within this program.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
R1 Switch	99	67	57	-	-	223
RTU	69	49	14	-	-	132

/C

This program provides customer value by reducing the duration and frequency of outages and by enabling Toronto Hydro to manage and operate the distribution system more effectively. SCADA-Mate switches are an important feature of the overhead distribution system as they enable the control room to locate a fault on the feeder, isolate the affected sections of the feeder and restore

the unaffected customers, typically within 30 minutes. Without this technology, Toronto Hydro would have to deploy field crews to address the problem, which could take up to three hours. Furthermore, functional SCADA-Mate switches enable Toronto Hydro to better analyze the outages on feeders and diagnose feeders that are experiencing an increase in feeder faults. Customers benefit from this important functionality of the SCADA-Mate switches in the long-term, as it enables Toronto Hydro to take proactive steps to monitor, assess and remedy reliability on particular feeders.

SCADA-Mate switches have been strategically installed at locations of the feeder that enable optimal remote intervention. When SCADA-Mates malfunction, crews are unable to operate these switches for restoration purposes as intended. As a result, more customers are affected by an outage than would otherwise be required. The SCADA-Mate R1 Switch Renewal program is expected to remedy this problem, by replacing the malfunctioning R1 switches with new R2 switches.

The ability to remotely locate a fault also generates efficiency gains and safety benefits. Toronto Hydro fuel consumption is lower as fewer trips are taken to locate a fault. In terms of safety, Toronto Hydro personnel are not required to perform manual switching under dangerous conditions as noted above.

Table 2 summarizes the expected program benefits associated with the SCADA-Mate R1 Switch Renewal program.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Faster restoration of service from fully functioning SCADA-Mate switches ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $106.82 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.8.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $100.67 million, confirming the economic prudence of the investments (see Section E6.8.7).
Reliability	ƒ Functioning SCADA-Mate switches reduce the duration of trunk related outages, helping to manage SAIDI impacts from interruptions, including during major storm events.
Safety	ƒ Eliminates the risk of switch closing on itself during air-gap disconnect ƒ Eliminates the risk of flashover during use ƒ Eliminates the status indicator malfunction discrepancy from field to control room

Efficiency	ƒ The ability to safely establish open air-gap reduces switching activities ƒ Improves productivity by reducing the need to drive to and patrol the area where an issue is occurring and perform switching.
Other	ƒ Functioning SCADA-Mate switches will play an essential role in the expansion of Toronto Hydro's Feeder Automation program (refer to section E7.3 for details) ƒ SCADA-Mate R2 switch can operate without power supply due to manual charge spring in motor mechanism.

E6.8.3 Why the Program is Needed

The SCADA-Mate R1 Renewal program is needed to address the safety, reliability and operational issues associated with malfunctioning SCADA-Mate R1 switches. Mitigating the safety issues related to operating the switch requires additional switching procedures that usually involve further isolating more of the feeder circuit and, as a result, forcing more customers to experience an outage. This not only negatively affects reliability for the customers, but further complicates how switching operations are done to resolve a fault causing an outage. These issues will be discussed in greater detail below.

E6.8.3.1 Program Drivers

The trigger and secondary drivers of the SCADA-Mate R1 Switch Renewal program are outlined in Table 3.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ SCADA-Mate R1 switches do not operate as intended; therefore, the functionality in switching operations is significantly diminished. ƒ The R1 switches cannot be used as a physical open point to isolate a feeder when performing field work. ƒ Outages on feeders connected by R1 switches affect a larger number of customers, as crews have to create the open isolation point at the next load break switch.
Secondary Drivers	**Reasoning**
Safety	ƒ Due to corrosion of the internal components, the interrupter switch and interrupter indicator on the SCADA-Mate R1 have previously malfunctioned and are considered unsafe for operation due to the risk of a arcing and flashover while manually opening an energized switch. ƒ The interrupter switch has previously closed on its own, re-energizing the circuit while crews were operating the equipment, and the indicator has misrepresented the operating state to the control room.

Failure Risk	ƒ SCADA-Mate R1 switches present an increased failure risk because of the suspension of maintenance on these switches (due to the safety risks associated with working with them) and their susceptibility to corrosion build-up. ƒ Failure of this equipment results in the loss of remote functionality, which prolongs the duration of outages by making it more difficult to locate faults and restore power to customers.

(i) Safe Operation of the Switch

One of the main functions of the SCADA-Mate switch is to enable crews to create an open isolation point on the circuit in order to safely perform work on the feeder downstream. When using a SCADA-Mate switch for this purpose, the switch needs to provide a visible open air-gap, as shown in Figure 3, to ensure the circuit is physically open and to safeguard against any interrupter malfunction or user error in the field or control room that could cause the switch to close and re-energize the circuit while employees are working on it.

FIGURE 3: SCADA-MATE VISIBLE AIR-GAP ISOLATION

Before crews create the visible air-gap, a number of steps must be taken to confirm that the switch interrupter is in the open position, and that the primary circuit downstream of the switch is isolated: 1) the interrupters have to be opened, 2) crews have to visually confirm the open position of the interrupter indicator, and 3) the control room must confirm that the switch is open. Once these precautions are satisfied, crews can physically open the hinged disconnect switches

and create the visible air-gap required to safely work on the feeder. This is done by using a hot stick to engage the disconnect operating lever to rotate the disconnecting switches into open position. If for some reason the interrupters are closed and primary circuit is energized while crews are performing this task, the disconnect switch would arc and create a flashover, damaging the switch and posing a safety risk to employees as well as members of the public within close proximity.

(ii) Incidents of Switch Malfunction

In 2008, two incidents of SCADA-Mate R1 switches malfunctioning were reported by Toronto Hydro's field crews (see Appendix A). During routine maintenance, the interrupters unexpectedly closed, energizing the circuit while the crew was physically opening the switches. This created an electrical arc, which caused damage to the switches, led to outages on the feeder and posed a serious safety hazard for employees.

After the incidents, Toronto Hydro noted that the local mechanical switch indicator did not correspond with the SCADA switch status indicators in the control room. The switch state in the control room read that the switch was open, while the interrupter in the field indicated that it was closed. Conflicting information between the control room and the actual conditions in the field is problematic because it impairs the ability of field crews to make reliable and safe decisions when operating the equipment.

In 2011, three similar incidents were reported, causing Toronto Hydro to suspend all work activities involving SCADA-Mate R1 switches. The details of these incidents were communicated to Toronto Hydro crews through internal safety bulletins, as disclosed in section Appendix A.

Following the 2008 and 2011 incidents, Toronto Hydro conducted a joint investigation with the manufacturer, S&C Electric Ltd., to determine why the R1 switches malfunctioned. The conclusion of the investigation was that that the failures were caused by corrosion of the internal components of the equipment (see Figures 5 and 6). Corrosion was attributed to the design of the breather hole, located at the rear of the motor (Figure 7), which allows moisture to condense and water to collect. As seen in Figure 7, the source of the corrosion is only visible when the switch is disassembled. Since corrosion occurs internally, there are no visual indicators to determine which switches are damaged to the point where a malfunction could occur (see Figure 6 below). As a result, following its investigation and using an abundance of caution, Toronto Hydro concluded that the safest course of action would be to assume that all SCADA-Mate R1 switches are defective and pose safety hazards.

Detailed discussion on the defect of SCADA-Mate R1 switches was provided in Phase 1 of the 2012-2014 IRM filing (EB-2012-0064: Tab 4, Schedule B8).

FIGURE 4: DEFECTIVE SCADA-MATE R1 SWITCH USED FOR INTERNAL INVESTIGATION

The photos below illustrate the components of a disassembled SCADA-Mate R1 switch that had failed.

FIGURE 5 : FIRST LAYER OF DISASSEMBLY OF THE FAILED SCADA-MATE R1 SWITCH

FIGURE 6: CORRODED COMPONENTS INSIDE THE MOTOR OPERATOR OF THE FAILED SCADA-MATE R1 SWITCH

FIGURE 7: BREATHER INSIDE THE MOTOR OPERATOR OF FAILED SCADA-MATE R1 SWITCH

Following the 2008 and 2011 incidents, Toronto Hydro determined that it is no longer safe to use the SCADA-Mate R1 switch to create an open isolation point when crews need to perform work on a feeder. Since this is the most common and efficient method to repair faults and restore customers, Toronto Hydro's operational abilities have been impaired. Not being able to use the SCADA-Mate switches means that the isolation open must be established at the next loadbreak switch. In some cases, the loadbreak switch may be at the station, resulting in an outage on the entire feeder. In other circumstances, where a SCADA-Mate R1 switch is tied to another feeder, isolation may necessarily extend to the other feeder as well, effectively resulting in an unplanned outage on an additional feeder. In short, not being able to use SCADA-Mate R1 switches to isolate and restore faulty feeders means that more customers will experience outages on a feeder than would otherwise be affected if the SCADA-Mate switch operated as intended.

The SCADA-Mate R1 switches can still be used to transfer load and reconfigure the feeder using the interrupters as long as a physical open point is not required. However, because these switches are considered defective and unsafe, Toronto Hydro crews have not performed maintenance on them since 2011. The lack of maintenance means that these switches have likely been experiencing accelerated degradation since 2011. For example, the maintenance lifecycle to replace the backup battery in the RTU is every three years. The backup battery is required to ensure that the SCADA-Mate is powered to communicate and operate when there is a power outage and its primary source of power is no longer there. It is assumed that the majority of the

batteries will have very little capacity, if any, to supply backup power to the RTU and switch during an outage by 2015 and beyond.

Toronto Hydro's intends to replace the remaining SCADA-Mate R1 switching units with the SCADA-Mate R2 switching unit, which is portrayed below in Figure 8.

FIGURE 8: SCADA-MATE R2 SWITCH

The R2 is a new model of SCADA-Mate switch, and it has been used in Toronto Hydro's overhead system since September of 2000. A key features of the SCADA-Mate R2 is that it comes equipped with an interlock mechanism that blocks the operation of the visible air-gap disconnect until the interrupters are opened. Unlike the R1 interlock that opens the interrupters when the disconnect switches are being opened, this mechanism blocks the disconnect switches from opening if the interrupter is closed. This feature eliminates the arc-flash hazard posed by the R1 model. In addition, the R2 switch allows crews to operate the interrupter switch remotely or on-site from the local push button.

Another important feature of the R2 model is the ventilation mechanism, which has extra drain holes and vents that prevent condensation and water build-up by allowing the water dissipate before it corrodes the motor operator's internal components. An additional feature associated with the R2 models is the ability to open and close the interrupters multiple times without a 120V supply or battery backup by building a charge through a built in pull ring. In comparison, the R1 switches only allow one interrupter operation in the absence of the 120V supply. The ability of the

R2 to operate without the 120V supply improves the operational flexibility and reliability of the switch.

Toronto Hydro expects this program to offer significant reliability benefits, as functioning SCADA-Mate switches serve a critical role in reducing the duration of outages. To illustrate, it typically takes a control room operator 30 minutes to locate and isolate a feeder fault and restore the unaffected portions of the feeder using the SCADA-Mate switching functionality. In the absence of SCADA-Mate, a field crew must be deployed to determine the location of the fault, manually isolate the faulted section, and restore the remaining feeder. On average, this task takes three hours to complete. In some cases, where a feeder has many R1 switches, crews may need to leave the entire feeder isolated, and install or utilize existing disconnect switches to minimize impacts to the customers.

The importance of maintaining control of trunk related outages is illustrated in Figure 10 by comparing the SAIDI impact of trunk related outages to lateral ones. The feeder consists of the trunk, which is the main section of the feeder that is connected to the substation that supplies it. The laterals branch off the trunk section of the feeder and are usually protected by fuses. The laterals almost exclusively supply the customers on the feeder. When an outage occurs, the lateral contains the fault by isolating with a fuse. When an outage occurs on the trunk it affects the entire feeder as the trunk supplies all the laterals. The SCADA-Mate switches are then required to isolate the fault on the trunk and resupply the remaining portion of the feeder. As a result, the duration of outages on feeder trunks are almost twice as long as the duration of outages on laterals; a trunk outage typically lasts 40 minutes while a lateral outages lasts 20. If a trunk related outage cannot be managed and restored via SCADA-Mate switches, the outage duration will increase throughout the system as crews will have to manually locate and isolate the fault while restoring the unaffected sections. Furthermore, if the crew has difficulty isolating the faulted section of the feeder because the available switches are SCADA-Mate R1 switches, they will have to move upstream to the next available loadbreak switch or install a disconnect switch themselves as an isolation point.

FIGURE 9: SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI) COMPARISON BETWEEN TRUNK AND LATERALS

Functioning SCADA-Mate switches play an important role in the deployment of future technologies, such as feeder automation (see section E7.3 Feeder Automation) or other future technologies that may utilize the sensory capabilities and remote functionalities of this equipment. The switches generate efficiencies with respect to implementing future smart grid applications by utilizing the hardware of the SCADA-Mate switches. For example, by programming the controllers with Feeder Automation software and incorporating these switches into that solution, system restoration efforts would benefit and the operational workloads for the controller would decrease.

The R2 switch comes with a ratchet operation that allows the motor to wind the spring just short of its release point and hold it there until a switching operation is initiated. The interrupters can be operated remotely or on site from the local push button causing the motor to wind the spring past its release point and change the switch state. This allows the interrupter to be operated to an open or close position if the controller loses its 120V supply or battery backup. If field crews require to open the interrupter and the RTU controller had lost all power, the crew could still operate it using ratchet operation, which would then allow a safe method to open the disconnect switch.

E6.8.3.2 Asset Details

(i) Asset Lifecycle

With regular maintenance, the useful life of a SCADA-Mate switching unit is approximately 40 years. The majority of the SCADA-mate R1 switches targeted by this program were installed in the mid to late 1990's and have an average age of approximately 15 to 20 years. However, due to internal corrosion, the expected operational lifecycle of the R1 switching unit has been reduced to approximately less than half of what was expected. As such, Toronto Hydro is replacing these units due to their deterioration and their inability to function as required rather than because of their age.

Toronto Hydro expects that the malfunction rate will increase with respect to the remaining useful functions (i.e., interrupter usage for load transfers and sensory functions on the feeder) because maintenance activities can no longer be performed on these switches as mentioned earlier. Toronto Hydro anticipates that the first issue that will arise with respect to these switches is the depletion of the backup battery, as batteries have a replacement cycle of three years. By the time this program is deployed, the batteries will have not been replaced for four years, which means that any functionality will likely be lost if the switch loses its 120V power supply. The absence of battery power is problematic when a power outage occurs because the switch will go unpowered; if a fault occurs, the switch will not operate as needed.

(ii) Asset Failure Impacts

All SCADA-Mate R1 switches are considered defective and cannot be operated as intended. As a result, they do not have the capability to perform any load breaking operations, which means that Toronto Hydro must de-energize the circuit when it requires any isolation using SCADA-Mate R1 switches. The inability to operate SCADA-Mate R1's to isolate sections of the feeder during a fault impacts all customers associated with that section of feeder. The load breaking must be done at another location further upstream from the fault, causing more customers to experience an outage and for a longer duration than would otherwise be required. Figure 10 illustrates the situation where restoring a fault is more complicated due to the lack of an operating switch. The figure shows a simple feeder configuration where one of the switches is a SCADA-Mate R1 switch. When a fault occurs crews cannot create a physical air-gap using the disconnect switch on the SCADA-Mate R1 switch and have to deploy to the next location to create the open point. This causes an additional section of the feeder to be without power and, as a result, more customers experience an outage. While every feeder is configured differently, on average, a fault

could affect approximately a third of the feeder's load (typically about 5 MVA) and could affect approximately 1,000 customers.

FIGURE 10: OPERATIONAL DIFFICULTIES WITH SCADA-MATE R1 SWITCHES

Since crews cannot perform maintenance on SCADA-Mate R1 switches, component related failures are expected to increase, contributing to feeder outages where these switches are located, and impairing the remaining functionality of these switches (i.e., remote load transfers and sensory functions on the feeder). Along with not being able to use these switch locations to create an open air-gap, this could create issues with respect to sensing the status of the feeder and the ability to remotely operate the interrupter switches, particularly if there is a loss of supply due to battery depletion or further physical damage due to corrosion.

E6.8.4 Timing & Pacing of the Program

Following the OEB approval of the SCADA-Mate R1 capital investments, which were included as part of the Incremental Capital Module (ICM) within Toronto Hydro's 2012-2014 rate filing, Toronto Hydro commenced projects in 2013 designed to replace malfunctioning SCADA-Mate R1 switching units. To date, Toronto Hydro has replaced 90 R1 SCADA-Mate switches. Toronto Hydro proposes to replace all remaining R1 switching units from 2015 to 2017, with spending levels noted in the table below. Toronto Hydro is proposing an aggressive replacement program in order to reduce the duration of customer outages and address the known safety risks in a timely fashion. Due to the numerous safety, reliability and operational issues associated with SCADA-Mate R1 switches, Toronto Hydro cannot defer or delay this program.

TABLE 4: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	-	-	-	1.90	2.57	6.16	4.11	2.69	-	-

There is an increase in spending from 2014 to 2015 to accommodate carry-over projects from the 2012 to 2014 ICM program. Furthermore, the first two years of the program will address the highest priority and most urgent switches.

The replacement of switches must be performed in phases in order to mitigate the risks associated with practical considerations such as operational constraints, feeder loading restrictions, limited control room resources, and limited protection and control resources. Working in phases will allow the timely completion of this project given resource constraints.

E6.8.4.1 Ranking & Prioritization

The entire SCADA-Mate R1 switch population requires replacement as soon as possible. The ranking and prioritization of the replacement of the SCADA-Mate R1 switches is based on the following criteria:

- Switches on feeders near heavily contaminated areas and/or using obsolete RTU's
- Switches that are on feeders that have historically had outages on the feeder's trunk

SCADA-Mate R1 switches that are on feeders near heavily contaminated areas such as highways and arterial roads and that are using obsolete RTU's are at risk of being damaged due to excessive corrosion or failure of an unsupported obsolete RTU. Accordingly, these switches

were given highest priority. Next, Toronto Hydro plans to focus on switches that are on feeders that have historically experienced outages on the feeder's trunk as this is the main section of the feeder on which SCADA-Mate switches perform their switching operations. Toronto Hydro will address feeders with the highest number of outage events on the trunk first.

E6.8.5 Program Execution

As mentioned in section E6.8.4.1, the program must be executed in phases due to operational constraints, feeder loading restrictions, limited control room resources, and limited protection and control resources. To manage these constraints, Toronto Hydro plans to group the work by feeder in line with its prioritization scheme discussed in the previous section. Executing work in this manner will enable Toronto Hydro controllers to manage the work in an effective and efficient manner. Toronto Hydro will also create contingency plans in the event of outages. Where possible, Toronto Hydro will group switch replacements by geographic region in order to reduce travel times.

The construction execution process involves coordination with construction crews, the control room, and program and control (P&C) crews. Before any construction commences, the control room requires a feeder plan of the type of work involved and to ensure that customers will be supplied by alternative routes. The typical switch replacement process requires that the switch be isolated from the primary feeder circuit by connecting jumpers on the primary to bypass the switch, essentially creating a short circuit in parallel with the switch. The switches are then disconnected from the primary feeder and the switch is removed from the pole. The new switch is installed, programmed by the P&C crew and tested for operation on location and remotely from the control room. If the switch passes the testing phase, it is connected back to the primary feeder and the jumpers are disconnected.

If the RTU is obsolete (such as a MOSCAD RTU) or the radio unit requires upgrading to the new SD-9 radio, it will be replaced during the switch replacement. Replacing obsolete RTU units while the switch is being removed also allows the entire switch to be brought up to standard with the most recent RTU and radio at the same time, instead of using two separate construction schedules to replace each piece of equipment. At times during complete switch installations, poles will be replaced if necessary in order to avoid having to undertake additional construction at a later time. If the switch and the RTU require replacement, it is assumed that the pole will require replacement as well. It is also assumed that every location will require a new SD-9 radio since most switches are using an obsolete radio system.

E6.8.5.1 Program Risks

The main risks to completing this program are summarized below:

- Operational Constraints: The SCADA-Mate switches are located on the main portion of the feeder known as the trunk. If an alternate supply does not exist to supply all the customers on that feeder, then complex switching and temporary disconnect switch installations will be required to minimize outages associated with the work.

- Feeder Loading Restrictions: During the summer, feeders are running at capacity and transferring any load over to a feeder to accommodate work can increase the risk of an outage due to the over-loading of a feeder. In order to reduce this risk, certain program phases that affect areas that have lighter loads will be planned and executed in the summer.

- Limited Control Room Resources : There are limited control room resources available to accommodate the large number of planned outages associated with this program. This risk is mitigated by planning the work in geographical phases and trying to replace as many switches on a feeder as possible at the same time in order to reduce the number of planned outages required.

- Limited Protection and Control Resources: There are a limited number of protection and control resources available for commissioning and decommissioning of the SCADA-Mate switches. By keeping the work in a local area, Toronto Hydro will reduce the travel time associated with commissioning and will allow control room resources to focus on localized areas.

E6.8.6 Evaluation of Alternatives

E6.8.6.1 Quantification/Evaluation of Options

Toronto Hydro evaluated three options to address the problems associated with the SCADA-Mate R1 switches.

Option 1: Status Quo

The status quo option involves replacing R1 switches upon failure and continuing to use them in their limited capacity, such as for sensing and interrupter switch control. Toronto Hydro does not recommend maintaining the status quo for following reasons.

- Although R1 switches have some remaining functionality, they no longer provide Toronto Hydro with the full suite of services that Toronto Hydro requires to effectively manage and operate the distribution system. The limited functionality of the SCADA-Mate R1 switches prolongs the duration of outages and causes more customers to experience an outage than would otherwise be required if the SCADA-Mate switches functioned as designed.

- Since maintenance in not performed on the SCADA-Mate R1 switches (as it is classified as defective equipment), their rate of failure is expected to increase.

- Toronto Hydro expects that backup batteries will no longer function adequately by 2015 because they have not been replaced since 2011, and cannot be replaced due the safety hazards associated with this equipment. As mentioned earlier, the backup battery requires replacement every four years for to ensure adequate functionality. When there is an outage and the main 120 V supply is lost to the switch, RTU and communication systems require backup power from the battery. If there is no backup to the 120 V supply, the already limited functionality of SCADA-Mate switches will be impacted further.

- Replacing switches reactively would prolong the time that defective switches remain in service. Accordingly, the operational and safety issues related to these defective switches would remain and the risk of failure would increase due to a lack of maintenance.

Option 2: Install Retrofit Kit Provided by the Manufacturer

The second option is for the manufacturer to install a retrofit kit that will upgrade the SCADA-Mate R1 switch into an R2 switch. Toronto Hydro does not recommend this option for the following reasons:

- The retrofit kit can only be installed by the manufacturer at its facilities; therefore, this option requires the switch to be removed from the pole and to be delivered to the manufacturer. A replacement R2 switch from storage would have to be installed in place of the removed R1 that has been shipped for retrofitting. When the manufacturer returns the retrofitted switch, it would then be installed in another location. This process is costly and time consuming.

- The retrofit kit does not upgrade all the components of the switch; it only upgrades the motor operator to the R2 version. The motor operator is the source of where moisture and corrosion builds; however, if corrosion has spread to other parts of the unit, the switch will remain defective regardless of the retrofit.

The cost of retrofitting a switch is $3,600 less than the cost of replacing the switch. If further corrosion has occurred beyond the motor mechanism that is being replaced, the switch is deemed unsafe and would have to be scrapped, negating potential savings.

Option 3: Replace SCADA-Mate R1 Switches with New R2 Switches

The third option is to proactively replace the SCADA-Mate R1 switches with SCADA-Mate R2 switches. Toronto Hydro recommends this option because it addresses the safety, reliability and operational issues associated with the SCADA-Mate R1 switches and generates a net benefit of $100.66 million as explained below.

The cost of ownership (COO) and program net benefit (NPV) associated with the SCADA-Mate R1 Renewal program is further detailed in Table 5. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities in this program. The cost of ownership (COO) of a state reflects the risk of asset failure, including both direct and indirect costs; these costs include customer interruptions, emergency repairs, and asset replacements associated with a given state. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NAR_E) and proposed (NAR_N) state. Non-asset risks are further explained in Section D3.3. All of these factors combine

to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3.

When the difference in cost of ownership ($\hat{u}COO_1$) is compared to the associated program costs (PC_1) for the first of activities, SCADAMATE R1 Renewal produces a net benefit (NPV_1) value of $100.66 million, as shown in Tables 5 and 6.

TABLE 5: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	334.82
Non Asset Risk [NAR_E]	1023.04
Maintenance Cost [MC_E]	0
Additional Quantifiable Benefits [AQB_E]	0
Cost of Ownership of Existing Assets [COO_E]	1357.87

TABLE 6: SCADAMATE R1 REPLACEMENT BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 1: SCADAMATE R1 Replacement (N)	
Asset Risk [AR_N]	283.79
Non Asset Risk [NAR_N]	967.26
Maintenance Cost [MC_N]	0
Additional Quantifiable Benefits [AQB_N]	0
Cost of Ownership of New Assets [COO_N]	1251.05
Option 1: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_N)$]	106.82
Program Cost [PC_1]	6.16
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	100.66

E6.8.7 2015 Project Details

Table 7 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

(a) previously filed projects that appeared as jobs in the OEB approved SCADA-Mate R1 Switches segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 7: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	CIR Projects
1.72	4.44

In total, the 2015 work program is targeting the replacement of 72 SCADA-Mate R1 switches. Table 8 lists all projects that will be partially or completely executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

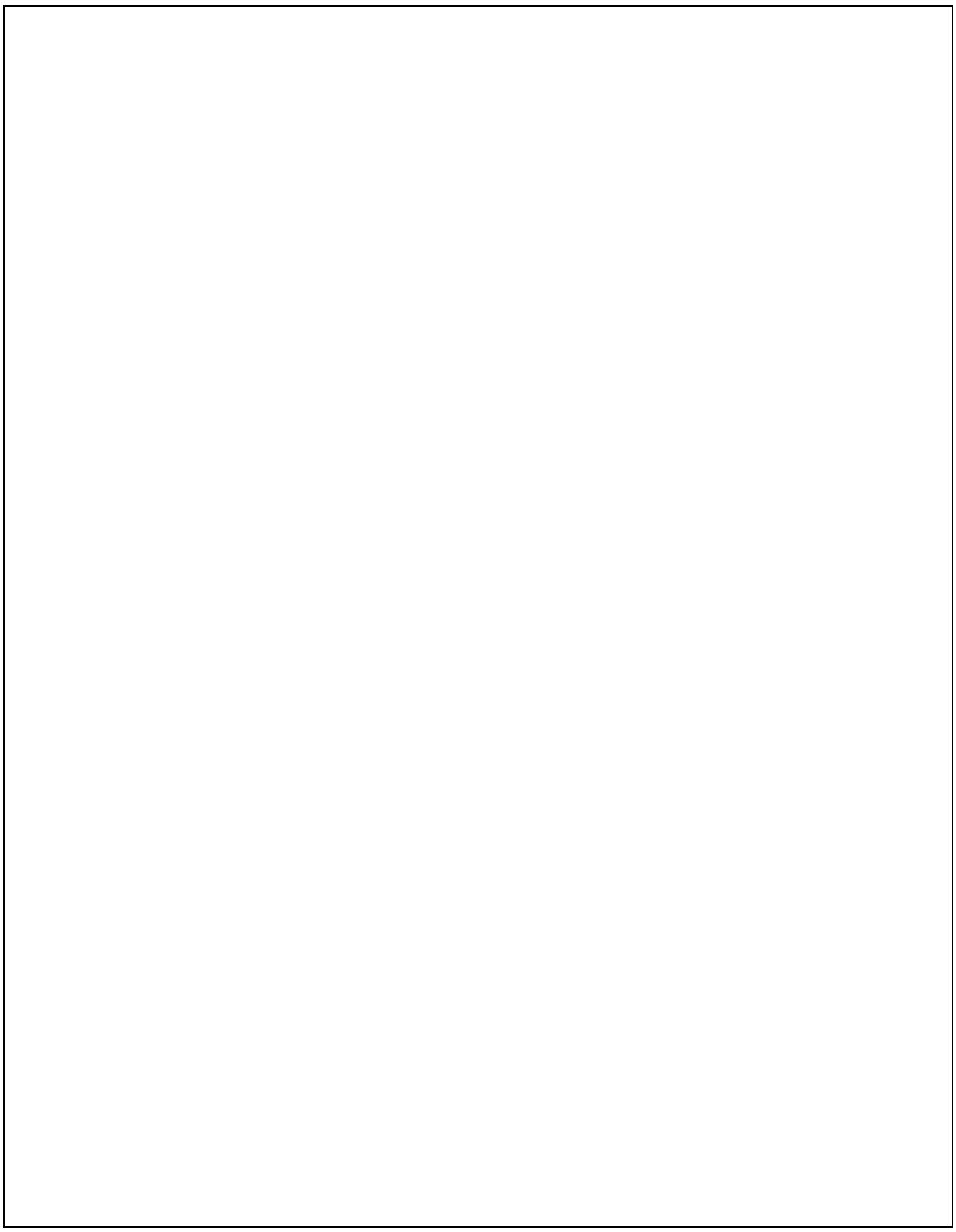
TABLE 8: 2015 PROJECTS

Project Number	Project Name	Total Project Cost ($M)	Start Date	Project Type (ICM or CIR)
W14630	W14630-P11-R1 Replacement Richview PH1, Richview TS	0.59	2015	ICM
W14631	W14631-P11-R1 Replacement Richview PH2, Richview TS	0.52	2015	ICM
W14649	W14649-P11-R1 Replacement North York Ph1, Runnymede TS, Finch TS	0.32	2015	ICM
W14650	W14650-P11-R1 SCADA Replacement North York PH2, Richview TS, Leslie MS	0.29	2015	ICM
E15497	E15497 Sheppard West TS feeders R1 Replacement NA47 SCNA47M13	0.87	2015	CIR
E15496	E15496 Sheppard East TS feeders R1 Replacement NT47 SCNT47M1	0.66	2015	CIR
X15551	X15551 Duplex R1 SCADA Replacements	0.31	2015	CIR
X15546	X15546 Main R1 SCADA Replacements	0.45	2015	CIR
X15554	X15554 Dufferin R1 SCADA Replacements Phase 1	0.66	2015	CIR

Project Number	Project Name	Total Project Cost ($M)	Start Date	Project Type (ICM or CIR)
X15555	X15555 Dufferin R1 SCADA Replacements Phase 2	0.31	2015	CIR
X15556	X15556 Dufferin R1 SCADA Replacements Phase 3	0.59	2015	CIR
X15534	X15534 George and Duke R1 SCADA Replacements	0.59	2015	CIR

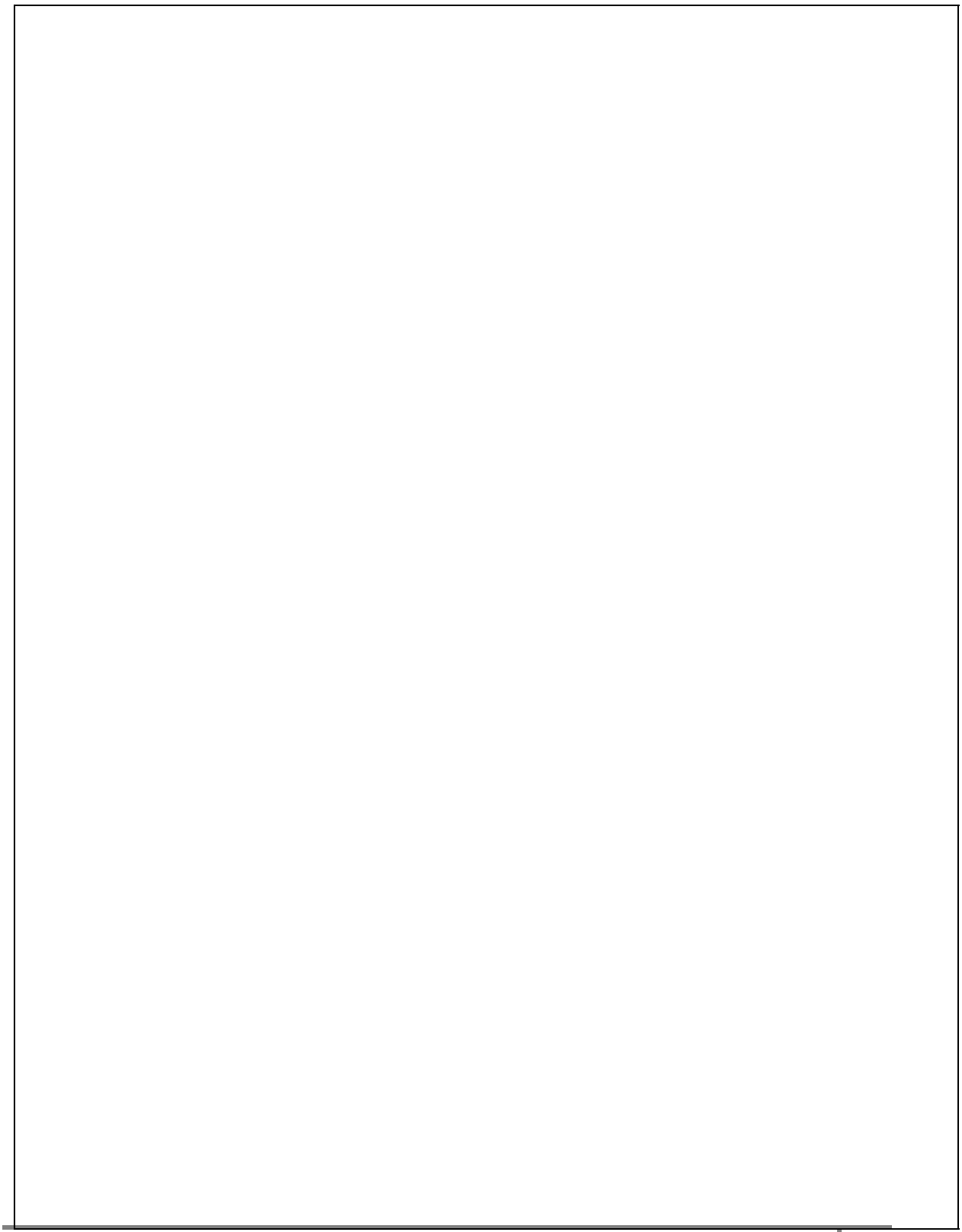
Appendix A	SCADA-MATE R1 SWITCH RENEWAL BULLETINS & LETTERS

A1 Environment Safety and Health Bulletin 2008

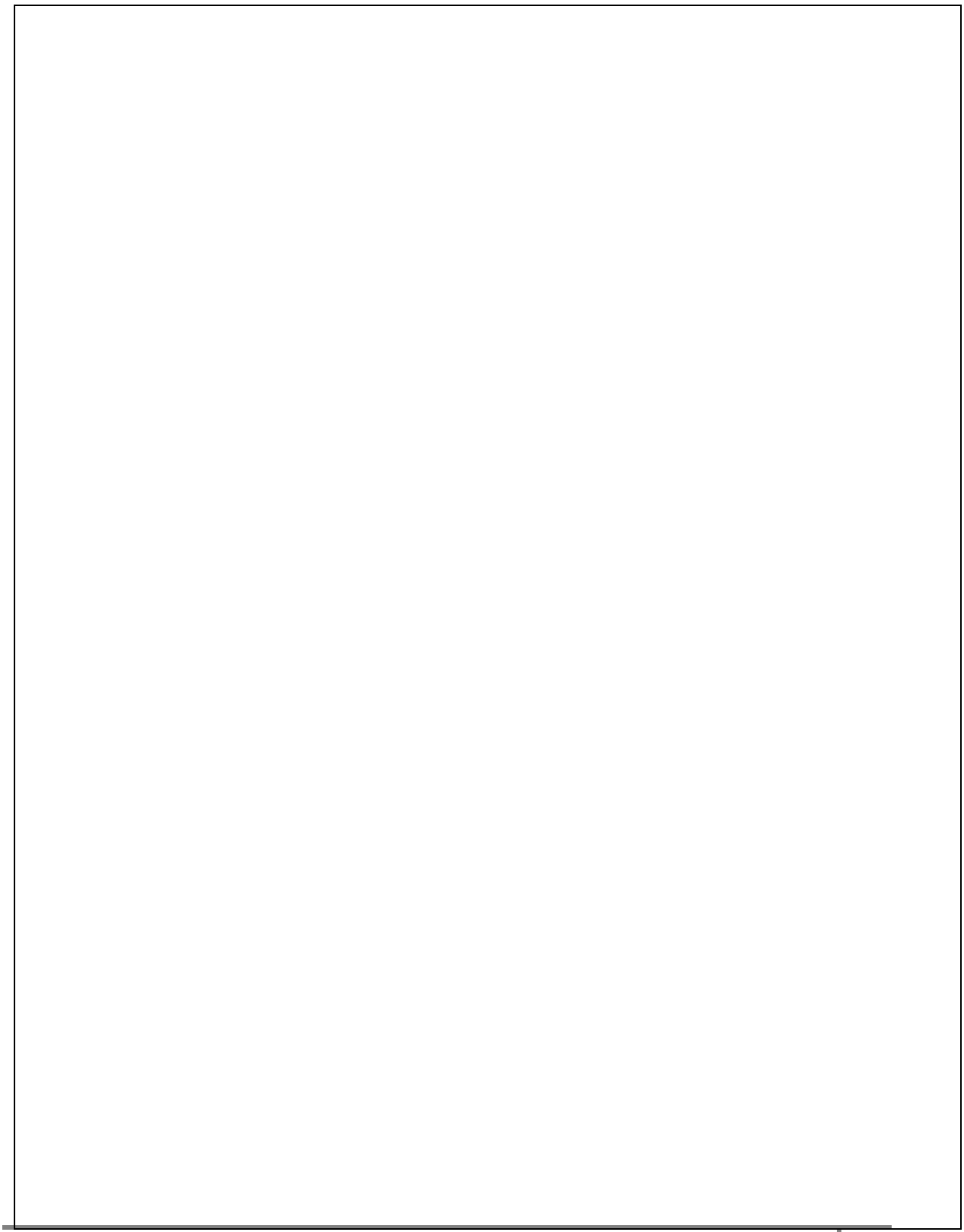


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A2 Environment Safety and Health Bulletin 2011



A3 Environment Safety and Health Bulletin 2012



A4 Letter from S&C Electric Canada Ltd. Apr 2011

E6.9 Network Vault Renewal

EQUIPMENT PLACEMENT IN NEWLY BUILT VAULT

E6.9.1 Summary

Program Description

The Network Vault Renewal program is a continuation of the network vault rebuild and decommissioning activities previously detailed in Phase 1 and 2 of Toronto Hydro's 2012-2014 ICM application. The projects that comprise this program are identical in nature to the jobs in the Network Vaults and Roofs segment approved by the OEB in EB-2012-00641.

The network vaults associated with the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown Toronto core. The function of the network vaults is to provide physical isolation from energized Toronto Hydro equipment. Today, there are many critical structural issues inherent with the condition of these assets, which must be addressed in order to mitigate (1) potential failure risks that can negatively impact the reliability and effective operation of Toronto Hydro's distribution system and (2) potential safety risks to the public and Toronto Hydro's crews.

The Network Vault Renewal program is designed to address these condition related issues when they can no longer be mitigated by routine maintenance. The function of the network vaults is to provide physical isolation from energized Toronto Hydro equipment. The vaults identified for

[1] EB-2012-0064, Tab 4, Schedule B9.

renewal in this program require one of the following three interventions during the 2015-2019 period.

(1) Toronto Hydro plans to decommission two vaults where load displacement has eliminated the need for the vaults.

(2) Toronto Hydro plans to rebuild 15 network vault roofs that have been identified as having severe structural deficiencies, but which are located on network vaults that are otherwise structurally sound.

(3) Toronto Hydro plans to rebuild 40 network vaults that have been identified as having severe structural deficiencies requiring a complete reconstruction. These vaults cannot be decommissioned, but require more extensive repairs beyond a vault roof replacement.

The anticipated benefits of the Network Vault Renewal program are summarized in the following table.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Helps ensure physical isolation from Toronto Hydro equipment for heavy pedestrian traffic ƒ Ensures safe and uninterrupted passage for pedestrians, as a deteriorated vault structure may need to be cordoned off, causing interruption in pedestrian traffic
Reliability	ƒ Reduction of failure risk; outages related to deteriorated network vaults can affect power supply to approximately 500 to 3000 customers ƒ New standards implemented to build two separate adjacent civil structures for vaults with two transformers will help safeguard against vault fires spreading from one transformer to the other
Safety	ƒ Helps safeguard the public and Toronto Hydro crews against tripping hazards ƒ Mitigation of slipping and falling hazards, especially in bad weather. ƒ Toronto Hydro vaults are designed as per "Canadian Highway Bridge Design Code" CSA-S6-06 CL-625 ONT Live Loading. During emergencies, a fire truck may be required to park over the sidewalk where the vault is located. In such a case, a badly deteriorated vault roof and structure may not be able to hold the load of a fire truck and thus compromise the emergency response team's ability to provide services
Efficiency	ƒ New standard galvanized beams used for roofs are expected to age at a slower rate than non-galvanized beams ƒ Fibreglass rebar is being investigated for use in 2015-2019 projects; this will help reduce the aging process due to corroding metal rebar

Program Drivers

The trigger and secondary drivers for Network Vault Renewal program are summarized in the following table.

TABLE B: PROGRAM DRIVERS

	Drivers	Reasoning
Trigger Driver	Failure Risk	ƒ 80% of the vault roofs are over 25 years old. ƒ Over 60% of the vaults will be 60 years or older within 10 years. ƒ Accelerated aging of some vaults has been observed ƒ Poor vault condition is expected to contribute to the poor condition of electrical assets housed inside the vault, impacting reliability of distribution system
Secondary Drivers	Safety	ƒ Risk of tripping and slipping to the public and Toronto Hydro employees

Preferred Alternative

Toronto Hydro evaluated the following alternatives for addressing the assets in this program:

(1) Continue with routine maintenance repairs until such time that reactive replacement is required, typically after a structural failure.

(2) Renew the network vaults which are in poor condition before there is a structural failure.

Option II is the preferred alternative as it reduces the risk of injury to the public and Toronto Hydro employees, while also reducing the risk to system reliability due to asset failure.

The completion of the first year of activities in this program will result in an avoided estimated risk cost (ARC) of $4.63 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.9.7).

Timing and Pacing

Toronto Hydro invested $17.02 million in network vault renewals between 2010 and 2013. The investment level for 2014 is forecasted to be $0.93 million, which is lower than previous and future amounts due to resource constraints. The amount and pace of future spending is based on

need that was evaluated using the ACA and additional civil assessments. Thus, Toronto Hydro plans to rehabilitate 57 of the highest risk vaults during this planning horizon.

Table C provides historical and projected program spending.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	1.69	0.87	3.65	10.81	0.93	3.95	10.37	10.29	10.25	10.24

Through its workforce staffing strategy (Exhibit 4A, Tab 4, Schedule 3), Toronto Hydro is working to ensure that the required resources are available to carry out a pace in 2016-2019 that is equivalent to what was achieved in 2013. Renewing at this pace will allow Toronto Hydro to address many of the vaults that require near-term proactive action given the utility's limited resources to perform this complex work. Given the relatively slow pace of vault rehabilitation relative to the age of the asset population, Toronto Hydro plans to continue to implement a rigorous network vault maintenance program to patch up deficiencies appearing in the increasing number of aging network vaults. This maintenance program includes inspection of network vault structures every six months and the issuance of work orders for required patch work to fix deficiencies.

E6.9.2 Program Description

The Network Vault Renewal program is a continuation of the network vault rebuild and decommissioning activities previously detailed in Phase 1 and 2 of Toronto Hydro's 2012-2014 ICM application. The projects that comprise this program are identical in nature to the jobs in the Network Vaults and Roofs segment approved by the OEB in EB-2012-0064.

The network vaults associated with the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown Toronto core. Today, there are many critical structural issues inherent with the condition of these assets, which must be addressed in order to mitigate (1) potential failure risks that can negatively impact the reliability and effective operation of Toronto Hydro's distribution system and (2) potential safety risks to the public and Toronto Hydro's crews

Toronto Hydro works to ensure that customers are not only supplied reliable electricity, but are also provided physical isolation from energized Toronto Hydro equipment. This is especially important in dense downtown core areas where pedestrian traffic can be heavy and many people rely on safe passage to make their way from one destination to another. If a vault roof or structure fails, it is highly likely to disrupt the pedestrian traffic resulting from rerouting of the walkway, which can be very challenging in busy downtown core areas. Degradation of these vaults can expose customers to hazards, such as tripping or more critical safety risks as further explained in section E6.9.3.

As vaults are inspected each year, maintenance to the civil structure is typically performed as needed to fix small problems and to further extend the life of a vault. However, once a vault reaches the point where there are major structural failures and maintenance can no longer sufficiently address the problem, Toronto Hydro considers one of three different options:

(1) Decommissioning the vault

(2) Rebuilding the vault roof

(3) Rebuilding the entire vault

Toronto Hydro also considers evolving customer needs and system requirements when choosing the best intervention for any given vault location.

With the 2015-2019 Network Vault Renewal program, Toronto Hydro plans to eliminate immediate structural vault deficiencies of 57 high risk vaults identified through Toronto Hydro's Asset Condition Assessment (ACA) process as being in "poor" or "very poor" condition. In

addition to the ACA process, Toronto Hydro carries out civil assessments wherein a civil engineer visually inspects the network vault roof and walls to recommend whether a roof or whole vault rebuild is required (see section E6.9.3.5 for additional details).

The 2015 to 2019 program includes decommissioning two vaults, rebuilding 15 vault roofs and completely rebuilding 40 vaults. Figure 1 shows the various projects forecasted to be completed during this timeframe. The estimated total cost of this program over 2015-2019 period is $45.1 million.

FIGURE 1: LOCATIONS OF NETWORK VAULT RENEWAL PROJECTS 2015-2019

The following subsections describe each of the three network vault intervention options in additional detail.

E6.9.2.1 Network Vault Decommissioning

Toronto Hydro plans to decommission two network vaults between 2015 and 2019 where load displacement has eliminated the need for the vaults. This will remove any structural deficiencies associated with these vaults and any corresponding system reliability or safety issues for both Toronto Hydro crews and pedestrians.

Load displacement on the original secondary network system is largely due to development in the downtown area. When buildings in the city are redeveloped, the low voltage network connection is typically no longer a viable option for the customer. This is because redeveloped or new buildings usually have a customer-owned substation inside the building, with a supply configuration that is either 'dual radial' or 'spot network'. If Toronto Hydro no longer requires the secondary network system capacity from a specific vault, that vault can be decommissioned. The typical cost to decommission a vault is approximately $50,000 and it takes approximately one month to perform the work. Decommissioning a network vault involves removing the network transformer and protectors within the vault, along with primary and/or secondary cables. The empty vault is then backfilled with gravel, and the sidewalk overtop is rebuilt. Figure 2 below shows a vault in the process of being decommissioned.

FIGURE 2: IN-PROGRESS VAULT DECOMMISSIONING

E6.9.2.2 Network Vault Roof Rebuild

Toronto Hydro plans to rebuild 15 network vault roofs between 2015 and 2019 that have been identified as having severe structural deficiencies (see section E6.9.3 for additional details), but which are located on network vaults that are otherwise structurally sound. A network vault roof rebuild is not as complex as a complete vault rebuild, but replacement or re-arrangement of the secondary and primary cables within the vault is still required. This involves the removal of the existing damaged roof and replacement with a new vault roof.

Rebuilding the network vault roof can take between three and nine months to perform because (1) a temporary roof (refer to Figures 3, 4 and 5 below) must be constructed to protect the vault equipment, cables and fuse panels, (2) work restrictions prevent work during peak pedestrian times, and (3) extensive precautions are required due to work safely around live electrical equipment. The work also involves removing any Asbestos-Insulated Lead-Covered (AILC) secondary cable and Paper-Insulated Lead-Covered (PILC) primary cables, installing new primary and secondary cables, rebuilding the actual vault roof and rebuilding the adjoining sidewalk. New standard galvanized beams are also used to hold the roof slabs in place, which help reduce the rate of corrosion caused by seepage of salty water. The typical cost of rebuilding a vault roof is approximately $250,000.

While the overall network vault has a useful life of 60 years, network vault roofs must be rebuilt more frequently because of their relatively modest useful life of 25 years. The useful life for a vault roof is shorter because it undergoes significantly more stress from pedestrian traffic, snowplows and salting.

Figure 3 shows a vault roof during a rebuild process. The roof is in the process of being demolished while a temporary roof is put in place to cover the electrical assets housed inside the vault. Figures 4 and 5 show a new roof in the rebuilding phase and a completed vault roof.

FIGURE 3: TEMPORARY ROOF BEFORE NEW ROOF IS BUILT

FIGURE 4: TEMPORARY ROOF BEFORE NEW ROOF IS BUILT

FIGURE 5: COMPLETED VAULT ROOF

E6.9.2.3 Network Vault Rebuild

Toronto Hydro plans to rebuild 40 network vaults that have been identified as having severe structural deficiencies requiring a complete reconstruction. These vaults cannot be decommissioned, but require more extensive repairs beyond a vault roof replacement.

A complete rebuild or relocation of defective network vaults in some cases requires rebuilding the neighbouring cable chamber, installing new ducts and replacing both the primary cables and secondary grid cables. Also, in order to maintain power to customers during a vault rebuild, Toronto Hydro must install additional secondary cables from the network grid or add additional temporary transformers in an adjacent vault.

In some cases, the vaults will be rebuilt in the original location and existing auxiliary civil infrastructure will be maintained. In other cases, a new vault, along with auxiliary civil infrastructure, will be constructed in a new location, and the old vault will be decommissioned. In general, Toronto Hydro will replace the existing network units with new network units at the time of a full vault rebuild. This is done to avoid the planning inefficiencies inherent in returning to the same site for unit replacement at a later date. Older network vaults typically contain aging network units; however, to ensure that asset value is maximized, Toronto Hydro assesses the

remaining useful life of the removed network units and keeps a number of units with useful life remaining on hand for use in reactive replacement scenarios.

The rebuilt vaults are redesigned according to current design and construction standards. For example, Toronto Hydro currently uses galvanized steel I-beams instead of regular steel to support the vault roof, which addresses the problem of rapid corrosion caused by sidewalk salt exposure. Toronto Hydro has also updated its standards to rebuild vaults originally containing two transformers as two separate, adjacent civil structures. This will help mitigate the risk of a potential fire damaging all equipment within the vault, as a potential fire from one side will not be able to affect equipment on the other side. Furthermore, in an effort to continuously improve standards to extend the useful life of the assets, Toronto Hydro plans to investigate the use of fiberglass rebar to further enhance the vault roof and walls structure. This new material standard for vaults is expected to address problems with rebar corroding rapidly from salt exposure. Furthermore, reduction in corrosion of rebar will reduce the cost of maintenance and increase safety for Toronto Hydro crews. The investigation for this standard should conclude by the end of 2014 and the new standard is tentatively planned for deployment in 2015 to 2019 projects. The ventilation grade of vaults will also be redesigned to meet the latest applicable by-laws.

The typical cost for rebuilding a vault, including both civil and electrical work, is approximately $1 million, which includes the average costs for both civil and electrical plant replacement in adjacent network vaults. Depending on the complexity of the job, Toronto Hydro estimates that it will take between 18 and 24 months to complete a vault rebuild job (refer to section E6.9.6 for additional details). Figure 6 illustrates a fully rebuilt vault.

FIGURE 6: COMPLETELY REBUILT VAULT

Table 2 summarizes the number of assets forecasted for replacement during the 2015-2019 period.

TABLE 1: ASSETS TO BE RENEWED

Assets (Units)	2015	2016	2017	2018	2019	Total
Vaults	6	9	9	9	9	42
Roofs	4	2	2	3	4	15
UG Network Units	11	18	17	20	20	86

The Network Vault Renewal program delivers customer value in a number of ways, including improved reliability, safety and efficiency. A summary of these program benefits is provided in Table 3.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Ensures physical isolation from Toronto Hydro equipment for heavy pedestrian traffic ƒ Ensures safe and uninterrupted passage for pedestrians, as a deteriorated vault structure may need to be cordoned off, causing interruption in pedestrian traffic ƒ The completion of the first year of activities in this program will result in an avoided estimated risk cost (ARC) of $4.63 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.9.7).
Reliability	ƒ Structurally sound network vaults provide protection against physical damage to electrical equipment ƒ Reduction of failure risk; outages related to deteriorated network vaults can affect power supply to approximately 500 to 3000 customers ƒ New standards implemented to build two separate adjacent civil structures for vaults with two transformers will help safeguard against vault fires spreading from one transformer to the other
Safety	ƒ Helps safeguard the public and Toronto Hydro crews against tripping hazards ƒ Mitigation of slipping and falling hazards, especially in bad weather. ƒ Safer environment for Toronto Hydro crews working inside the network vaults, specifically from falling debris. ƒ Toronto Hydro vaults are designed as per 'Canadian Highway Bridge Design Code' CSA-S6-06 CL-625 ONT Live Loading. During emergencies, a fire truck may be required to park over the sidewalk where the vault is located. In such a case, a badly deteriorated vault roof and structure may not be able to hold the load of a fire truck and thus compromise the emergency response team's ability to provide services
Efficiency	ƒ New standard galvanized beams used for roofs are expected to age at a slower rate than non-galvanized beams ƒ Fibreglass rebar is under investigation, which Toronto Hydro anticipates using 2015-2019 projects; this will help reduce the aging process due to corroding metal rebar ƒ Avoided high costs of emergency repairs

E6.9.3 Why the Program is Needed

Network vaults are a critical part of Toronto Hydro's secondary network system, especially in the downtown core. The vaults house various types of underground equipment, including network unit(s), automatic transfer switches (ATS), reverse power breakers (RPB) and compact radial design (CRD) assets. Most of these vaults were built nearly 50 to 60 years ago and, in certain cases, network vaults have reached an unacceptably low level of physical integrity. These

conditions increase the risk of structural failure, which may cause network equipment to fail and may pose an increased risk of injury to the public and Toronto Hydro employees.

E6.9.3.1 Program Drivers

Toronto Hydro has classified the continuing Network Vault Renewal program as a System Renewal activity because the assets being addressed require immediate replacement due to age and condition. Failure risk is therefore identified as the trigger driver, with safety as a secondary driver. Table 3 explains the drivers in further detail.

TABLE 3: PROGRAM DRIVERS

	Drivers	Reasoning
Trigger Driver	Failure Risk	ƒ 80% of the vault roofs are over 25 years old. ƒ Over 60% of the vaults will be 60 years or older within 10 years. ƒ Accelerated aging of some vaults has been observed ƒ Poor vault condition is expected to contribute to the poor condition of electrical assets housed inside the vault, impacting reliability of distribution system ƒ At risk electrical assets include critical secondary network equipment, e.g. ATS, RPB, CRD, cable, etc.
Secondary Drivers	Safety	ƒ Risk of tripping and slipping to the public and Toronto Hydro employees ƒ Falling debris hazard for workers inside vaults

The structural deficiencies of the vaults that Toronto Hydro continues to address through this program are mainly caused by old age and the adverse environment. Over 80% of vault roofs have reached the end of their expected useful lifespan of 25 years. In addition, over 60% of the vault civil structures will have reached the end of their expected useful lifespan of 60 years within 10 years. As well, the ACA suggests that some vaults have been aging at an accelerated pace and require repairs even though they have yet to reach their expected end-of-life age of 60 years. These vaults are generally located in high pedestrian areas under sidewalks in the downtown core that are excessively salted in the winter to melt ice and snow. When melted, this salted water drains into the vaults, corroding and damaging the vault structure.

A network vault provides the necessary foundation for the assets contained within; a poor condition vault is expected to contribute to the poor condition of electrical assets housed inside the vault (e.g., network units, ATS, RBP, CRD assets, cables, etc.). Therefore, poor structural

condition of the vaults may lead to failure of the electrical equipment housed inside the vault, causing prolonged power outages and severely impacting the reliability of the distribution system.

Some commonly found structural deficiencies caused by asset aging and environmental factors are explained below in the following sections.

(i) Exposed Roof Rebar

Exposed roof rebar weakens the vault's roof structure and can potentially lead to the collapse of the entire network vault roof, which may damage the equipment in the vault and may pose a risk to pedestrian and Toronto Hydro crew safety, as they could suffer injuries by tripping on the crumbling or depressed vault roof. Furthermore the workers inside the vaults could face hazard from falling debris. Figure 7 shows exposed rebar on the inside of a network vault roof.

FIGURE 7: ROOF EXPOSED REBAR

(ii) Exposed Wall Rebar

The walls within a network vault are critical to the load bearing capability of the entire vault. Corrosion of the rebar within these walls significantly weakens the structural integrity of the vault as a whole. Over time, corrosion can result in the collapse of the vault walls, which may damage

the electrical assets contained within, causing a power outage and costly repairs. Figure 8 shows an example of a network vault wall with exposed rebar.

FIGURE 8: NETWORK VAULT WALL WITH EXPOSED REBAR

(iii) Corroded I-Beams

The I-beam is the major support structure for the vault roof. In addition to age, environmental factors can accelerate the corrosion of an I-beam, e.g., salt used to melt snow that seeps through the roof. This could lead to a failure of the I-beam, which may result in the complete collapse of the roof. Figure 9 below shows a heavily corroded I-beam.

FIGURE 9: CORRODED I-BEAMS

(iv) Cracked roof

A cracked roof can result in water leaking into the vault. This can accelerate the degradation of rebar and I-beams and may also lead to rusting, contamination and degradation of the electrical assets inside. Leaking water may also increase the risk of catastrophic failure of critical electrical assets such as network units. (A network unit consists of a protector and transformer, where the protector works like an automatic breaker.) If this equipment is damaged, the supply to the customer may be disrupted. In addition, pedestrians may trip and fall due to the uneven surface caused by the cracks. These risks are further illustrated in Figure 10 below.

FIGURE 10: CRACKED ROOF

(v) Cracked Wall

When a network vault wall develops cracks it increases the likelihood of water entering the vault, which may ultimately result in vault flooding, thus potentially causing a short circuit and overall outage to the secondary network system. Figure 11 illustrates a typical crack found inside a Toronto Hydro vault.

FIGURE 11: CRACKED WALL

Deferring the proposed vault and vault roof rebuild activities will likely increase the risk of structural failure that can lead to catastrophic failure of the network assets contained within the vault, ultimately leading to power outages in the downtown core.

E6.9.3.2 Asset Details

(i) Asset Lifecycle

In addition to tracking the age of its assets, Toronto Hydro analyzes the useful life of network vaults through its Asset Condition Assessment (ACA) program and additional physical inspections by civil engineers. The ACA uses inspection data to determine the condition of an asset and to drive replacement of that asset at the optimal time. The ACA for network vaults classifies vaults requiring major civil rebuilding as "very poor" or "poor". Along with ACA results, civil assessment reports have been used to prioritize vaults that require partial or complete rehabilitation. Civil assessments are carried out in addition to the ACA process by a certified civil engineer. During the assessments, a civil engineer physically conducts a visual inspection of the network vault roof and walls and comments on the extent of damage and deterioration to all parts of the vault structure. Based on these comments, the engineer recommends a roof or whole vault rebuild. When a project scope is issued, a copy of this report is attached with the package.

The replacement of a network vault may take up to 24 months to complete because of the complexity of rebuilding civil and electrical infrastructure in the downtown core. This long project timeframe necessarily means that planning for network vault rehabilitation must begin well in advance of execution.

Currently, Toronto Hydro has 1,067 network vaults in the downtown core supplying the network system. Figure 12 shows the age distribution of all network vaults with reference to the useful life of both the overall vault and the roof. While a vast majority of vaults have reached or are quickly approaching their expected end-of-life age (60% will have reached end-of-life within ten years or less), a majority (80%) of network vault roofs are already well past the vault roof expected life of 25 years and in need of a rebuild. The ACA also suggests that some vaults have been aging at an accelerated pace and require repairs even though they have yet to reach their expected end-of-life of 60 years.

Toronto Hydro plans to address six per cent of all existing network vaults between 2015 and 2019.

FIGURE 12: DISTRIBUTION OF NETWORK VAULTS

(ii) Asset Failure Impacts

As described in section E6.9.3.1, there are several failure modes and deficiencies that may lead to structural failure leading to failure of the equipment inside the vault. These failure modes are classified as exposed roof rebar, exposed wall rebar, corroded I-beams, cracked roof and cracked walls. Such damage to the network vaults is likely to negatively affect the performance of the electrical equipment contained inside, potentially contributing to a catastrophic failure of the network assets contained within the vaults and thereby causing a power outage in the downtown core. Such a power outage could impact between 500 customers (5 MVA) for smaller network grids, up to 3,000 customers (50 MVA) for the large network grids in the downtown core, and can last between several hours to a few days, depending on the location and which network distribution system is impacted by an outage. The cost of repairing the vaults under reactive circumstances – which must typically occur on weekends and during the night – are much higher than planning and performing the work during regular hours. It is also important to note that damage to equipment as a result of vault failures is often extensive (as in the case of vault fires,

for example), and tends to result in incremental costs beyond regular costs related strictly to the restoration of power.

Furthermore, deteriorated vaults may cause safety issues for the public as well as Toronto Hydro crews. Toronto Hydro values the safety of its customers and employees and takes its responsibility to ensure public safety around distribution plant very seriously. Poor condition network vaults must be rebuilt in a timely manner to avoid risk of failure and mitigate safety hazard to employees and the public.

Because these vaults are beneath sidewalks in the busy downtown core, any failure in the vault structure could cause a person to trip and fall, potentially onto hazardous areas. In addition, the risk of injury increases even more in the presence of rain and snow. To properly address this issue and maintain a high standard of safety for the customer, Toronto Hydro must address deteriorated vaults through the vault renewal program. Table 4 shows some of the potential safety risks that could occur due to deterioration of network vault structures.

TABLE 4: SAFETY RISK & DESCRIPTIONS

Safety Risk	Description
Tripping	A deteriorated vault roof may lead to tripping, which could cause injury to members of the public or Toronto Hydro crews.
Slipping	A deteriorated vault roof may lead to slipping, especially in bad weather, which could cause injury to the public or Toronto Hydro crews.
Falling	Tripping or slipping could cause a person to fall, which may result in more severe injury.
Falling Debris	Toronto Hydro crews working inside the vault may encounter falling debris from the deteriorated roof or walls of a given vault. This could lead to serious injury, especially when working near live equipment.
Fire	Poor condition of vaults can be a contributing factor to catastrophic failures such as vault fires.

The reliability of the Toronto Hydro network vaults civil structure is not only critical for the equipment housed inside the vaults but also for the safety of public and Toronto Hydro employees. For example if a vault roof is not replaced in time, later removing it to replace faulty equipment can cause it to collapse and thereby make it more dangerous and challenging for the crew to replace the equipment. In this scenario, the feeder providing power supply to the failed equipment will be turned off for longer periods of time, which will increase the risk of an outage to

the customers fed by that feeder. In order to maintain reliable service to the relevant customers, it is imperative that these assets be renewed before they fail.

Figures 13 and 14 below show the structural failure of a vault located in front of a bus shelter near a major intersection in North York (March 2010). To make this location safe, the hole in the vault roof was covered temporarily by a piece of plywood, and surrounded by pylons. This step was taken on an emergency basis until the location could be permanently fixed. This failure resulted in disruption to daily commuter traffic in the vicinity of the station and presented a potential safety hazard to pedestrians.

FIGURE 13: STRUCTURAL FAILURE OF VAULT LOCATED NEAR LAWRENCE/YONGE ST FRONT OF A BUS SHELTER, WITH PLYWOOD TEMPORARILY COVERING THE HOLE IN SIDEWALK

FIGURE 14: STRUCTURAL FAILURE OF VAULT LOCATED NEAR LAWRENCE/YONGE STREET, AS SEEN FROM WITHIN THE VAULT CHAMBER

Figure 15 below shows a network vault at another busy intersection downtown (April 2010) where a large piece of concrete has fallen off the vault wall. This was caused by a structural deficiency as a result of old age, as well as salt and water entering the vault through cracks in the vault roof and side walls. Falling concrete has the potential to cause damage to the electrical equipment resulting in power interruptions and creates a potential safety hazard for Toronto Hydro crews working inside the vault.

FIGURE 15: PHOTO OF A LARGE PORTION OF CONCRETE DETACHED FROM VAULT WALL KING/YONGE STREET

Figure 16 illustrates the failure of a vault roof located in a busy downtown area. The edges of the concrete roof cracked and fell into the vault. It was determined that both the beams and roof slabs had deteriorated due to old age and salt usage on the sidewalk during winter. As this failure occurred in a busy area with a large amount of pedestrian traffic, it posed a potential safety risk to the public.

FIGURE 16: PHOTO OF A VAULT ROOF COLLAPSED DUE TO FAILED SUPPORTING BEAM

E6.9.4 Timing & Pacing of the Program

As per the table below, the total cost of this program over the 2015-2019 period is $45.10 million.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending ($Million)					Future Spending ($Million)				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	1.69	0.87	3.65	10.81	0.93	3.95	10.37	10.29	10.25	10.24

Prior to 2010, Toronto Hydro replaced network vaults on a reactive basis. In 2010, Toronto Hydro established a proactive network vault renewal program in order to deal with the growing backlog of network vaults reaching end-of-life. Toronto Hydro expects 60% of the total population of 1,067 vaults will have reached their end-of-life during 2015 to 2019 period. To manage the reliability and safety risks associated with the high number of end-of-life vaults and vault roofs, Toronto Hydro must maintain a steady pace of proactive vault rehabilitations, complimented by an efficient maintenance program, during the forecast period and beyond.

Toronto Hydro invested $17.02 million in network vault renewals between 2010 and 2013. The investment level for 2014 is forecasted to be $0.93 million, which is lower than previous and future amounts due to resource constraints. The amount and pace of future spending is based on need that was evaluated using the ACA and additional civil assessments. Toronto Hydro plans to rehabilitate 57 of the highest risk vaults during the planning horizon. This includes decommissioning two vaults, rebuilding 15 vault roofs and completely rebuilding 40 vaults.

Through its workforce staffing strategy (Exhibit 4A, Tab 4, Schedule 3), Toronto Hydro is working to ensure that the required resources are available to carry out a pace in 2016-2019 that is equivalent to what was achieved in 2013. Renewing at this pace will allow Toronto Hydro to address many of the vaults that require near-term proactive action given the utility's limited resources to perform this complex work. Given the relatively slow pace of vault rehabilitation relative to the age of the asset population, Toronto Hydro will continue to implement a rigorous network vault maintenance program to patch up deficiencies appearing in the increasing number of aging network vaults. This maintenance program includes inspection of network vault structures every six months and the issuance of work orders for required patch work to fix deficiencies.

E6.9.4.1 Ranking & Prioritization

Toronto Hydro considers several factors when determining the sequencing of work within the Network Vault Renewal program. Some factors may be considered before others depending on the situation. However, generally, asset condition, municipal planning and customer type are considered as primary prioritization criteria. These factors are described as follows:

- Asset Condition and Safety: Asset age and condition are both determining factors when prioritizing network vault rehabilitation projects. Deterioration of a network vault poses potential safety risks to the public and Toronto Hydro employees, and can negatively affect system reliability and customer satisfaction.

- Municipal Planning: City of Toronto moratoriums are another important consideration. Specific moratoriums may already be in effect or will come in to effect during the planning and execution period of 2015 to 2019. These are generally road moratoriums where a newly paved road is not allowed to be repaved for a set period of time. Toronto Hydro coordinates with the city to obtain permits in order to perform vault rebuilds and a permit may or may not be granted based on the existing moratoriums. Toronto Hydro works with

the City to anticipate moratoriums so that projects can be appropriately advanced or deferred in coordination with pending roadwork.

- Customer Type: The type of customer is also an important factor in prioritizing projects. For example, if the customer is a hospital, that would likely result in the project being given higher priority.

E6.9.5 Program Execution

A network vault renewal project may involve decommissioning a vault, rebuilding a roof or rebuilding a whole vault. The process of decommissioning and roof rebuilding has been described in sections E6.9.2.1 and E6.9.2.2 respectively. Execution of a vault rebuild project is a more complex process that can take up to 24 months from start to finish and requires resources with specialized skills. The planning stages of the project include coordination with the city, obtaining construction permits, scheduling outages, allocating extra distribution capacity to handle contingency situations and maintaining uninterrupted supply to the customers fed from the vault being rebuilt.

Another important consideration is to ensure that the work is scheduled so that during the summer peak months vault rehabilitation work does not compromise the Toronto Hydro grid. The utility has specific summer restrictions, where operations is notified to ensure that certain feeders are flagged as at risk for being overloaded in case of a contingency situation during peak hours or summer days.

The construction process itself is complex and requires the mitigation of risks to worker and pedestrian safety while Toronto Hydro carries out construction. Figures 17 through to 22 illustrate the process of rebuilding the vault and demonstrate the complexity of the project execution in the construction phase.

Figure 17 below shows a construction crew demolishing the roof and walls. It should be noted that in many cases, as shown below, the secondary cables supplying the customers remain connected during construction of the new vault and must be protected to ensure uninterrupted supply. This requires extra caution and time to demolish and reconstruct the vault.

FIGURE 17: VAULT ROOF & WALLS BEING DEMOLISHED

Furthermore, Figure 18 below shows the new rebar framing being installed to serve as the base for the grout used to form the vault's wall and roof. Special care must be taken when installing and aligning the framing to ensure that walls and roofs are built to the design specification and hence are structurally sound. Any duct banks connected to the vault walls must also be maintained.

FIGURE 18: REBAR FRAMING FOR NEW WALLS AND ROOF

In Figure 19 below, the grouting process is illustrated, where grout is a mixture of water, cement, sand and gravel. This is another critical step in the construction process where the crew must ensure that the rebar framing is filled with grout uniformly without air pockets. If this is not done properly, it can result in unforeseen structural deficiencies.

FIGURE 19: GROUTING FOR VAULT WALLS AND ROOF

Fully cured walls and parts of the roof are shown in Figure 20 below. The crews have removed the wooden framing and the vault is prepared for the transformers and auxiliary equipment to be installed.

FIGURE 20: FINISHED WALLS & PARTIALLY COMPLETED ROOF

Figure 21 below shows the network unit (transformer mounted with network protector) being placed in the vault. A crane is used to lift and lower the equipment in the vault. The crane blocks one or two lanes on the adjacent roadway.

FIGURE 21: PLACEMENT OF EQUIPMENT IN THE NEWLY BUILT VAULT

Lastly, the following pictures illustrate a completely rebuilt vault, with the area surrounding the vault fully restored.

FIGURE 22: COMPLETELY REBUILT VAULT

E6.9.5.1 Proposed Work Plan

Table 6 below shows the number of different projects planned for completion during the 2015-2019 period. Further details on 2015 projects can be found in section E6.9.8.

TABLE 6: 2015-2019 LONG TERM PLAN

Year	Vault Decommissioning	Vault Roof Rebuild	Vault Rebuild
2015	2	4	4
2016	0	2	9
2017	0	2	9
2018	0	3	9
2019	0	4	9

E6.9.5.2 Program Risks

Throughout the program planning and execution process, a number of implementation risks are considered. Some of these risks can be mitigated during the planning phase of the project and others can impact the project at later stages. Some of the risks include:

- Moratoriums: As noted earlier, and although existing moratoriums by the City of Toronto are considered when planning for the vault renewal projects, it is possible that new moratoriums are introduced after the planning has been completed. This can result in delays to the work. To mitigate this risk, Toronto Hydro continuously receives information about moratoriums from the city. This helps Toronto Hydro better plan and execute projects within the allotted window before or after the moratorium.

- Summer Restrictions: Toronto Hydro imposes switching restrictions on certain feeders during the summer months when peak load demand is highest. In other words, the switching off of any restricted feeders may cause overloading on other vaults in the distribution grid during summer peaks and these feeders therefore cannot be turned off for any planned work or operations. If the vault being planned for rebuild is fed from one of the restricted feeders, then the work can only be conducted in the off-peak times and this may hinder the execution of a given project. Toronto Hydro's Load Demand program for 2015-2019 (Section E5.4 of the DSP) is intended to help mitigate these risks by enhancing the grid so that feeder restrictions during the summer peak times are minimized.

- Metrolinx Subway Expansion: Projects such as the expansion of the subway system in Toronto are especially challenging to plan for, as these projects have a dynamic decision making process which can take decades to conclude. When such large projects are in the execution phase, the City or Metrolinx may impose a moratorium to suspend all planned capital work until critical phases of subway expansion projects are completed. In

addition, relocation of Toronto Hydro assets in order to accommodate construction of the subway may have consequences for how a vault rebuild has been planned and designed by Toronto Hydro. To mitigate this risk, Toronto Hydro communicates with Metrolinx throughout the year to ensure that the impact of development work by Metrolinx on the Toronto Hydro projects is minimal.

Toronto Hydro has considered each of these program risks when developing the five-year plan for network vault renewals.

E6.9.6 Evaluation of Alternatives

E6.9.6.1 Quantification/Evaluation of Options

There are two ways that Toronto Hydro can address poor condition network vaults going forward. The first option is to maintain the network vaults in the current known conditions and the second option is to proceed with rebuilding the network vaults prior to failure. Both of these options are discussed below in further detail.

(i) Status Quo

Under the status quo option, Toronto Hydro would continue to maintain the network vaults in their current state. Maintenance of the vaults involves structural patching up of the roof, wall(s) and/or floor as triggered by network vault inspections conducted two times a year. Because the vaults proposed for renewal are in "poor" to "very poor" condition, maintaining rather than rebuilding will inevitably increase the risk of structural failure, which may lead to failure of the equipment housed inside the vaults. Furthermore, the safety issues such as tripping and falling, for both the public and Toronto Hydro crews, may become more likely. Toronto Hydro will be required to resolve these issues reactively, incurring higher costs and unplanned interruptions of supply to the customers.

(ii) Renew Network Vaults

Toronto Hydro's program to proactively renew the highest risk network vaults, which are in "poor" to "very poor" condition, will reduce the risk of injury to the public and Toronto Hydro crews and the risk to system performance due to asset failure. The replacement of the network vaults in the first year of the program will result in an avoided estimated risk cost (ARC) of $4.63 million, as detailed in Table 7. This value represents the avoided cost of executing the first year of activities

as scheduled as opposed to deferring these activities until 2020. The ARC is representative of the economic prudence of executing the activities within the program when compared to the programs' associated capital costs, taking into account the risk costs to the customer due to power outages. These avoided costs include quantified risks, taking into account the assets' probability of failure, and multiplying this by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement. A positive ARC value is indicative of a reduction in impacts due to outages to customers through the renewal of the assets within this program. Further detail on the ARC approach is provided in Section D3.3. These investments will also result in long term benefits for the civil structures of the vaults as well as the equipment housed inside them. Such benefits include longer expected life for the civil structure of the vault as well as the electrical equipment by using improved standards and materials.

TABLE 7: BCE RESULTS

Business Case Element	Cost (in Millions)
Asset Renewal	
Present Value of Net Cost in 2020 [PV(NET_COST(2020)]	$ 5.04
Net Cost for the First Year of Activity [NET_COST(First Year of Activity)]	$ 0.41
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - NET_COST(First Year of Activity))]	$ 4.63

E6.9.7 2015 Projects

Table 8 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

- previously filed projects that appeared as jobs in the OEB approved Network Vaults and Roofs segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and
- projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 8: 2015 PROGRAM COST

Years	2015 CAPEX ($M)	
	ICM Projects	CIR Projects
CAPEX	3.48	0.47

Table 9 lists all projects that are expected to be partially or completely executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 9: 2015 PROJECTS

Estimate Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
X12263	X12263 Vault Loc#Z0005, Rebuild Vault Roof Danforth/Coxwell	$179,643	2015	ICM
X12289	X12289 New Vault - Adelaide St. West Loc #4412	$606,108	2015	ICM
X12830	X12830 Loc#4432 vault rebuild 2013	$1,227,692	2015	ICM
X13692	X13692 P13 Vault 4731 - Rebuild Roof	$178,605	2015	ICM
X14591	X14591 Vault Roof Rebuild, Loc 4830	$168,677	2015	ICM
X14592	X14592 Vault Rebuild, Loc 4210	$500,951	2015	ICM

Estimate Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
X14597	X14597 Vault Rebuild, Loc 4258	$620,069	2015	ICM
X14587	X14587 Network Vault Roof Rebuild - LOC4872 A48H	$169,326	2015	CIR
X14682	X14682 - Abandon vaults 4325 and 4330 Ph1 (Electrical)	$198,007	2015	CIR
X14602	X14602 - Abandon vaults 4325 and 4330 Ph2 (civil)	$102,822	2015	CIR

The following map shows the locations of all Network Vault Renewal projects planned for 2015. Further details are provided for the 2015 projects in the following subsections.

FIGURE 23: LOCATIONS OF NETWORK VAULT RENEWAL PROJECTS 2015

E6.9.7.1 X12263 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: X12263 Vault Loc#Z0005, Rebuild Vault Roof Danforth/Coxwell

Project Number: X12263 (ICM)

Project Year: 2015

Estimated Cost: $179,643

(i) Objective

This project rebuilds the roof for vault location Z0005, located at a very busy downtown intersection near a bus stop. Completion of this project will help improve the asset condition and greatly reduce safety risk to the public and Toronto Hydro crew.

(ii) Scope of Work

TABLE 10: X12263 SCOPE OF WORK DETAILS

District Neighborhood	DANFORTH AVE. & COXWELL AVE.
Station(s)	MAIN
Feeder(s)	A736M, A738M

TABLE 11: X12263 ASSETS REPLACED

Assets (Units)	2015
Roof	1

(iii) Justification & Benefits

Vault Z0005 is located at a busy downtown intersection of Danforth Ave. and Coxwell Ave. This vault is part of the sidewalk next to a bus station and hence exposed to very high volume of pedestrian traffic. Due to its location, the roof receives large quantities of salt in the winter; there is deterioration of the roof and I-beams that hold the roof slab in place.

Inspection of this location shows that large parts of concrete slabs of the roof have been destroyed and replaced by asphalt. Cracks at the bottom of the slabs are also visible and the I-

beams have severe corrosion requiring replacement. The figure below shows some instances of damage to the roof at this location.

FIGURE 24: DAMAGED ROOF SLAPS WITH CRACKS AND CORRODED I-BEAMS

Based on this information, the roof of vault Z0005 must be rebuilt to alleviate reliability and safety risks.

E6.9.7.2 X12289 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: X12289 Loc #4412, Complete Vault Rebuild - Adelaide St. West

Project Number: X12289 (ICM)

Project Year: 2015

Estimated Cost: $606,108

(i) Objective

Vault at location 4412, located near Adelaide St. W. and Yonge St., has been assessed as severely damaged, raising reliability and potential safety concerns. Hence, by executing this project, Toronto Hydro plans to wholly rebuild this vault to minimize these concerns.

(ii) Scope of Work

TABLE 12: X12289 SCOPE OF WORK DETAILS

District Neighborhood	ADELAIDE ST. W. & YONGE ST.
Station(s)	GEORGE & DUKE
Feeder(s)	A4010 GD, A4610 GD

TABLE 13: X12289 ASSETS REPLACED

Assets (Units)	2015
Vault	1
UGN/W Units	2

(iii) Justification & Benefits

This is a 58 year old vault located at 11 Adelaide St. W. (intersection of Adelaide St. W. and Yonge St.) on a sidewalk. This is a busy downtown area with high pedestrian traffic.

The roof of the vault is covered by stone pavement and is in reasonably good condition. However, inspections show that the walls of the vault have severely deteriorated. This damage includes spalled concrete caused by age and exposure to salt and moisture. Furthermore the rebar of the

walls is exposed and rusted. Such damage may lead to failure of the structure causing damage to the electrical equipment and may compromise the safety of the public and Toronto Hydro crew. The figure below shows the severely deteriorated walls of this vault.

FIGURE 25: DAMAGED WALLS WITH SPALLING AND CORRODED REBAR

Considering the information above, this vault must be fully rebuilt to restore the integrity of the structure and maintain high reliability as well as minimizing safety risks to the public and Toronto Hydro crew posed by poor condition of the vault.

E6.9.7.3 X12830 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: X12830 Loc#4432 vault rebuild

Project Number: X12830 (ICM)

Project Year: 2015

Estimated Cost: $1,227,692

(i) Objective

Vault 4432, located at the north east corner of King St. W. and John St., has damaged walls and a moderate level of deterioration on the roof. Completion of this project will rehabilitate this vault completely to help mitigate the risk its current condition poses to reliability and safety in this busy downtown area.

(ii) Scope of Work

TABLE 14: X12830 SCOPE OF WORK DETAILS

District Neighborhood	KING ST. & JOHN ST.
Station(s)	WINDSOR
Feeder(s)	A62 WR, A66 WR

TABLE 15: X142830 ASSETS REPLACED

Assets (Units)	2015
Vault	1
UGN/W Units	2

(iii) Justification & Benefits

Located in downtown Toronto, this vault is part of a busy sidewalk and also serves as a cover for isolation of electrical equipment from pedestrians. This vault has reached the end of its life as it is over 60 years old.

Furthermore, the inspection of the vault shows that its roof has deteriorated moderately with some patches of asphalt having been applied to repair the damage. However, the walls show clear signs of aging with cracks and spalled concrete. This vault poses a high risk of failure. Figures below show the extent of deterioration to the roof as well as walls of this vault.

FIGURE 26: REPAIRED ROOF AND LARGE CRACK IN THE WALL OF THE VAULT

FIGURE 27: SEVERE SPALLING OF CONCRETE AND EXPOSED RUSTED REBAR IN THE WALLS OF THE VAULT

The condition of this vault warrants a full rebuild. The risks posed to system reliability and to the safety of the public and Toronto Hydro crews will be mitigated by rebuilding this vault completely.

E6.9.7.4 X13692 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: X13692 P13 Vault 4731 - Rebuild Roof

Project Number: X13692 (ICM)

Project Year: 2015

Estimated Cost: $178,605

(i) Objective

This project will rebuild the severely deteriorated roof of vault 4731.

(ii) Scope of Work

TABLE 16: X13692 SCOPE OF WORK DETAILS

District Neighborhood	OVERLEA BLVD & THORNCLIFFE PARK DR.
Station(s)	LEASIDE
Feeder(s)	A16L, A17L

TABLE 17: X13692 ASSETS REPLACED

Assets (Units)	2015
Roof	1

(iii) Justification & Benefits

This vault is located in the Thorncliffe area of Toronto, in the eastern part of the downtown core. Inspection of this vault show that the roof is in very poor condition. The roof has heavy damage to the seals around the slabs and wide cracks in the perimeter walls. In addition, wide cracks and large spalling areas are present at the bottom of slabs indicating advanced corrosion of rebar. Some I-beams are also heavily damaged by corrosion and degraded beyond repair. The figure below shows the deterioration of the vault roof.

FIGURE 28: SEVERELY CORRODED I-BEAM AND CRACKS IN THE ROOF SLAB

The condition of the vault roof presents a serious risk to the reliability of the system as well as to the safety of the public and Toronto Hydro crews. Therefore, the roof must be completely rehabilitated.

E6.9.7.5 X14591 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: X14591 Vault Roof Rebuild, Loc 4830

Project Number: X14591

Project Year: 2015

Estimated Cost: $168,677

(i) Objective

To rebuild the roof of vault 4830 in order to minimize the tripping hazards and risk of failure.

(ii) Scope of Work

TABLE 18: X14591 SCOPE OF WORK DETAILS

District Neighborhood	QUEEN ST. E. & VICTORIA ST.
Station(s)	GEORGE & DUKE
Feeder(s)	A4-13 GD, A4-19 GD

TABLE 19: X14591 ASSETS REPLACED

Assets (Units)	2015
Roof	1

(iii) Justification & Benefits

This vault is located near Queen St. E. and Victoria St. with high volumes of pedestrian traffic. The inspection report for this vault shows that there is a tripping hazard because of the corrosion of the vents and deformations of concrete slabs. There is also risk of leakage from the roof cracks and corroded seals causing further corrosion of rebar, I-beams and the electrical equipment housed inside the vault. The figure below shows deteriorated roof and rusted rebar of the roof structure.

FIGURE 29: DETERIORATED ROOF (TRIPPING HAZARD) AND EXPOSED REBAR WITH CORROSION

Based on this information the roof of this vault must be rebuilt. Completion of this project is expected to result in a safe roof structure for both the equipment in the vault and the public.

E6.9.7.6 X14592 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: X14592 Vault Rebuild, Loc 4210

Project Number: X14592 (ICM)

Project Year: 2015

Estimated Cost: $500,951

(i) Objective

To improve the reliability of the distribution system and increase the safety of the public and Toronto Hydro crew by rebuilding vault 4210 located in the busy downtown core of Toronto.

(ii) Scope of Work

TABLE 20: X14592 SCOPE OF WORK DETAILS

District Neighborhood	ADELAIDE ST. W & YONGE ST.
Station(s)	TERAULEY
Feeder(s)	A-B4-1A, A-B6-1A

TABLE 21: X14592 ASSETS REPLACED

Assets (Units)	2015
Vault	1
UGN/W Units	2

(iii) Justification & Benefits

This vault under a sidewalk is located at the intersection of Adelaide St. and Yonge St., which are two major arterial roads of Toronto with very high volume of pedestrian traffic. This area of the downtown core has an extensive distribution network of which vault 4210 is a part.

The vault is over 65 years old and the inspection shows that there is severe damage to the roof and walls. The roof has severe damage to the perimeter wall with one I-beam corroded beyond repair. Similarly, the walls of the vault show signs of aging with spalled concrete, corroded rebar

and cracks. The figure below shows some instances of damage to this vault. A full rebuild of the vault is required.

FIGURE 30: DAMAGE AND CRACKS ALL AROUND ROOF PERIMETER WALL. WALL WITH CRACKS AND EXPOSED CORRODED REBAR

E6.9.7.7 X14597 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: X14597 Vault Rebuild, Loc 4258

Project Number: X14597 (ICM)

Project Year: 2015

Estimated Cost: $620,069

(i) Objective

To rebuild the aging vault 4258 completely, in order to minimize the risk of damage to electrical equipment inside and safety hazards posed to the public and Toronto Hydro crews.

(ii) Scope of Work

TABLE 22: X14597 SCOPE OF WORK DETAILS

District Neighborhood	ISABELLA ST. & YONGE ST.
Station(s)	CHARLES
Feeder(s)	A7 5 CS, A7 7 CS

TABLE 23: X14597 ASSETS REPLACED

Assets (Units)	2015
Vault	1
UGN/W Units	2

(iii) Justification & Benefits

Located at the busy intersection of Isabella St. and Yonge St., this vault is over 70 years old and is due for a complete rebuild. Records indicate that holes and cracks in the roof have been filled with asphalt and the steel I-beams have been affected by corrosion. Similarly, the walls of the vault have large cracks and corroded and exposed rebar. There is also spalling areas on the walls. Based on this information the vault structure is in a condition that poses a risk to system

reliability and to public and Toronto Hydro crew safety. The figure below shows some instances of the effect of aging.

FIGURE 31: CORRODED VAULT ROOF I-BEAMS AND DETERIORATED WALLS EXPOSED CORRODED REBAR

The optimal way of addressing the structural deficiencies and the safety risks posed to the public and Toronto Hydro crews is to rebuild this vault completely.

E6.9.7.8 X14587 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: Network Vault Roof Rebuild - LOC4872 A48H

Project Number: X14587

Project Year: 2015

Estimated Cost: $169,326

(i) Objective

This project rebuilds the roof of vault 4872. The newly built roof will minimize the safety risks to the public and Toronto Hydro crews.

(ii) Scope of Work

TABLE 24: X14587 SCOPE OF WORK DETAILS

District Neighborhood	ST. CLAIR AVE. E & YONGE ST.
Station(s)	HIGH LEVEL
Feeder(s)	A4-48 H

TABLE 25: X14587 ASSETS REPLACED

Assets (Units)	2015
Roof	1

(iii) Justification & Benefits

Records indicate that the roof of this vault has deteriorated beyond repair and must be rebuilt. There is heavy damage to concrete of the slabs and perimeter wall. This includes spalled concrete and heavy cracking in the perimeter wall of the roof. These conditions are a tripping hazard and there is a risk of failure that could damage the equipment inside the vault. The figure below shows damage on the vault roof.

FIGURE 32: DAMAGED ROOF PERIMETER WALL AND SLABS

E6.9.7.9 X14682 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: X14682 - Abandon vaults 4325 and 4330 Ph1 (Elec)

Project Number: X14682

Project Year: 2015

Estimated Cost: $198,007

(i) Objective

To transfer electrical loads from the lightly loaded vaults 4325 and 4330 to the neighboring vaults fed by Windsor West (WR-W). Execution of this project will complete phase 1 of the project and mainly consists of electrical work.

(ii) Scope of Work

TABLE 26: X14682 SCOPE OF WORK DETAILS

District Neighborhood	SIMCOE ST. & DUNDAS ST. W.
Station(s)	CECIL AND WINDSOR
Feeder(s)	A5-50 CE, A5-51 CE, A6-51 WR, A6-52 WR

TABLE 27: X14682 ASSETS REPLACED

Assets (Units)	2015
No assets replaced	

(iii) Justification & Benefits

Located in the busy part of downtown Toronto, vaults 4325 and 4330 are over 79 and 65 years old respectively. This age is well past the end-of-life for vault structures of 60 years. Records show that the CE (Cecil) network along Simcoe St. is now very lightly loaded where these vaults are located. Extending the neighboring WR-W network north and picking up the load on the south end of CE (Cecil) network on Simcoe St. will allow Toronto Hydro to abandon vaults 4325 and 4330. Project X14602 (described in following subsection) will be executed to abandon these

vaults following completion of X14682. This project will result in better utilization of distribution network capacity and will provide service to customers from more structurally reliable vaults.

E6.9.7.9 X14602 Project Description

Investment Category: System Renewal

Program: Network Vault Renewal

Project Title: X14602 - Abandon vaults 4325 and 4330 Ph2 (civil)

Project Number: X14602

Project Year: 2015

Estimated Cost: $102,822

(i) Objective

To abandon vaults 4325 and 4330 as the load served by these vaults will be transferred to the neighboring network with the completion of X14682. Execution of this project will mainly consist of civil work.

(ii) Scope of Work

TABLE 28: X14602 SCOPE OF WORK DETAILS

District Neighborhood	SIMCOE ST. & DUNDAS ST. W.
Station(s)	CEL CIL
Feeder(s)	A5 50 CE, A5 51 CE

TABLE 29: X14602 ASSETS REPLACED

Assets (Units)	2015
Vault	2
UGN/W Units	3

(iii) Justification & Benefits

Vaults 4325 and 4330 are reported to be in severely deteriorated condition with ages of 79 and 65 years respectively. These vaults are located in an area with a high volume of pedestrian traffic and pose a safety risk to the public and Toronto Hydro crews and a risk to distribution system reliability.

The inspection report for vault 4325 indicates that the roof and walls are severely deteriorated with a severe crack in the west wall and corroded I-beams. The roof on the north side is severely damaged. Similarly, inspection report for 4330 shows that the vault roof is severely damaged with corroded I-beams and cracked slabs. The pictures below show the severity of the damage on both vaults.

FIGURE 33: DETERIORATED ROOF AND CRACKED WALL

FIGURE 34: DETERIORATED ROOF WITH SEVERELY CORRODED I-BEAMS

Rehabilitation of these vaults is projected to cost over $1 million. The optimal course of action is abandonment, given the change in loading conditions in the area..

This project is planned for completion once the electrical work has been completed as part of X14, during which the load served by these vaults will be transferred to the neighboring distribution network.

E6.10 Network Unit Renewal

VAULT FIRE EVENT

E6.10.1 Summary

Program Description

Toronto Hydro's Network Unit Renewal (NUR) program addresses obsolete and deteriorated Network Units that are at risk of failure. These Network Units have experienced degradation such that they are in poor condition and may not operate correctly going forward. Toronto Hydro plans to replace 240 Network Units during the 2015 to 2019 period. The Network Units to be replaced are classified as Fibertop Network Units (see Figure 1) and Semi-Dust-Type Network Units (see Figure 2).

The proactive replacement of certain Fibertop Network Units is an activity that was previously presented to the Ontario Energy Board (OEB) and approved in the Fibertop Network Units segment of Toronto Hydro's 2012-2014 ICM rates application[1]. The Network Unit Renewal program will complete the removal of Fibertop Network Units from the system.

Toronto Hydro plans to replace old and obsolete Network Units with modern Submersible Network Units first introduced in 2003.

The anticipated benefits of the Network Unit Renewal (NUR) program are as follows:

[1] EB-2012-0064, Tab 4, Schedule B10.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Mitigation of reliability and safety risks for customers in the downtown area.
Reliability	ƒ Reduces the number of failures, including catastrophic failures that would otherwise impact the system.
Safety	ƒ Removing Fibertop Network Units are expected to reduce the risk of vault fires and explosions that could harm Toronto Hydro employees and the general public.
Efficiency	ƒ The Submersible Network Unit comes equipped with sensors that monitor the transformer and protector. These sensors allow controllers in Toronto Hydro's control room the ability to remotely view real time statuses such as flooding, temperature and loading.
Environmental	ƒ Leaking Network Units are expected to be replaced as part of this program and their vaults will be cleaned thoroughly prior to the installation of new Network Units.

Program Drivers

The trigger and secondary drivers for Network Unit Renewal (NUR) program are summarized in the following table.

TABLE B: PROGRAM DRIVERS

Primary Driver	Reasoning
Failure Risk	ƒ Network Units addressed by the program are aging and exhibit various signs of deterioration (i.e. protector contamination, corrosion, leaking oil, etc). ƒ Deterioration of Network Units leads to a heightened risk of failure that can have widespread and prolonged outage impacts.
Secondary Driver	**Reasoning**
Safety	ƒ A fire-related failure incident can expose Toronto Hydro employees and the general public to significant safety risks.

Preferred Alternative

Toronto Hydro considered the following alternatives for addressing aging and deteriorated Network Units.

(1) Continue to maintain existing deteriorated Fibertops and Semi-Dust-Type Network Units and replace each unit upon failure

(2) Address safety risks associated with deteriorating Network Units and improve the reliability and efficiency of the network system proactively.

Option II is the preferred alternative because it reduces the risk of injury to the public and Toronto Hydro employees, while also reducing the risk to system reliability due to asset failure.

The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $7.11 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.10.7).

Timing and Pacing

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	1.69	0.87	3.65	10.81	0.93	3.95	10.37	10.29	10.25	10.24

Toronto Hydro has approximately 1,892 Network Units in the distribution system. As is further discussed in Section D2 the expected useful life of a network unit is 30 years. In order to maintain an asset base that is within the expected useful life, Toronto Hydro plans to continue making replacements throughout the 2015 to 2019 period. Prior to 2012, Toronto Hydro executed Fibertop Network Unit replacements as part of wider network unit replacement initiative that included other types of heavily degraded end-of-life Network Units. The overall pace at which Network Units were replaced was about 50 units per year; Toronto Hydro will continue with this pace throughout the 2015 to 2019 period.

E6.10.2 Program Description

Toronto Hydro's Network Unit Renewal (NUR) program addresses obsolete and deteriorated Network Units that are at risk of failure. These Network Units have experienced degradation such that they are in poor condition and may not operate correctly going forward. Toronto Hydro plans to replace 240 Network Units during the 2015 to 2019 period. Table 1 shows the number of units forecasted for replacement each year during this period. The Network Units to be replaced are classified as Fibertop Network Units (see Figure 1) and Semi-Dust-Type Network Units (see Figure 2).

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Network Unit (Transformer and Protector)	40	50	50	50	50	240

Network Units are comprised of both a network transformer and a network protector. At least two Network Units are connected together to form a grid. For reliability purposes, customers connected to this grid receive supply from multiple sources. The network protector opens and isolates the secondary side of the circuit from the supply side should a fault be detected. This important action prevents reverse current flowing from the low-voltage secondary network grid, feeding the fault on the supply side of the circuit. If the protector fails to operate, the fault will continue to be fed, damaging the equipment.

Fibertop Network Units

Fibertop Network Units are designed such that their secondary terminals are placed directly on top of the protector component (see Figure 1). This design allows debris and salt to accumulate, which can cause tracking between phases that can lead to a vault fire. These units are also susceptible to failure due to flooding; the case of the protector is not water tight and, in locations where flooding occurs, water can damage the internal mechanism of the network protector component. Fibertop Network Units are also the oldest type of Network Units in the system and were most recently installed in the early 1970s. Many of these units are corroding and in some cases have started to leak oil. The `

FIGURE 1: FIBERTOP NETWORK UNIT (TRANSFORMER AND PROTECTOR), RIGHT: TOP OF PROTECTOR COMPONENT

Semi-Dust-Type Network Units

Semi-Dust-Type Network Units (see Figure 2) are the second oldest type of network unit currently in service. This second generation of network unit was installed from 1970 to 2003. These units have a raised secondary bus as seen in Figure 2. This connection point is raised off the top of the protector component, which reduces the chance of tracking between phases. Like the Fibertop Network Units, the casing on the Semi-Dust-Type units is not water tight and, due to their location, some are at risk of being flooded. Over time, flooding can cause corrosion to the structure and operating mechanism of the network unit.

Many of the oldest Semi-Dust-Type units are in need of replacement due to corrosion and severe rust – characteristics that can also lead to oil leaking from the transformer tank. All of the Semi-Dust-Type Network Units addressed by this program have been inspected and have been identified as having reached their end-of-life.

FIGURE 2: SEMI-DUST-TYPE NETWORK UNIT (TRANSFORMER AND PROTECTOR), RIGHT: PROTECTOR COMPONENT

Replacement Solution: Submersible Network Units

Old and obsolete Network Units are expected to be replaced with modern submersible Network Units first introduced in 2003. Submersible Network Units addresses many of the issues that contribute to the deterioration and failure of the older units; they feature a raised secondary bus bar (as illustrated in Figure 3) that reduces the chances of inter-phase tracking. The case of the protector component is also water tight, preventing flooding. In all, these features reduce the risk of a catastrophic failure of the network unit. The new units also feature sensors that provide enhanced load monitoring capabilities for controllers and better visibility into the conditions of the equipment inside the network vault.

FIGURE 3: SUBMERSIBLE NETWORK UNIT (TRANSFORMER AND PROTECTOR)

The total cost of the program, over the 2015 to 2019 period is $34.38 million. Figure 4 shows the geographic location of each replacement that will be taking place in 2015 in red and projects for 2016 – 2019 in grey. The replacements will predominantly occur in the downtown region of Toronto. The prioritization of projects is discussed in E6.10.4.1.

FIGURE 4: MAP OF NETWORK UNITS TO BE REPLACED

The anticipated benefits of this program are summarized in the table below.

TABLE 2: PROGRAM BENEFITS

Customer Value	ƒ Mitigation of significant potential reliability and safety risks for customers in the downtown area. ƒ The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $7.11 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.10.7).
Reliability	ƒ Reduces the number of failures, including catastrophic failures that would otherwise be more likely to occur.
Safety	ƒ Removing Fibertop Network Units is expected to reduce the risk of vault fires and potential explosions that could

	harm Toronto Hydro employees and the general public.
Efficiency	ƒ The Submersible Network Unit comes equipped with sensors that monitor the transformer and protector. These sensors allow controllers in Toronto Hydro's control room the ability to remotely view real time statuses such as flooding, temperature and loading.
Environmental	ƒ Leaking Network Units will be replaced as part of this program and their vaults will be cleaned thoroughly prior to the installation of new Network Units.

E6.10.3 Why the Program is Needed

E6.10.3.1 Program Drivers

Table 3 explains the primary and secondary drivers of the NUR program. Toronto Hydro has classified the NUR program as a System Renewal initiative, with a primary driver of failure risk.

TABLE 3: PROGRAM DRIVERS

Primary Driver	Reasoning
Failure Risk	ƒ Network Units addressed by the program are aging and exhibit various signs of deterioration (i.e. protector contamination, corrosion, leaking oil, etc). ƒ Deterioration of Network Units leads to a heightened risk of failure that can have widespread and prolonged outage impacts.
Secondary Driver	**Reasoning**
Safety	ƒ A fire-related failure incident may expose Toronto Hydro employees and the general public to significant safety risks.

The objective of the NUR program is to mitigate the failure and safety risks associated with the catastrophic failure of aging and obsolete Network Units. A catastrophic failure is defined as an event, such as a vault fire or transformer failure, that requires the station bus to be dropped, affecting several feeders in order to isolate the affected vault. Fibertop Network Units are at risk of failure because they have deteriorate and because of their inherent design issues. Semi-Dust-Type Network Units are at risk of failure because they have deteriorated over time.

Certain design aspects of Fibertop Network Units create an elevated risk of fires and explosions (although Semi-Dust Type Network Units are also susceptible to fires). The top of the protector component on the Fibertop Network Unit, where interconnections are made to the secondary grid,

is susceptible to moisture and contamination (refer to Figure 1). The interconnections are spaced very closely together and allow for leaves and other debris to collect between contacts. This design flaw increases the probability of a short-circuit between phases (i.e., inter-phase tracking) occurring across these connections, which can potentially ignite a vault fire. Vault fires have occurred at a rate of one per year over the last five years and generally have a significant impact on reliability and safety of customers and Toronto Hydro staff.

Vault fires caused by Fibertop Network Units can jeopardize the safety of Toronto Hydro employees, fire fighters, and the general public, partly due to the fact that these assets are often located in high traffic pedestrian areas. In addition, these assets are often connected to the secondary grid using asbestos-insulated lead-covered (AILC) secondary cables. If these cables are involved in a vault fire, they can pose a potential health risk to Toronto Hydro crews during cleanup efforts and nearby pedestrians because asbestos fibers can be released into the air. To address the health risks, the AILC cables require a specialized cleanup crew to removed burned cable, which can increase restoration times. Finally, the structural integrity of the network vault may become compromised as a result of a fire, increasing the overall costs of repair. This was the case in a recent vault fire at 95 St. Clair Ave West in January 2013, further details of which can be found in section E6.10.3.2 (ii).

In addition to the risks of fires and explosions, Fibertop and Semi-Dust-Type Network Units are at risk of oil leakage. In some cases, oil leakage has resulted in low oil levels, which has, in turn, exposed the internal windings. Exposed internal windings can lead to internal failure of the Network Unit. These failures can negatively impact the reliability of the system by causing four- to eight-hour outages while the equipment is replaced.

As well, both types of underground network vaults are prone to flooding. Fibertop and Semi-Dust-Type Network Units are susceptible to failure as a result of a flood in the vault because the ventilation fins that allow the equipment to cool-off also permit water to penetrate the unit. Over time, water contact can cause equipment to corrode and ultimately fail to operate (i.e., fail to open), creating a dangerous back-feed of electricity to parts of the system that are either unintentionally grounded because of a fault or intentionally grounded as part of planned feeder work. Toronto Hydro's current network protector standard uses a submersible protector case to prevent flooding of components inside the case. Additional details of a back-feed incident caused by flooding are provided in Section E6.14.3.2.

E6.10.3.2 Asset Details

(i) Asset Lifecycle

Fibertops are the oldest type of network unit in Toronto Hydro's system, having last been installed in the early 1970s. At a minimum 40 years of age, these units are well past their effective useful life of 30 years, and show signs of wear and tear. With respect to Semi-Dust-Type units, although the majority of replacements are for assets between the ages of 30 and 50, Toronto Hydro is planning on replacing some units that are less than 30 years old, but are in locations that are prone to flooding.

Figure 5 provides demographic information for both Fibertop and Semi-Dust-Type Network Units that are scheduled to be replaced under the NUR program. In general, the Network Units continue to deteriorate as they age. In addition to taking into account the age of assets, inspections were conducted to identify and prioritize corroded and leaking units, which can lead to incidents such as transformer failure, fires, and explosions. As well, Toronto Hydro studied the location of assets to determine which are susceptible to flooding. In short, assets that are at risk of failure are scheduled to be replaced under this program.

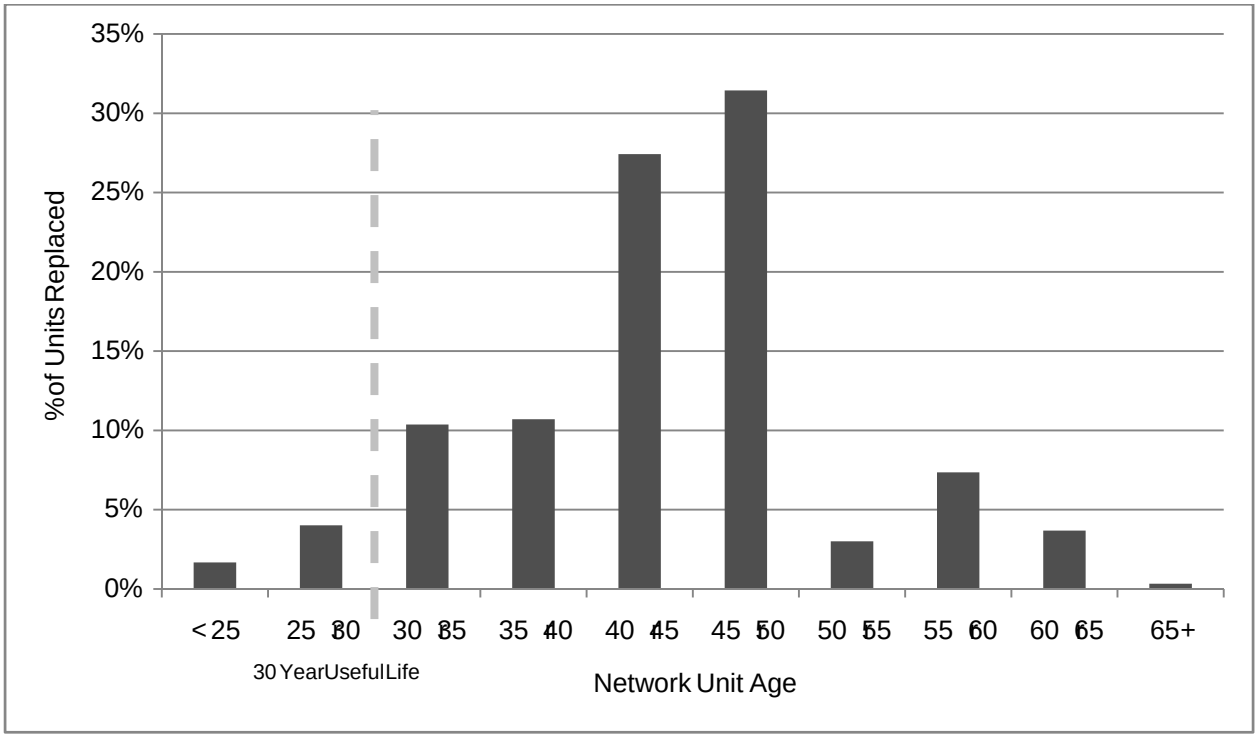


FIGURE 5: NETWORK UNIT RENEWAL - PLANNED REPLACEMENT DEMOGRAPHIC

(ii) Asset Failure Impacts

The failure of assets scheduled to be replaced under this program can negatively impact both the reliability of power supply and the safety of the public.

With respect to reliability issues, approximately 5,000 customers are directly connected to Network Units that will be replaced; they include office buildings, other medium sized commercial buildings and residential customers. These customers are exposed to both catastrophic failures and localized failures than only impact one feeder.

During a network vault fire, the fire department requires that the network grid be dropped. This can impact anywhere between three to six feeders, which means that a few city blocks may be without power for up to four hours while the affected equipment is isolated. After the grid is brought back online, the affected vault and connected customers are usually left without power until the Network Units are replaced, which can take up to an additional 12 hours.

The most recent fire took place on January 28, 2013 at 95 St. Clair Avenue West. The fire was a result of a catastrophic failure of a Network Unit. This fire caused damage to all of the equipment located in the vault, leading to a 49-hour outage for customers in the building. Feeders A53H and A54H were dropped during the outage and both feeds were out until the affected vault could be isolated. In total, this outage affected over 16 high-rise buildings. Certain customers experienced a power outage lasting about an hour, such as Upper Canada College, The Avenue (condominium) and the High Level Pumping Station. Toronto Hydro restored their power by switching to a standby supply on a feeder that was unaffected by the vault fire. In contrast, other customers were left without power for 16 hours; these customers experienced a prolonged outage until the affected vault could be safely isolated and power restored to both supply feeders. Once the debris and equipment was removed from the vault, a new temporary transformer was installed to restore power to all of 95 St. Clair Avenue West.

FIGURE 6: VAULT FIRE EVENT

The fire caused extensive damage; equipment in the vault needed to be entirely replaced and the network vault's civil structure was damaged. As seen in the photos below, the entire civil structure had to be rebuilt before the equipment could be restored. The process of designing and rebuilding the vault took just over one year and, during this time, 95 St Clair Avenue West was supplied by only one of its original feeders, with no ability to be switched to a standby supply in case of a failure or fault. If the building's supply feeder had failed, the customer would have likely experienced another extended service interruption of up to 12 hours.

FIGURE 7: AFTERMATH OF VAULT FIRE EVENT

In the case of localized network failures, some customers connected to the network may not be affected at all. However, dual radial customers, such as large downtown buildings, that are connected to the affected feeder will experience an interruption. Typically, outages on the primary feeder can leave four to five customers without power until they are switched over to their alternate supply, which can take up to 1.5 hours.

A localized network unit failure occurred on August 20, 2013 when a network unit failed to open on reverse current. Customers on feeder A40GD, the primary feeder for this network unit, had to be transferred to their standby supply. After inspecting the unit, crews discovered that the network unit failed because water damage had caused the protector mechanism to malfunction. The corrosion caused by the water damage is visible in the picture below on the right.

FIGURE 8: CORRODED NETWORK UNIT REMOVED FROM VAULT 4080

In addition to reliability issues, the public is put at risk if Network Units are allowed to fail. A catastrophic failure can cause explosions and fires, which pose a potential risk to members of the public. This issue is compounded by the fact Network Units are typically located under pedestrian sidewalks. Figure 9 is a picture of a network vault located under a pedestrian sidewalk.

FIGURE 9: SIDEWALK NETWORK VAULT

E6.10.4 Timing & Pacing of the Program

In order to mitigate the risks outlined in Section E6.13.3, investment is necessary to replace the remaining Fibertop Network Units and to begin addressing Semi-Dust-Type Network Units that are in poor condition or otherwise vulnerable to flooding. The pace of spending under the NUR program is provided in Table 4.

TABLE 4: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	7.26	4.43	5.07	7.30	3.58	5.18	7.36	7.30	7.28	7.26

Toronto Hydro has approximately 1,892 Network Units in the distribution system. As is further discussed in Section D2 the expected useful life of a network unit is 30 years. In order to maintain an asset base that is within the expected useful life, Toronto Hydro will continue to make

replacements throughout the 2015 to 2019 period. Prior to 2012, Toronto Hydro executed Fibertop Network Unit replacements as part of wider network unit replacement initiative that included other types of heavily degraded end-of-life Network Units. The overall pace at which Network Units were replaced was about 50 units per year; Toronto Hydro plans to continue with this pace throughout the 2015 to 2019 period.

In the early stages of the NUR program, Toronto Hydro will focus on the ongoing replacement of Fibertop Network Units because these pose the most immediate risk of failure. Only 120-140 Fibertop Network Units remain in the system and all will be replaced from 2015 to 2017.

Following replacement of all Fibertop Network Units, Toronto Hydro will begin to replace Semi-Dust-Type Network Units that are degraded, beyond their useful life and at risk of flooding. These activities will continue beyond 2019.

E6.10.4.1 Ranking & Prioritization

The replacement of Network Units has been prioritized based on the following factors:

- Fibertop Protectors Design Flaw – All Fibertop network units will be replaced at the beginning of the NUR program. These units pose the highest risk of failure to the system (refer to section E6.13.3).
- Asset Condition – The asset condition data collected from inspections conducted three times per year is used to determine replacement priority within specific asset classes. Severely deteriorated assets are given the highest priority. Projects can be reprioritized if an urgent/critical need is discovered.
- Flooding – Network Units located in areas that are prone to flooding and have non-submersible equipment will be prioritized to prevent failures.
- Risk – The Feeder Investment Model (FIM) uses asset condition and customer impact to determine optimal intervention time; this information is used to further prioritize the replacement schedule.
- Efficiency - Network units that are fed from the same feeder will be grouped together so as to replace several Network Units at the same time. This allows for more efficient use of resources.

E6.10.5 Program Execution

Over the past five years, Toronto Hydro has undertaken replacements that are similar in nature to the work to be performed under the NUR program. That experience has provided valuable insight on how to optimize the processes and resources to properly support this program.

The projects under the NUR program have been structured so that multiple network units on the same feeder can be replaced together, which maximizes the efficiency of each switching event required to take the primary feeder offline. Using this approach, the amount of time customers are reliant on only one source of supply is minimized.

Each replacement involves similar steps. First the Network Unit is isolated from the system by scheduling the primary feeder to be taken offline and grounded. Next, Toronto Hydro will remove connections to the Primary Feeder and Secondary Network. The Network Unit is then removed from the vault using a crane, and if it is in a sidewalk location the roof slab is removed to allow access to the underground unit. The new Network Unit is then placed in the same footprint of the old unit. Afterwards, the primary cable is re-terminated and the secondary network connections are reinstalled. Finally, the primary feeder is re-energized and the Network Unit will begin supplying power to the Secondary Network.

E6.10.5.1 Program Risks

Toronto Hydro's control room may restrict the replacement of certain Network Units during the summer months because their feeders will not be able to be taken out of service due to operational constraints. Another program risk is that must be managed is the fact that the removal of a Network Unit may cause the remaining Network Units to experience overloads. Toronto Hydro will manage these risks by scheduling the replacement of Network Units outside of the peak summer months where possible.

E6.10.6 Evaluation of Alternatives

E6.10.6.1 Quantification/ Evaluation of Options

Two alternatives were considered to address the issues generated by Network Units. Each alternative was evaluated using a net present value (NPV) calculation.

(i) Maintain status quo

In maintaining the status quo, Toronto Hydro would continue to maintain existing deteriorated Fibertops and Semi-Dust-Type Network Units and replace each unit upon failure. By maintaining the status quo, the multitude of issues discussed throughout the narrative would persist.

(ii) Replace deteriorated Network Units

By proceeding with the NUR program, Toronto Hydro plans to address safety risks associated with deteriorating Network Units and will improve the reliability and efficiency of the network system.

The replacement of Network Units in the first year of the program is expected to result in an avoided estimated risk cost (ARC) of $7.11 million, as detailed in Table 5. This value represents the avoided cost from executing the first year of activities in the year scheduled, as opposed to deferring these activities until 2020. These avoided costs include quantified risks, taking into account the probability of failure of the assets, and multiplies this figure by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement. Further details on the ARC approach is provided in Section D3.3.

TABLE 5: AVOIDED RISK COST BUSINESS CASE EVALUATION ($ MILLIONS)

Business Case Element	Cost
Asset Renewal	
Present Value of Net Cost in 2020 [PV(NET_COST(2020)]	$7.72
Net Cost for the First Year of Activity [NET_COST(First Year of Activity)]	$0.61
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - (NET_COST(First Year of Activity))]	$7.11

E6.10.7 2015 Project Details

Table 6 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

(a) previously filed projects that appeared as jobs in the OEB approved Fibertop Network Units segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 6: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	CIR Projects
4.33	0.86

Table 7 lists all projects that are planned to be partially or completely executed as part of the 2015 work program. Note that the table shows total costs for each program. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 7: 2015 PROJECTS

Project Number	Project Name	Total Project Cost ($)	Start Date	Project Type (ICM or CIR)	Project Details
X11508	4452_A52CS	14,486.87	2015	CIR	The Network Unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration and degradation of the oil insulation. Inspection shows that the Network Units are leaking oil due to corrosion of the network transformer tank and require replacement.
X12279	N1033_A62H, A70H	88,760.97	2015	CIR	Inspection shows that the Network Units are leaking oil due to corrosion of the network transformer tank and require

Project Number	Project Name	Total Project Cost ($)	Start Date	Project Type (ICM or CIR)	Project Details
					replacement. Low oil levels in the network transformers can lead to internal failures of the network unit. Removing leaking Network Units is a benefit to the environment. In addition, this project will remove two Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past
X12338	4336_A44GD, A48GD	641,067.93	2015	CIR	The Network Unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove a pair of Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14450	4476_A16L	144,634.63	2015	ICM	The Network Unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove a Fibertop Network Unit from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14452	4667_A30DN	189,820.69	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as

Project Number	Project Name	Total Project Cost ($)	Start Date	Project Type (ICM or CIR)	Project Details
					degradation of the oil insulation. Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove a Fibertop network unit from the system, an asset type that has been identified to be a root cause of several vault fires in the past.
X14454	4948, N1105_A 52DX	23,248.63	2015	CIR	The Network Units being replaced in this project are approaching end-of-life and have begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the Network Units are leaking oil due to corrosion of the network transformer tank and require replacement. In addition this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14455	4627, 4658_A6 0CS	24,685.10	2015	CIR	The Network Units being replaced in this project are approaching end-of-life and have begun showing signs of physical deterioration as well as degradation of the oil insulation. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14456	4627, 4658_A6 1CS	24,685.10	2015	CIR	The Network Units being replaced in this project are approaching end-of-life and have begun showing signs of physical deterioration as well as degradation of the oil insulation. In addition, this project will remove

Project Number	Project Name	Total Project Cost ($)	Start Date	Project Type (ICM or CIR)	Project Details
					Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14457	4653NV, 4654EV, 4696SV_A63CS	514,102.15	2015	ICM	The Network Units being replaced in this project are approaching end-of-life and have begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the Network Units are leaking oil due to corrosion of the network transformer tank and require replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14459	4317_A91A	121,050.17	2015	ICM	The Network Unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the Network Unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14461	4654WV, N1109_A65CS	306,735.11	2015	ICM	Inspection shows that the Network Units are leaking oil due to corrosion of the network transformer tank and require replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.

Project Number	Project Name	Total Project Cost ($)	Start Date	Project Type (ICM or CIR)	Project Details
X14462	4917SV, N1114_A 69WR	258,223.89	2015	ICM	Inspection shows that the Network Units are leaking oil due to corrosion of the network transformer tank and require replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14463	N1045, 4421, N1053, 4293_A7 1CS, A77CS	29,455.34	2015	CIR	The Network Units being replaced in this project are approaching end-of-life and have begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the Network Units are leaking oil due to corrosion of the network transformer tank and require replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14470	4210_A4 3A, A36A	246,529.73	2015	ICM	Inspection shows that the Network Units are leaking oil due to corrosion of the network transformer tank and require replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14476	4230EV_ A40GD	189,820.69	2015	ICM	The Network Unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. In addition, this project will remove Fibertop Network Units from the system, an asset type which has

Project Number	Project Name	Total Project Cost ($)	Start Date	Project Type (ICM or CIR)	Project Details
					been identified to be a root cause of several vault fires in the past.
X14477	4753_A48H	186,403.71	2015	ICM	The Network Unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14478	4753_A49H	189,804.82	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14484	4176_A5K	168,202.08	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14485	4696NV_A55CS	189,902.32	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as

Project Number	Project Name	Total Project Cost ($)	Start Date	Project Type (ICM or CIR)	Project Details
					degradation of the oil insulation. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14486	4774_A63H	144,634.63	2015	ICM	Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14487	4499EV_A65H	144,634.63	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14488	N1114_A65WR	121,155.61	2015	ICM	Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14491	4003_A68H	11,614.29	2015	CIR	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause

Project Number	Project Name	Total Project Cost ($)	Start Date	Project Type (ICM or CIR)	Project Details
					of several vault fires in the past.
X14492	N1102_A 72CE	121,155.61	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14493	4400NV_ A72CS	144,562.07	2015	ICM	Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14494	4254WV, 4752_A7 5VS	261,784.86	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14495	4543EV_ A7GL	275,995.85	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the network

Project Number	Project Name	Total Project Cost ($)	Start Date	Project Type (ICM or CIR)	Project Details
					unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14498	4769_A92B	168,221.35	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.
X14501	4005_A57H	238,387.46	2015	ICM	The network unit being replaced in this project is approaching end-of-life and has begun showing signs of physical deterioration as well as degradation of the oil insulation. Inspection shows that the network unit is leaking oil due to corrosion of the network transformer tank and requires replacement. In addition, this project will remove Fibertop Network Units from the system, an asset type which has been identified to be a root cause of several vault fires in the past.

E6.11 Legacy Network Equipment Renewal (ATS & RPB)

NEW EQUIPMENT INSTALLED IN UNDERGROUND VAULT

E6.11.1 Summary

Program Description

The Legacy Network Equipment Renewal program is a continuation of the activities previously described in the OEB approved Automatic Transfer Switches (ATS) and Reverse Power Breakers (RPB) segment within the Incremental Capital Module (ICM) as part of Toronto Hydro's 2012-2014 rate filing[1]. ATS and RPB assets are functionally obsolete, as they are no longer supported by the original manufacturer and no spare parts are produced or available. These issues prevent Toronto Hydro from supporting these assets through the utility's maintenance practices and policies.

These assets are installed within the secondary network system and are used to supply medium-sized customers that require a reliable power supply, such as schools, supermarkets, and seniors' homes. ATS units typically fail due to a malfunction of the control electronics. When the control electronics fail, the unit either continuously switches back and forth between supplies, or

[1] EB-2012-0064, Tab 4, Schedule B11.

simply fails to perform the switching operation. Similarly, RPB failures are typically associated with failure of the circuit breaker to open due to malfunction of the controls electronics. Flooding of underground vaults is a contributing factor to such equipment failures. Water and contaminants corrode metals, which results in the rusting of equipment and other potential damage. Contact with water can damage sensitive electronics within the equipment while water and contaminants entering the equipment can cause electrical arcing and faults, potentially leading to catastrophic failures. The failure of ATS and RPB units can have extensive negative impacts on the reliability of the system and on the service provided to Toronto Hydro's customers, as further described in section E6.11.3.2.

Toronto Hydro plans to continue replacing ATS & RPB assets in order to mitigate their elevated failure risk. Toronto Hydro plans to replace 21 high priority legacy ATS and RPB units between 2015 and 2019 with standard equipment.

The anticipated benefits of the Network Vault Renewal program are summarized in the following table.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Mitigate vault fires that result in potential damages to adjacent properties, risk of injuries and environmental issues such as oil spills and cleanup activities ƒ Reduce customer interruptions resulting from asset failure.
Reliability	ƒ Mitigate potential equipment failure and system outages ƒ Improve outage restoration time
Safety	ƒ Mitigate the risk of vault fires and catastrophic failure events ƒ Mitigate potential risk of injuries to the public and crews
Efficiency	ƒ Increase operational efficiencies due to automation ƒ Improve maintenance and service support ƒ Improved availability of spare parts for equipment repair ƒ Reduction in inventory cost

Program Drivers

The trigger and secondary drivers for the Legacy Network Equipment Renewal program are summarized in the following table.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Non-submersible equipment legacy network equipment is prone to rusting and failure ƒ Spare parts no longer available for the assets address by this program ƒ Lack of spare parts precludes maintenance as an alternative for extending the life of the assets over the long-term
Secondary Drivers	**Reasoning**
Failure Risk	ƒ ATS failure can cause multiple brief power outages and power quality problems for customers. ƒ When an ATS fails to open, the customer can experience an outage until Toronto Hydro crews are notified to investigate the nature of the outage and address the problem. ƒ RPB failure can cause transformers overheat and fail, which ultimately causes the standby feeder breaker at the station to operate. As a consequence, customers that are fed by affected feeders will experience an outage. ƒ ATS and RPB asset related outages typically affect between 50-100 customers for the duration of one to four hours. ƒ Flooded vaults can cause non-submersible equipment to short-circuit, resulting in overheating and failure. In some cases, a catastrophic failure may occur, which could result in equipment and property damage.
Safety	ƒ Catastrophic failure due to ATS and RPB equipment can cause a vault fire ƒ Potential risk of injuries to customers and crews

Preferred Alternative

Toronto Hydro evaluated the following options for addressing obsolete and deteriorate ATS and RPB units.

(1) Continue to operate the ATS and RPB units as is, and replace them reactively upon failure.

(2) Replace ATS and RPB units in the form of like-for-like replacement

(3) Replace these assets with new, standard network equipment

Option III is the preferred alternative because it allows Toronto Hydro to continue to supply its customers reliably and mitigates the safety risks outlined in this narrative. This option is also the most cost-effective for Toronto Hydro's customers.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $0.55 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.11.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $0.098 million, confirming the economic prudence of the investments (see Section E6.11.7).

Timing and Pacing

Table C provides historical and projected program spending.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.39	0.03	0.09	1.60	0.25	0.45	0.98	1.14	0.91	1.14

Under this program, 21 high priority ATS and RPB locations are planned for replacement from 2015 to 2019 at a total cost of $4.6 million. An average of four ATS or RPB locations will be targeted annually, which is based on the severity of the asset condition and Toronto Hydro's forecasted resource availability.

E6.11.2 Program Description

The Legacy Network Equipment Renewal program is a continuation of the activities previously described in the OEB approved Automatic Transfer Switches (ATS) and Reverse Power Breakers (RPB) segment within the Incremental Capital Module (ICM) as part of Toronto Hydro's 2012-2014 rate filing.

ATS and RPB are types of network equipment installed within the secondary network system and are used to supply medium-sized customers that require a reliable power supply, such as schools, supermarkets, and long term care homes. An ATS automatically switches a customer to a designated standby feeder in the event the primary feeder fails, helping deliver reliable power supply to the customer. Similarly, an RPB automatically isolates a faulted primary feeder in the event of a feeder outage, which isolates faulted components and prevents potentially dangerous back-feed conditions.

ATS and RPB assets are functionally obsolete, as they are no longer supported by the original manufacturer and no spare parts are produced or available. These issues prevent Toronto Hydro from supporting these assets through the utility's maintenance practices and policies. Figure 1 and Figure 2 are images of typical ATS and RPB units housed in underground vaults.

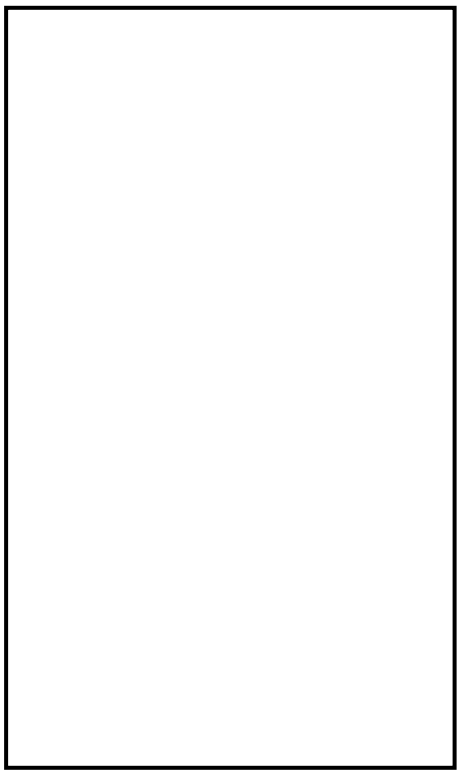


FIGURE 1: ATS UNIT (EXISTING NON-SUBMERSIBLE EQUIPMENT)

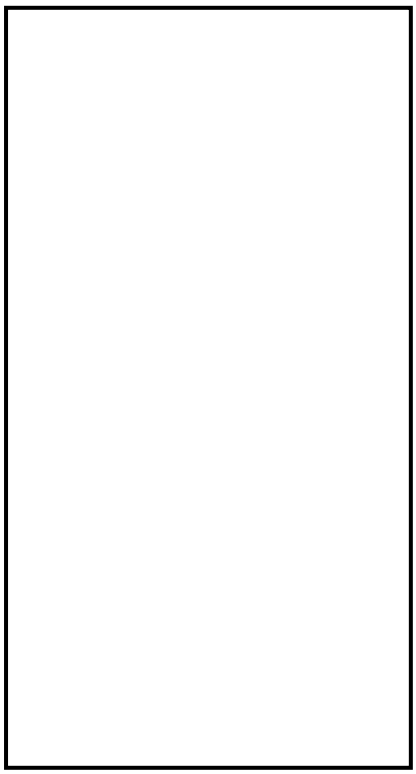


FIGURE 2: RPB UNIT (EXISTING NON-SUBMERSIBLE EQUIPMENT)

ATS units typically fail due to a malfunction of the control electronics. When the control electronics fail, the unit either continuously switches back and forth between supplies, or simply fails to perform the switching operation. Similarly, RPB failures are typically associated with failure of the circuit breaker to open due to malfunction of the controls electronics. Flooding of underground vaults is a contributing factor to such equipment failures. Water and contaminants corrode metals, which results in the rusting of equipment and other potential damage. Contact with water can damage sensitive electronics within the equipment while water and contaminants entering the equipment can cause electrical arcing and faults, potentially leading to catastrophic failures. The failure of ATS and RPB units can have extensive negative impacts on the reliability of the system and on the service provided to Toronto Hydro's customers, as further described in section E6.11.3.2.

As part of its 2012-2014 rate filing, Toronto Hydro developed a proactive ATS & RPB replacement program within the Incremental Capital Module to specifically target ATS and RPB assets identified as being in Very Poor or Poor condition (see section E6.11.3 for details). Toronto

Hydro plans to continue proactively replacing these obsolete assets with equipment that aligns with its current engineering standards during the 2015 to 2019 planning period.

Toronto Hydro plans to replace 21 high priority legacy ATS and RPB units between 2015 and 2019 with standard Toronto Hydro equipment. The anticipated annual breakdown of units replaced is shown in the following Table 1.

TABLE 1: ASSETS TO BE REPLACED

Assets (Vault Locations)	2015	2016	2017	2018	2019	Total
ATS	3	2	3	2	3	13
RPB	0	2	2	2	2	8

The total cost of the Legacy Network Equipment program is forecast to be $4.6 million from 2015 to 2019. Figure 3 shows a map of all the ATS and RPB assets Toronto Hydro proposes to proactively replace in 2015. Replacement priority is primarily determined based on asset condition. A detailed discussion of the prioritization of work within this program appears in Section E6.11.4.1.

FIGURE 3: MAP OF ATS AND RPB ASSET LOCATIONS (2015- 2019 REPLACEMENT)

Replacement Alternatives

In terms of assets to be installed in place of the legacy network equipment, Toronto Hydro considers several alternatives. The recommended course of action for each location is ultimately decided on a case-by-case basis, as each customer's solution will depend on various circumstances, such as the existing infrastructure type and size, system voltage requirements and customer loading. Toronto Hydro plans to replace legacy network equipment with one of the following standard alternatives depending on the specific circumstances:

(1) Stand alone network protectors,

(2) Network transformer units, or

(3) 600 A manual secondary switches.

A detailed description of each of these asset types is provided in the following subsections.

E6.11.2.2 Stand Alone Network Protectors (SANP)

The preferred solution for the replacement of ATS and RPB units is Stand Alone Network Protectors (SANPs), shown in Figure 4. This option is applicable to 120/208 V and 240/416 V vaults (i.e., two of the three secondary voltages).

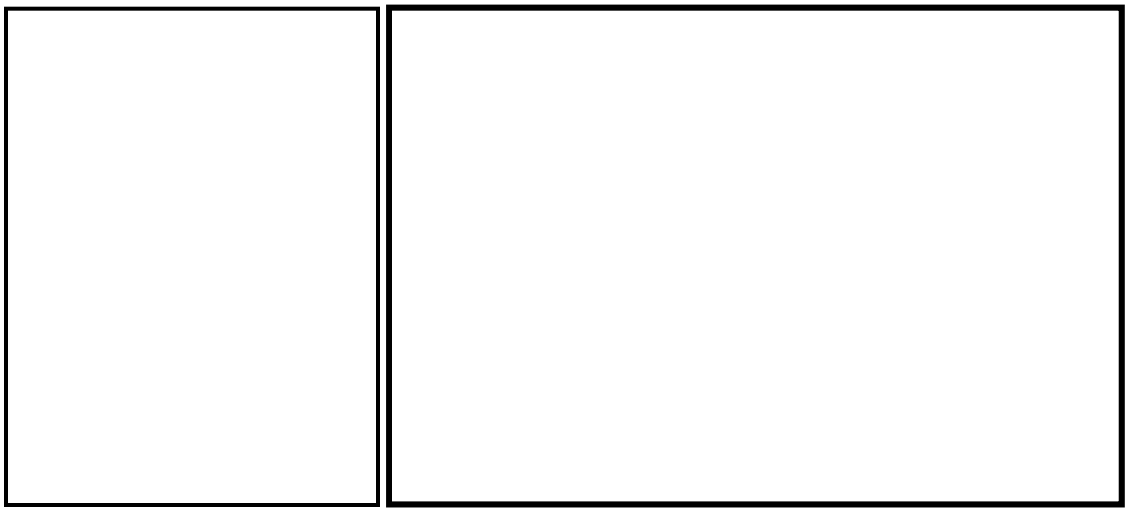


FIGURE 4: STAND-ALONE NETWORK PROTECTOR (SUBMERSIBLE EQUIPMENT)

The SANP provides the system with dual redundancy at the transformers and switches level and automatically performs feeder switching, both of which are not provided by either ATS or RPB assets. The feasibility of this option is conditional on customer load, customer service voltage, physical dimensions of existing civil infrastructure, and the condition of existing transformers. For example, when the physical dimensions of the civil infrastructure and the loading of the customer do not permit the use of SANP, the network unit option (described below) will be used instead. Although SANPs have a slightly larger footprint than existing ATS equipment, SANPs fit into most existing customer vaults except for larger sized customers. Toronto Hydro expects that this option will generally provide customers with improved quality of service with limited momentary interruptions from unplanned feeder outages as compared to the existing ATS and RPB assets.

Installing two SANPs and removing the ATS or RPB equipment typically costs $145,000 per location. In situations where the transformers are also in need of replacement, the replacement cost is typically $330,000 per location.

E6.11.2.3 Network Unit

Another alternative for ATS and RPB replacement is the installation of two standard network units, as shown in Figure 5. This option is only applicable to a secondary voltage of 120/208 V and large customers requiring 500 kVA transformation or greater. Standard network units can fit into almost all existing customer vaults. The reliability improvements associated with this option are expected to be the same as those provided by the use of SANPs. With this option, Toronto Hydro expects that customers will generally experience improved service quality with limited momentary interruptions from unplanned feeder outages in comparison to existing ATS and RPB assets. The network unit option provides the system with dual redundancy at the transformers and switches level and automatically performs feeder switching – functions that are not provided by either ATS or RPB assets. The average cost of this option is $230,000 per location.

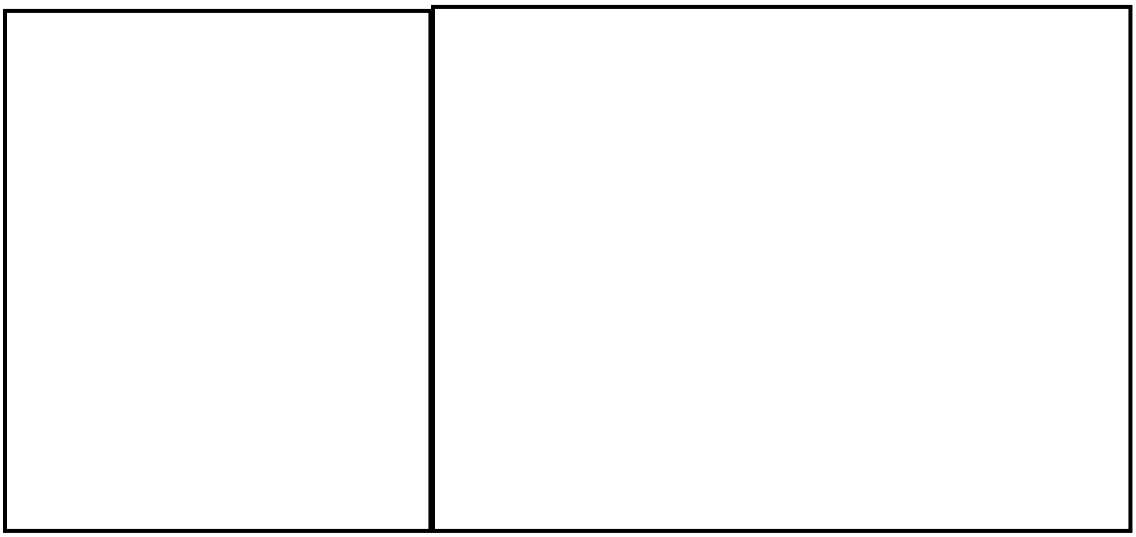


FIGURE 5: NETWORK VAULT (SUBMERSIBLE OR NON-SUBMERSIBLE EQUIPMENT)

E6.11.2.1 600A Manual Secondary Switch

Another option for the replacement of ATS or RPB units are modified 600 A Manual Secondary Switches, shown in Figure 6 below. This switching equipment is compact and will fit into virtually all existing customer vaults, but is limited to smaller customers with a service size no greater than 600 A. This option is applicable for secondary voltages of 120/208 V, 240/416 V and 347/600 V (i.e., all three secondary voltages). It is least preferable to use 600 A Manual Secondary Switches because manual switching is required. As a result, customers could experience inferior operating characteristics due to service restoration delays following unplanned feeder interruptions. The time required to perform the manual switching operation would typically take one to four and a half hours.

The cost of using a 600A Manual Secondary Switches is between $80,000 and $200,000 depending on the condition of the existing transformers and is applicable for secondary voltages of 120/208 V, 240/416 V and 347/600 V (i.e., all three secondary voltages).

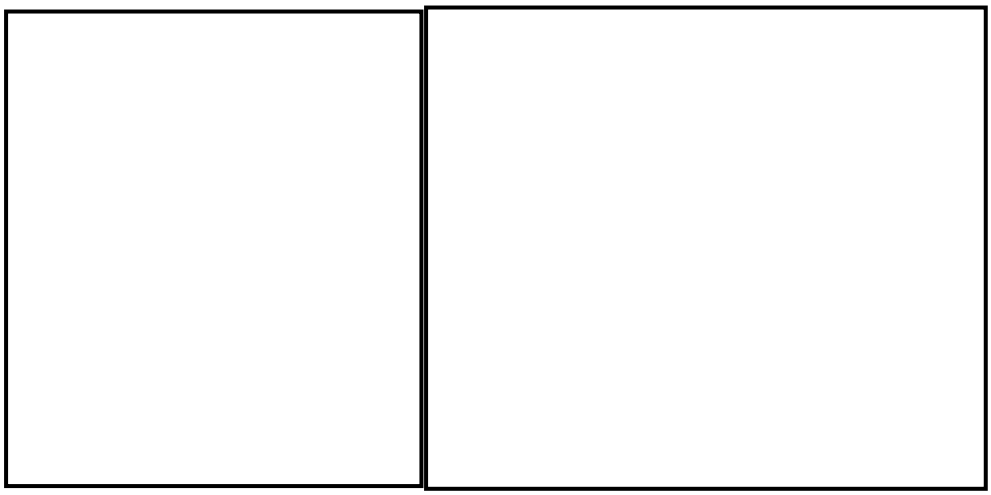


FIGURE 6: MODIFIED TTC VAULT (NON-SUBMERSIBLE EQUIPMENT)

For all three replacement options, existing electrical and civil infrastructure will be utilized wherever feasible; vaults and transformers in good condition will be left in service in order to make the most prudent and cost effective investments in the system. Details of individual unit location assessments and description of work is available in Section E6.11.8.

By replacing the legacy types of network equipment with equipment that aligns to Toronto Hydro's current standards, Toronto Hydro will realize program benefits outlined in Table 2.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Mitigate vault fires that may result in damage to adjacent properties, risk of injuries and environmental issues such as oil spills and cleanup activities ƒ Reduce customer interruptions resulting from asset failure. ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $0.55 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.11.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $0.098 million, confirming the economic prudence of the investments (see Section E6.11.7).
Reliability	ƒ Mitigate potential equipment failure and system outages ƒ Improve outage restoration time
Safety	ƒ Mitigate the risk of vault fires and catastrophic failure events ƒ Avoid potential risk of injuries to customers and crews
Efficiency	ƒ Increase operational efficiencies due to automation ƒ Improve maintenance and service support ƒ Improved availability of spare parts for equipment repair ƒ Reduction in inventory cost

E6.11.3 Why the Program is Needed

ATS and RPBs are types of legacy network equipment that are obsolete, in poor condition, and prone to failure due to various factors such as water penetration, exposure to heavy debris and contamination, which results in equipment rusting and control electronics failure. The penetration of water damages sensitive electronics within the equipment while water and contaminants entering the equipment can cause electrical arcing and faults, which may lead to catastrophic failures. In the years leading up to the 2012-2014 IRM period, Toronto Hydro began experiencing an increasing number of ATS and RPB unit failures. This led Toronto Hydro to replace these units on a less effective, more costly reactive basis. In 2008 and 2009, Toronto Hydro replaced one to two ATS units reactively due to equipment failure. In 2010, the number of ATS units rose to thirteen. Similarly, in both 2011 and 2012, nine ATS units were replaced reactively. As part of its 2012-2014 rate filing, Toronto Hydro established a new program to proactively replace nine ATS & RPB units in 2013, which were identified as being in Very Poor and Poor condition. Despite the execution of this program, an additional six assets failed during this time period and had to be

replaced reactively. Due to these continued failures, Toronto Hydro must carry this proactive replacement program forward during the 2015 to 2019 period.

E6.11.3.1 Program Drivers

The following table summarizes the drivers of the Legacy Network Equipment Renewal program. The trigger driver of this program is functional obsolescence.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Non-submersible equipment legacy network equipment is prone to rusting and failure ƒ Spare parts no longer available for the assets address by this program ƒ Lack of spare parts precludes maintenance as an alternative for extending the life of the assets over the long-term
Secondary Driver	**Reasoning**
Failure Risk	ƒ ATS failure can cause multiple brief power outages and power quality problems for customers. ƒ When an ATS fails to open, the customer can experience an outage until Toronto Hydro crews are notified to investigate the nature of the outage and address the problem. ƒ RPB failure can cause transformers overheat and fail, which ultimately causes the standby feeder breaker at the station to operate. As a consequence, customers that are fed by affected feeders will experience an outage. ƒ ATS and RPB asset related outages typically affect between 50-100 customers for the duration of one to four hours. ƒ Flooded vaults can cause non-submersible equipment to short-circuit, resulting in overheating and failure. In some cases, a catastrophic failure may occur, which could result in equipment and property damage.
Safety	ƒ Catastrophic failure due to ATS and RPB equipment can cause a vault fire ƒ Potential risk of injuries to customers and crews

(i) Functional Obsolescence

Both ATS and RPB units are non-submersible equipment types operated in harsh environments. These units are typically exposed to dirt, debris and water, often resulting in the corrosion of the

non-submersible enclosures and damage of the control electronics, as seen in Figures 7 to 9. Toronto Hydro considers ATS and RPB units to be functionally obsolete equipment designs due to the equipment enclosure's inability to prevent moisture ingress, which subsequently leads to equipment failure.

FIGURE 7: WATER, DEBRIS AND CONTAMINATION IN A VAULT

FIGURE 8: RUSTING AT BASE AND FOOTING OF ATS UNIT

FIGURE 9: RUSTING ON EQUIPMENT SURFACE

Another factor contributing to the functional obsolescence of these assets is that the manufacturer no longer supports this specific type of equipment. Spare parts are unavailable for equipment repairs, making it difficult for Toronto Hydro to achieve alignment with current maintenance and inspection practices. Going forward, the lack of spare parts precludes long-term maintenance as a viable option to extend the service life of the assets. For these reasons, this legacy network equipment no longer meets Toronto Hydro's standards.

(ii) Failure Risk

In the event of a system fault, failed or defective ATS and RPB units may not operate as intended, and in some instances catastrophic failures can occur, examples of which are described in section E6.14.3.2. There are many instances when ATSs have reportedly failed to transfer customers to the standby feeder after the normal feeder supplying customers became faulted. As well, Toronto Hydro has documented several instances of RPB units failing to properly isolate a fault as the RPB breaker failed to open. RPB malfunction can prolong equipment

exposure to large amounts of fault current, damaging equipment such as cables and transformers that are fed on common feeders. This damage can lead to vault fires and catastrophic failures.

Since 2010, Toronto Hydro has averaged 12 ATS or RPB replacements per year due to equipment deficiencies and equipment failures. Over 20% of the combined population of ATS and RPBs are known to be rusted or have failed to operate in the field and are considered high priority for replacement. There are currently a total of 21 ATS and RPB vault locations in need of replacement due to equipment rusting and potential failures as described in section E6.11.3.2.

(iii) Safety

Failing ATS and RPB assets can potentially put the safety of the public and Toronto Hydro employees at risk. In some incidences, catastrophic failure of ATS and RPB assets has resulted in damage to related equipment leading to vault fires that can harm individuals in proximity to the vault. The inherent safety risk of vault fires is heightened by the fact that these assets are generally located in populated downtown areas, as described in Section E6.11.3.2.

E.2 Asset Details

(i) Asset Lifecycle

Toronto Hydro plans to address 13 vault locations with ATS units and eight vault locations with RPB units over the 2015-2019 period. The typical useful life of an ATS unit is 40 years. As shown in Figure 10, of the 34 ATS units currently in service, over 32% will be in operation past their useful lives by 2015, with additional units reaching end-of-life within the 2015-2019 period.

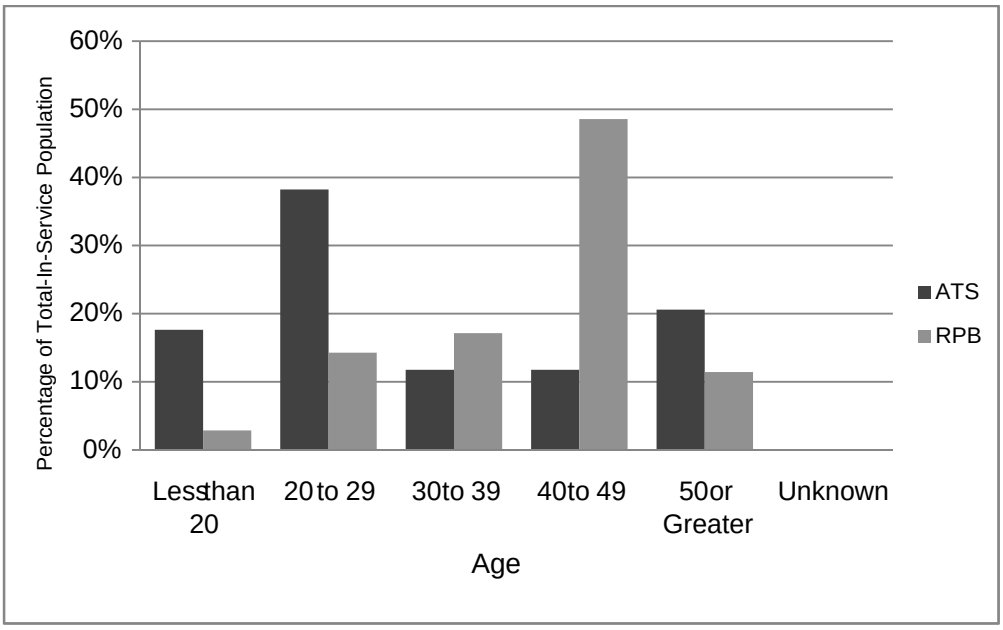


FIGURE 10: ASSET AGE DISTRIBUTION BY 2015

Annual inspections play an important role in identifying ATS and RPB units that are exposed to severe rusting conditions, as well as units that are currently malfunctioning. Of the 34 ATS vault locations and 70 RPB vault locations currently in service, 21 locations (i.e., 20%) are experiencing rusting conditions or were malfunctioning due to contact with debris, contaminants and water, which can damage control electronics. Figure 11 shows the number of ATS and RPB vault locations that are in need of replacement due to the aforementioned problems. The broad age distribution of the assets in need of replacement illustrates the fact that these assets were not designed to withstand exposure to the given environmental and operating conditions.

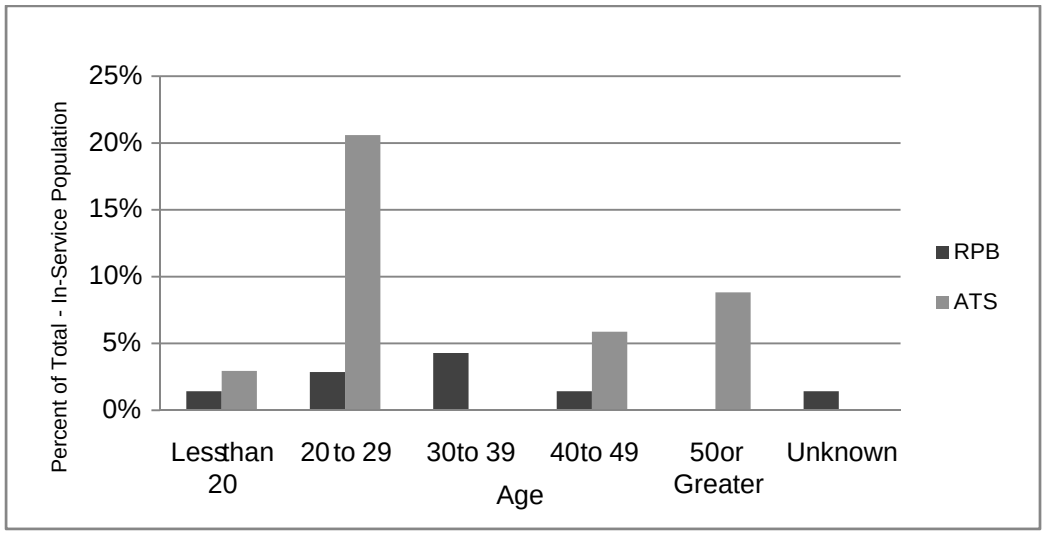


FIGURE 11: LEGACY NETWORK ASSETS IN NEED OF REPLACEMENT

There is an increasing rate of failure of legacy network assets, which is reflected in the increasing trend in reactive equipment replacements shown in Figure 12. Toronto Hydro has been replacing a large number of ATSs and RPBs since 2010. From 2010 to 2013, an annual average of 12 legacy network equipment locations required ATS or RPB replacement due to equipment deficiencies and equipment failures.

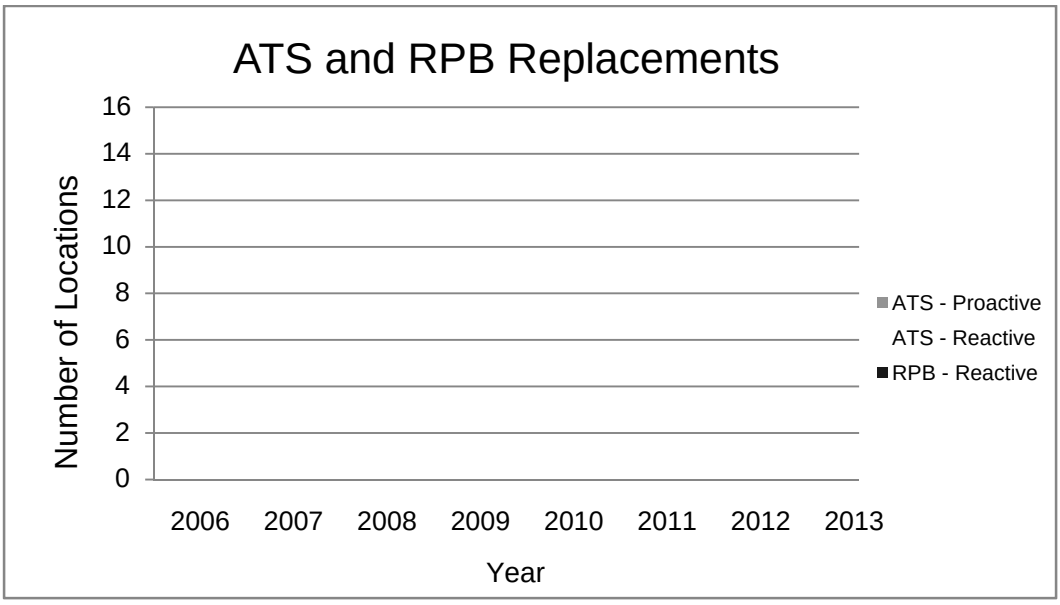


FIGURE 12: ATS & RPB REACTIVE REPLACEMENTS

(ii) Asset Failure Impacts

When an ATS fails, it may continuously transfer back and forth between supplies, causing customers to experience multiple brief power outages and power quality problems. When an ATS fails to open, the customer will experience an outage until Toronto Hydro crews are notified to investigate the nature of the outage and address the problem.

When an RPB fails to open, both supplies are connected to the customer, leading to a back-feed current that continues to feed the faulted part of the system. As a result, the transformers overheat and fail, which ultimately causes the standby feeder breaker at the station to operate. As a consequence, customers that are fed by affected feeders will experience an outage. ATS and RPB asset related outages typically affect between 50-100 customers for the duration of one to four hours.

In flooded vaults, when water reaches a certain level, equipment will short-circuit, resulting in overheating and failure. In some cases, a catastrophic failure may occur, which could result in equipment/property damage and significant safety risks to the public and Toronto Hydro employees. Previously recorded incidences of catastrophic failure are detailed below.

Failure at 33 Princess Street on January 16, 2012

An ATS unit failed on January 16, 2012 at approximately 1:25 pm, igniting a vault fire near Front and Sherbourne and two feeders, A14GD and A15GD. This fire was contained within the ATS vault; however, the fire damaged the primary cables on both feeders as well as the two distribution transformers supplying 33 Princess Street. The feeders were isolated at the station and power was promptly restored to most customers. Approximately 460 students from George Brown College, 50 seniors from a nearby retirement home, Fifty children from a daycare, and customers from 246 The Esplanade were evacuated because of this incident. Two large customers (Esplanade Development Corp and King James Place) supplied solely from feeders A14GD and A15GD also experienced extended outages. Some were left without power until approximately 2:00 pm the following day. Figures 13 to 15 illustrate the extensive equipment damage caused the fire.

FIGURE 13: THE FIRE DEPARTMENT PUTTING OUT THE FIRE AT 33 PRINCESS ST. (PHOTO TAKEN JANUARY 16, 2012)

FIGURE 14: DAMAGES FROM ATS EQUIPMENT FAILURE AT 33 PRINCESS ST. (PHOTO TAKEN JANUARY 17, 2012)

FIGURE 15: LOCATION REPLACED WITH TRANSFORMERS AND ATS AFTER THE FIRE. (PHOTO TAKEN JANUARY 23, 2012)

Failure at 50 Marlborough Court on January 10, 2010

On January 10, 2010 a malfunctioning RPB in a vault near Yonge and Davenport with a history of flooding failed to open. The RPB failure allowed a back-feed of electricity into a primary fault, which damaged the transformers within the RPB vault, caused a catastrophic failure at another vault location (CTY), and damaged equipment in nearby vaults. Figures 16 to 19 below show the damaged transformers with overheated cables and burned oil discharge from the pressure relief valves. This incident resulted in ten hours of interruption to the associated network grid and over 26 hours of interruption to 50 Marlborough Avenue, impacting over 3,000 residential and large commercial customers in the downtown core (along roads such as Bloor St., Davenport Rd.,

Avenue Rd. and Yonge St.). One Toronto Hydro crew member suffered minor injuries related to the fault that occurred within the vault.

FIGURE 16: RPB UNITS FOLLOWING FAILURE AT 50 MARLBOROUGH (PHOTOS TAKEN JANUARY 10, 2010)

FIGURE 17: DAMAGE AT 50 MARLBOROUGH. (PHOTOS TAKEN JANUARY 10, 2010)

FIGURE 18: EQUIPMENT DAMAGE AT CUSTOMER (CTY) DUE TO RPB FAILURE

E6.11.4 Timing & Pacing of the Program

Under this program, 21 high priority ATS and RPB locations are planned for replacement from 2015 to 2019 at a total cost of $4.6 million. An average of four ATS or RPB locations will be targeted annually, which is based on the severity of the asset condition and Toronto Hydro's forecasted resource availability. Historical and future spending is outlined in Table 4.

TABLE 4: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.39	0.03	0.09	1.60	0.25	0.45	0.98	1.14	0.91	1.14

Historically, Toronto Hydro has replaced ATS and RPB equipment on a reactive basis, which has resulted in greater interruption costs to customers, higher per-unit replacement costs, and lower reliability for customers. As described in Section E6.11.3.2, Toronto Hydro has transitioned to a proactive replacement program to reflect the age and condition of these assets.

It is prudent that ATS and RPB assets be replaced in a timely matter to avoid asset failure, as the number of failures has increased in recent years. The five-year schedule was established to address equipment that is considered high priority due to permanent degradation issues such as oil leaks and rusting, equipment with a history of malfunctioning and equipment in locations that are exposed to heavy contamination, flooding and/or dampness in the vaults.

E6.11.4.1 Ranking & Prioritization

The sequencing of work within the Legacy Network Equipment program is determined based on several factors. These include:

- Inspection Results: Annual inspections play an important role in identifying ATS and RPB units that are exposed to severe rusting conditions, as well as units that are currently malfunctioning. Failure of these assets is largely due to the wear and tear of the mechanical operating mechanism, corrosion of the equipment and electronics malfunction due to water damage. Inspection records of ATS and RPB assets are considered key information to be evaluated for prioritization of work.

- Failure Risk and Impact: Equipment failure is associated with varying risks. ATS and RPB failure can result in one to four hours of customer outages, equipment and property damages and/or the risk of a catastrophic failure or a vault fire. The Legacy Network Equipment Renewal program gives priority to locations with higher failure risks such as rusted equipment enclosure and previous flooded locations.

- Reliability: Assets that are malfunctioning, have major deficiencies, or are being exposed to poor environmental conditions are deemed to be at higher risks of failing. In turn, asset failures can affect system reliability. The Legacy Network Equipment Renewal program considers reliability concerns associated with system performance when establishing work priorities.

- Asset Age: The sequencing of work takes into account an asset's useful life. Assets operating well past industry projected useful life are considered high risk in terms of potential failures.

- Coordination: To achieve greater efficiency, equipment fed from the same Toronto Hydro feeders in the region is coordinated in terms of replacement schedule and sequencing. This approach is intended to reduce disruption of supply and to provide continuous power to customers wherever possible. Reduced disruption to feeders translates into fewer outages for customers, and improved project efficiencies.

Assets in poor condition are prone to failure and are a safety and reliability concern to Toronto Hydro and its customers, especially considering to the potential for catastrophic failures like the ones described in Section E6.11.3.2. Equipment that is heavily rusted and that has a history of water penetration is ranked as high-priority for asset replacement due to greater risk of failure.

Accordingly, asset condition and failure risk are the primary factors considered in determining which ATS and RPB units need to be replaced first.

E6.11.5 Program Execution

Project execution begins with a portion of the legacy assets being removed from the vault as shown in Figure 19 and Figure 20. Toronto Hydro generally maintains service to the customers using the remaining legacy assets until new standard network equipment is installed, at which point the newly installed equipment will be used to re-service the customer. The remaining legacy assets are then removed from the system. The process of equipment removal and installation is performed by certified power cable persons (CPCP) with over five years of specialized training. The process is shown from Figures 21 to 24.

FIGURE 19: REMOVING ATS EQUIPMENT IN UNDERGROUND VAULT

FIGURE 20: OLD EQUIPMENT REMOVED BY CRANE

FIGURE 21: CRANING NEW EQUIPMENT TO BE INSTALLED

FIGURE 22: LOWERING NEW EQUIPMENT TO BE INSTALLED

FIGURE 23: NEW EQUIPMENT INSTALLED IN UNDERGROUND VAULT

FIGURE 24: NEW EQUIPMENT INSTALLED IN UNDERGROUND VAULT

Due to access and space limitations, a crane is used to remove and install equipment. When equipment is placed into position, cables are installed, terminated, racked into position, and then the system is tested prior to supplying the customer with power. Upon job completion, the vault roof is placed back into position and the location is restored to its original condition.

E6.11.5.1 Proposed Work Plan

The long term plan addresses 21 vault locations from 2015 to 2019 as outlined in Table 5, averaging four locations annually.

TABLE 5: 2015-2019 LONG TERM PLAN

Year	Asset	Location
2015	ATS	4268
2015	ATS	D9016
2015	ATS	4914
2016	ATS	2 locations
2016	RPB	2 locations
2017	ATS	3 locations
2017	RPB	2 locations
2018	ATS	2 locations
2018	RPB	2 locations

2019	ATS	3 locations
2019	RPB	2 locations

E6.11.5.2 Program Risks

The challenges of operating in central Toronto – including access to vaults situated in high traffic sidewalks/laneways and the inherent difficulties of switching in the downtown core due to high loading conditions in summer – could potentially impact the pace of ATS and RPB replacements. Toronto Hydro's resource planning teams will coordinate and plan projects so that they are implemented in spring and fall seasons to account for switching complications. As well, Toronto Hydro plans to communicate with customers to create an agreeable timeline in accordance with system priorities.

The integrity of the civil structure at each vault location is reviewed in the planning and design stages of the project and may impact the project completion timeline. When safety deficiencies such as weak structural integrity of customer-owned vaults are identified, as shown in Figure 25, the customer will be made aware through a Customer Advice Form (CAF) at least a year in advance of the actual replacement of ATS and RPB units. This helps ensure that customers are given adequate advanced notice to address the civil work that needs to be carried out in relation to customer-owned vaults. Safety-related concerns such as major structural problems or trip hazards must be addressed either prior to the commencement of work or as part of the work being performed by Toronto Hydro crews. The work specified in a CAF may involve the rebuild of the vault roof or the entire vault depending on the condition of the site, in order to protect the safety of individuals, as well as Toronto Hydro and customer assets.

FIGURE 25: CIVIL STRUCTURE PROBLEMS

E6.11.6 Evaluation of Alternatives

E6.11.6.1 Quantification/ Evaluation of Options

(i) Status Quo

Maintaining the status quo entails continuing to operate the ATS and RPB units as is, and replacing them reactively upon failure. While failure rates have increased substantially in recent years, manufacturer support and spare parts are not available. Accordingly, Toronto Hydro forecasts that maintaining the status quo will negatively affect system reliability and will pose potential safety risks to customers as well as Toronto Hydro personnel. As such, this option is not recommended.

(ii) Like-for-Like Replacement

Non-standard equipment is required in order to replace ATS and RPB units in the form of like-for-like replacement. The use of non-standard equipment can be very expensive due to high

engineering, training, maintenance, manufacturing and inventory costs spread over a relatively small number of assets. In addition, when custom equipment is purchased, availability of spare parts and support is limited. As such, this option is not recommended.

(iii) Replacement with Standard Equipment

Replacing legacy network equipment with standard network equipment allows Toronto Hydro to continue to supply its customers reliably and mitigates the safety risks outlined in this narrative. Pursuant to the analysis below, this option is also the most cost-effective for Toronto Hydro's customers. Standard Toronto Hydro network equipment such as 600 A secondary manual switches, stand alone network protectors and network transformer units can be used to replace legacy network equipment as described in Section E6.11.2. The cost of this option is $70,000 to $300,000 per location depending on the existing infrastructure in place.

The cost of ownership (COO) and program net benefit (NPV) associated with Legacy Network Equipment Renewal program is further detailed in Table 6. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities in this program. The COO of a state reflects the risk of asset failure including both direct and indirect costs. These costs include customer interruptions, emergency repairs, and asset replacements associated with a given design. For further details on the COO approach, please refer to Section D3.3.

TABLE 6: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	$0.70
Non Asset Risk [NAR_E]	$0
Maintenance Cost [MC_E]	$0
Additional Quantifiable Benefits [AQB_E]	$0
Cost of Ownership of Existing Assets [COO_E]	$0.70

When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first of activities, the Legacy Network Equipment Renewal program produces a NPV of $0.098 million, as shown in Table 7. As the net present value is positive, this means that the benefits of executing the work outweigh the capital expenditures and the work is therefore economically prudent. A positive NPV shows a net reduction in risk when factoring in impacts to customers due to power interruptions.

TABLE 7: STANDARDIZED REPLACEMENT BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 2: Replacement with Standard Equipment (N)	
Asset Risk [AR_N]	$0.16
Non Asset Risk [NAR_N]	$0
Maintenance Cost [MC_N]	$0
Additional Quantifiable Benefits [AQB_N]	$0
Cost of Ownership of New Assets [COO_N]	$0.16
Option 2: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_N)$]	$0.55
Program Cost [PC_1]	$0.45
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	$0.098

E6.11.7 2015 Project Details

Table 8 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

- previously filed projects that appeared as jobs in the OEB approved ATS and RPB segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and
- projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 8: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	CIR Projects
0.26	0.19

Table 9 lists all projects that are planned for partial or complete execution as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 9: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
X12953	X12953, ATS Replacement, Loc 4268	$255,693	2015	ICM
X14520	X14520, ATS Replacement, Loc 4914	$138,042	2015	CIR
X14521	X14521, ATS Replacement, Loc D9016	$54,123	2015	CIR

The following subsections provide details for each of the 2015 projects listed in the table above.

E6.11.7.1 X12953 Project Description

Investment Category: System Renewal

Program: Legacy Network Equipment Renewal

Project Title: X12953, ATS Replacement, Loc 4268

Project Number: X12953 (ICM)

Project Year: 2015

Estimated Cost: $255,693

(i) Objective

The purpose is to replace ATS equipment located at 1130 Bloor St. W. with network equipment.

(ii) Scope of Work

TABLE 10: X12953 SCOPE OF WORK DETAILS

District Neighborhood	BLOOR DAVENPORT VILLAGE
Station(s)	DUFFERIN
Feeder(s)	A41 DN, A89 DN

TABLE 11: X12953 ASSETS REPLACED

Assets (Units)	2015
ATS	1
Transformers	2

(iii) Justification & Benefits

This ATS equipment in location 4268 was installed in 1963. Maintenance inspection records identified that the base of the ATS unit is rusting. This is due to a wet underground vault located beneath pedestrian walkways that is heavily salted. Rusting of the enclosure and water penetration often leads to equipment failure as described in detail in section E6.11.2. Replacing the non-submersible ATS equipment in poor condition with network equipment that is designed to be submersible in water and to be operated under harsh environments will mitigate impending failures and ensure the safe and reliable operation of the grid.

E6.11.7.2 X14520 Project Description

Investment Category: System Renewal

Program: Legacy Network Equipment Renewal

Project Title: X14520, ATS Replacement, Loc 4914

Project Number: X14520

Project Year: 2015

Estimated Cost: $138,042

(i) Objective

The purpose of this project is to replace ATS equipment located adjacent to 1537 Davenport.

(ii) Scope of Work

TABLE 12: X14520 SCOPE OF WORK DETAILS

District Neighborhood	CARLETON VILLAGE
Station(s)	WILTSHIRE
Feeder(s)	A2-25 kV, A3-39 kV

TABLE 13: X14520 ASSETS REPLACED

Assets (Units)	2015
ATS	1
Transformers	2

(iii) Justification & Benefits

Maintenance inspection records identified that the ATS unit in location 4914 is rusting. The footing of the unit has been rusting badly since 2010. This is an indication of a wet underground vault. Due to rusting of the enclosure and water penetration, the ATS unit malfunctioned and failed to perform the feeder transfer operation. Delaying the ATS unit replacement at location 4914 would risk failure and safety issues as detailed in sections E6.11.3.1.

As discussed in sections E6.11.2, the equipment cannot be serviced and spare parts are no longer available. Replacing the non-submersible ATS equipment with network equipment that is

designed to be submersible in water and to be operated under harsh environments will mitigate impending failures and ensure the safe and reliable operation of the grid.

E6.11.7.2 X14521 Project Description

Investment Categories: System Renewal

Program: Legacy Network Equipment Renewal

Project Title: X14521, ATS Replacement, Loc D9016

Project Number: X14521

Project Year: 2015

Estimated Cost: $54,123

(i) Objective

The purpose of this project is to replace ATS equipment located on the east side of Brant St. and south of Richmond St. W.

(ii) Scope of Work

TABLE 14: X14521 SCOPE OF WORK DETAILS

District Neighborhood	FASHION DISTRICT
Station(s)	WINDSOR
Feeder(s)	A6-64 M WR, A6-69 M WR

TABLE 15: X14521 ASSETS REPLACED

Assets (Units)	2015
ATS	1

(iii) Justification & Benefits

Maintenance inspection records identified that the ATS unit in location D9016 is rusting. Although the ATS unit was installed in 1993 and has been in service for a short duration, it is heavily rusted. The unit has signs of surface rust and the footings have been heavily rusted since 2010.

The equipment cannot be serviced or repaired and is in need of replacement as rusting of the enclosure and water penetration often leads to equipment failure. Replacing the non-submersible ATS equipment in poor condition with network equipment that is designed to be submersible in

water and to be operated under harsh environments will mitigate impending failures and ensure the safe and reliable operation of the grid.

E6.12 Network Circuit Reconfiguration

SWITCH AND FUSE UNITS

E6.12.1 Summary

Program Description

The Network Circuit Reconfiguration program addresses the functionally obsolete design of the existing secondary network distribution system in certain areas of Toronto. This program is made up of the following two initiatives:

(1) Enhancement of secondary network grid flexibility: Toronto Hydro plans to upgrade the secondary grid by splitting large grids into more robust spot vaults and enhanced mini-grids, each with fewer primary feeders. The objective of this initiative is to minimize customer interruptions, improve planning and operational flexibility, enhance the ability of the network system to operate under extreme events and, most importantly, to prevent the secondary network distribution system from becoming functionally obsolete in the face of incremental changes that have been made to the distribution system over time. (In particular, the network system was designed for pure network loads and not the mixed network and radial loads that exist today. Enhancement of secondary network grid flexibility is necessary to adapt to this new standard.)

(2) 600 V network distribution initiative: Toronto Hydro plans to supplement existing 433Y/250V and 216Y/125V network equipment with new 600Y/347V network equipment in order to prevent the secondary network distribution system from becoming obsolete in light of changing customer needs. (In particular, the need for reliable supply to customers with significantly greater building heights than the network system was originally designed to accommodate).

The anticipated benefits of the Network Circuit Reconfiguration program are summarized in the following table.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Following major equipment failures, fewer customers will be dropped, fewer customers will be required to reduce load and customers will experience shorter outages. ƒ Eliminates customer outages due to special switching requirements in some locations. ƒ Improves Toronto Hydro's ability to meet the service needs of new customers through new service supply options.
Reliability	ƒ Improved ability to operate networks under multiple contingency events. ƒ Forecast two-thirds reduction in load interruptions during second contingency events. ƒ Eliminates special operating restrictions that interrupt a second feeder following a failure on specific feeders. ƒ Permits station to station feeder ties to improve reliability as part of the Downtown Contingency program.
Safety	ƒ Minimizes hazardous manual switching activities following major equipment failures. ƒ Reduced loss of supply to life support equipment. ƒ Eliminates hazardous Sachsenwerk switch and fuse units in four locations.
Efficiency	ƒ Improves the productivity of power system controllers and system response crews. ƒ Removes special operating procedures at four locations.
Other	ƒ Reconfigured network feeders can be tied to feeders from other stations as part of the Downtown Contingency program. ƒ Improved ability to transfer loads.

Program Drivers

The trigger and secondary drivers for the Network Circuit Reconfiguration program are summarized in the following table.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ The network system was designed for pure network loads and not the mixed network and radial loads that exist today. Enhancement of secondary network grid flexibility is necessary to adapt to this new standard. ƒ The network system is becoming functionally obsolete due to its inability to supply new classes of customers, while at the same time existing classes of customers are dwindling. The 600 V network distribution initiative is necessary in order to allow the secondary network distribution system to operate as needed for new classes of customers.
Secondary Drivers	**Reasoning**
Reliability	ƒ The secondary network system was originally designed to withstand first contingency operation; however, multiple contingency events are now a common occurrence, which result in widespread outages. ƒ Although the network system was originally designed to allow faulted equipment to burn clear, present operating practices often require Toronto Hydro to cut all power, resulting in widespread customer outages. ƒ Operating restrictions on existing hazardous Sachsenwerk switch and fuse units reduce the reliability of power supply.
System Efficiency	ƒ Network Circuit Reconfiguration will relieve power system controller workload during multiple contingency events and reduce the need for system response crews to perform load relief and restoration tasks.
Safety	ƒ Sachsenwerk loadbreak switches in use pose safety hazards.

Preferred Alternative

Toronto Hydro considered the following alternatives for preventing the functional obsolescence of the network system.

(1) Allow the network system reliability to degrade as new customer loads are added, radial and network loads are mixed on the same feeders and operating practices are continuously modified to meet safety requirements.

(2) Implement the Network Circuit Reconfiguration program to ensure long term load growth and system flexibility needs are met.

The current operational constraints within the existing network circuit configuration create one to two complete network interruptions each year following multiple contingency network outages. Without Network Circuit Reconfiguration, Toronto Hydro expects that network system reliability continue to degrade as new customer loads are added, radial and network loads are mixed on the same feeders and operating practices are modified to enhance safety and satisfy new requirements. The utility also expects that the secondary network distribution system will continue to become functionally obsolete and will not be able to meet customers' changing needs. Also, by maintaining the status quo, existing 600 V switch and fuse units that use Sachsenwerk switches and that require switching restrictions will remain in place, negatively impacting system reliability and safety. For these reasons, Option II is preferred.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $3.08 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.12.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $0.77 million, confirming the economic prudence of the investments (see Section E6.12.7).

Timing and Pacing

The Network Circuit Reconfiguration program addresses issues that have been developing over the past few decades and that are expected to continue to worsen. Toronto Hydro plans to start this program during the 2015 to 2019 period in order to begin clearing a growing backlog of required investments, but anticipates work to continue beyond 2019. Table C provides historical and projected program spending.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	0	2.30	2.29	2.28	2.27

E6.12.2 Program Description

The Network Circuit Reconfiguration program addresses the functionally obsolete design of the existing secondary network distribution system in certain areas of Toronto. This program is made up of the following two initiatives, which are further discussed in the following sections:

(1) Enhancement of secondary network grid flexibility, and

(2) 600 V network distribution initiative.

Both the enhancement of secondary network grid flexibility and 600 V network distribution initiative projects proposed for the 2015 to 2019 timeframe are illustrated in Figure 1 below. The total cost of the program for the 2015 to 2019 period is estimated to be $9.14 million. As this is a long-term planned renewal program, Toronto Hydro expects to continue reconfiguring the secondary network distribution system beyond 2019.

FIGURE 1: NETWORK CIRCUIT RECONFIGURATION PROJECT MAP

E6.12.2.1 Enhancement of Secondary Network Grid Flexibility

The enhancement of secondary network grid flexibility addresses the major components of the secondary network system, including secondary grids, network transformers and primary feeders. Toronto Hydro plans to upgrade the secondary grid by splitting large grids into more robust spot vaults and enhanced mini-grids, each with fewer primary feeders. The goal is to minimize customer interruptions, improve planning and operational flexibility, enhance the ability of the network system to operate under extreme events and, most importantly, to prevent the secondary network distribution system from becoming functionally obsolete in the face of incremental changes that have been made to the distribution system over time. Pressures facing the existing network system are discussed in detail in section E6.12.3.

Secondary network distribution systems behave very differently than other common distribution systems and have unique and demanding operating requirements. In order to understand how the network system works and why the Network Circuit Reconfiguration program is necessary, an introductory outline of the secondary network distribution systems follows.

Secondary Network Distribution Systems

The secondary network distribution system is unique in that it utilizes multiple transformers connected to multiple feeders to simultaneously supply several customers through an interconnected secondary grid. Figure 2 illustrates how a simple network system is connected. The key component to making this system work is the network protector. The network protector automatically connects and disconnects individual transformers from the secondary grid to compensate for primary feeder switching and equipment failures. Secondary network systems are, by this means, able to provide uninterrupted service to customers even if one or more components in the grid fail.

Network vaults are either configured as grid vaults or spot vaults. In grid vaults, secondary grid cables are tied to cables of neighbouring vaults, as illustrated in Figure 2. A mini-grid is an area in which a few network vaults are tied together, but the group is not tied to the rest of the grid. In spot vaults, the secondary grid cables are not connected to any neighbouring vaults. Spot vaults always contain two or more network transformers and are needed when either the secondary voltage is different than neighbouring vaults or when it is not practical to interconnect the secondary cables with other vaults.

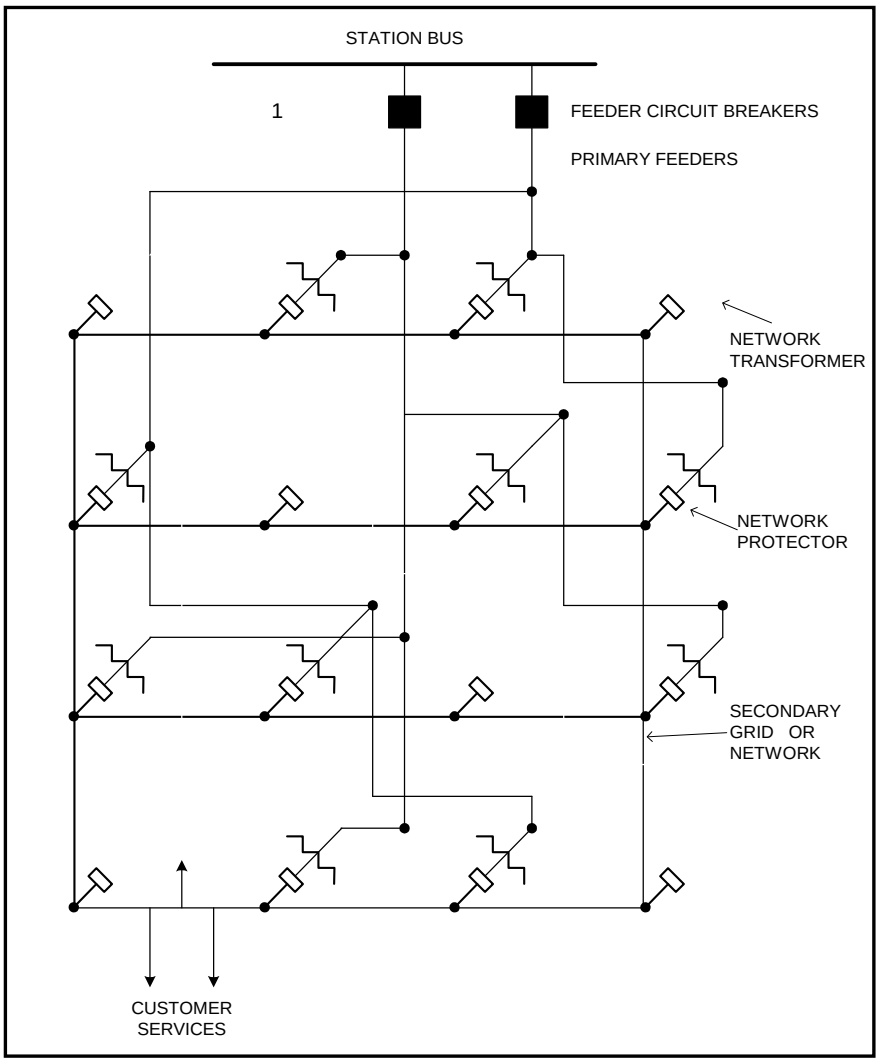


FIGURE 2: BASIC SECONDARY NETWORK DISTRIBUTION SYSTEM

Contingency Events and the Evolution of the Network System

Toronto Hydro's network system is designed to operate under first contingency conditions, meaning that any one primary feeder, transformer, or other critical piece of equipment can be put out of service without causing a service interruption to customers. A second contingency occurs when any two primary feeders, transformers, or other critical pieces of equipment are out of service. Although the system is not designed to operate under second or higher multiple contingency conditions, they can sometimes be sustained for short periods of time. When second or multiple contingency conditions arise, the situation as a whole must be evaluated and if it is

determined that the network is unable to sustain the event, the entire network grid must be dropped.

In order to assess whether a system can operate reliably under first contingency conditions, network systems are modeled, taking into account primary cables, transformers, secondary grids and customer loads, and simulations are conducted. These assessments are typically conducted whenever major changes are made to a network. Over the years, Toronto Hydro has had to make many small, urgent, reactive changes in order to add load to existing customers, add new customers, transfer customers and modify primary feeders without the opportunity to evaluate the net effect..

In addition to the modifications mentioned above, Toronto Hydro has made changes to its safety and operating practices, which has also considerably impacted the network's ability to sustain outages. When Toronto Hydro originally developed the network system, it was designed to sustain equipment outages for a single day without exceeding the thermal limits of the equipment remaining in service. Today's planned feeder outages typically last three days, which result in higher equipment peak temperatures and an accelerated loss of life for equipment. Another issue is that the secondary network distribution system was not originally designed to allow network primary feeders to mix with radial primary feeders. However, at the present time, network and radial loads are mixed on the same feeders and the network grids have not been reconfigured to reflect this new reality.

Proposed Changes to the Network System

Toronto Hydro plans to reconfigure large network grids so that either: (a) sufficient grid flexibility is introduced to enable the sustainment of multiple contingency events, or (b) sufficient customer loads are automatically dropped during multiple contingency events to allow the remainder of the grids to continue operating properly. Examples of how these objectives can be achieved and the impact that they would each have on the network system follow.

As a starting point, Figures 3 through 5 provide an example of a mini-grid consisting of three vaults that each contain two network transformers. This mini-grid is able to operate under first contingency conditions but not under second contingencies. Second contingency events result in transformer overloads that require intervention by the power system controllers to identify the problem and drop the mini-grid. If the overloading problem is not identified and corrected in time, it could result in equipment failure and widespread customer interruptions.

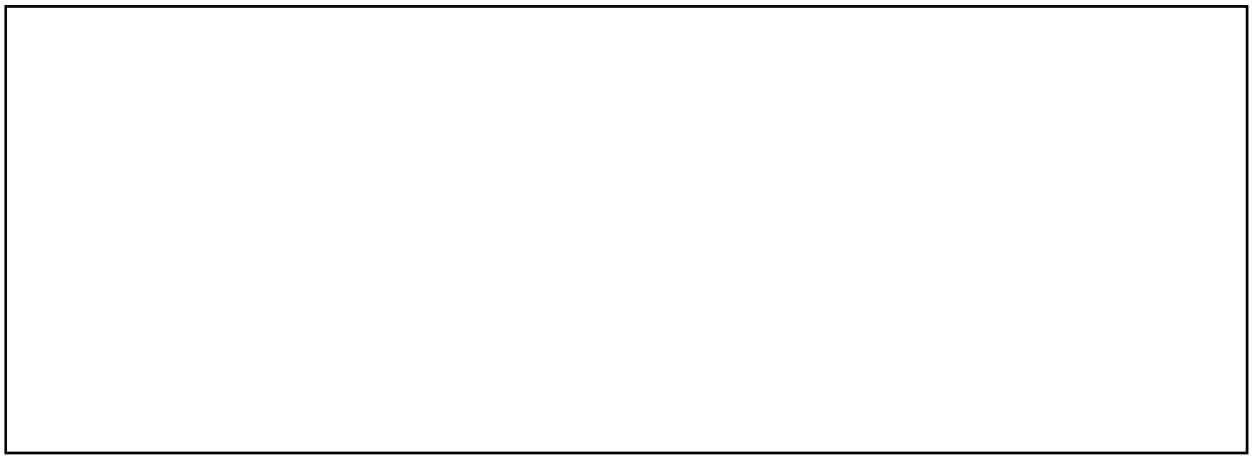


FIGURE 3: EXISTING NETWORK CONFIGURATION (1 OF 3)

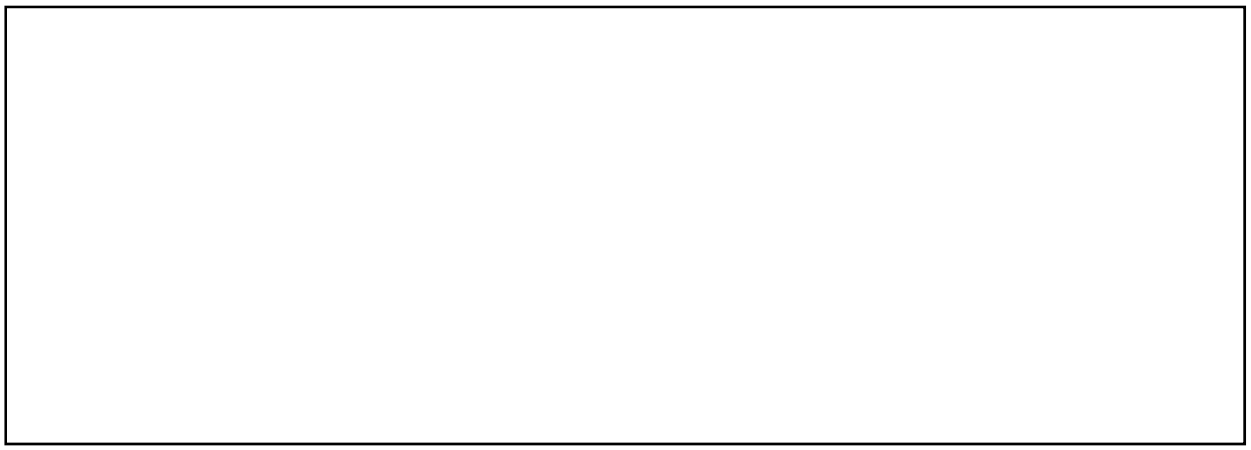


FIGURE 4: EXISTING NETWORK CONFIGURATION (2 OF 3)

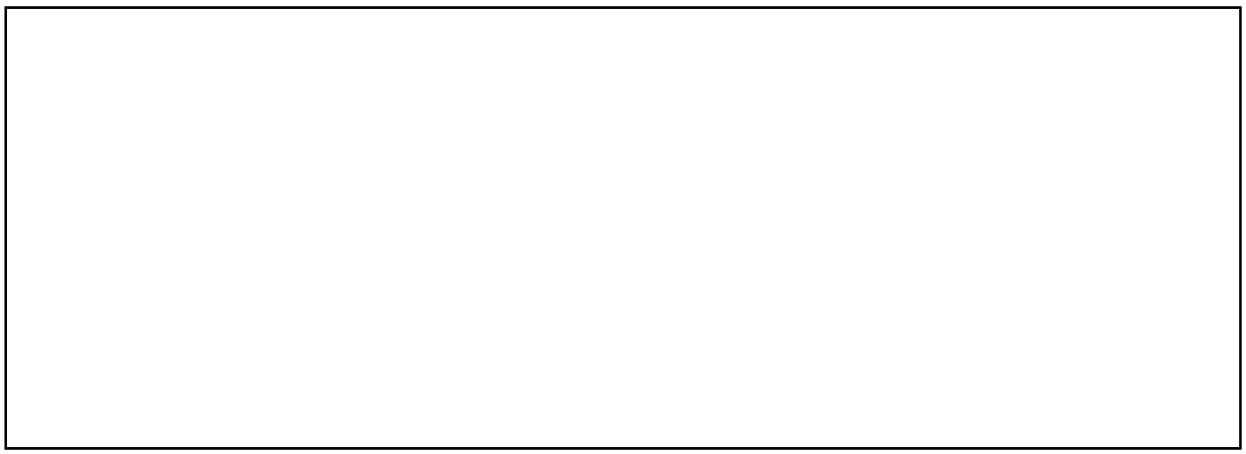


FIGURE 5: EXISTING NETWORK CONFIGURATION (3 OF 3)

The Network Circuit Reconfiguration program uses a number of different options to address the problems and risks associated with multiple contingency events, including:

(1) splitting grid into spot vaults,

(2) splitting grid into enhanced mini-grids,

(3) upsizing transformers, and

(4) primary feeder changes.

These four options are listed in order of increasing benefit, i.e. option four is generally superior to option 1 in terms of reducing the number of customers dropped and equipment damages during second or third contingencies.

Splitting grid into spot vaults

Figures 6 and 7 below illustrate converting a network grid into spot vaults. This option solves overload problems under second contingency events that could result in equipment failure, and eliminates the need for power system controller intervention during these events. On the downside, up to two-thirds of customer loads would automatically dropped during second and third contingency events.

FIGURE 6: FIGURE E6.12-6: SPLITTING GRID INTO SPOT VAULTS (1 OF 2)

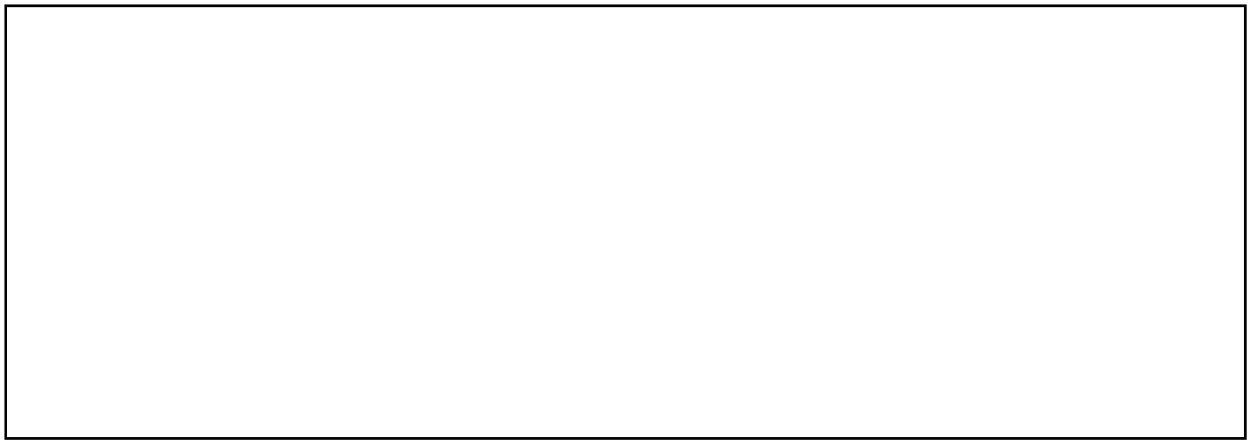


FIGURE 7: SPLITTING GRID INTO SPOT VAULTS (2 OF 2)

Splitting grid into enhanced mini-grids

Figures 8 and 9 below illustrate the second option of dividing a large grid into smaller enhanced mini-grids and spot vaults. This option is able to better sustain customer loads under multiple contingency events than what is possible using the first option. However, a third contingency would still result in a serious transformer overload and require prompt action by the power system controllers to identify the problem and drop the load on the grid.

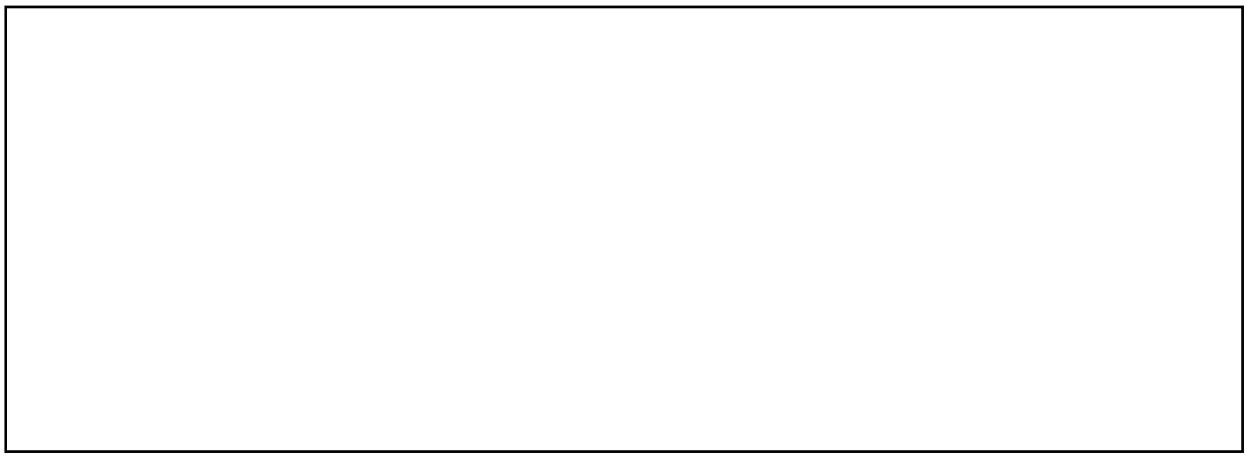


FIGURE 8: SPLITTING GRID INTO ENHANCED MINI-GRIDS (1 OF 2)

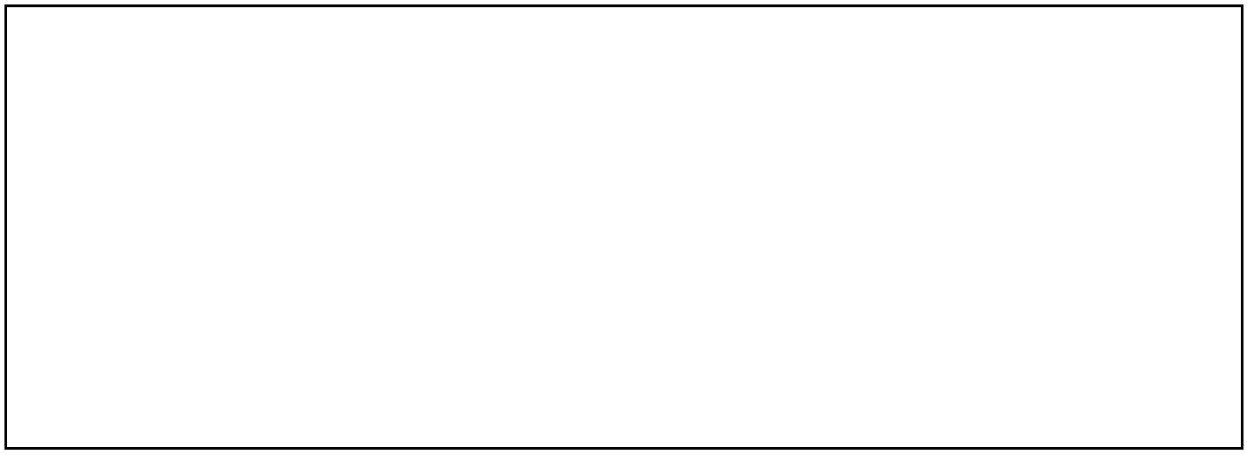


FIGURE 9: SPLITTING GRID INTO ENHANCED MINI-GRIDS (2 OF 2)

Upsizing transformers

Another option to enhance the grid is to upsize transformers where necessary to sustain continuous first contingency and limited second contingency conditions. Figures 10 and 11 below illustrate this third option.

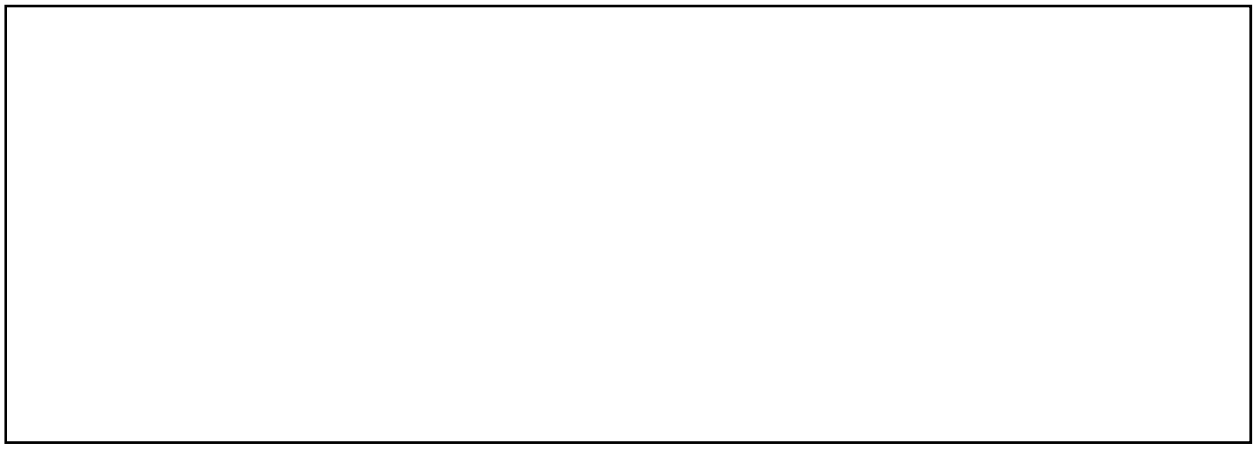


FIGURE 10: UPSIZING TRANSFORMERS (1 OF 2)

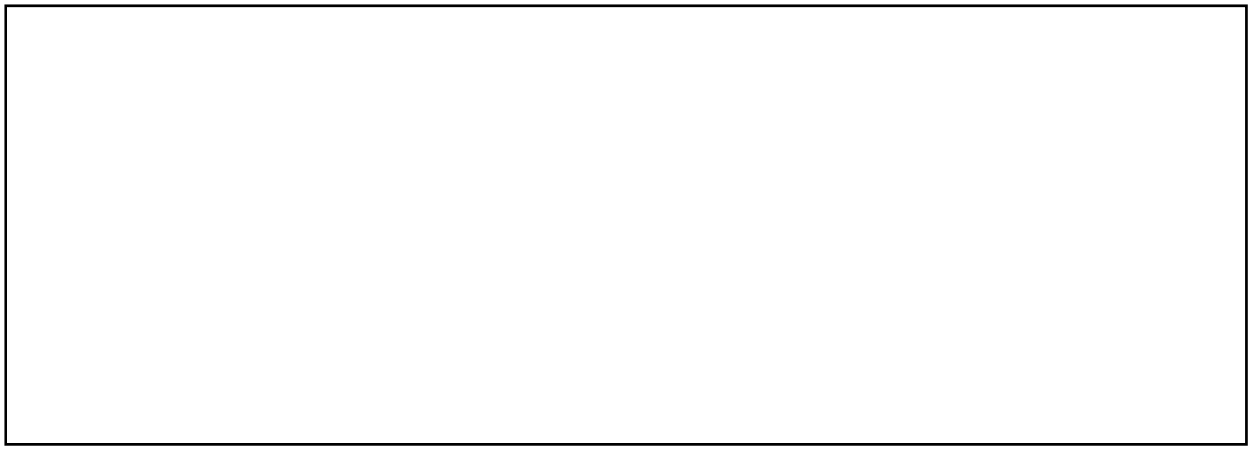


FIGURE 11: UPSIZING TRANSFORMERS (2 OF 2)

The option allows all customer loads to be sustained during any second contingency condition; however, a third contingency would still result in a serious transformer overloads and would require prompt action by the power system controllers to identify the problem and drop the load on the grid.

Primary feeder changes

A fourth option is to change primary feeder connections where necessary to sustain continuous first contingency and limited second contingency conditions. Figures 12 and 13 below use the same network grid to show how this can be implemented.

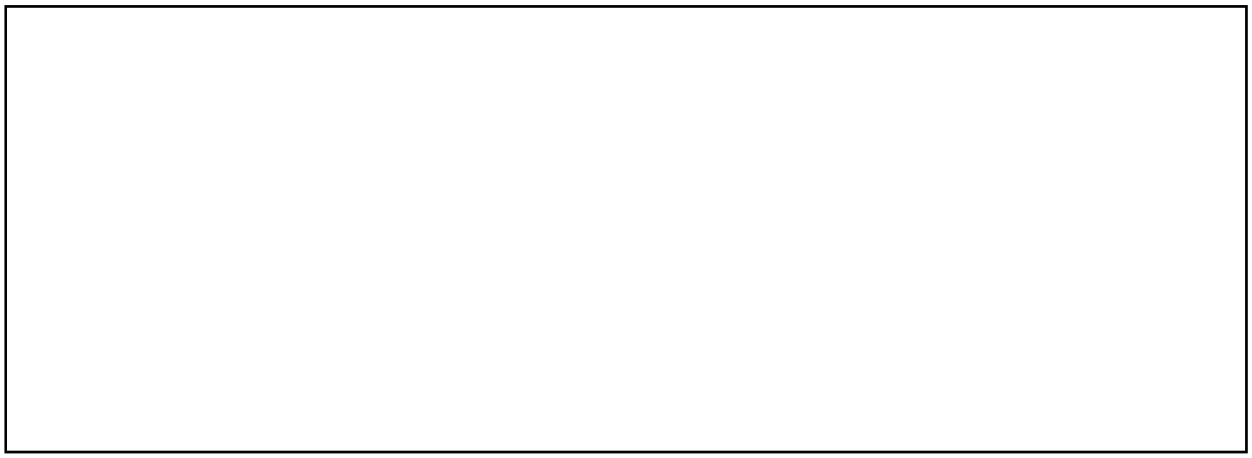


FIGURE 12: PRIMARY FEEDER CHANGES (1 OF 2)

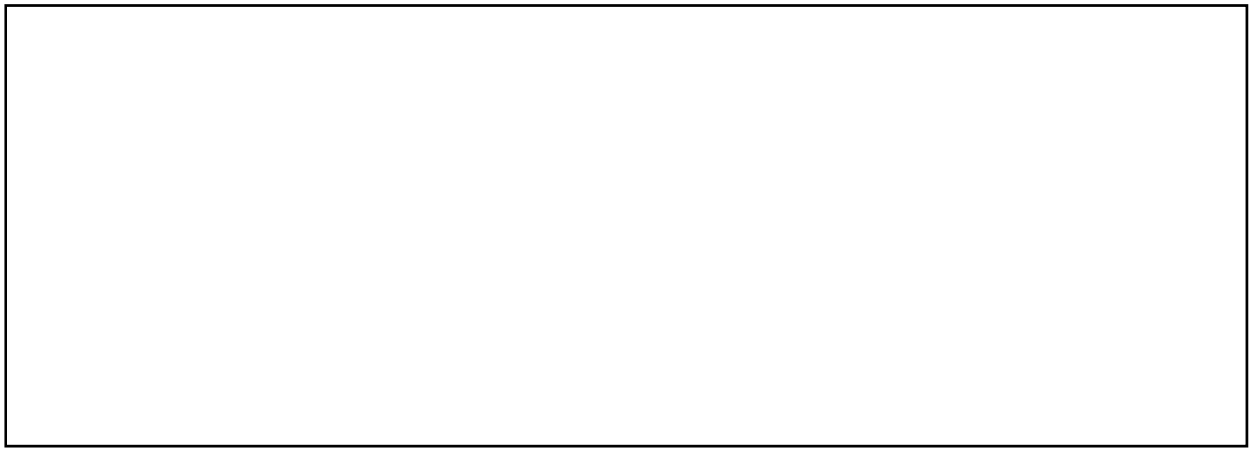


FIGURE 13: PRIMARY FEEDER CHANGES (2 OF 2)

All customer loads would be sustained during any second contingency condition and some third contingencies. However, certain third contingency conditions would result in serious transformer overloads and would require prompt action by the power system controllers to identify the problem and drop the load on the grid.

Summary

While the options above are generally listed in order of increasing benefit, this order of merit varies depending upon the circumstances of each individual network. In other words, each of the

above options may be the optimal solution in a particular circumstance, and each reconfigured network will typically use a combination of these options. For example, combining primary feeder changes with transformer upsizing would allow customer loads to be sustained during any third contingency condition. The optimal combination will maximize the reliability of power supply for customers under multiple contingency events and greatly simplify the problems that the power system controllers must deal with during the same events.

When an entire network must be dropped, up to 50 MVA of customers are interrupted. Currently, the entire network is typically dropped for four hours, with smaller portions dropped for 12 to 24 hours. As a result of the enhancement of secondary network grid flexibility, the impact of outages will decrease. While the amount of improvement will vary substantially from network area to network area, the amount of customer load dropped on a typical six feeder network grid would be reduced by approximately two-thirds.

Since reconfigured network areas are expected to require much less effort to restore widespread service interruptions, emergency response resources will be freed up and can be redirected to restore other, longer outages. Although the number of customers experiencing longer outages may not be dramatically reduced as a result of this initiative, the duration of outages will drop.

Finally, Network Circuit Reconfiguration is a prerequisite for Downtown Contingency station-to-station feeder ties (refer to section E7.7 for details on the Downtown Contingency program). The proposed work under the enhancement of secondary network grid flexibility initiative will permit further service reliability improvements that the Downtown Contingency station-to station program has to offer.

The network reconfiguration projects proposed for the 2015 to 2019 timeframe are illustrated in Figure 2. Network reconfiguration projects were selected to include areas both east and west of Yonge Street in order to balance labour requirements. Particular networks were selected because they are relatively small and simple, and can be quickly and efficiently reconfigured to improve reliability. An additional benefit of this small-scale approach is that Toronto Hydro expects to gain useful experience on how to manage issues and problems with respect to network reconfiguration; later, Toronto Hydro will apply its learnings to other, more challenging networks.

E6.12.2.2 600 V Network Distribution Initiative

The 600 V network distribution initiative proposes to supplement existing 433Y/250V and 216Y/125V network equipment with new 600Y/347V network equipment in order to prevent the

secondary network distribution system from becoming obsolete in light of changing customer needs.

The 600 V initiative will develop and introduce new network distribution equipment as a standard option for future installations. Four locations are included in this initiative in 2016:

- X15511 - Replace Equipment at location PCS with 600Y/347V NW Equipment
- X16148 – Replace Equipment at location CTS with 600Y/347V NW Equipment
- X16149 – Replace Equipment at location DHC with 600Y/347V NW Equipment
- X16150 – Replace Equipment at location ECE with 600Y/347V NW Equipment

Currently, Toronto Hydro supplies network customers with either 433Y/250V or 216Y/125V network equipment.

433Y/250V

Distribution equipment rated 433Y/250V is rarely used in new installations because it is obsolete, difficult to acquire and is no longer supported by Toronto Hydro for new customer installations. Accordingly, 433Y/250V has essentially been superseded by 600Y/347V.

216Y/125V

While equipment rated 216Y/125V is still considered current, it is constrained by a practical building height limit of approximately 25 stories due to excessive voltage drop within the building. As such, upper floors of tall buildings would not be able to maintain voltage at utilization points in accordance with minimum acceptable levels. Consequently, downtown redevelopments above 25 stories cannot be connected to the network system using this technology, and must therefore use less reliable radial distribution equipment. The 600 V network distribution initiative will provide a highly reliable alternative for customers in highrise buildings. Distribution equipment is readily available at 600Y/347V and the practical building height limit at this voltage is about 70 stories. This increased height limit accommodates most network area redevelopment projects.

Sachsenwerk Switch

In addition to new network customers, several existing customers are already supplied by hazardous Sachsenwerk switch and fuse locations at 600Y/347V. Please refer to Section E6.12.3.1 for further details of these locations. Most of these locations have relatively large vaults that are candidates for 600 V network equipment. The 600 V network distribution initiative will replace four of these switches with 600 V network equipment in 2016, while the remainder of the locations will be addressed as part of the Underground Legacy Infrastructure program (Section E6.3).

Introduction of 600 V

The use of 600 V network distribution equipment is an evolutionary development to the lower voltage secondary network equipment that is currently used by Toronto Hydro. In incorporating the new network equipment into the system, Toronto Hydro will take into account the unique maintenance and operating requirements that arise out of the use of higher voltages. In particular, to ensure safe operations, Toronto Hydro must plan for the new design and operating constraints associated with greater arc flash energy levels. Toronto Hydro plans to address these constraints by introducing a number of useful features, including: a submersible case; current limiting fuses (as opposed to alloy type fuses used in lower voltage submersible protectors); arc flash isolating upper links to permit protector overhaul without customer interruption; and network automation to allow remote monitoring and control of the protectors from the control center. A composite photo rendering of these features of the proposed protector is illustrated in Figure 14.

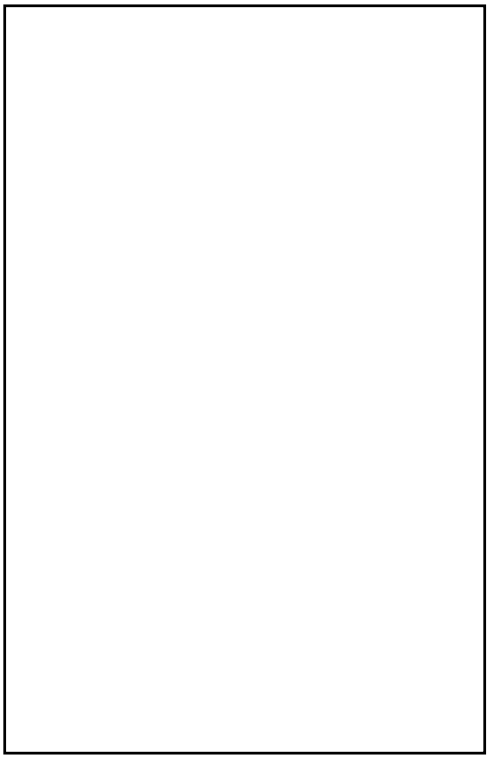


FIGURE 14: COMPOSITE PHOTO RENDERING OF PROPOSED 600V NETWORK PROTECTOR

Another proposed 600 V network feature is the use of transformers of up to 2500 kVA rating, compared to 1000 kVA maximum at 216Y/125V and 2000 kVA at 433Y/250V. These transformers are associated with lower losses than existing lower voltage units, which should generally enable Toronto Hydro to retrofit them so that they can be placed into existing vault structures. The reuse of existing vault structures would be desirable in the case of an existing building being refurbished, or where an underutilized sidewalk vault is repurposed to feed a new building.

Toronto Hydro plans to use multiple single unit vaults when new vaults are required in order to prevent the failure of one network unit damaging other units. This design will improve the reliability of power supply for customers that are fed from the vault and for the network grid as a whole, which would otherwise be exposed to a multiple contingency event. The first four 600 V network installations will reuse existing vaults that currently contain Sachsenwerk switchgear. (Saschenwerk switch and fuse units are a type of legacy underground equipment used to provide certain customers with a dual radial supply; these switches are planned for replacement during 2015-2019 as part of the Underground Legacy Infrastructure program (E6.3)).

The layout, primary cabling and secondary cabling of a typical 600 V network vault is illustrated in Figure 15. This layout is representative of one that would is planned for all four Sachsenwerk switchgear vault projects. In this example, two network units are installed in the vault.

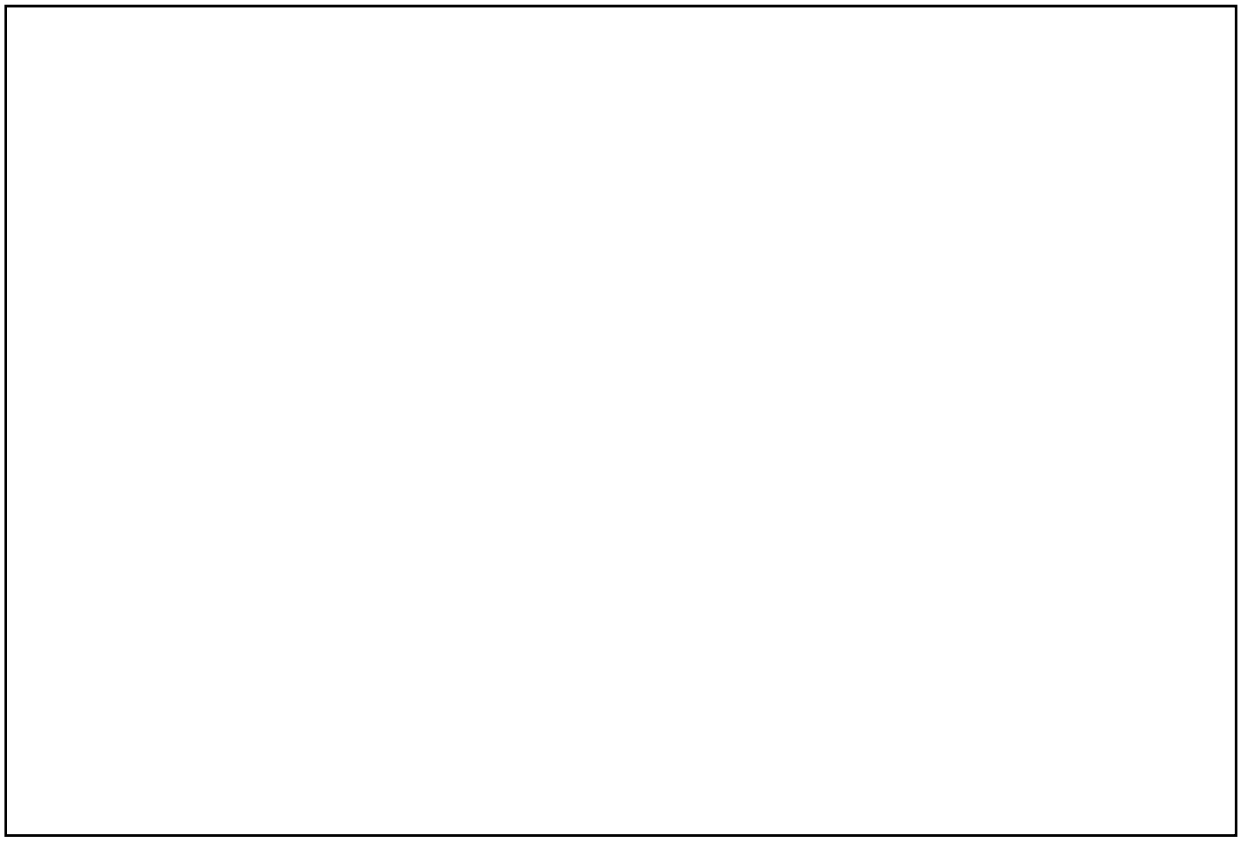


FIGURE 15: LAYOUT OF TYPICAL 600V NETWORK VAULT

The 600 V network distribution initiative involves the replacement of eight switchgear and four transformers with eight new network units as illustrated in Table 1 below.

TABLE 1: ASSETS TO BE ADDED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
UG Transformers		8				8

The benefits of the Network Circuit Reconfiguration program include increased customer value along with improvements to reliability, efficiency and safety. A summary of these anticipated benefits is provided in Table 2 below.

TABLE 2: PROGRAM BENEFITS

Customer Value	ƒ Following major equipment failures, fewer customers will be dropped, fewer customers will be required to reduce load and customers will experience shorter outages. ƒ Eliminates customer outages due to special switching requirements in some locations. ƒ Improves Toronto Hydro's ability to meet the service needs of new customers through new service supply options. ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $3.08 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.12.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $0.77 million, confirming the economic prudence of the investments (see Section E6.12.7).
Reliability	ƒ Improved ability to operate networks under multiple contingency events. ƒ Two-thirds reduction in load interruptions during second contingency events. ƒ Eliminates special operating restrictions that interrupt a second feeder following a failure on specific feeders. ƒ Permits station to station feeder ties to improve reliability as part of the Downtown Contingency program.
Safety	ƒ Minimizes potentially hazardous manual switching activities following major equipment failures. ƒ Eliminates hazardous Sachsenwerk switch and fuse units in four locations.
Efficiency	ƒ Improves the productivity of power system controllers and system response crews. ƒ Removes special operating procedures at four locations.
Other	ƒ Reconfigured network feeders can be tied to feeders from other stations as part of the Downtown Contingency program. ƒ Improved ability to transfer loads.

E6.12.3 Why the Program is Needed

The main driver for the Network Circuit Reconfiguration program is Functional Obsolescence, which is a result of urgent, incremental changes being made to the system and the evolution of

operative practices to accommodate new customers. Other secondary drivers include Reliability, System Efficiency, and Safety.

E6.12.3.1 Program Drivers

Table 4 presents the primary and secondary drivers for Network Circuit Reconfiguration, which is considered a System Renewal initiative because the primary driver is Functional Obsolescence.

TABLE 3: PROGRAM DRIVERS

Primary Driver	Reasoning
Functional Obsolescence	ƒ The network system was designed for pure network loads and not the mixed network and radial loads that exist today. Enhancement of secondary network grid flexibility is necessary to adapt to this new standard. ƒ The network system is becoming functionally obsolete due to its inability to supply new classes of customers, while at the same time existing classes of customers are dwindling. The 600 V network distribution initiative is necessary in order to allow the secondary network distribution system to operate as needed for new classes of customers.
Secondary Drivers	**Reasoning**
Reliability	ƒ The secondary network system was originally designed to withstand first contingency operation; however, multiple contingency events are now a common occurrence, which result in widespread outages. ƒ Although the network system was originally designed to allow faulted equipment to burn clear, present operating practices often require Toronto Hydro to cut all power, resulting in widespread customer outages. ƒ Operating restrictions on existing hazardous Sachsenwerk switch and fuse units reduce the reliability of power supply.
System Efficiency	ƒ Network Circuit Reconfiguration will relieve power system controller workload during multiple contingency events and reduce the need for system response crews to perform load relief and restoration tasks.
Safety	ƒ Sachsenwerk loadbreak switches in use pose safety hazards.

(i) Functional Obsolescence

The primary driver for the Network Circuit Reconfiguration program is Functional Obsolescence. The network grid has not been adjusted to account for incremental modifications that were made to the network to accommodate new customers, which reduces its ability to operate under multiple contingency conditions. As well, Functional Obsolescence is an issue because changes

to operating practices now force multiple contingency events, which the system was not originally designed to manage.

Mixing of Different Types of Loads

The secondary network distribution system was originally designed and constructed when network primary feeders were not mixed with radial primary feeders. Since then, network and radial loads have been mixed on the same feeders, raising the following issues:

(1) Network feeders are designed with high loading factors, which is acceptable because when a primary feeder is out of service, loads automatically get redistributed across all of the other network feeders. However, radial feeders must be designed with low loading factors because radial loads are either entirely on the normal feeder, or entirely on the standby feeder. As a result, when radial loads are connected to network feeders, the loading margins needed to operate the network under multiple contingency events quickly disappear.

(2) Radial customer work often requires feeders to be de-energized for extended periods of time. Network equipment, on the other hand, is designed to operate with overloads that can only be sustained for short periods of time when a feeder is out. As a result, radial loads tend to erode the margins required to operate networks. This can be a serious problem during multiple contingency events.

The problems mentioned above are having an increasingly negative impact on Toronto Hydro's ability to manage the secondary network distribution system. For example, 54 network feeders could not undergo planned interruptions during the summer of 2014, in order to avoid cable and equipment overloads. Enhancement of secondary network grid flexibility is required in order to compensate for the present practice of mixing network and radial loads on the same feeders.

Downtown Redevelopment Customers and Existing Customers Declining

The network system is also becoming functionally obsolete due to existing network equipment being unsuitable for use with new classes of downtown redevelopment customers, while at the same time, the number of existing network customers is dwindling. Figure 16 below illustrates the recent drop in network load as a percentage of total downtown loads. Over the past seven years, the network portion of downtown loads has dropped by more than 25%.

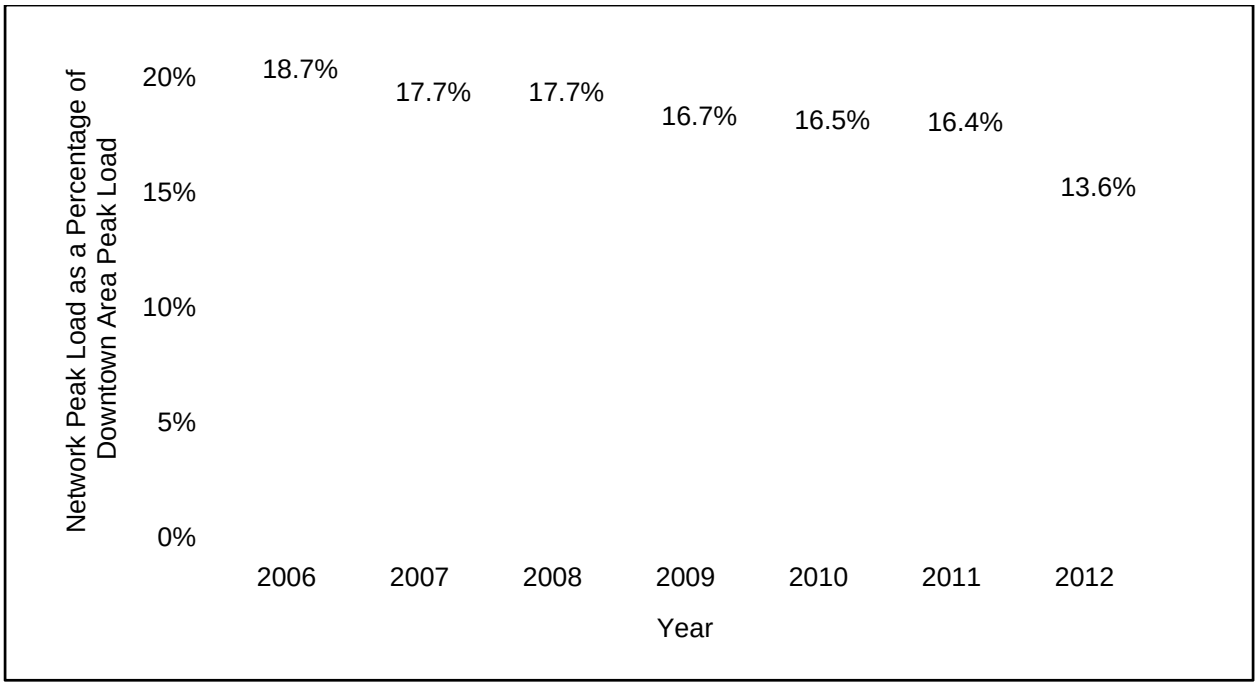


FIGURE 16: NETWORK PEAK LOAD TO TORONTO DOWNTOWN AREA PEAK LOAD

Total load carried by the network system has dropped over the last seven years from 307.8 MVA down to 243.5 MVA. This represents a decrease of almost 21% and is shown in Table 4 below:

TABLE 4: NETWORK SYSTEM & TORONTO DOWNTOWN AREA SYSTEM PEAK LOADS

Year	2006	2007	2008	2009	2010	2011	2012
Toronto Downtown Area System Peak Load (MVA) (a)	1,648	1,705	1,684	1,663	1,701	1,694	1,789
NWK System Load (MVA) (b)	307.8	301.3	298.8	278.1	280.6	277.3	243.5
Ratio (b/a)	18.68%	17.67%	17.74%	16.72%	16.50%	16.37%	13.61%

The decreasing percentage of total downtown peak load supplied by the network, combined with continually decreasing network loads, demonstrates that the existing network system no longer provides suitable connection services for customers and as a result, is becoming obsolete. There are three major reasons for this trend.

(1) High-rise redevelopment of network areas . New developments in the downtown area are generally made up of office and condominium buildings that are 35 stories or higher. These redevelopments are rapidly replacing existing buildings that are generally two to four stories high and that are supplied by secondary network distribution. As such, the redevelopment represents a very significant demographic switch from when the network system was first constructed. Given that existing 216Y/125V network equipment has a practical height limitation of about 25 stories, it is unable to supply the majority of new construction. As a result, new redevelopments have to depend on the less reliable 13.8 kV radial distribution option. In addition, the existing network infrastructure is generally not suitable for reuse with radial distribution, so costly new construction is often required to supply new customers.

(2) Customer updating of electrical equipment . Existing mid-rise buildings that use electrical equipment at their end-of-life often replace obsolete 433Y/250V equipment with modern 600Y/347V equipment. Seeing as Toronto Hydro does not currently possess 600Y/347V network option, customers are forced to depend on the less reliable 13.8 kV radial distribution option.

(3) Network customer supply size limit . Toronto Hydro is no longer offering new customers 433Y/250V network service. The service size limit for new 216Y/125V network customers is 750 kVA. Since new high-rise customers typically have a demand of 2500 kVA or more, they must connect to the 13.8 kV radial distribution option, which does not have the same reliability benefits as the network system.

All of the issues described above can be resolved by Toronto Hydro offering a 600Y/347V network option to customers with increased service size limitations. The high-rise redevelopment of network areas limit is resolved by the practical building height limit at 600Y/347V being about 70 stories; the customer updating of electrical equipment issue is resolved by providing service at the customers' desired voltage; and the network customer supply size limit is resolved by offering multi-MVA supply sizes.

To summarize, this program is needed so that Toronto Hydro can sustain the network system and continue to offer new customers the highly reliable secondary network distribution system as a supply option. Should this work not proceed, downtown customers' reliability may suffer. The 600 V network distribution initiative is necessary so that the secondary network distribution system maintains its relevance and performance.

(ii) Reliability

Reliability is an important secondary driver of the program. The secondary network distribution system has experienced reduced reliability in the past few decades. System reliability has been impacted by changes that were made to operating practices that force multiple contingency interruptions, and by incremental modifications that were made to the network in order to accommodate new customers, which reduces its ability to operate under multiple contingency conditions. The Network Circuit Reconfiguration program is intended to restore network reliability to original design levels.

Evolving Operating Practices

The secondary network system was originally designed to burn clear faults and self-isolate damaged equipment; meaning that that most failures of network transformers and primary and secondary cabling do not result in customer interruptions. Virtually all failures of primary and secondary cabling are cleared without requiring intervention from the power system controllers and without interruption to network customers. However, a small number of transformer failures result in vault fires.

The fire department's current practice is to require that Toronto Hydro immediately cut all power supplies into the vault as a first step in fighting the fire. As a consequence, multiple network primary feeders must be tripped, which leaves insufficient remaining contingency capacity to sustain the network grid. As a result, entire network grids, with as much as 50 MVA of customer loads, often must be dropped, causing widespread and long outages. Assuming a typical residential customer load of 4 kVA, this 50 MVA interruption represents 12,500 residential customers.

By reconfiguring the network grids into spot vaults and enhanced mini-grids, the need to drop entire network areas can be greatly reduced or eliminated. These reconfigured grids will be able to better sustain the majority of loads; only small portions of customers will experience outages. Overall network reliability can thereby be substantially improved.

For a typical six primary feeder network, a second contingency failure incident entails dropping about 30 MVA of load for four hours. A reconfigured network grid should be able to sustain a second contingency incident without requiring the entire network to be dropped. The reconfigured network should, by design, shed sufficient load under second contingency conditions to allow the remainder of the grid to continue to operate. This should typically result in only about 10 MVA of

load being dropped, a two-thirds reduction in interrupted load. This reliability enhancement is illustrated in Figure 17 below.

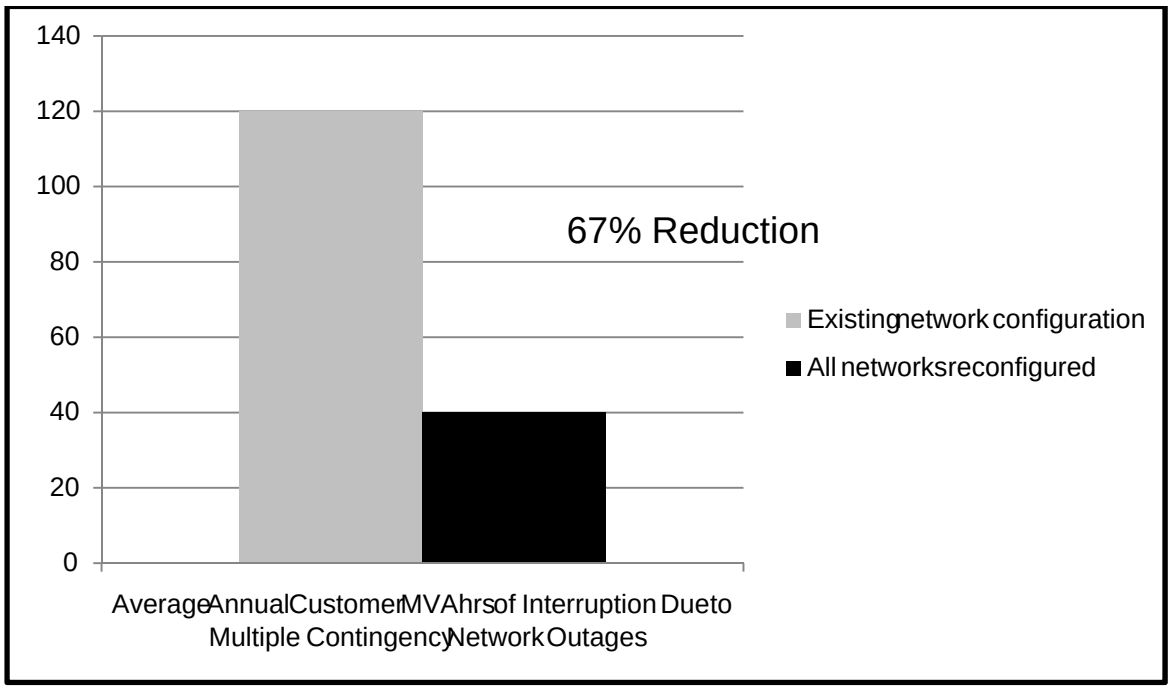


FIGURE 17: RELIABILITY IMPROVEMENT FROM NETWORK CIRCUIT RECONFIGURATION

Multiple Contingency

Multiple contingency operation of the network system imposes daunting requirements on operating personnel. First, a network expert must analyze the grid, identify critical overload conditions and propose customer load reductions and necessary reactive tasks all within restrictive time limits. Should such an expert not be immediately available at the control center, the power system controllers may be forced to drop the entire grid in order to prevent a network cascade failure. A network cascade failure would likely result in the loss of up to 50 MVA of customer load for at least 24 hours.

Second, once the necessary reactive switching and load reduction tasks are identified, system response crews must perform this work, and customers need to reduce their loads within the identified time limitations. Reconfigured networks will generally be able to continue operating under multiple contingency events by automatically shedding unsustainable loads, relieving

power system controller workload and reducing the need for system response crews to perform reactive load relief and restoration tasks.

Secondary Interconnections

Another shortcoming of the existing network configuration is that it is not practical to provide network feeders with station-to-station feeder ties. The large number of secondary interconnections means that network feeders must be energized simultaneously rather than one at a time. This causes two significant problems:

(1) The entire alternate station bus that would pick-up the network experiencing a station loss-of-supply incident must be dropped. This would cause unacceptable widespread outages to customers that would otherwise not experience an outage.

(2) The subsequent requirement to simultaneously pick-up both the emergency transferred network load and the original alternate station bus loads would almost certainly exceed the cold load pick-up capabilities of the station bus.

Reconfigured network grids will permit station-to-station feeder ties to be picked-up one at a time. These grids are therefore compatible with the Downtown Contingency program (see Section E7.7), and thereby permit further reliability improvements.

Downtown Developments and the Sachsenwerk Switch

Many new downtown developments require 347/600V services. However, at the present time, all available options involve the use of dual radial distribution equipment, which do not provide reliable service to customers. Accordingly, the development and use of 600Y/347V secondary network distribution equipment will significantly enhance customer reliability.

In addition, operating restrictions are currently in place on the hazardous Sachsenwerk switch and fuse units, which results in unnecessary customer interruptions following feeder failures. The replacement of these switches through the 600 V network distribution initiative will eliminate the operating restrictions and improve service reliability on the associated feeders.

Toronto Hydro plans to replace four locations containing eight Sachsenwerk switch and fuse units with 600Y/347 V network equipment in 2016. The age of these Sachsenwerk units vary between 25 and 27 years and are detailed in Figure 18 below.

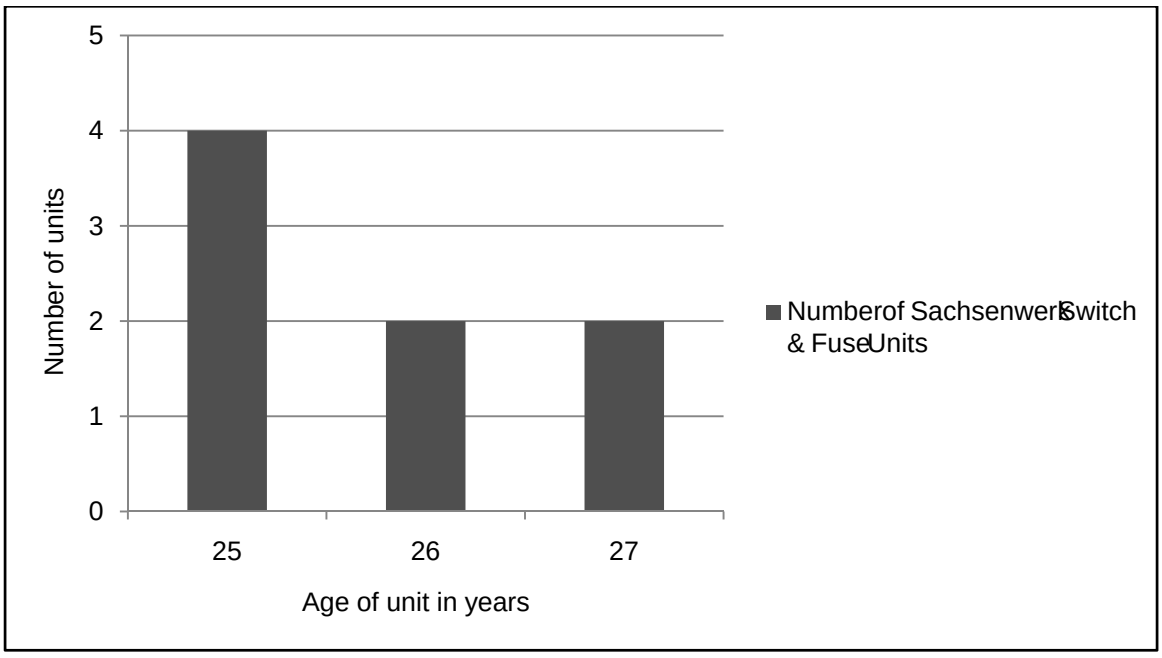


FIGURE 18: AGE OF SACHSENWERK SWITCH AND FUSE UNITS TO BE REPLACED IN 2016

The Sachsenwerk switch and fuse units must be replaced, as they are no longer manufactured and serviced, and can pose serious hazards (as described below).

Flashovers in Saschenwerk Units

Presently four locations in downtown Toronto are supplied from hazardous dual-radial switch and fuse vaults with 600Y/347V transformers. These particular switch and fuse units use Sachsenwerk load break switches that periodically fail to engage properly during open and close operations, resulting in flashover that causes the station breaker to open, and presents a hazard to the switch operator. As a result, Toronto Hydro has introduced operating restrictions to manage this risk. Further discussion of Sachsenwerk switch and fuse units can be found in Section E6.3 Underground Legacy Infrastructure.

In order to reduce the risk of flashovers occurring in Saschenwerk units during switching operations, they are only operated in paralleling operations that do not make or break loads. This means that even if a Saschenwerk switch malfunctions during its operation, it will not cause a hazardous flashover. During most normal switching operations, customers will not experience service interruptions. However, during emergency switching operations, customer service is impacted. For example, if one feeder goes out on fault, the second feeder will be interrupted prior to operating the Sachsenwerk switches. The result is a second contingency event that likely results in a number of otherwise unnecessary customer interruptions.

The 600 V network distribution initiative will replace the equipment in four of these Sachsenwerk switch and fuse locations, which will eliminate unnecessary customer interruptions. Furthermore, the provision of secondary network distribution equipment will provide additional customer reliability improvements over alternative dual-radial equipment.

Subway Transformers

In addition to the Sachsenwerk switch and fuse units, Toronto Hydro plans to replace related 600Y/347 V subway transformers. Subway transformers are designed for use in underground applications; however, they are not compatible with network equipment and therefore must also be replaced.

The age of these subway transformers vary between 25 and 27 years as shown in Figure 19 below. Subway transformers have a useful life of 35 years and the transformers removed from service will have their condition reassessed. If the subway transformers are evaluated to be in good condition, they will be retained for reuse in other parts of the system, rather than scrapped.

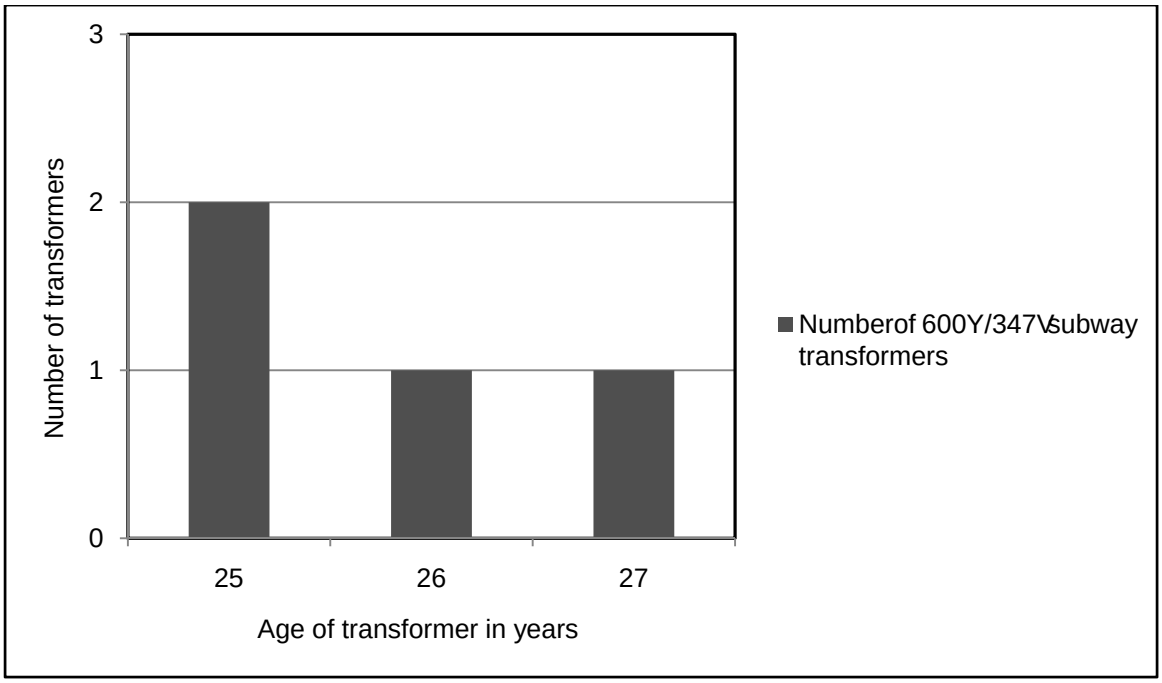


FIGURE 19: AGE OF SUBWAY TRANSFORMERS TO BE REPLACED IN 2016

Reach of the Secondary Network Distribution System

The secondary network distribution system represents 13.6% of the downtown Toronto peak load, or 243.5 out of 1789 MVA. Although it is Toronto's most reliable distribution system, when a major secondary network equipment failure occurs, the impact is widespread. Often entire station switchgear, with up to 50 MVA of customer load, equivalent to approximately 12,500 residential customers, must be interrupted following such events. These widespread service interruptions average about four hours in length, with some customers being interrupted for 12 to 24 hours. The resulting customer interruption costs are significant. Assuming an average of two four-hour interruptions of 30 MVA each year, the average annual customer interruption cost for entire networks being dropped is estimated to be $2.7 million. Refer to section D3.1 for customer interruption cost evaluation.

In recent years, such events have typically occurred once to twice each year. A recent example of a failure in a single location causing widespread customers interruptions took place on September 3, 2012. This incident transpired after a customer accidentally dug into buswork directly supplied from four transformer network vault locations at 4384 St Clair Avenue West. In order to isolate this customer fault, Toronto Hydro had to interrupt the entire High Level St. Clair

network. In all, Toronto Hydro was required to interrupt 41 MVA of load for 109 minutes, affecting 3,073 customers, including Upper Canada College, Hyatt Hotel, the Royal Ontario Museum, adjacent TTC stations, and Bishop Strachan School. If the network supply in this area had been reconfigured, this fault would likely have automatically cleared without requiring interruption of the entire network. Photos from this incident are included in Figure 20 below.

FIGURE 20: SEPTEMBER 3, 2012 INCIDENT AT LOC 4384

Reconfiguring Networks

In addition to ongoing efforts with respect to Fibertop Network Unit replacements (refer to Section E.6.10), Toronto Hydro can further reduce service outages by reconfiguring networks to minimize the number of feeders that must be interrupted following multiple contingency events. With an average of six feeders per network, a typical second contingency incident would leave four feeders in service; typically reducing the number of customer and load interrupted by

approximately two-thirds. This benefit would apply to both network and radial supplied customers fed from these network feeders, and may exceed 33 MVA of load that otherwise would be interrupted. The benefits of particular reconfiguration changes are illustrated in the Figures of Section E6.12.2.1.

The three network reconfiguration projects forming part of this program impact the services of 2,038 customers, many of which are large customers. Total load on the three networks is 50.6 MVA, which represents the equivalent of 12,600 residential customers of 4 kVA load each.

(iii) System Efficiency

Another secondary driver of the program is System Efficiency. The network system in Toronto was designed to handle first contingency operation. Under any first contingency event, power system controllers at the control center do not need to take any action to ensure continued reliable supply to network customers. Multiple contingency events, however, require immediate action by power system controllers and system response crews. Often, only minutes are available to take effective action in order to prevent a cascading failure of network grids.

Network Circuit Reconfiguration will generally allow a network to sustain a second contingency incident without requiring the entire network to be dropped. The reconfigured network should, by design, shed sufficient load under second contingency conditions to allow the remainder of the grid to continue to operate. Since almost all network emergencies involve only first and second contingency outages, this will result in an efficiency improvement within system control.

In addition, most multiple contingency network emergencies require the power system controllers and system response crews to spend hours conducting switching operations to stabilize the network and restore as many customers as possible. As a result, work to isolate and repair failed equipment may be delayed until this work is completed. Network Circuit Reconfiguration will reduce the workload required to stabilize the network and restore customers. This should allow restoration work to begin at the earliest opportunity and thereby minimize the time required to restore the network to normal operation.

The 600 V network distribution initiative will also eliminate the switching restrictions presently imposed on four existing 600 V switch and fuse locations with Sachsenwerk switches. Presently these switches may only be operated under conditions that do not make or break load. As a result, following the failure of a feeder supplying a customer fed from one of these vaults, the power system controllers must arrange an interruption to the second feeder supplying the vault.

This planned second contingency outage involves extra switching operations and service interruptions to some customers that would otherwise not require outages. It also greatly extends the duration of the outage to the customer supplied by the vault. The 600 V network project will eliminate the hazardous equipment and remove the switching restrictions on the associated feeders.

An additional benefit to the power system controllers is the automatic switching of network equipment following feeder outages compared to the manual switching required by dual radial equipment. Network supplied customers do not require power system controller intervention to restore power following feeder failures.

(iv) Safety

Safety is an additional secondary driver for this program. Some existing 347/600 V supplied customers are fed from Toronto Hydro vault equipment utilizing 13.8 kV Sachsenwerk loadbreak switches. Since these switches have been identified as being hazardous to operators, Toronto Hydro has imposed operating restrictions to maintain safety.

Safety is an issue because the switch operating mechanism on a Sachsenwerk switch and fuse unit uses spring action to rapidly snap open and close when operated in order to safely interrupt the 13.8 kV arc. At times, Toronto Hydro has found that the over-center spring does not engage properly and the switch slowly operates under the direct motion of the operating handle. As a result, the switch could draw an arc for an excessive length of time and fault to ground. This flash-over poses a serious risk of injury to the switch operator

A detailed discussion of Sachsenwerk switch and fuse units can be found in Section E6.3 Underground Legacy Infrastructure.

As part of the 600 V network distribution initiative, Toronto Hydro plans to remove this hazardous equipment from four locations where 600 V secondary network distribution equipment was determined to be the most suitable replacement equipment. The remaining Sachsenwerk Loadbreak switch locations are not suitable for 600 V network equipment and will have alternative equipment installed as detailed in Section E6.3 Underground Legacy Infrastructure. Photos of this equipment are included in Figures 21 and 22 below.

FIGURE 21: PHOTO A SHOWS THE SACHSENWERK SWITCH REMOVED FROM ITS CABINET, PHOTO B SHOWS THE SWITCH AND FUSE UNITS (NOTE SEPARATE COMPARTMENTS FOR EACH) AND THE SWITCH HANDLE BEING OPERATED, EXTERNAL DOOR IS OPEN.

FIGURE 22: PHOTOS OF SWITCH COMPARTMENTS FROM LOCATION MDH (LEFT) AND LOCATION GWD (RIGHT) AFTER FLASH-OVER INCIDENTS

The Network Circuit Reconfiguration program will reduce the number of manual switching operations performed by field staff. As these manual switching operations potentially expose the operator to high energy flashovers, they pose the highest risk of all activities performed by field staff. The Network Circuit Reconfiguration program will therefore positively impact worker safety.

Another important consideration is life-support customers. Life-support equipment generally has battery back-up that can last no more than a few hours during a service interruption. Long outages therefore increase the risk that life-support equipment could be compromised. Toronto Hydro keeps track of known life-support customers. However, there is a high likelihood that additional life-support customers unknown to Toronto Hydro exist. These customers could face serious consequences from a prolonged service interruption. The Network Circuit Reconfiguration program will reduce the likelihood of secondary network distribution supplied life-support customers experiencing outages by two-thirds, and also reduce the duration of outages when they do occur.

(v) Other Benefits

The Downtown Contingency program provides ties between feeders originating from different stations, and provides an alternate source of supply for customers should the normal supply station experience a major outage. Network feeders are presently not suitable candidates for such station to station feeder ties because the substantial cross connection of secondary cables between network transformers supplied by a number of different feeders makes it difficult to pick up loads in manageable pieces.

Currently, two possibilities exist for re-energizing a network; (1) all at once and (2) feeder by feeder. In order to pick-up a network all at once, the station switchgear at the transformer station must first be dropped. Next, all of the station to station feeder ties must be closed and finally, the station switchgear picked up. The cold load pick-up requirement of two complete switchgears will exceed the capability of the Hydro One Networks Inc. (HONI) supply and trip out the HONI circuit breakers. Therefore this is not a viable option.

The alternative option requires the feeder ties to be closed one at a time. Although this resolves the station cold load pick-up problem, it creates a multiple contingency problem for the network, with a significant risk of creating a cascade failure. In order to avoid the risk of cascade failure, detailed loading analysis and unusual and elaborate switching is required. The risks and effort associated with this solution are considered to be sufficiently excessive as to make this a non-viable option.

Network Circuit Reconfiguration projects enable the transfer of loads via station to station feeder ties, one at a time, with mitigated risk of cascade failure. Therefore reconfigured networks become suitable candidates for inclusion in the Downtown Contingency program. The Network

Circuit Reconfiguration program is both an enabler and prerequisite for inclusion of network feeders in the Downtown Contingency program.

E6.12.4 Timing & Pacing of the Program

Although the Network Circuit Reconfiguration program has only recently been established, it addresses issues that have been developing over the past few decades and that will continue to worsen going forward. Toronto Hydro plans to start this program during the 2015 to 2019 period in order to begin clearing a growing backlog of required investments, but anticipates work to continue beyond 2019.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	0	2.30	2.29	2.28	2.27

In 2015, Toronto Hydro plans to do the preliminary engineering work necessary for projects to take place in subsequent years. In 2016, Toronto Hydro plans to address three of the 45 secondary distribution networks through enhancement of secondary network grid flexibility projects. As a foundation for the more complex projects planned for the following years, Toronto Hydro must first undertake these three basic projects. This enhancement work is required before the primary feeders of a network can be equipped with ties to feeders from another station as part of the Downtown Contingency program (E7.7). Eventually, the Network Circuit Reconfiguration and the Downtown Contingency programs will be coordinated to achieve implementation efficiencies.

Also, by utilizing this staggered schedule, Toronto Hydro can develop safe work practices and operating procedures and ensure the proper staff training prior to the commencement of construction. This approach requires the first years' projects to be executable without requiring changes to established work practices.

Toronto Hydro plans to implement the 600 V network distribution initiative in four locations that are currently served by hazardous dual-radial switch and fuse gears. These particular locations have operating restrictions in place and are targeted for prompt replacement. The timing of this portion of the program allows for development of new 600 V network distribution equipment prior to the first field installations in 2016. Figure 3 in the Program Description section includes a map identifying these project locations.

E6.12.4.1 Ranking & Prioritization

Virtually all networks in the downtown area require Network Circuit Reconfiguration in order to address multiple contingency operation and customer service reliability issues. The challenges, however, vary dramatically from one network to the other. In order to minimize program execution risk, networks will initially be ranked and prioritized by those posing the fewest difficulties and allowing for the most immediate completion timelines.

The 600 V network distribution initiative portion of this program is considered high priority because the four projects address serious safety and reliability risks associated with Sachsenwerk switch and fuse gear in four existing vault locations. All four locations pose the same risks and are therefore assigned the same ranking and prioritization.

E6.12.5 Program Execution

As explained in Section E6.12.2.2, there are generally multiple alternative options available to reconfigure a network. During the planning phase, various secondary network areas will be reviewed to determine what difficulties each present and afterwards, a priority sequence for execution will be established. Once a particular secondary network has been selected for reconfiguration, its weaknesses will be identified and a final state established. Various alternatives will be evaluated and the options with the highest benefit to cost ratio will be designed and implemented.

Construction work on individual jobs may include network transformer installation and replacement, primary cable installation and transfers, secondary cable installations, removals and transfers and civil construction and rebuild. The civil construction element poses execution risk because some civil rebuild requirements may not be able to be identified prior to beginning electrical construction.

The 600 V portion of the program requires Toronto Hydro to develop and install new equipment in four locations containing Sachsenwerk loadbreak switches with known safety and operational concerns. Given that new equipment is going to be developed, there is an elevated risk of delay during execution due to possible technical challenges in developing the new 600 V network equipment taking longer to resolve than anticipated.

E6.12.5.1 Proposed Work Plan

The first year of the Network Circuit Reconfiguration program, 2015, will focus on preliminary engineering work, to allow projects to be executed in following years. Seven projects are scheduled to be executed in 2016; three are enhancement of secondary network grid flexibility projects and four are 600 V network distribution initiative projects. Projects will continue in 2017 and subsequent years.

E6.12.5.2 Program Risks

The Network Circuit Reconfiguration program is subject to the usual risks facing downtown underground programs and projects.

Structures at the End of their Useful Lives

Since the program may involve the installation of additional cabling within existing cable chambers and duct structures, there is the possibility that the required structures will be at the end of their useful lives and may require replacement before the planned work can be executed. This would necessitate scope and timing changes to some projects. However, as identified in section E6.12.2.2, there are usually multiple options to reconfigure a network. Should the optimal design require civil structure replacement, an alternative that still provides the required reliability and operational improvements, but that does not require civil structure replacement, can likely be found. The design would be revised accordingly to mitigate the cost and timing impacts.

Switching Restrictions

Many downtown network feeders have summer switching restrictions. As such, the months available to execute work on these network feeders would be limited, which would impact the scheduling and timing of work. This risk can be mitigated by scheduling projects so that construction on restricted feeders is performed outside of the restriction period.

Customer-Owned Civil Structures

There may be unforeseen condition or access problems with some customer-owned civil structures. In these situations, the customer may have to perform civil rebuild work as a precursor to Toronto Hydro commencing its activities, causing project delays. This risk can be mitigated by fully inspecting all civil plants prior to finalizing the design, and introducing lead times for customer civil design and construction activities in the project schedule.

Develop New Equipment

Another program risk is that there may be difficulties associated with developing new 600 V network equipment that complies with regulations and/or maintenance and operating constraints. The ability to comply with arc flash requirements is one such risk. In addition, unanticipated problems may arise in connection with developing new designs to address performance requirements. These risks may delay the program or increase its cost. However, these issues are mitigating by the fact that Toronto Hydro plans on beginning the development of 600 V network equipment in 2014 so that sufficient time is available to resolve equipment related problems prior to construction commencing in 2016.

E6.12.6 Evaluation of Alternatives

E6.12.6.1 Quantification/ Evaluation of Options

(i) Option 1: Status Quo

The current operational constraints within the existing network circuit configuration create one to two complete network interruptions each year following multiple contingency network outages. Without Network Circuit Reconfiguration, network system reliability is expected to continue to degrade as new customer loads are added, radial and network loads are mixed on the same feeders and operating practices are modified to enhance safety and satisfy new requirements. The secondary network distribution system is expected to be less able to meet customers' changing needs. Also, by maintaining the status quo, existing 600 V switch and fuse units that use Sachsenwerk switches and that require switching restrictions will remain in place, negatively impacting system reliability and safety.

(ii) Option 2: Network Circuit Re configuration – Proposed Program

By implementing the Network Circuit Reconfiguration program, several benefits discussed throughout this narrative will be produced, some of which are not monetized in the calculations below, including:

- Service reliability improvements and the elimination of safety risks through the replacement of the 600 V switch and fuse units that use Sachsenwerk switches with new 600 V network equipment.

- Operating efficiencies gained by the ability to reduce the amount of load that needs to be dropped following multiple contingency events by approximately two-thirds.

In terms of quantifiable benefits, assuming an average of two four-hour interruptions of 30 MVA each year, Toronto Hydro expects to avoid about $1.8 million in customer interruption costs annually from being able to reduce the amount of load that needs to be dropped following multiple contingency events.

The cost of ownership (COO) and program net benefit (NPV) associated with Network Circuit Reconfiguration is further detailed in Tables 6 and 7. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of activities in the program. The COO of a state reflects the risk of asset failure, including both direct and indirect costs; these costs incorporate customer interruptions, emergency repairs and asset replacements associated with each design. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first of activities, the Network Circuit Reconfiguration program produces a NPV value of $0.77 million, as shown in Tables 6 and 7.

TABLE 6: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	$5.97
Non Asset Risk [NAR_E]	$0
Maintenance Cost [MC_E]	$0
Additional Quantifiable Benefits [AQB_E]	$0
Cost of Ownership of Existing Assets [COO_E]	$5.97

TABLE 7: NETWORK RECONFIGURATION BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 1: Network Reconfiguration	
Asset Risk [AR_N]	$2.89
Non Asset Risk [NAR_N]	$0
Maintenance Cost [MC_N]	$0
Additional Quantifiable Benefits [AQB_N]	$0
Cost of Ownership of New Assets (Network Reconfiguration) [COO_N]	$2.89
Option 1: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_N)$]	$3.08
Program Cost [PC_1]	$2.30
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	$0.77

E6.13 Switchgear Renewal

E6.13.1 Summary

Program Description

Toronto Hydro's Switchgear Renewal program is a continuation of the switchgear replacement work undertaken in recent years. The program involves proactive replacement of obsolete and aging switchgear - the majority of which are past their useful lives of 50 years - with modern technology. Specifically, this program continues the work indentified as part of the Municipal Station Switchgear and Transformer Station Switchgear segments filed as part of the Incremental Capital Module (ICM) in Toronto Hydro's 2012-2014 IRM/ICM filing, which resulted in approval to proceed with replacement of four obsolete municipal station (MS) switchgear and four transformer station (TS) switchgear between 2012 and 2014[1]. Toronto Hydro plans to replace nine MS switchgear and 11 TS switchgear during the 2015-2019 planning horizon.

The anticipated benefits of this program are summarized in Table A below.

[1] EBr2012r0064, Tab 4, Schedules B13.1 and B13.2.

TABLE A: PROGRAM BENEFITS

Customer Value	ƒ Reduce the risk of switchgear failure, which can negatively affect service to a large number of customers.
Reliability	ƒ Reduce the risk of RTU failure and avoid potential prolonged station related outages ƒ Enable substations without SCADA connection to monitor and control feeder loading
Efficiency	ƒ Enable remote troubleshooting and switching capabilities at existing substations without SCADA connection, which are expected to result in labor cost savings by eliminating the need for station crews to go on-site to identify problems and perform manual switching ƒ Automatic switching capability will help achieve maintenance efficiency through the effective streamlining of functions, reducing the need for maintenance crews. ƒ Efficiency achieved through lower maintenance costs associated with vacuum circuit breakers as compared to existing air-blast, air-magnetic and oil circuit breakers
Safety	ƒ Enhance safety by replacing the existing non-arc resistant switchgear design with type C arc resistant design ƒ Mitigate the following risks associated with legacy circuit breakers by replacing them with vacuum circuit breaker: o Risk of a catastrophic failure due to presence of oil in oil breakers o Formation of non-friable asbestos due to degradation of arc chutes in air-magnetic breakers

Program Drivers

The Switchgear Renewal program is driven by the safety and reliability risk associated with non-arc proof legacy switchgear, as well as the obsolescence of the Remote Terminal Units (RTU's) currently installed with these legacy assets. These assets are therefore considered functionally obsolete. Table B summarizes the trigger and secondary drivers of the program.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Replacement parts for legacy breakers and obsolete RTUs and their associated communication channels are no longer available from the original manufacturer ƒ Design features of these obsolete switchgear do not adhere to Toronto Hydro's current practice for new switchgear design installations ƒ High number of assets are past their useful lives
Secondary Drivers	**Reasoning**
Reliability	ƒ Switchgear failure affects a large number of customers and has

	reactive costs
Safety	***f*** Arc-flash during switchgear failure can result in a catastrophic failure resulting in excessive damage to the equipment, surroundings and any personnel in the nearby vicinity *f* Consequences of a switchgear failure can be catastrophic due to presence of flammable oil in oil circuit breakers *f* Presence of non-friable asbestos in degrading arc-chutes of air-magnetic circuit breaker can be hazardous if those components are pulverized or damaged during a switchgear failure

Preferred Alternative

Toronto Hydro evaluated four alternatives to address the issues posed by functionally obsolete switchgear units.

(1) Reactive replacement of switchgear upon failure

(2) During failure of a 4.16 kV switchgear, the load from that failed switchgear can be transferred to an adjacent station bus as a temporary solution to minimize the impact of the failure.

(3) Converting the existing 4.16 kV load to 27.6 kV and decommissioning switchgear, where possible

(4) Replacing obsolete switchgears with metal clad enclosure, arc resistant design, and vacuum circuit breakers.

Option 4 is the preferred alternative because it addresses the obsolescence of the existing switchgear units and alleviates the associated reliability and safety risks in the most cost-effective manner. A complete analysis of the above options can be found in Section E6.13.7.

The completion of the first year of activities in this program will result in an avoided estimated risk cost (ARC) of $28.5 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.13.7).

Timing and Pacing

Toronto Hydro plans to replace three to four switchgears every year from 2015 through 2019. As detailed in Table C below, the total cost of this program is $106.2 million.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	14.9	12.9	11.6	7.9	24.6	11.9	18.9	25.5	27.6	22.4

Toronto Hydro plans to replace three to four switchgears every year from 2015 through 2019. The labour resources used for switchgear replacement are shared with other station renewal programs, including the Power Transformer Renewal program (E6.14), the Circuit Breaker Renewal program (E6.15) and the Station Control & Monitoring program (E6.16). In order to accommodate work involved in all of these important programs, Toronto Hydro must balance its resource availability to target a certain number of switchgears every year. All other things being equal, Toronto Hydro schedules the replacement of switchgears based on their age and condition. However, the schedule of the switchgear replacement is also planned in co-ordination with other station asset renewal activities, wherever possible. The strategy is to schedule all station renewal activities such as switchgear replacement, transformer replacement, circuit breaker replacement or RTU system replacement in the same year to efficiently utilize all available resources. Planning to replace both the assets at the same station in the same year allows control room to minimize planned station outages, resulting in cost savings, reduction in station downtime and increased work efficiency.

E6.13.2 Program Description

Toronto Hydro's Switchgear Renewal program is a continuation of the switchgear replacement work undertaken in recent years. The program involves proactive replacement of obsolete and aging switchgear - the majority of which are past their useful lives of 50 years - with modern technology. Specifically, this program continues the work indentified as part of the Municipal Station Switchgear and Transformer Station Switchgear segments filed as part of the Incremental Capital Module (ICM) in Toronto Hydro's 2012-2014 ICM rate-setting application[2], which resulted in approval to proceed with replacement of four obsolete MS switchgear and four TS switchgear between 2012 and 2014.

The purpose of this program is to proactively replace and modernize Toronto Hydro's aging and obsolete switchgear population. Switchgear are a critical link in the distribution system. Each switchgear supplies a very large number of customers, and an outage due to equipment failure could have severe consequences. This is especially true for TS switchgear, which supply areas that do not typically have provisions to transfer load to a back up bus or station. While switchgear are generally reliable, a significant and growing percent of Toronto Hydro's switchgear assets are beyond end-of-life, significantly increasing the risk of failure. Further to this, switchgear replacement projects are complex, require long lead times and may require the system to be in a contingency state for extended periods of time. Given these considerations, Toronto Hydro believes that a "run-to-failure" approach would create a number of unacceptable risks and would not be appropriate. The utility therefore plans to proactively replace its existing switchgear assets which are at end-of-life and employ obsolete technology, with modern equipment.

Located at a station, switchgear is an equipment assembly that is used to distribute power from a supply point to multiple individual feeders. It is generally comprised of an enclosure which is made up of a bus compartment and any number of cells. The individual cells contain disconnect switches, circuit breakers, instrumentation equipment and/or protection/control devices. There are two general categories of switchgear addressed as part of this program: transformer station (TS) switchgear and municipal station (MS) switchgear. Switchgear located at transformer stations (TS) operate at 13.8 kV and are supplied directly by HONI owned transformers. They generally supply a larger number of feeders compared to MS switchgear, and therefore are generally comprised of a larger number of cells. They also often house HONI's incoming circuit breakers, which connect the switchgear bus to the supplying transformer windings. Existing TS switchgear enclosures are either brick and mortar type, which utilize a brick structure with wooden doors or

[2] EBr2012r0064, Tab 4, Schedules B13.1 and B13.2.

non-arc resistant metal type. MS switchgear generally supply 3 feeders, although there are some exceptions. MS voltages range from 4.16 kV to 13.8 kV and utilize non-arc resistant metal enclosures. Some MS switchgear have been installed without SCADA systems to allow for remote monitoring and control of the equipment. Figures 1, 2 and 3 show a typical example of aging and obsolete non-arc resistant switchgear at Toronto Hydro's Carlaw TS, Windsor TS and Brimley Bernadine MS stations, respectively.

FIGURE 1: NON-ARC RESISTANT BRICK STRUCTURE TS SWITCHGEAR AT CARLAW TS

FIGURE 2: NON-ARC RESISTANT METAL-CLAD SWITCHGEAR WITH AIR MAGNETIC CIRCUIT BREAKERS AT WINDSOR TS

FIGURE 3: NON-ARC RESISTANT METAL-CLAD SWITCHGEAR AT BRIMLEY BERNADINE MS

Given the advanced age of Toronto Hydro's switchgear population, there are a number of obsolescence-related issued currently afflicting the population. These issues include:

Circuit Breakers

A key component of a switchgear lineup is the type and vintage of the circuit breakers. The legacy circuit breakers contained in older switchgear include oil breakers, air blast circuit breakers and air magnetic circuit breakers. These breaker types are obsolete and are associated with significant drawbacks (discussed in Section E6.13.3). Circuit breaker technology, which is differentiated based on the current interrupting medium, has evolved over the past several decades resulting in improvements to reliability, safety, operating cost and the environment. Modern vacuum breakers, such as those Toronto Hydro installs with new switchgear, offer several improvements over the legacy technology that is currently installed in the field (discussed

in Section E6.13.3). As is the case with most legacy equipment, maintenance costs are relatively high and spare parts are difficult to obtain.

Enclosures

The existing switchgear targeted as part of this program utilize non-arc resistant designs. Brick-and-mortar enclosures, which are used for some existing TS switchgear, use wooden doors and offer very little arc protection. Modern switchgear enclosures are specifically designed to safely handle an arc flash while minimizing the risk to nearby personnel and equipment.

SCADA

Some legacy MS switchgear were not designed or built with SCADA systems. SCADA systems are standard in modern distribution applications and allow for remote monitoring and control of equipment.

These factors and more are described in further detail in section E6.13.3.

Toronto Hydro plans to replace existing switchgear at MS and TS locations with “Type C,” arc-resistant switchgear design that features modern vacuum circuit breakers, modern SCADA integration, modern remote terminal units (RTU) for communication and microprocessor relays. Figure 4 shows this new Type C arc-resistant metal-clad switchgear.

FIGURE 4: NEW TYPE C ARC-RESISTANT METAL-CLAD SWITCHGEAR WITH VACUUM CIRCUIT BREAKERS

Arc-resistant switchgear are designed such that the energy generated by an internal arc is safety channeled in such a way as to prevent damage to equipment and people. When an arc fault occurs, the temperature increases and expands the air in the enclosure. This causes the pressure inside the enclosure to increase and can ultimately create a risk of an explosion. An explosion would not only severely damage the switchgear that experiences that fault, but also has the potential to cause collateral damage to nearby equipment and potential safety risks to any personnel who happen to be in the immediate area. The inability to proactively predict when arc faults may occur makes them more dangerous. The Type C arc-resistant design provides arc resistance from the front, sides and rear, and between compartments within the same cell or adjacent cells. The expanding hot gases are routed through a system of vents and flaps through the roof as shown in Figures 5 and 6.

FIGURE 5: FRONT VIEW OF THE ARC-RESISTANT METAL-CLAD SWITCHGEAR SHOWING THE EXPLOSION VENTS ON THE TOP

FIGURE 6: SIDE VIEW OF THE ARC-RESISTANT METAL-CLAD SWITCHGEAR SHOWING THE EXPLOSION VENTS

Switchgear replacement projects are complex and require a significant amount of planning and coordination. This is especially so for TS switchgear replacement projects, as they require coordination with HONI to replace their incoming circuit breakers and to connect the new switchgear to the supply transformers. To this end, Toronto Hydro is required to execute a Connection Cost Recovery Agreement (CCRA) outlining the scope of work and the capital contribution Toronto Hydro will pay to Hydro One Networks Inc. (HONI) to cover their costs. Additionally, significant work may be required at the transformer station building to prepare it for installation of the new switchgear. This could include reinforcing the floor or extending the building. At a high level, the scope of work for a TS switchgear replacement job involves the following:

(1) Coordinate with HONI to agree on their scope of work, schedule and costs.

(2) Prepare site.

(3) Purchase and install new switchgear.

(4) Coordinate with HONI to facilitate energization of the new switchgear.

(5) Transfer feeders from old switchgear to new switchgear

(6) Decommission the old switchgear.

If space is limited, load must be transferred to different stations by building new distribution infrastructure before the new switchgear can be installed. An MS switchgear replacement project involves many of the same steps, although no HONI coordination is required (as an MS is supplied by a Toronto Hydro distribution feeder) and site preparations are less likely to be as onerous given the smaller footprint and size of MS switchgear.

The estimated cost of the Switchgear Renewal Program for the 2015-2019 period is approximately $106.2 million. Table 1 summarizes the number of assets that are forecasted for replacement over the 2015 to 2019 period.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
TS Switchgear	0	3	2	2	2	9
MS Switchgear	3	4	2	1	1	11

Figure 7 shows a map of all the stations selected for switchgear replacement during this period.

FIGURE 7: MAP OF MS SWITCHGEAR REPLACEMENT LOCATIONS

A summary of the benefits associated with the Station Switchgear Renewal program is provided in Table 2.

TABLE 2: PROGRAM BENEFITS

Customer Value	***f*** Reduce the risk of switchgear failure, which can negatively affect service to a large number of customers. *f* The completion of the first year of activities in this program will result in an avoided estimated risk cost (ARC) of $28.5 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.13.7).
Reliability	*f* Reduce the risk of RTU failure and avoid potential prolonged station related outages *f* Enable substations without SCADA connection to monitor and control feeder loading

Efficiency	ƒ Enable remote troubleshooting and switching capabilities at existing substations without SCADA connection, which will likely result in labor cost savings by eliminating the need for station crews to go on-site to identify problems and perform manual switching ƒ Automatic switching capability will help achieve maintenance efficiency through the effective streamlining of functions, reducing the need for maintenance crews. ƒ Efficiency achieved through lower maintenance costs associated with vacuum circuit breakers as compared to existing air-blast, air-magnetic and oil circuit breakers
Safety	ƒ Enhance safety by replacing the existing non-arc resistant switchgear design with Type C arc resistant design ƒ Mitigate the following risks associated with legacy circuit breakers by replacing them with vacuum circuit breaker: o Risk of a catastrophic failure due to presence of oil in oil breakers o Formation of non-friable asbestos due to degradation of arc chutes in air-magnetic breakers

E6.13.3 Why the Program is Needed

The Switchgear Renewal Program is needed to minimize failure risk and address obsolescence issues associated with Toronto Hydro's aging switchgear population, a significant percentage of which has already exceeded its typical 50 year useful life. The existing switchgear utilizes obsolete technology such as brick and mortar built enclosures, non-arc resistant designs and legacy circuit breakers. Switchgears are high impact assets – failure has the potential to impact a large number of customers for an extended period of time. The deteriorating condition of aging units will eventually result in failure, a risk that increases each year.

Both TS and MS switchgear failures pose significant safety risks to Toronto Hydro personnel. Due to the non-arc-resistant design of some legacy switchgears, there is a high probability of explosion should an arc-flash occur during a switchgear failure. The consequence can be catastrophic if Toronto Hydro personnel are working in the vicinity. There are additional risks associated with the presence of flammable oil and non-friable asbestos in legacy circuit breakers. A summary of the risks associated with these obsolete technologies is contained in Table 3.

TABLE 3: SUMMARY OF THE RISKS ASSOCIATED WITH THE OBSOLETE TECHNOLOGIES

Switchgear Components	Component Type	Risks
Switchgear Enclosure	Brick Enclosure	ƒ Non-arc resistant ƒ Obsolete
	Metal-clad Enclosure	ƒ Non-arc resistant ƒ Obsolete
Legacy Circuit Breakers	Air-Magnetic Circuit Breaker	ƒ Spare parts not available ƒ Arc-chutes degrade with usage ƒ Presence of non-friable asbestos in arc-chutes
	Air-Blast Circuit Breaker	ƒ Air-compressors are obsolete and spare parts are difficult to obtain ƒ Higher maintenance cost due to deteriorating air-compressors
	Oil Circuit Breaker	ƒ Fire hazard due to presence of flammable oil
Obsolete Control & Monitoring	Obsolete RTUs and Communication Channel	ƒ Spare parts not available ƒ Increasing failure rate
	No SCADA Connection	ƒ Technologically obsolete ƒ No automatic switching ƒ Customers suffer longer outages during a Switchgear failure

E6.13.3.1 Program Drivers

Table 4 presents the trigger and secondary drivers for replacing TS and MS switchgears. Toronto Hydro has classified switchgear renewal as a System Renewal initiative because the trigger driver is functional obsolescence.

TABLE 4: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Replacement parts for legacy breakers and obsolete RTUs and their associated communication channels are no longer available from the original manufacturer ƒ Design features of these obsolete switchgear do not adhere to Toronto Hydro's current practice for new switchgear design installations ƒ High number of assets are past their useful lives
Secondary Drivers	**Reasoning**

Reliability	*f*	Switchgear failure affects a large number of customers and has reactive costs
Safety	*f*	Arc-flash during switchgear failure can result in a catastrophic failure resulting in excessive damage to the equipment, surroundings and any personnel in the nearby vicinity
	f	Consequences of a switchgear failure can be catastrophic due to presence of flammable oil in oil circuit breakers
	f	Presence of non-friable asbestos in degrading arc-chutes of air-magnetic circuit breaker can be hazardous to Toronto Hydro personnel if they are pulverized or damaged during a switchgear failure

There are a number of underlying issues supporting the Program Drivers that will be addressed proactively by Toronto Hydro through execution of this program. These issues, the majority of which are due to asset age, are described in detail in the sections that follow. Toronto Hydro's primary concern is that a very large number of switchgear assets are past end of life (refer to section E16.6.3 for more details). While switchgear have been historically very reliable, at some point in time failures will begin to occur based on the advanced equipment age. Given the number of switchgear assets in Toronto Hydro's system, and the lead times and complexity associated with a switchgear replacement project, it will not be possible to deal with a large number of failure on a reactive basis without a significant impact on system reliability.

Functional Obsolescence of Circuit Breakers

As discussed earlier, circuit breaker technology is differentiated based on the medium used to interrupt current. Over the years, circuit breaker technology has evolved significantly resulting in significant advances in safety, operating cost, reliability and environmental impact. The circuit breakers installed in existing assets are one of three types:

(a) Oil circuit breakers, which use the dielectric properties of oil to extinguish the current. A primary risk associated with oil breakers is that if a failure occurs, there is a high risks of collateral damage to nearby equipment and personnel. Failures can lead to fires or explosions and pose a high risk of serious injury to personnel working in the vicinity, or to damaging nearby equipment. For this reason, oil breakers require regular maintenance to ensure their proper operation, which results in higher maintenance cost.

(b) Air blast circuit breakers, which use compressed air to extinguish current. Air blast circuit breakers require dedicated air compressor systems to maintain adequate air pressure.

When these systems fail, a circuit breaker is no longer able to interrupt a fault, which could lead to equipment damage and a large outage. Maintenance costs are higher due to the frequency at which inspections of the air compressors and associated air pipes are required. The supplied air must also be very dry, or there is a risk of condensation or ice forming on the insulators or contacts. In addition, the air compressors are themselves old, obsolete and spare parts for their repair are also difficult to obtain.

(c) Air-magnetic breakers, which utilize magnetic fields to stretch and ultimately extinguish the arc created by separation of the breaker contacts. The arc chutes in air magnetic breakers, which are used to quench the electrical arc, degrade with usage and are a safety risk due to the presence of non-friable asbestos. Non-friable asbestos can become a safety issue if they are disturbed or damaged during an arc-fault explosion and release asbestos fibers into the air, effectively turning non-friable into friable.

All of these legacy circuit breakers are past their individual end-of-lives, increasing the risk of failure. Additionally, in the majority of cases the original equipment manufacturer is no longer manufacturing these devices and good quality new spares are difficult to acquire. In many cases, spare parts are only custom manufactured when required, which is neither cost effective nor sustainable. Lastly, annualized maintenance costs are higher relative to modern vacuum breakers. Vacuum circuit breakers require less periodic maintenance in comparison to the legacy breakers currently in use. This is primarily because the current interruption in a vacuum breaker occurs in a sealed environment. The legacy circuit breakers have a maintenance cycle of 3-4 years whereas vacuum circuit breakers have a maintenance cycle of eight years. Efficiency savings due to vacuum breakers can be calculated in the form of a maintenance cost reduction. The cost reduction is shown in Table 5.

TABLE 5: COST REDUCTION OF USING A VACUUM CIRCUIT BREAKER

	Air-Magnetic Circuit Breaker	Air-Blast Circuit Breaker	Oil Circuit Breaker	Vacuum Circuit Breaker
Unit Maintenance Cost	$943	$1,415	$943	$943
Maintenance Cycle	4 Years	3 Years	4 Years	8 Years
Cost Reduction by installing Vacuum Circuit Breaker	**50%**	**75%**	**50%**	

To provide a better illustration of the maintenance savings realized as a result of switchgear modernization, Tables 6 and 7 show a sample comparison between an old and new switchgear

asset. For the purpose of this analysis, we have selected Windsor TS A5-6WR Switchgear, which will be in-service in 2017 and Brian Elinor MS T1 Switchgear, which will come in-service in 2016.

TABLE 6: BREAKER MAINTENANCE COST COMPARISON BETWEEN OLD AND NEW WINDSOR TS A5-6WR SWITCHGEAR

Windsor TS A5-6WR Switchgear		
Status	Existing	New
Number of Circuit Breakers	12	18 (This number is subject to change based on design decision)
Type of Breakers	Air-Blast	Vacuum
Maintenance Cost Over 8-Year Cycle	$45,280	$16,974
Savings	**$28,306**	

TABLE 7: BREAKER MAINTENANCE COST COMPARISON BETWEEN OLD AND NEW BRIAN ELINOR MS T1 SWITCHGEAR

Brian Elinor MS T1 Switchgear		
Status	Old	New
Number of Circuit Breakers	3	3
Type of Breakers	Air-Magnetic	Vacuum
Maintenance Cost Over 8-Year Cycle	$5,658	$2,829
Savings	**$2,829**	

Integration of Modern RTU and SCADA Systems at MS Switchgear

Certain existing MS switchgear do not currently have an integrated SCADA system or have a SCADA system with an obsolete remote terminal unit (RTU). Toronto Hydro has a program, Station Control and Monitoring, which aims to proactively address these stations where no switchgear work is planned. In parallel, Toronto Hydro plans to leverage the Switchgear Renewal Program to integrate SCADA and a modern RTU with the replacement switchgear. Therefore, for MS locations which do not already have SCADA, this program has the added benefits of additional control and monitoring capabilities.

The lack of a SCADA communication system can result in longer outage durations. Substations selected for the Switchgear Renewal Program either have no SCADA system or are equipped with obsolete Remote Terminal Units (RTU) and communication systems. These obsolete RTUs

and communication systems are past their useful lives of 22.5 years with no spare parts available for replacement. The impact of a switchgear failure in terms of outage duration with and without the presence of a SCADA system at the substation is 180 minutes and 30 minutes, respectively. This will minimize outage duration in case of a failure and improve system reliability.

For stations with no SCADA, operators in the control room are currently unable to control and monitor critical equipment at the substation. A failure will result in longer outages since manual switching is required to correct faults. Installation of a SCADA communication system at municipal stations alongside switchgear replacement will help operators to minimize outage impacts and improve overall system efficiency by automating many of the tasks such as problem troubleshooting and station equipment maintenance. Remote troubleshooting allows SCADA console operators to identify the exact location of the outage and perform automatic switching to isolate the outage. Task automation is expected to result in labour cost savings by preventing the need for station crews to go to site and perform lengthy inspections and manual switching.

Automatic switching capability achieved through SCADA system installation will also help improve maintenance efficiency by reducing maintenance crew hours to complete the same work through harmonization of tasks and elimination of redundancies. As a result, planned maintenance outages and certain related maintenance cost will likely decrease.

Arc-Flash Susceptibility and Other Legacy Safety Concerns

When designing and constructing new infrastructure, Toronto Hydro employs safety-by-design principles to minimize hazards and risks to staff. In recent years there has been a significant amount of focus within the electricity industry on arc-flash, which is essentially a flash of electricity released into the environment due to a short circuit failure. New switchgear are specifically designed to limit the risk to workers and nearby equipment should an arc flash occur.

Existing switchgear were not designed with this in mind. The non-arc resistant design of legacy switchgear makes it vulnerable to damage from internal arc faults. A non-arc resistant switchgear is not designed to safely channel out the electricity released during an internal arc fault, which causes a rapid rise in pressure in an enclosed compartment. The occurrence of an internal arc fault in non-arc resistant switchgear can result in an explosion, which poses a safety hazard to nearby personnel and equipment and a potentially serious crew safety risk. There are more dangerous effects of this phenomenon occurring. An internal arc-fault can result in the development of poisonous gases due to the vaporizing of metals and insulation materials. These

gases can be harmful to person(s) inhaling them. Moreover, the explosion due to the arc-flash can be very loud that it has a risk of causing hearing damage to anyone in the vicinity.

All switchgear compartments have a front and rear door to make them accessible. Figures 8, 9, and 10 show the front and rear door designs of the brick and metal-clad enclosure of the existing obsolete switchgears. Figure 8 shows a non-arc-resistant switchgear construction, which features a rear entry mesh door of brick enclosure switchgear. Similarly, Figure 9 shows a front entry mesh door of non-arc resistant metal-clad switchgear. When an arc fault occurs, flames and hot gases can escape through the mesh and ignite nearby materials.

FIGURE 8: REAR DOOR OF A NON-ARC RESISTANT, BRICK STRUCTURE SWITCHGEAR

FIGURE 9: FRONT DOOR OF A NON-ARC RESISTANT METAL-CLAD SWITCHGEAR

FIGURE 10: FRONT DOOR OF A NON-ARC RESISTANT BRICK STRUCTURE SWITCHGEAR

Figure 10 shows the front door of brick enclosure switchgear. As air temperature increases in an enclosed compartment of the switchgear, so does the pressure. Without arc-resistant protection, explosion due to the rapid pressure build-up within a switchgear compartment can project objects such as the metal or wooden doors.

Proper maintenance of switchgear is essential in preventing the equipment failures that cause interruption of power supply to customers. Maintenance work includes testing and cleaning of circuit breakers, relays, disconnect switches, voltage transformers and current transformers to ensure proper operation. However, maintaining these existing obsolete switchgear requires maintenance personnel to be exposed to live, high voltage parts of the switchgear. For example, during circuit breaker maintenance inside a switchgear, the circuit breaker is isolated and verified dead before the maintenance work beings. However, the adjacent breaker compartments still remain energized. If an arc-flash occurs at any of the adjacent breaker compartments, there is a potential risk of an explosion due to the non-arc resistant design of the switchgear. Maintenance

personnel wear appropriate Personal Protective Equipment (PPE) categories to perform the tasks. However, the PPE categories only provide protection for the effects of the heat, but they do not necessarily provide protection against other potential consequences of an explosion. Toronto Hydro has protocols in place to reduce the potential safety risks associated with this work; nevertheless, the exposure risk to live equipments or the destructive effect of an arc fault is a significant safety risk that can only be further mitigated through improved switchgear design. This safety risk is also mitigated through SCADA connection to the new switchgear at non-SCADA substations. Another example of a maintenance safety risk is the cable temperature monitoring, which is essential to the maintenance of the switchgear since excessive temperature can be an indication of problem with a connection. Currently, the temperatures are monitored using infra-red scanners by opening the rear door of the energized switchgear. However, this exposes the maintenance personnel to live equipments. The new switchgears are equipped with infrared viewing ports which allow maintenance personnel to monitor temperatures of the cable and bus connection points in the rear of the switchgear while it is energized and under load.

Lastly, another safety issue associated with brick enclosure switchgear is reduced clearance for operating equipment. Tasks such as maintenance or troubleshooting may require work in areas where live parts are exposed. Reduced clearance in brick enclosure switchgear exposes Toronto Hydro personnel to this potential risk.

Impact of Failure

Failure of a switchgear, at either municipal or transformer stations, has the potential to have a significant customer impact due to the number of customers supplied from a single asset. Figures 11 and 12 show the number of customers connected to the targeted municipal and transformer stations, respectively, who are would be impacted in the event of a switchgear failure.

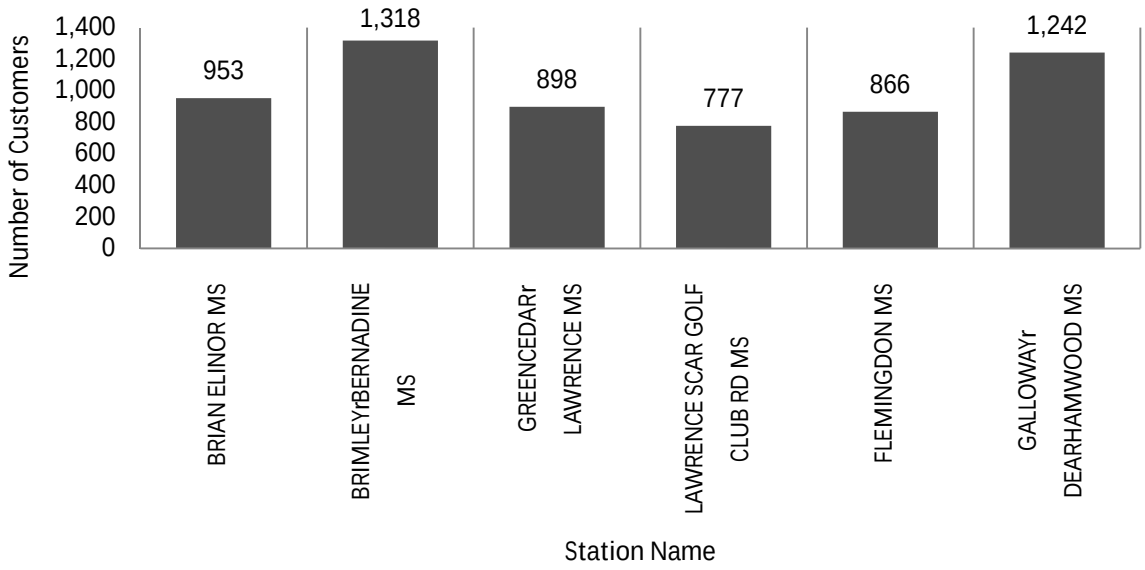


FIGURE 11: NUMBER OF CUSTOMERS SUPPLIED BY TARGETED MS SWITCHGEAR

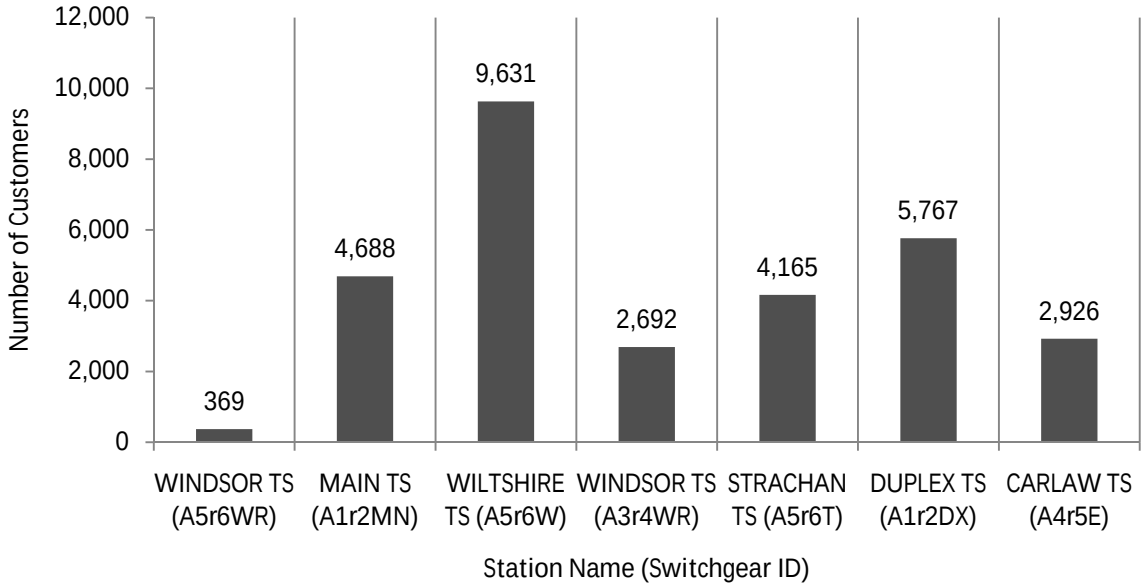


FIGURE 12: NUMBER OF CUSTOMERS SUPPLIED BY TARGETED TS SWITCHGEAR

The customer impact would be especially large in the event of a TS switchgear failure, as the 13.8 kV distribution system in the areas these switchgear are located does not have the provisions to enable load to be easily resupplied from an alternative sources. Thus, it is crucial that the switchgear be maintained, managed and operated in a reliable manner throughout its lifecycle. Given the advanced age of a large percentage of the existing switchgear population, the risk of failure is ostensibly increasing year over year. That, coupled with the complexity of a switchgear replacement project, makes it imperative that Toronto Hydro replace the oldest and poorest condition assets in a planned and proactive manner.

Given that a switchgear is made up of many different individual components, there are a number of different failure modes to be cognizant of. If a breaker fails to clear a fault, or becomes overloaded for some reason, then all equipment in the circuit will be subjected to extreme amounts of energy until an upstream breaker can sense and clear the overload. On the other hand, if a breaker fails to close, this means all downstream circuits that receive power from that feed point will not function. Additionally, over time, contaminants will build up on the internal insulators separating energized parts from grounded components. At some point, this contamination will likely lead to a flash, which in turn can cause an explosion or fire. These functional or catastrophic failures may severely damage or even destroy the switchgear itself and, in some cases, nearby equipment. It could also result in serious injury to Toronto Hydro personnel in the vicinity.

The purpose of switchgears is to connect and protect hundreds of feeders supplying thousands of customers. Switchgear faults and failures will typically have a high negative impact on both Toronto Hydro and its customers. The repair, replacement and clean-up costs associated with switchgear failure can be significant, and customers fed by the failed bus and feeders associated with the switchgear are likely to experience prolonged outage periods unless the circuit can be brought to service. Switchgears at municipal substations support the neighboring substations during contingency or during switchgear or transformer maintenance. If switchgear fails, there will be a cascading effect on the neighboring substations that back up its load by limiting their capability to handle additional load under second contingency. However, if switchgear at one MS fails and the contingent switchgear at another MS also fails, a significant outage could occur since the load of two switchgears cannot be backed up without experiencing capacity shortage and/or voltage drop problems. Toronto Hydro experienced a similar problem during a switchgear failure at Lesmil MS in 2007. When the Lesmil MS switchgear was out of service, switchgear at a neighboring substation, Don Mills MS, also failed. This resulted in a major outage where 700

customers were without power for almost 11 hours. The case is different for a TS switchgear failure, especially if the TS is located in a downtown location.

The switchgear addressed by this program are functionally obsolete due to a lack of spare parts and critical maintenance support, design features that do not adhere to Toronto Hydro's current design practice, and the increasing risk of failure due to switchgears reaching or surpassing end-of-life.

E6.13.3.2 Asset Details

(i) Asset Lifecycle

The expected useful life of switchgear is 50 years. Out of the 252 Toronto Hydro-owned switchgear, 44% are past their designed useful lives, as illustrated in Figure 13. In the absence of a switchgear renewal program, by 2019 this number will reach 62%.

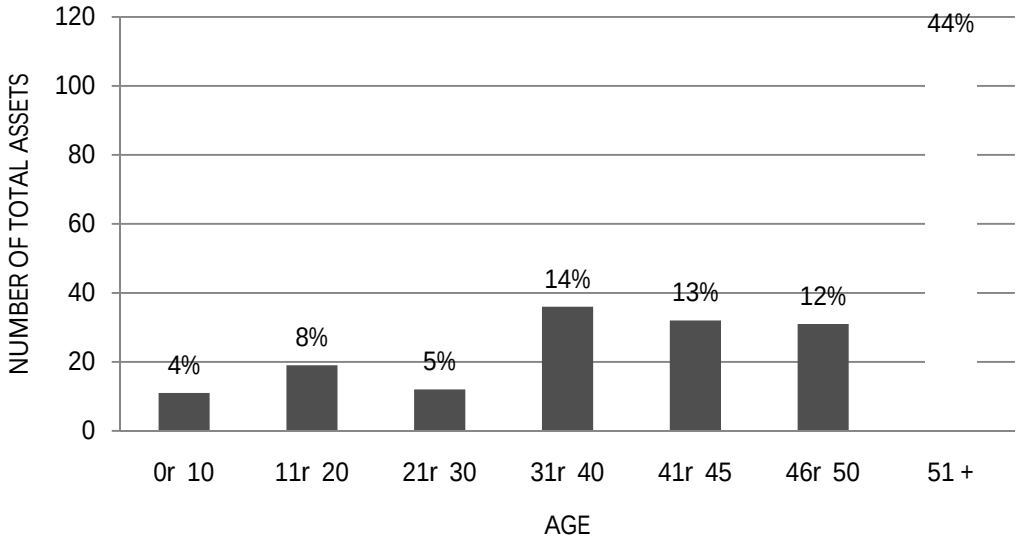


FIGURE 13: AGE DEMOGRAPHICS OF TORONTO HYDRO OWNED SWITCHGEAR

(ii) Asset Failure Impacts

Switchgears are high impact assets and the consequences of switchgear malfunctions are often catastrophic. Damage to the switchgear itself can be extremely expensive, but corollary damage and potential safety hazards to Toronto Hydro personnel and customers are an even greater risk.

The occurrence of an internal arc fault inside non-arc resistant design switchgear can have destructive effects. An incident might expel hot gases into the surrounding area and result in door/covers of the enclosures being blown out. Safety precautions and PPE may reduce the risk, but do not protect personnel from shrapnel and molten metal parts that may be projected as a result of a potential explosion.

Table 8 provides a list of switchgear failure experienced by Toronto Hydro in recent years, the duration of the resulting outage, and the number of customers affected.

TABLE 8: IMPACT OF AN INTERNAL ARC FAULT IN SWITCHGEAR AT TERAULEY TS

Year	Station Name	Failure Type	Outage Duration	Customers Affected
2001	Brimley Seminole MS	Switchgear Failure – Arcing Fault	3.6 Hours	3,908
2005	Walney MS	Switchgear Failure – Arcing Fault	15.8 Hours	339
2007	Glengrove TS	Switchgear Failure – Arcing Fault	5.5 Hours	4,971
2007	Terauley TS	Switchgear Failure – Arcing Fault	18 Hours	31,322
2008	Jane MS	Switchgear Failure – Busbar fault	2.7 Hours	1,754

One of the biggest incidents was the switchgear failure at Terauley TS in 2007. The arc fault at Terauley TS resulted in an explosion in the circuit breaker compartment and caused the front door to be removed from its mounts, as illustrated in Figure 14. No personnel were present at the time, but the explosion damaged surrounding equipment. A total of 31,322 customers suffered an outage for 18 hours as a result of this catastrophic failure.

FIGURE 14: IMPACT OF AN INTERNAL ARC FAULT IN SWITCHGEAR AT TERAULEY TS

All the switchgear currently proposed for replacement serve large numbers of customers (refer to Figures 11 and 12). Depending on the extent of the damage, a switchgear failure can result in prolonged customer outages. The outage duration and restoration times are much longer and more expensive for TS switchgears, since transformer stations do not have spare capacity to take load from an adjacent station during an emergency.

E6.13.4 Timing & Pacing of the Program

Toronto Hydro plans to replace eleven MS switchgears and nine TS switchgears at a total estimated cost of $106.2 million over the five year period from 2015 to 2019, as shown in Table A and Table 9.

TABLE 9: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	14.9	12.9	11.6	7.9	24.6	11.9	18.9	25.5	27.6	22.4

Table 9 also shows the historical spending associated with the Switchgear Renewal program. The Switchgear renewal program was planned to proactively replace and modernize these obsolete and aging assets. However, the historical spending does not reflect the original proposed plan. This can be attributed to the complex nature of the work, and the degree of external coordination (with HONI) required to execute a single project. In recent years, projects have been delayed due to the timing of funding approval from the OEB and unforeseen delays and complications associated with the HONI connection application process.

Every switchgear replacement job involves a set of unique circumstances which can impact project scope, cost and schedule. This includes the size of the switchgear, the need to reinforce, rebuild, expand or renovate a building, and operational complexity associated with transferring load from an old switchgear to a new switchgear. These factors are considered in the project planning phase, however it is an extremely challenging exercise to produce a highly accurate forecast of project requirements and cost. These difficulties result in a year-over-year spending profile that, despite a consistent number of planned units, appears to be somewhat erratic.

Spending from 2012 to 2014 was inconsistent due to a number of factors. Toronto Hydro received approval to replace four MS Switchgear and four TS Switchgear between the 2012 and 2014 period, whereas the utility's original plan was to replace ten MS Switchgear and four TS Switchgear from 2012 to 2014. Additionally, Toronto Hydro was not able to proceed with the work until mid-2013, which delayed the start of these projects as long lead items could not be procured. These delays also had a cascading effect and resulted in downstream impacts on resource allocation to the projects. Currently, the ICM approved projects are underway but behind schedule. In 2014, $24.6M is planned to be spent on these switchgear replacement projects. The cost is relatively high primarily due to the HONI payments associated with the switchgear replacement jobs done during the 2012 to 2014 period. Toronto Hydro plans to continue working on these projects and anticipates completion in 2015 and 2016.

Additional schedule delays have occurred as a result of complications with HONI coordination. For TS projects their support is required to purchase, install and commissioning their incoming breakers cells and to connect Toronto Hydro's new switchgear to their transformers. HONI's new

process requires Toronto Hydro to submit a connection application requesting HONI to perform an Engineering Study to identify the scope, costs and schedule necessary to connect their transformers to the new switchgear. Following that the study, both HONI and Toronto Hydro are required to enter in to a Connection and Cost Recovery Agreement (CCRA) for HONI to proceed with the design and construction of the incoming feeder cells. Introduction of this new process added additional time in the switchgear replacement projects, which pushed the in-service date of the TS Switchgear jobs to 2015 and 2016 Capital year.

As shown previously in Figure 13, 44% or approximately 110 of Toronto Hydro's existing switchgears will be past their useful lives of 50 years by 2015. Since switchgear is a high impact asset, the risk of executing this program on a reactive work basis is too high. In order to mitigate the risk of switchgear failure, Toronto Hydro plans to proactively replace this aging obsolete switchgear with metal-clad switchgear of Type C arc-resistant design, consisting of vacuum circuit breakers equipped with modern RTUs and communication media. All the TS Switchgear projects included in this program are large, complex and will be completed over multiple years. Each switchgear job is unique and is customized to meet the design needs and system constraints. This is a major contributing factor to the cost variation as shown in Table 10.

Toronto Hydro plans to replace three to four switchgears every year from 2015 through 2019. The labour resources used for switchgear replacement are shared with other station renewal programs, including the Power Transformer Renewal program (See E6.17), the Circuit Breaker Renewal program (See E6.18) and the Station Control & Monitoring program (See E6.19). In order to accommodate work involved in all of these important programs, Toronto Hydro must balance its resource availability to only target a certain number of switchgears every year. All other things being equal, Toronto Hydro schedules the replacement of switchgears based on their age and condition. However, the schedule of the switchgear replacement is also planned in co-ordination with other station asset renewal activities, wherever possible. The strategy is to schedule all station renewal activities such as switchgear replacement, transformer replacement, circuit breaker replacement or RTU system replacement in the same year to efficiently utilize all available resources. Planning to replace both the assets at the same station in the same year allows control room to minimize planned station outages, resulting in cost savings, reduction in station downtime and increased work efficiency.

E6.13.4.1 Ranking & Prioritization

Identifying switchgear assets for replacement is based on several factors, including asset condition, degree of equipment obsolescence, station criticality and whether the switchgear is

part of a substation targeted for voltage conversion. Since the impact of TS and MS switchgear failures are different, the replacement jobs for these respective switchgears are treated separately.

- **Asset condition and age** are determining factors in evaluating the failure probability of switchgear. Switchgear that is in poor condition and is past its useful life is given a higher priority for replacement. Any failure due to deteriorating condition will impact a large number of customers.

- The **obsolete** nature of the technologies used in legacy switchgear designs is another important factor in prioritization within the program. Ultimately, the relative seriousness of the safety risks that various obsolete technologies introduce is the overriding concern when ranking projects according to the level of obsolescence. Taking this factor into consideration, Toronto Hydro ranks the replacement of switchgear based on the following obsolete technologies:

    - Brick structure built enclosure
    - Non-arc resistant
    - Legacy Circuit Breakers
        - Oil Circuit Breaker
        - Air Magnetic Circuit Breaker
        - Air-Blast Circuit Breaker
    - No SCADA system or obsolete RTUs and Communication Channels
    - Brick structure built enclosure is the primary obsolescence factor since it is the oldest technology and poses the most risks in comparison to other obsolete technologies mentioned above. It is non-arc resistant by design, difficult to maintain, has high maintenance cost and also deteriorating due to age.

- The **criticality** of a station is determined by the number of customers connected to the bus and the load on the feeders. If a bus within a switchgear has feeders that are highly loaded and are connected to a large number of customers, the impact of a failure is naturally more severe.

- **Work coordination** with feeder investment groups is an additional factor when prioritizing work for MS switchgear replacement jobs. Many of the 4.16 kV municipal stations with aging obsolete switchgears, which are ideal for replacements, are targeted in the Box Construction Conversion program for decommissioning and thus will not be renewed.

E6.13.6 Program Execution

The execution of the Switchgear renewal program is outlined in detail section E6.13.8 Program Scopes and E6.13.6.1 Proposed Work Plan. A general description of work involved in MS and TS switchgear replacement is described below:

(i) MS Switchgear: Execution of Work

Station designers and engineers will prepare all necessary drawings and documents to purchase the new switchgear. Site or building upgrades are made as necessary. While the new switchgear is in the process of being delivered, the proposed switchgear is removed after the existing load from the bus is temporarily transferred to an adjacent substation. The new switchgear is then installed and commissioned along with the installation and commissioning of the communication system. Once the new switchgear is energized, the load from the adjacent station is transferred back to the new switchgear.

(ii) TS Switchgear: Execution of Work

In most TS switchgear replacement work, station designers and engineers design, procure, and purchase the new switchgear. Simultaneously, the site is prepared for the installation of the new switchgear, which could involve reinforcement of a floor, expansion of a building or other civil upgrades. However, there are cases such as Windsor TS A5-6WR Switchgear replacement, where the station does not have any additional space to install new switchgear. In that circumstance, Toronto Hydro would transfer the load from the targeted switchgear to a switchgear with spare capacity, and then remove the existing switchgear to prepare for the installation of the new switchgear. Once the new switchgear is delivered, it is installed, commissioned and tested. Toronto Hydro co-ordinates with HONI to purchase, install and commission the incoming feeder cells and configures the new bus. Following the completion of these tasks, the new switchgear is energized and the load from the existing obsolete switchgear bus is transferred to the new switchgear. The obsolete switchgear is then decommissioned.

E6.13.6.1 Proposed Work Plan

Table 10 shows the long term plan for the 2015-2019 periods being completed at select stations.

TABLE 10: 2015-2019 LONG TERM PLAN

Year	Bus	Station	Asset Age
2015	T1-T2SG	Porterfield MS	59
2015	T1-T2SG	Neilson Dr MS	61
2015	T1-T2SG	Thornton MS	60
2016	A6-7E	Carlaw TS	46
2016	A3-4W	Wiltshire TS	60
2016	A7-8T	Strachan TS	58
2016	T1-T2SG	Islington MS	59
2016	T1SG	Brian Elinor MS	59
2016	T1SG	Brimley Bernadine MS	54
2016	T1SG	Greencedar Lawrence MS	53
2017	A5-6DX	Duplex TS	39
2017	A5-6WR	Windsor TS	57
2017	1035TV	Scarborough Civic Centre (YMCA)	25
2017	T2SG	Lawrence Scarborough Golf Club MS	56
2018	A5-6W	Wiltshire TS	59
2018	A1-2MN	Main TS	57
2018	QYSG & QZSG	Flemingdon MS	52
2019	A3-4WR	Windsor TS	57
2019	A5-6T	Strachan TS	57
2019	T1SG	Galloway Dearhamwoods MS	54

E6.13.6.2 Program Risks

Space for transitioning switchgear is one risk associated with the switchgear renewal program. In some cases, substations do not have space available to install new switchgear. This issue is addressed via load transfer to adjacent stations, but is only feasible if the adjacent stations have enough spare capacity to take the load. Among the switchgear proposed for replacement, Windsor TS is the only station with no space available for new switchgear. Windsor TS A5-6WR switchgear replacement will be made possible due to the construction of Copeland TS. The A5-6WR bus will transfer the load to the new A1-2CL bus at Copeland TS and then be decommissioned to make space for the new switchgear.

Another program risk is scheduling of planned outages. Planned outages are required to transfer load between switchgears. However, scheduling planned outages at the desired time is not always possible because of its dependencies on factors like high load peak and emergency load restoration. Toronto Hydro's distribution grid has high load peak demand during summer and winter period. Hence, planned outages are not scheduled during these periods. This narrows down the window for planned outages to take place during spring and fall only. Furthermore, any emergency load restoration work during spring or fall takes precedence over planned outages for asset replacement. Thus, there is always the possibility of switchgear replacement work being delayed due to difficulty in scheduling a planned outage for load transfer.

E6.13.6.3 External Constraints

Toronto Hydro is required to co-ordinate with HONI for the installation and commissioning of the incoming feeder cells during switchgear replacement. This is a critical part of the switchgear replacement work. This dependency constrains Toronto Hydro from bringing switchgear to service until HONI completes their portion of the job. This risk is mitigated by coordinating with HONI to complete the work in phases with a planned schedule.

E6.13.7 Evaluation of Alternatives

E6.13.7.1 Quantification/Evaluation of Options

The alternatives for addressing the issues with functionally obsolete Switchgear at MS and TS are evaluated below:

(i) Status Quo

The status quo would have Toronto Hydro maintain a "run to failure" scenario, with replacement of existing switchgear only when failure occurs. Since all the selected assets are obsolete and majority of them are past their useful lives, Toronto Hydro would have to incur additional cost to maintain these assets. The associated safety and operational risks and issues detailed above would remain. The status quo would also only allow Toronto Hydro to defer this capital investment temporarily. However, the replacement will eventually be required on a reactive work basis, which will be more costly than replacing on a planned basis. Considering the safety concerns and the age of the assets, the impact of failure is high.

(ii) Load transfer to Adjacent Sub-stations

When 4.16 kV switchgear fails at a municipal station, the load from that failed switchgear bus can be transferred to an adjacent station bus to minimize outage duration. This contingency plan, however, is only a temporary solution. Over the long term, a voltage drop will become an issue especially if the load is transferred to a substation located far from the existing load centre. Moreover, substation equipment within the same area is also typically in poor condition. If the switchgear at the adjacent substation also fails, it can create a cascading effect that can lead to more customer outages. In many cases, load transfer is also not possible due to geographical constraints.

In the case of TSs, transferring load to adjacent sub-stations would require the receiving TS to have spare capacity, sufficient feeder positions, and physical space for additional infrastructure. The location of the receiving station would also need to be sufficiently close to the load centre to avoid a voltage drop. These conditions cannot be met for any of the TSs addressed by this program.

(iii) Convert the existing 4.16 kV load to 27.6 kV and decommission Switchgear

This option only applies to MS Switchgear. Toronto Hydro's program to convert the 4.16 kV stations to 27.6 kV infrastructure would be expected to result in improvements to safety, reliability, system efficiency and operational flexibility. However, this conversion requires large amounts of capital investment and is only feasible if the substation is located on the boundary of the 27.6 kV distribution system. Also, it is only economically reasonable to convert the load if the associated distribution assets are also in poor condition. All the stations selected for MS Switchgear replacement do not meet the criteria for load conversion and are planned to be kept in-service.

(iv) Switchgear Replacement

This option would involve replacing the existing switchgear with metal clad enclosure, Type C arc-resistant design and vacuum circuit breakers, as proposed by Toronto Hydro. This will help address all safety and operational issues concerning the existing switchgear.

Metal clad switchgear encloses all high voltage live parts in a metal built enclosure to ensure safety to operators during operation and maintenance work. To further improve reliability, interlocks installed in the metal clad switchgear prevent potential operational errors.

The Type C design includes arc resistant construction at the front, back and sides, and between compartments within the same cell or adjacent cells. This design does not allow an arc to propagate inside the enclosure into adjacent cells or other parts of the equipment, and protects personnel from injury and surrounding equipment from potential damage.

Vacuum circuit breakers do not require filling of any gas or oil. Therefore, they do not need any auxiliary air system, oil handing, and are free from periodic maintenance. Since no gas decomposition occurs in a vacuum, the sealed breaker does not have any environmental liability. In addition, vacuum circuit breakers can detect and interrupt an arcing fault more quickly in comparison to air magnetic or oil circuit breaker. All these factors help mitigate the risk associated with arc flash and remove hazards concerning non-friable asbestos and flammable oil.

Toronto Hydro's 4.16 kV MSs operate under a first contingency plan. In the event of a switchgear failure, the load from the affected bus can be transferred to an adjacent station. Under this configuration, a single-bus single-breaker configuration is the most cost effective bus configuration for 4.16 kV MS. Also, single bus single breaker scheme is very simple in design and very convenient to operate. Therefore, all new MS Switchgear are expected to be designed as a single-bus single-breaker arrangement.

Downtown Toronto distribution system relies heavily on the stability of the incoming high voltage supply and redundant station equipments. This design provides quick restoration for common failure modes, but does not provide back-up for low-probability, high impact events such as a switchgear failure. TS buses carry high load with no spare capacity to take on additional load. Therefore, downtown Toronto substations do not have load transferring capabilities in the event of a switchgear failure. In the absence of a contingency plan, a breaker-and-a-half bus arrangement is the most reliable and operationally flexible option. Maintenance of a breaker on this scheme can be performed without an outage to any circuit. Furthermore, either main bus can be taken out of service with no interruption to the service.

Recommendation

Of the alternatives, switchgear replacement is the preferred prudent option. It addresses all identified safety and operational issues and helps improve system reliability and efficiency at optimal cost.

The replacement of the Switchgear assets in the first year of the program will result in an avoided estimated risk cost (ARC) of $28.5M, as detailed in Table 11. This value represents the avoided

cost of executing the first year of activities as scheduled as opposed to deferring these activities until 2020. These avoided costs include quantified risks, taking into account the assets' probability of failure, and multiplying this by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement. For further details on the ARC approach is provided in Section D3.3.

TABLE 11: AVOIDED RISK COST BUSINESS CASE EVALUATION

Business Case Element	**Cost (in Millions)**
Asset Renewal	
Present Value of Net Cost in 2020 **[PV(NET_COST(2020)]**	$43.3
Net Cost for the First Year of Activity **[NET_COST(First Year of Activity)]**	$14.7
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - (NET_COST(First Year of Activity))]	$28.5

E6.13.8 2015 Projects

Table 12 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

(a) previously filed projects that appeared as jobs in the OEB approved Municipal Stations Switchgear and Transformer Stations Switchgear segments as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 12: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	**CIR Projects**
10.1	**1.8**

Table 13 lists all projects that are planned for partial or complete execution as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 13: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
S14741	Windsor TS A5-6WR Switchgear Replacement Update Pilot Wire Customer Relays	$87,564	2014	ICM
S14005	Windsor TS A5-6WR Switchgear Replacement	$1,094,547	2014	ICM
S12416	Porterfield MS Replace 4kV SWGR Planned Capital	$437,867	2015	ICM
S13126	Neilson Dr MS Replace Switchgear	$547,334	2015	ICM
W13233	Neilson MS DB cable Replacement	$656,800	2015	ICM
S14070	Thornton MS Replace Switchgear	$54,734	2015	ICM
S12045	Wiltshire TS Replace A3-4W Switchgear	$109,467	2015	ICM

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
S13412	Wiltshire TS A3-4 Capital Contribution	$546,384	2015	ICM
S12557	Carlaw TS Commission A10-11E Switchgear	$109,467	2015	ICM
S13433	Strachan TS Replace A7-8T Switchgear	$328,400	2015	ICM
S13413	Strachan TS A7-8 Capital Contribution	$437,107	2015	ICM
S13415	Duplex TS A5-6: Capital Contribution Duplex(13.8 kV)	$2,731,921	2015	ICM
X11423	Windsor TS A5-6WR Replacement Load Transfer to Copeland TS	$657,052	2015	CIR
S13009	Windsor TS A5-6WR Replacement Feeder Transfer to new Copeland TS bus	$422,294	2015	CIR
X13097	Windsor TS A5-6WR Replacement Feeder Transfers to A17-18WR Bus	$215,212	2015	CIR
S14371	Windsor TS A5-6WR Switchgear Replacement Capital Contribution	$2,950,474	2015	CIR

E6.13.8.1 S12416 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Porterfield MS Replace 4kV SWGR Planned Capital

Scope Number: S12416

Scope Year: 2015

Estimated Cost: $437,866.98

(i) Objective

The objective of this project is to design, purchase and install modern single-bus single-breaker arc-resistance switchgear of Type C along with modern RTUs and communication media to replace the existing 4.16 kV aging and obsolete switchgear connected to T1-T2 transformer at Porterfield MS.

(ii) Scope of Work

TABLE 14: S12416 SCOPE OF WORK DETAILS

District Neighborhood	WEST
Station(s)	PORTERFIELD MS
Bus	T1rT2SG

TABLE 15: S12416 ASSETS REPLACED

Assets (Units)	2015
MS Switchgear	1

(iii) Justification & Benefits

The existing non-arc resistant switchgear at Porterfield MS, as shown in Figure 15, will be 59 years old in 2015 and is past its useful life of 50 years. This switchgear houses oil circuit breakers that are 59 years old, past their useful lives of 40 years. These circuit breakers are obsolete and require a high ongoing maintenance cost. The manufacturer no longer produces these devices and spare parts are difficult to acquire. Presence of flammable oil in oil breakers poses safety risks to Toronto Hydro personnel.

Replacing the existing switchgear with an arc resistant design and vacuum circuit breakers will protect the equipment from arc faults and address all reliability and safety issues concerning oil circuit breakers. Installation of a SCADA communication system will allow Toronto Hydro control operators to monitor the equipment conditions, correct faults remotely, provide automated switching and feeder re-routing in both planned outages and unplanned emergency work. This will improve system reliability and efficiency.

FIGURE 15: NON-ARC RESISTANT METAL-CLAD SWITCHGEAR AT PORTERFIELD MS

E6.13.8.2 S13126 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Neilson Dr MS Replace Switchgear

Scope Number: S13126

Scope Year: 2015

Estimated Cost: $547,333.73

(i) Objective

The objective of this project is to design, purchase and install modern single-bus single-breaker arc-resistance switchgear of Type C along with modern RTUs and communication media to replace the existing 4.16 kV aging and obsolete switchgear connected to T1-T2 transformer at Neilson Drive MS.

(ii) Scope of Work

TABLE 16: S13126 SCOPE OF WORK DETAILS

District Neighborhood	WEST
Station(s)	NEILSON DRIVE MS
Bus	T1rT2SG

TABLE 17: S13126 ASSETS REPLACED

Assets (Units)	2015
MS Switchgear	1

(iii) Justification & Benefits

The existing non-arc resistant switchgear at Neilson Drive MS, as shown in Figure 16, will be 61 years old in 2015 and is past its useful life of 50 years. This switchgear houses oil circuit breakers that are 61 years old, past their useful lives of 40 years. These circuit breakers are obsolete and require a high ongoing maintenance cost. The manufacturer no longer produces these devices and spare parts are difficult to acquire. Presence of flammable oil in oil breakers poses safety risks to Toronto Hydro personnel.

Replacing the existing switchgear with an arc resistant design and vacuum circuit breakers is expected to protect the equipment from arc faults and address all reliability and safety issues concerning oil circuit breakers. Installation of a SCADA communication system will allow Toronto

Hydro control operators to monitor the equipment conditions, correct faults remotely, provide automated switching and feeder re-routing in both planned outages and unplanned emergency work. This is expected to improve system reliability and efficiency.

FIGURE 16: NON-ARC RESISTANT METAL-CLAD SWITCHGEAR AT NEILSON DRIVE MS

E6.13.8.3 W13233 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Neilson MS DB cable Replacement

Scope Number: W13233

Scope Year: 2015

Estimated Cost: $656,800.47

(i) Objective

The objective of this project is to replace the existing PILC direct cable with standard 500 TRXLPE trunk cable in duct for the feeders coming out from the T1-T2SG Switchgear at Neilson Drive MS.

(ii) Scope of Work

TABLE 18: W13233 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	NEILSON DRIVE MS
Bus	T1rT2SG

TABLE 19: W13233 ASSETS REPLACED

Assets (Units)	2015
MS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Neilson Drive T1-T2 Switchgear replacement. It is done in co-ordination with the switchgear replacement project for resource utilization. See section E6.13.8.1 S13126 Scope Description for more details.

E6.13.8.4 S14070 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Thornton MS Replace Switchgear

Scope Number: S14070

Scope Year: 2015

Estimated Cost: $547,333.73

(i) Objective

The objective of this project is to design, purchase and install modern single-bus single-breaker arc-resistance switchgear of Type C along with modern RTUs and communication media to replace the existing 4.16 kV aging and obsolete switchgear connected to T1-T2 transformer at Thornton MS.

(ii) Scope of Work

TABLE 20: S14070 SCOPE OF WORK DETAILS

District Neighborhood	WEST
Station(s)	THORNTON MS
Bus	T1rT2SG

TABLE 21: S14070 ASSETS REPLACED

Assets (Units)	2015
MS Switchgear	1

(iii) Justification & Benefits

The existing non-arc resistant switchgear at Porterfield MS, as shown in Figure 17, will be 60 years old in 2015 and is past its useful life of 50 years. This switchgear houses oil circuit breakers that are 60 years old, past their useful lives of 40 years. These circuit breakers are obsolete and require a high ongoing maintenance cost. The manufacturer no longer produces these devices and spare parts are difficult to acquire. Presence of flammable oil in oil breakers poses safety risks to Toronto Hydro personnel.

Toronto Hydro expects that replacing the existing switchgear with an arc resistant design and vacuum circuit breakers will protect the equipment from arc faults and address all reliability and safety issues concerning oil circuit breakers. Installation of a SCADA communication system will allow Toronto Hydro control operators to monitor the equipment conditions, correct faults remotely, provide automated switching and feeder re-routing in both planned outages and unplanned emergency work. This is expected to improve system reliability and efficiency.

FIGURE 17: NON-ARC RESISTANT METAL-CLAD SWITCHGEAR AT THORNTON MS

E6.13.8.5 S12045 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Wiltshire TS Replace A3-4W Switchgear

Scope Number: S12045

Scope Year: 2015

Estimated Cost: $109,466.75

(i) Objective

The objective of this project is to purchase, install and commission new double-bus double-breaker arc-resistant Type C, 4-wire, 3000A metal-clad switchgear along with modern RTUs and communication systems to replace the existing 13.8KV A3-4W Switchgear at Wiltshire TS.

(ii) Scope of Work

TABLE 22: S12045 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	WILTSHIRE TS
Bus	A3r4W

TABLE 23: S12045 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Wiltshire TS A3-4W Switchgear replacement.

The existing non-arc resistant A3-4W Switchgear at Wiltshire TS will be 61 years old in 2015 which is past its useful life of 50 years. This switchgear houses air-blast type circuit breakers which are 60 years old, past their useful lives of 42 years. The original manufacturer no longer produces this device, and spare parts are difficult to obtain and in many cases need to be custom manufactured. This makes the maintenance cost high and unsustainable over the long term.

Since the switchgear is of non-arc resistant design it is vulnerable to internal arc faults. This increases the risk of collateral damage and personnel injury during a catastrophic failure.

Replacement of the existing A3-4W Switchgear with an arc-resistant Type C Switchgear with vacuum circuit breakers is expected to improve the system reliability and address all safety risks associated with the old switchgear.

Note: This is an ICM-approved partial carry-over job from 2014. Most of the work has been completed in 2014.

E6.13.8.6 S13412 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Wiltshire TS A3-4 Capital Contribution

Scope Number: S13412

Scope Year: 2015

Estimated Cost: $546,384.13

(i) Objective

The objective of this project is for HONI to replace the incoming circuit breakers connected to Wiltshire TS A3-4W switchgear. Toronto Hydro will pay for this HONI work through a Capital Contribution.

(ii) Scope of Work

TABLE 24: S13412 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	WILTSHIRE TS
Bus	A3r4W

TABLE 25: S13412 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Wiltshire TS A3-4W Switchgear replacement. See section E6.13.8.1 S12045 Scope Description for more details.

Note: This is an ICM-approved partial carry-over job from 2014. Most of the HONI Contribution has been made in 2014.

E6.13.8.1 S12557 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Carlaw TS Commission A10-11E Switchgear

Scope Number: S12557

Scope Year: 2015

Estimated Cost: $109,466.75

(i) Objective

The objective of this project is to purchase, install and commission new double-bus double-breaker arc-resistant Type C, 4-wire, 3000A metal-clad switchgear along with modern RTUs and communication systems to replace the existing 13.8KV A6-7E Switchgear at Carlaw TS.

(ii) Scope of Work

TABLE 26: S12577 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	CARLAW TS
Bus	A6r7E

TABLE 27: S12557 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Wiltshire TS A6-7E Switchgear replacement.

The existing non-arc resistant A6-7E Switchgear at Carlaw TS will be 51 years old in 2015 which is past its useful life of 50 years. This switchgear houses air-blast type circuit breakers which are 46 years old, past their useful lives of 42 years. The original manufacturer no longer produces this device, and spare parts are difficult to obtain and in many cases need to be custom manufactured. This makes the maintenance cost high and unsustainable over the long term.

Since the switchgear is of non-arc resistant design, it is vulnerable to internal arc faults. This increases the risk of collateral damage and personnel injury during a catastrophic failure.

Replacement of the existing A6-7E Switchgear with an arc-resistant Type C Switchgear with vacuum circuit breakers is expected to improve the system reliability and address all safety risks associated with the old switchgear.

Note: This is an ICM approved partial carry-over job from 2014. Most of the work has been completed in 2014.

E6.13.8.7 S13433 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Strachan TS Replace A7-8T Switchgear

Scope Number: S13433

Scope Year: 2015

Estimated Cost: $328,400.24

(i) Objective

The objective of this project is to purchase, install and commission new double-bus double-breaker arc-resistant Type C, 4-wire, 3000A metal-clad switchgear along with modern RTUs and communication systems to replace the existing 13.8KV A7-8T Switchgear at Strachan TS.

(ii) Scope of Work

TABLE 28: S13433 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	STRACHAN TS
Bus	A7r8T

TABLE 29: S13433 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Wiltshire TS A7-8T Switchgear replacement.

The existing non-arc resistant A7-8T Switchgear at Strachan TS will be 59 years old in 2015 which is past its useful life of 50 years. This switchgear houses air-blast type circuit breakers which are 58 years old, past their useful lives of 42 years. The original manufacturer no longer produces this device, and spare parts are difficult to obtain and in many cases need to be custom manufactured. This makes the maintenance cost high and unsustainable over the long term.

Since the switchgear is of non-arc resistant design, it is vulnerable to internal arc faults. This increases the risk of collateral damage and personnel injury during a catastrophic failure.

Replacement of the existing A7-8T Switchgear with an arc-resistant Type C Switchgear with vacuum circuit breakers is expected to improve the system reliability and address all safety risks associated with the old switchgear.

Note: This is an ICM approved partial carry-over job from 2014. Most of the work has been completed in 2014.

E6.13.8.8 S13413 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Strachan TS A7-8 Capital Contribution

Scope Number: S13413

Scope Year: 2015

Estimated Cost: $437,107.30

(i) Objective

The objective of this project is for HONI to replace the incoming circuit breakers connected to Strachan TS A7-8T switchgear. Toronto Hydro will pay for this HONI work through a Capital Contribution.

(ii) Scope of Work

TABLE 30: S13413 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	STRACHAN TS
Bus	A7r8T

TABLE 31: S13413 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Strachan TS A7-8T Switchgear replacement. See section E6.13.8.1 S13433 Scope Description for more details.

Note: This is an ICM approved partial carry-over job from 2014. Most of the HONI Contribution has been made in 2014.

E6.13.8.1 S13415 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Duplex TS A5-6: Capital Contribution Duplex (13.8 kV)

Scope Number: S13415

Scope Year: 2015

Estimated Cost: $2,731,920.65

(i) Objective

The objective of this project is for HONI to replace the incoming circuit breakers connected to Duplex TS A5-6DX switchgear. Toronto Hydro will pay for this HONI work through a Capital Contribution.

(ii) Scope of Work

TABLE 32: S13415 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	DUPLEX TS
Bus	A5r6DX

TABLE 33: S13415 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Duplex TS A5-6DX Switchgear replacement.

The existing non-arc resistant A5-6DX Switchgear at Duplex TS will be 40 years old in 2015. This switchgear houses air-magnetic type circuit breakers which are 40 years old. There are two other switchgears at this station which are much older than A5-6DX. However, in order to replace those switchgears, A5-6DX needs to be replaced first based on the position of the switchgears. There is also the risk of the basement being flooded with water from the HONI deluge system which is located on the main floor above the switchgear. To mitigate this risk, and to address the aging issue of the switchgears, Toronto Hydro plans to replace in stages all the switchgear at Duplex TS which are located in the basement with waterææsistant switchgear. The A5æ6DX switchgear is the first to be replaced. This switchgear is in a fair condition. However, it must be replaced first in

order to be able to replace the A1a2DX switchgear which is in a very poor condition but could not be replaced first due to space constraint.

Note: This is a partial carry-over job from 2014. Most of the work has been completed in 2014.

E6.13.8.9 S14005 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Windsor TS A5-6WR Switchgear Replacement

Scope Number: S14005

Scope Year: 2015

Estimated Cost: $1,094,547.11

(i) Objective

The objective of this project is to purchase, install and commission new double-bus double-breaker arc-resistant Type C, 4-wire, 3000A GIS (SF6) switchgear along with modern RTUs and communication systems to replace the existing 13.8KV A5-6-9-10WR Switchgear at Windsor TS.

(ii) Scope of Work

TABLE 34: S14005 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	WINDSOR TS
Bus	A5r6WR

TABLE 35: S14005 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

The existing non-arc resistant A5-6WR Switchgear at Windsor TS, as shown in Figure 18, will be 60 years old in 2016, past its useful life of 50 years. This switchgear houses air-blast type circuit breakers that are 57 years old, past their useful lives of 42 years. The original manufacturer no longer produces this device, and spare parts are difficult to obtain and in many cases need to be custom manufactured. This makes the maintenance cost high and unsustainable over the long term.

Since the switchgear is of non-arc resistant design, it is vulnerable to internal arc faults. This increases the risk of collateral damage and personnel injury during a catastrophic failure.

Replacement of the existing A5-6WR Switchgear with an arc-resistant Type C Switchgear with vacuum circuit breakers is expected to improve the system reliability and address all safety risks associated with the old switchgear.

This project is planned for completion over a three-year period starting 2014 and ending in 2016.

TABLE 36: S14005 PROJECT COST INCURRED

Year	Cost
2014	$0.2M
2015	$1.09M
2016	$5.68M
Total	$6.97M

This is a supporting project for Windsor TS A5-6WR Switchgear replacement.

FIGURE 18: NON-ARC RESISTANT METAL-CLAD SWITCHGEAR A5-69-10WR AT WINDSOR TS

E6.13.8.10 S14741 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Windsor TS A5-6WR SWG Replacement Upgrade Pilot Wire Customer Relays

Scope Number: S14741

Scope Year: 2015

Estimated Cost: $87,563.77

(i) Objective

The objective of this project is to replace the existing electro-mechanical relays at pilot wire customer locations (Dome stadium and John Pumping station) with micro-processor SEL 411L type relays and connect the customer relays to Copeland TS A1-2CL bus relays.

(ii) Scope of Work

TABLE 37: S14741 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	WINDSOR TS
Bus	A5r6WR

TABLE 38: S14741 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Windsor TS A5-6WR Switchgear replacement. See section E6.13.8.1 S14005 Scope Description for more details.

This project is planned for completion over a two-year period starting 2014 and ending in 2015.

TABLE 39: S14741 PROJECT COST INCURRED

Year	Cost

2014	$0.53M
2015	$0.09M
Total	$0.62M

E6.13.8.11 X11423 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Windsor TS Load Transfer to Copeland TS

Scope Number: X11423

Scope Year: 2015

Estimated Cost: $657,052.25

(i) Objective

The objective of this project is to remove all feeders from the A17-18WR bus in order to create space for future transferring of A5-6WR bus feeders at Windsor TS.

(ii) Scope of Work

TABLE 40: X11423 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	WINDSOR TS
Bus	A5r6WR

TABLE 41: X11423 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Windsor TS A5-6WR Switchgear replacement. See section E6.13.8.1 S14005 Scope Description for more details.

E6.13.8.12 X13097 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Windsor TS A5-6WR Bus Feeder Transfers to A17-18WR Bus

Scope Number: X13097

Scope Year: 2015

Estimated Cost: $215,211.50

(i) Objective

The objective of this project is to transfer / terminate and upgrade the existing network feeders (A50, 51, 53, 54, 55, 56, 57, & 58 WR) and proposed radial feeders (A73,79WR) from the existing Windsor TS A5-6WR Bus to the existing A17-18WR Bus.

(ii) Scope of Work

TABLE 42: X13097 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	WINDSOR TS
Bus	A5r6WR

TABLE 43: X13097 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Windsor TS A5-6WR Switchgear replacement. See section E6.13.8.1 S14005 Scope Description for more details.

This project is planned for completion over a two-year period starting 2015 and ending in 2016.

1 **TABLE 44: X13097 PROJECT COST INCURRED**

Year	Cost
2015	$0.22M
2016	$0.07M
Total	$0.29M

E6.13.8.13 S13009 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Windsor TS A5-6WR Replacement Feeder Transfer to new Copeland TS bus

Scope Number: S13009

Scope Year: 2015

Estimated Cost: $422,294.35

(i) Objective

The objective of this project is provide stations support for feeder transfer from Windsor TS to new Copeland TS under distribution project X11423 and X13097.

(ii) Scope of Work

TABLE 45: S13009 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	WINDSOR TS
Bus	A5r6WR

TABLE 46: S13009 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Windsor TS A5-6WR Switchgear replacement. See section E6.13.8.1 S14005 Scope Description for more details.

E6.13.8.14 S14371 Scope Description

Portfolio: Stations

Program: Switchgear Renewal

Scope Title: Windsor TS A5-6WR Switchgear Replacement Capital Contribution

Scope Number: S14371

Scope Year: 2015

Estimated Cost: $2,950,474.30

(i) Objective

The objective of this project is for HONI to replace the incoming circuit breakers connected to Windsor TS A5-6WR switchgear. Toronto Hydro would pay for this HONI work through a Capital Contribution.

(ii) Scope of Work

TABLE 47: S14371 SCOPE OF WORK DETAILS

District Neighborhood	DOWNTOWN TORONTO
Station(s)	WINDSOR TS
Bus	A5r6WR

TABLE 48: S14371 ASSETS REPLACED

Assets (Units)	2015
TS Switchgear	1

(iii) Justification & Benefits

This is a supporting project for Windsor TS A5-6WR Switchgear replacement. See section E6.13.8.1 S14005 Scope Description for more details.

This project is planned for completion with two installments paid over three years starting 2015 and ending in 2017 as shown below.

TABLE 49: S14371 PROJECT COST INCURRED

Year	Cost
2015	$2.95M
2017	$0.50M

Total	$3.45M

E6.14 Power Transformer Renewal

NEW TRANSFORMER INSTALLATION AT CHAPMAN MS

E6.14.1 Summary

Program Description

The Power Transformer Renewal program is a continuation of the activities previously presented in the OEB-approved Station Power Transformer segment that formed part of Toronto Hydro's 2012-2014 rates application[1]. Toronto Hydro plans to replace 24 power transformers located at 22 municipal stations (MS) across the city over the 2015-2019 planning horizon. Figure 1 depicts the locations of projects comprising the 2015-2019 Station Transformer Renewal program.

Of the 24 transformers identified for replacement, 22 have been in service for longer than 45 years (the useful life of a transformer) as of 2015. The two remaining transformers, Flemingdon MS TR1 and Redcliff MS TR2, require replacement due to specific technical considerations. For each of the 24 transformers, Toronto Hydro considered the need to modify each transformer's capacity based on the load in each of their respective service areas. In all cases, Toronto Hydro determined that a like-for-like replacement of station transformers is optimal. The transformers range in capacity from 4 MVA to 12 MVA.

[1] EB-2012-0064, Application and Evidence (May 10, 2012), Tab 4, Schedule B12.

The anticipated benefits of this program are summarized in Table A below.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	A total of 19,109 customers are expected to experience: ƒ a reduced risk of long-duration outages caused by individual transformer failure (see Section E6.14.3.2(ii)), and ƒ improved system reliability
Reliability	By replacing Toronto Hydro's highest risk transformers and decreasing the proportion of transformers past their end-of-life, Toronto Hydro intends to: ƒ reduce the probability of the distribution system operating under contingency (See Section E6.14.3.1), ƒ reduce the frequency of outages due to transformer failure
Safety	Expected reduction in the risk of fires due to transformer failure, thereby improving the safety of working personnel and the residents or businesses adjacent to the transformer.
Efficiency	As part of the Power Transformer Renewal program, Toronto Hydro will remove overhead bus structures at stations where present. This work is expected to: ƒ Remove the potential for animal contact, ƒ Increase the work efficiency of station crews, and ƒ Increase the reliability of stations (by design) where more than one transformer is present
Environmental Benefit	ƒ Along with the new power transformers, Toronto Hydro will install concrete pad oil containment systems that reduce the risk of environmental soil contamination from potential oil leaks.

Program Drivers

This program is required to mitigate the possibility of widespread and prolonged outages due to the failure of a power transformer. The trigger driver for this program is summarized below.

TABLE B: STATION POWER TRANSFORMERS RENEWAL PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ By 2015, an estimated 51.6% of in-service station power transformers will be beyond their expected useful lives of 45 years, with an additional 10% reaching end-of-life by 2020. ƒ Risk of prolonged outages to customers connected to aged and poorly performing transformers. ƒ Increased strain on the system during contingencies compromises the security of power supply to customers beyond the area of immediate impact of a failed transformer.

A power transformer failure will result in an outage to all connected customers lasting between one and six hours. In addition, when a failure occurs, Toronto Hydro reconfigures the system to re-supply the affected customer, which places the system in a state of contingency that can strain the system. In addition, since the majority of these transformers are past their useful lives of 45 years, Toronto Hydro may have to renew these transformers reactively rather than proactively in the event of a power outage.

Preferred Alternative

Toronto Hydro considered the following alternatives for mitigating the safety and reliability risks associated with these assets:

(1) Do Nothing. Accept the risk of a potential transformer failure and address it on a reactive basis

(2) Voltage Conversion of the MS that the transformer serves, thereby eliminating the need for the step down transformer

(3) Replace the aged transformers with new ones, thereby maintaining the existence of the MS

Option 2 depends on the timing of distribution feeder projects to convert load from 4 kV to higher standard voltages. If a voltage conversion project is planned for the service area of an MS whose transformer has reached end-of-life, then Toronto Hydro chooses to address the transformer's need for replacement by decommissioning after the voltage conversion project has been completed. All of the transformers addressed in this program will be required for 4 kV service during the 2015-2019 period and beyond. Therefore, Option 3 is the preferred alternative for these assets because it allows Toronto Hydro to proactively mitigate the failure risk posed by end-of-life and poor condition power transformers within its system and thereby reduce the risk of outages to customers.

The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $2.66 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.14.7).

Timing and Pacing

Toronto Hydro plans to continue to address its aging station power transformer population through proactive replacement of units identified as being at the highest risk and consequence cost of failure. To stabilize annual costs and labour requirements, the program is paced as uniformly as possible. The proposed annual investment for the program along with the historical costs is provided in Table C below. Toronto Hydro plans to address approximately five of the highest risk power transformers per year over this period. Toronto Hydro also expects to decommission approximately three transformers per year.

TABLE C: PROPOSED ANNUAL PACING AND INVESTMENT

	Historical Costs					Future Investment					
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
CAPEX ($M)	1.83	4.04	2.66	1.68	1.30	1.68	2.61	2.58	2.72	2.72	12.30

E6.14.2 Program Description

The Power Transformer Renewal program is a continuation of the activities previously presented in the OEB approved Station Power Transformer segment that formed part of Toronto Hydro's 2012-2014 rates application.[2] Toronto Hydro plans to replace 24 power transformers located at 22 municipal stations (MS) across the city over the 2015-2019 planning horizon. Figure 1 depicts the locations of projects comprising the 2015-2019 Station Transformer Renewal program.

FIGURE 1: STATIONS COMPRISING THE 2015-2019 STATION TRANSFORMER RENEWAL PROGRAM BY YEAR

Toronto Hydro identified this group of assets for replacement using a combination of the following criteria:

[2] EB-2012-0064, Application and Evidence (May 10, 2012), at Schedule B-12.

- Asset condition and Health Index (HI) Score (refer to Asset Condition Assessment - Section D3.1.2.1 (ii));
- Asset age (relative to a 45-year useful life);
- Probability of failure (refer to Hazard Rate Distribution of Assets – Section D3.1.1.2); and
- Cost of failure (refer to Impact Cost of Failure - Section D3.1.2.1 (i))

Prior to identifying transformers for replacement, Toronto Hydro considers converting the area that a transformer serves to a higher voltage and decommissioning the transformer, thereby eliminating the need for replacement. None of the transformers comprising this program are located in areas which are planned for voltage conversion.

Of the 24 transformers identified for replacement, 22 have been in service for longer than 45 years (the useful life of a transformer) as of 2015. The two remaining transformers, Flemingdon MS TR1 and Redcliff MS TR2, require replacement due to specific technical considerations. Flemingdon MS TR1 was chosen for replacement because of poor oil tests results as discussed in Section E6.14.4.1; Redcliff MS TR2 was chosen for replacement because of the presence of an overhead bus structure as discussed in the paragraph below. For each of the 24 transformers, Toronto Hydro considered the need to modify each transformer's capacity based on the load in each of their respective service areas. In all cases, Toronto Hydro determined that a like-for-like replacement of station transformers is optimal. The transformers range in capacity from 4 MVA to 12 MVA.

The transformers scheduled for replacement at Norseman MS, Redcliff MS, and York MS use an obsolete overhead bus structure, shown in Figures 2 and 3 below. The purpose of the overhead bus structure is to connect the power transformers to their 27.6 kV supply lines, but the bus structure obstructs access to the power transformers from above, which is required for replacement. The bus structure also requires that the entire MS be taken out of service when one transformer is taken out of service, which impacts the reliability of the MS. Additionally, the bus structure introduces a risk associated with animal contact. Animals occasionally climb on top of the bus structure and then attempt to climb down the bushings of the transformer. When this occurs, the animal serves as a short circuit which results in an outage. Accordingly, as part of the Transformer Renewal program, Toronto Hydro proposes to remove the overhead bus structures at Norseman MS, Redcliff MS, and York MS, and replace them with a more modern padmount design.

FIGURE 2: CLOSE-UP OF OVERHEAD BUS STRUCTURE AND TRANSFORMERS AT REDCLIFF MS

The alternative padmount design uses a padmount switch to connect transformers to their supply lines, and permits one transformer to be taken out of service at a time. The padmount switch also allows the transformer to be safely isolated by station crews. Otherwise, with overhead bus structures, station crews may require assistance from overhead crews to complete this isolation safely. Consequently, replacement of the overhead bus structure with the padmount design is expected to save time and expenses for future maintenance, repairs, and replacements. Centre Dr. MS was converted from the obsolete overhead bus structure setup to the modern padmount setup in 2008, and is shown in Figure 3.

FIGURE 3: CENTRE DRIVE MS AFTER CONVERSION TO PADMOUNT SETUP (NOTE THE PADMOUNT SWITCH IN THE BOTTOM RIGHT, AND THE UNOBSTRUCTED OVERHEAD ACCESS TO THE TRANSFORMER)

At Redcliff MS, there is an overhead bus structure with two transformers (See Figure 4); one transformer has passed end-of-life, and the second transformer is near end-of-life. In this case, it is more cost effective to replace both transformers at the same time. Since both transformers are connected to the bus structure, Toronto Hydro needs to remove the entire bus structure in order to replace a single transformer. If Toronto Hydro does not eliminate the bus structure by replacing it with a padmount switch (which requires the replacement of both transformers), then the bus structure would have to be reinstalled after the first transformer replacement. When the second transformer is replaced in the future, the bus structure would have to be removed and put back a second time. For this reason, it is economically preferable to replace both transformers at the same time, in order to remove the bus structure once and permanently replace it with a padmount switch.

FIGURE 4: TRANSFORMERS AND OBSOLETE OVE RHEAD BUS STRUCTURE SETUP AT REDCLIFF MS

Since most of the transformers identified for replacement came into service in the 1950s and 1960s, a number of them do not have an oil containment system to prevent the environmental impact of oil spills that may cause soil contamination. When replacing old transformers, Toronto Hydro plans to correct this legacy deficiency by installing concrete oil containment systems for transformers that currently lack them. This oil containment system is composed of a concrete pad on which the transformer is placed, a concrete dyke which surrounds the pad and base of the transformer (and switchgear if applicable), a drain from the concrete pad, and an underground tank. Should oil leak from the transformer, it will be captured in the dyke and drained into the underground tank until it can be properly collected and disposed. Figure 5 shows the concrete dyke which surrounds the transformer and switchgear at Chapman MS. The underground tank is accessed through manholes near the transformers, which are shown in Figure 6.

Toronto Hydro plans to include a project to install oil containment at Jane MS in this program. The two power transformers at Jane MS have been replaced recently. During activities at Jane MS to replace the switchgear and rebuild civil structures to support the switchgear replacement, the oil containment project was delayed to avoid conflict of work schedules. Large underground pipelines installed by other gas and oil industries are located in close proximity to Jane MS. As a

proactive and preventative measure, Toronto Hydro plans to install an oil containment system to prevent any potential environmental damage to the surrounding soil, and to mitigate the risk of damage to any of the large industry pipelines.

FIGURE 5: OIL CONTAINMENT CONCRETE DYKE

FIGURE 6: OIL CONTAINMENT UNDERGROUND TANK MANHOLES

The following table summarizes the anticipated benefits of the Power Transformer Renewal program.

TABLE 1: SUMMARY OF PROGRAM BENEFITS

Customer Value	A total of 19,109 customers are expected to experience: x a reduced risk of long-duration outages caused by individual transformer failure (see Section E6.14.3.2(ii)), and x improved system reliability (see below). The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $2.66 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.14.7).
Reliability	By replacing Toronto Hydro's highest risk transformers and decreasing the proportion of transformers past their end-of-life, Toronto Hydro intends to:

	x reduce the probability of the distribution system operating under contingency (See Section E6.14.3.1), x reduce the frequency of outages due to transformer failure, and x prevent further transformer wear.
Safety	Expected reduction in the risk of fires due to transformer failure, thereby improving the safety of working personnel and the residents or businesses adjacent to the transformer.
Efficiency	As part of the Power Transformer Renewal program, Toronto Hydro plans to remove overhead bus structures at stations where present. This work is expected to: x Reduce the potential for animal contact, x Increase the work efficiency of station crews, and x Increase the reliability of stations (by design) where more than one transformer is present
Environmental Benefit	x Along with the new power transformers, Toronto Hydro plans to install concrete pad oil containment systems that reduce the risk of environmental soil contamination from potential oil leaks. x When transformers fail, they may leak oil to their surroundings. By replacing transformers without oil containment systems and that are identified to have a material risk of failure, Toronto Hydro will prevent potential oil contamination to the surrounding environment

E6.14.3 Why the Program is Needed

The replacement of station transformers is required to mitigate the risk of prolonged outages to customers served by these at-risk assets. When a power transformer fails, along with the potential safety risk to personnel and the public, all customers connected to the failed transformer will experience an outage lasting between one to six hours. Even when Toronto Hydro transfers the affected customers to an alternate supply source, system reliability remains at risk until the failed transformer is replaced, as other parts of the system are put under increased strain. Given their age and condition, Toronto Hydro proposes to replace 24 transformers over 2015-2019 period to improve the security of supply to the customers they serve, and maintain system reliability as a whole.

E6.14.3.1 Program Drivers

The purpose of the Power Transformer Renewal program is to optimally manage Toronto Hydro's portfolio of station power transformers for the long term, with the objective of minimizing the risk of customer outages, maximizing system reliability and stabilizing future annual transformer replacement costs. The trigger driver of the Power Transformer Renewal program is failure risk.

Accordingly, the Power Transformer Renewal program falls under the System Renewal investment category for distribution system assets.

TABLE 2: STATION POWER TRANSFORMERS RENEWAL PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ By 2015, an estimated 51.6% of in-service station power transformers will be beyond their expected useful lives of 45 years, with an additional 10% reaching end-of-life by 2020. ƒ Risk of prolonged outages to customers connected to aged and poorly performing transformers. ƒ Increased strain on the system during contingencies compromises the security of power supply to customers beyond the area of immediate impact of a failed transformer.

The immediate and direct impact of station transformer failure is the interruption of supply to the customers connected to the failed transformer. Should a failure occur, Toronto Hydro must restore power to customers by reconfiguring the system into a contingency state, i.e. a backup configuration designed to isolate the failed equipment and restore supply to as many affected customers as possible. While these measures provide short-term relief, leaving Toronto Hydro's system in a contingency state places the system at an elevated level of risk due to the following issues:

- Increased Vulnerability to Further Outages: When a transformer fails, Toronto Hydro transfers its customers' load, by opening and closing tie switches between adjacent feeders in the distribution system, to a supporting transformer located either at the same station or at a nearby station. Should the supporting transformer also fail, the affected customers will experience an outage until at least one of the two transformers is replaced. Additionally if other equipment in the distribution system should fail, such as the tie switches or adjacent feeders needed to support the load, then customers will experience an outage even if the supporting transformer is available to receive load. For these reasons, Toronto Hydro's system experiences an increased vulnerability to further outages during a contingency state.

- Longer and Larger Outages: Should a supporting transformer fail following the initial failure, affected customers would experience an outage of about 72 hours until at least one transformer is replaced. This outage would also affect even more customers than those initially interrupted. (See Section E6.14.3.2ii).

- Increased Risk of Failure on Supporting Transformers: When a transformer fails, the supporting transformers receive additional load such that their loading level could go up to 100% of their capacity, which is much higher than the normal load level of 50% or lower. Operating at loading levels well above the norm tends to increase the risk of failure of the supporting transfers, even after the system is restored to its normal state out from the contingency state.

- Increased Replacement Costs: Replacing a transformer on an emergency basis is approximately twice as expensive as a planned replacement under the proposed program. This is due to additional costs such as unplanned work from control center for interruption schedule, inefficiency due to diversion of work from other planned capital work, and increased labour cost for overtime work.

By 2015, over half of Toronto Hydro's station power transformers will be beyond their 45-year useful lives. Allowing these transformers to remain in operation increases their probability and frequency of failure. Given the severity of potential consequences of transformer failure, it is necessary to replace these high-risk station transformers proactively, in the manner proposed in this program.

E6.14.3.2 Asset Details

(i) Asset Lifecycle

Power transformers typically fail when their internal windings experience an electrical fault as a result of deteriorated insulating materials. The major insulating materials of a power transformer are the mineral oil surrounding the windings, and the cellulose paper wrapped around the wire of the windings. Figure 7 displays the internal core and windings of a typical station transformer.

FIGURE 7: INTERNAL CORE AND WINDINGS OF A POWER TRANSFORMER

Degradation of insulation materials occurs naturally and inevitably. However, the rate of degradation is strongly influenced by exposure to three factors: oxygen, moisture, and high temperature.

When a power transformer is new, the oxygen and moisture content of its insulating oil are at their minimum. Over time, oxygen and moisture seep into the transformer from the atmosphere through seasonal heating and cooling cycles. Oxygen reacts with the mineral oil to form alcohols and acids, which reduce the insulating properties of the oil. Along with the acids produced in the oil, oxygen also reacts with the paper insulation, which causes decomposition of the paper. Moisture has the same effect on the oil and paper insulation under the influence of high temperature or the strong electric field present near the transformer windings.

Under normal operating conditions, a power transformer will generate heat due to the small but unavoidable transformer winding losses. This heat gradually causes the mineral oil to degrade into simple gases (such as methane and ethane). These gases are poor insulators compared to the mineral oil and, as a result, reduce the insulating ability of the mineral oil. When a fault

occurs, a transformer produces more heat than normal, causing its insulating materials to reach high temperatures. High heat causes the rates of all above-noted degradation processes to increase drastically. In addition, the occurrence of faults themselves causes significant degradation of insulating materials in the manner described below.

There are typically two main types of faults which power transformers may experience: electrical and thermal. An electrical fault happens when unintentional current flow occurs, usually due to a breakdown of the transformer's insulating materials. This type of fault tends to char the paper insulation, and cause rapid degradation of the oil insulation into simple gases due to the electrical phenomena of the fault. A thermal fault occurs when a transformer overheats, usually due to overloading. The intense heat also causes charring of the paper insulation; once charred, the paper loses its insulating ability and becomes prone to flaking. Thermal faults have a tendency to decrease the insulating properties of the paper and ultimately deteriorate the paper insulation on the transformer windings.

While it is possible to restore the condition of the oil through the process of oil reclamation, which filters out the moisture and contaminants, it is not possible to restore the condition of the paper insulation once it has deteriorated. Toronto Hydro regularly undertakes oil reclamation for power transformers showing poor oil condition. However, when the condition of the power transformer has deteriorated and/or when the transformer has exceeded its useful life, oil reclamation is typically not an economic solution. For power transformers beyond their useful lives and/or those whose condition has deteriorated, the risk of failure increases significantly. Toronto Hydro takes action to proactively replace these transformers before they fail.

Toronto Hydro's power transformer population currently consists of 248 units, excluding 20 transformers that serve only the Toronto Transit Commission. In 2015 over half the transformer population (51.6% or 128 transformers) will have been in operation past their useful lives (see Figure 8). If no transformer interventions occur by 2020, the proportion of transformers past their end-of-life will increase to approximately 60% (149 units).

FIGURE 8: HISTOGRAM OF YEARS IN-SERVICE FOR TORONTO HYDRO'S TRANSFORMER POPULATION AS OF 2015

As more transformers continue aging past their end of useful life, the probability and frequency of failure increases. As the above figure indicates, in addition to a significant proportion of transformers at or near the end of their expected useful lives, a large subset of Toronto Hydro's transformers are far beyond their useful lives, further amplifying the failure risk. If Toronto Hydro does not renew its aging fleet of transformers, then at some point in the near future the power transformers would fail faster than the proactive replacement program. Given the severity of potential consequences of transformer failure (discussed in the following Section E6.14.3.2(ii)), Toronto Hydro prefers proactive transformer replacement, compared to the run-to-fail approach. The Power Transformer Renewal program is planned with a focus on long term benefits, to help ensure that in the future, Toronto Hydro will be able to implement similar proactive transformer replacement programs at reasonable paces, in order to avoid the run-to-fail approach (and thereby mitigate outage and reliability risks to customers).

(ii) Asset Failure Impacts

When a power transformer fails, numerous customers experience an outage ranging from one to six hours until the load of the failed transformer is transferred to the adjacent station transformers. When this occurs, the distribution system in the affected area is operating under contingency. Each of the transformers scheduled for replacement over the 2015-2019 period currently serves an average of 796 customers, with an average peak load of 3,333 kVA (see Table 4). As noted in

section E6.14.3.1, even though power can be restored after a single transformer failure, Toronto Hydro's distribution system operations are constrained and under contingency after a power transformer failure. Until Toronto Hydro replaces the failed transformer, customers in the general area remain at an elevated level of outage risk compared to normal operating conditions. For instance, should a supporting transformer fail following the failure of the original transformer, than the customers served by these units will experience an outage until at least one transformer is replaced. It typically takes Toronto Hydro 72 hours to replace at least one failed transformer, causing a prolonged outage to the customers served by the originally failed unit, and those served by the supporting unit.

Under normal circumstances, procurement of a station transformer unit typically takes 12 months once an order has been placed. For this reason, Toronto Hydro carries spare transformers to manage the duration of outages caused by transformer failures. With a spare transformer available, a failed transformer can be replaced in 3 to 5 days, while the affected customers continue receiving supply from the adjacent supporting transformers. Table 4 provides the number of customer served by each power transformer proposed for replacement.

TABLE 3: NUMBER OF CUSTOMERS SERVED BY EACH POWER TRANSFORMER

Power Transformer	Peak Load (kVA)	Customers Served
BELLAMY-LAWRENCE-TMSTR1	3,930	1,756
BLAKETOM MSTR1	3,980	138
BRIAN-ELINOR-MSTR1	3,600	1,298
BRIMLEY-BERNADINE-MSTR1	3,530	1,264
CANADIAN-RD-BIRCHMOUNT-MSTR1	1,910	900
CENTENNIAL-MSTR1	2,640	687
CORONATION-BENNETT-MSTR1	1,790	813
FLEMINGDON MSTR1	3,150	695
GREENCEDAR-LAWRENCE-TMSTR1	3,840	822
HIGH-LEVEL MSTR2	8,160	1,372
LAWRENCE-KENNEDY-MSTR1	1,880	1,200
LAWRENCE-SCARP-GOLF-CLUB-RD-MSTR1	3,040	548
MIDLAND-LAWRENCE-TMSTR1	2,350	665
NORSEMAN MSTR1	3,630	519
OBERON MSTR1	4,230	815

Power Transformer	Peak Load (kVA)	Customers Served
PHARMACY CPR MSTR1	1,770	953
REDCLIFF MSTR1	1,970	555
REDCLIFF MSTR2	1,950	
ROSSCOWAN PHARMACY MSTR1	3,590	198
SENTINEL MSTR1	7,770	1,355
TAYSHAM MSTR1	4,060	551
UNDERWRITERS ROUSE MSTR1	3,575	919
YORK MSTR1	1,950	1,086
YORK MSTR2	1,690	
Total:	79,985	19,109
Average:	3,333	796

In extreme case, a transformer failure may involve a rupture of the oil tank, and subsequent fire upon ignition of the exposed oil. In addition to lengthy outages, transformer failure events accompanied by a fire can cause significant damage to the surrounding properties, and pose a significant potential safety risk to working personnel and the residents adjacent to the MS.

Toronto Hydro experienced a transformer failure accompanied by fire in June 2003, when a 49-year old power transformer TR2 at Dupont MS failed and caught fire, and set two other power transformers at the station on fire. The two adjacent transformers experienced minor damage by the fire, but not to the point of failure. The failure of the TR2 transformer and the associated restoration efforts resulted in interruptions to a total of 5,675 customers, with a total of 23,341 customer hours interrupted. The outage lasted 6.6 hours from when the first transformer failed to when all customers were restored to service. Figures 9 to 11 depict the aftermath of the Dupont MS fire, and illustrate the possible impact of a transformer failure accompanied by fire.

FIGURE 9: FAILED POWER TRANSFORMER AT DUPONT MS (NOTE THE CHARRING OF THE TRANSFORMER)

FIGURE 10: FAILED POWER TRANSFORMER AT DUPONT MS (NOTE THE DAMAGE TO THE MS WALL TO THE LEFT, AND THE NUMEROUS BRICK FRAGMENTS ALONG THE GROUND)

FIGURE 11: FAILED POWER TRANSFORMER AT DUPONT MS (NOTE THE VARIOUS FLUIDS EXPOSED ON THE GROUND)

E6.14.4 Timing & Pacing of the Program

Toronto Hydro plans to continue to address its aging station power transformer population through proactive replacement of units identified as being at the highest risk and consequence cost of failure. To stabilize annual costs and labour requirements, the program is paced as uniformly as possible. The proposed annual investment for the program along with the historical costs is provided in Table 5 below.

TABLE 4: PROPOSED ANNUAL PACING AND INVESTMENT

	Historical Costs					Future Investment					
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
CAPEX ($M)	1.83	4.04	2.66	1.68	1.30	1.68	2.61	2.58	2.72	2.72	12.30

The transformers selected for this program are all past their expected useful lives with the exception of Flemingdon MS TR1 and the Redcliff MS TR2. The Flemingdon MS TR1 was selected because its oil tests show evidence of a high thermal fault (>700 °C). A high thermal fault such as this indicates significant damage to the paper insulation of the transformer, whose condition cannot be improved using oil reclamation. The Redcliff MS TR2 is proposed for replacement because of work efficiencies associated with the removal of the overhead bus structure, required for the replacement of Redcliff MS TR1, as explained in Section E6.14.2.

Table 6 provides more details regarding the transformers that are included in this program. Based on transformer age and condition, the insulating materials of these units are expected to have deteriorated, or are expected to soon deteriorate, to the point that the associated risk of failure is such that the transformers must be replaced (see Section E6.14.3.1i). Toronto Hydro anticipates that deferring these transformer replacements beyond the 2015-2019 period will raise the risk of severe reliability impacts due to failure, and increase the proportion of transformers past end-of-life from 51.6% to 60.1% by 2020.

TABLE 5: SUMMARY OF AGE AND HEALTH OF TRANSFORMERS PLANNED FOR REPLACEMENT

Transformer	Age at Time of Proposed Replacement	Health Index Score	Remark
BELLAMY LAWRENCE MS TR1	55	48	
BLAKETON MS TR1	45	67	Evidence of medium-range thermal fault (see Section E6.14.9.1)
BRIAN ELINOR MS TR1	61	48	
BRIMLEY BERNADINE MS TR1	57	45	
CANADIAN RD BIRCHMOUNT MS TR1	56	57	
CENTENNIAL MS TR1	55	64	

Transformer	Age at Time of Proposed Replacement	Health Index Score	Remark
CORONATION BENNETT MS TR1	58	36	
FLEMINGDON MS TR1	25	73	Oil tests show evidence of a high-range thermal fault (above 700°C)
GREENCEDAR LAWRENCE MS TR1	57	48	
HIGH LEVEL MS TR2	68	48	
LAWRENCE KENNEDY MS TR1	62	42	
LAWRENCE SCAR GOLF CLUB RD MS TR1	58	63	
MIDLAND LAWRENCE MS TR1	56	45	
NORSEMAN MS TR1	58	59	Overhead bus structure present (See Section E6.17.2)
OBERON MS TR1	56	63	
PHARMACY CPR MS TR1	58	58	
REDCLIFF MS TR1	59	63	Overhead bus structure present (See Section E6.14.2)
REDCLIFF MS TR2	42	75	Overhead bus structure present (See Section E6.14.2)
ROSSCOWAN PHARMACY MS TR1	58	55	
SENTINEL MS TR1	58	65	
TAYSHAM MS TR1	60	67	
UNDERWRITERS CROUSE MS TR1	60	58	
YORK MS TR1	65	63	Overhead bus structure present (See Section E6.14.2)
YORK MS TR2	61	63	Overhead bus structure present (See Section E6.14.2)

The units that Toronto Hydro proposes to replace over the 2015-2019 timeframe are part of a long-term plan to prudently manage the backlog of in-service, end-of-life power transformers. Replacing eight of the highest risk transformers per year will help mitigate the risk to system

reliability of the aging transformer population, at a pace that is achievable given the resources available for this type of work.

During the 2015-2019 period, voltage conversion work is planned at rate that should allow for the decommissioning of three transformers per year on average. On top of that, approximately five replacements are planned annually so that eight transformers in total will be removed from service each year. This pace for transformer replacement will also match Toronto Hydro's average historical investment over the 2010-2014 period.

E6.14.4.1 Ranking & Prioritization

To determine the sequencing for replacement of its fleet of 248 station power transformers, Toronto Hydro considers a combination of the following criteria:

- Asset condition and Health Index (HI) score [refer to Asset Condition Assessment - Section D3.1.2 (ii)];
- Asset age;
- Probability of failure [refer to Hazard Rate Distribution of Assets – Section D3.1.1]; and
- Cost of failure [refer to Impact Cost of Failure - Section D3.1.2 (i)]

Having removed the units eligible for area voltage conversion and those whose condition and vintage do not warrant replacement, Toronto Hydro produces a prioritized transformer replacement schedule. This way, transformers in greatest need of replacement are replaced first.

For stations with both an overhead bus structure (which must be removed in order to remove the old transformer) and two transformers, if at least one transformer is justified for replacement, then it can be more economical to replace both transformers at the same time, rather than replacing the two transformers at different times. Such transformers are added back into the program; as is the case with Redcliff TR2 described in Section E6.14.2.

Finally, Toronto Hydro derives significant benefits from coordinating all planned station work, thereby avoiding taking a station out of service multiple times. When a station is taken out of service, part of Toronto Hydro's system must be put into a contingency state, with associated risks that are described in section E6.14.3.1; therefore, minimizing station outage times minimizes outage risks to customers. Additionally when station work is coordinated, Toronto Hydro can use its labour resources more efficiently. For these reasons, the priority for certain transformers

selected for replacement in the 2015 – 2019 period was adjusted in order to coordinate the Power Transformer Renewal program with the Switchgear Renewal program (see Section E6.16).

E6.14.5 Program Execution

The Power Transformer Renewal program planning process considers any proposed voltage conversion to confirm that transformer replacement does not occur at municipal stations where transformers will soon be decommissioned. The Power Transformer Renewal program is also aligned with the MS Switchgear Renewal program (see Section E6.16) to ensure transformer and switchgear replacement occur at the same time, in order to reduce planned station outages and maximize labour efficiencies. The following steps comprise the task of transformer replacement:

(1) Design and Procurement : once station designers complete a detailed design of the new transformer's configuration, Toronto Hydro issues a Request for Proposal (RFP) to its suppliers. It normally takes one year for a winning supplier to build the transformer and deliver it to Toronto Hydro. If a replacement transformer is targeted for a station with an overhead bus structure design, Toronto Hydro also procures a padmount switch at the same time.

(2) Decommissioning : in coordination with the control centre, Toronto Hydro switching crews seamlessly switch all customers supplied by the MS receiving the new transformer to an adjacent MS, and take the targeted MS out of service. Station crews remove all connections to the transformer; and where present, construction crews dismantle the overhead bus structure. After this, an overhead crane removes the transformer and places it onto a flatbed truck to be taken away.

(3) Installation : prior to installing the new transformer, construction crews install the oil containment tank and the associated concrete pad and dykes. Once this work is complete, a crane places the replacement transformer into its position as shown taking place at Chapman MS in Figure 12.

FIGURE 12: NEW TRANSFORMER INSTALLATION AT CHAPMAN MS. NOTICE THAT IF AN OVERHEAD BUS STRUCTURE WERE PRESENT, IT WOULD BE AN OBSTRUCTION TO THE CRANE AND REPLACEMENT WORK WOULD BE MUCH MORE COMPLICATED.

(4) Connection: Once the new transformer is in position, workers remove the old segment of the direct-buried primary Paper Insulated Lead Covered (PILC) cable that connected the transformer to its primary supply feeder. In the place of the old PILC cable, workers install a concrete-encased Cross-Linked Polyethylene (XPLE) cable. For MSs where an overhead bus structure has been removed, workers also install a pad-mounted switch on the ground, which allows crews to disconnect the supply feeder from the transformer. The workers then connect all the primary and secondary cables to the new transformer. Once the control room energizes the new transformer, workers transfer customers to their new transformer.

E6.14.5.1 Program Risks

As evidenced by the description in the section E6.14.6, the transformer replacement process requires a significant amount of coordination between the design technicians, supply chain specialists, construction and switching crews, and control room operators. Moreover, given the need to take an entire MS out of service and transfer its customers to an alternate source of supply, this work can only occur during limited times of the year when station loading levels permit the necessary switching. Misalignment of any of these procedural steps constitutes a considerable risk to timely program execution. Toronto Hydro mitigates these risks through careful advanced planning and coordination of the responsible parties.

E6.14.6 Evaluation of Alternatives

E6.14.6.1 Quantification/Evaluation of Options

When a power transformer is in need of intervention based on its condition or age and oil reclamation is no longer a reasonable alternative (see Section E6.3.2i), Toronto Hydro considers three options as listed below:

(1) No Transformer Intervention : With this option, no intervention is performed on the power transformer. This option may be chosen if the MS that the power transformer serves has already been planned for voltage conversion (see option 2 below). This strategy carries the risk and associated costs of a potential power transformer failure occurring prior to completion of the voltage conversion.

Applying this option to the transformers planned for renewal in this program (which are not subject to decommissioning due to voltage conversion) would have the following implications:

Outage Risk: All power transformers but Redcliff MS TR2 were selected for replacement because they have passed their useful life and/or are in poor condition (see Section E6.14.4). Each of these transformers has a material potential for failure that may cause long outages to an average of 796 customers; replacement costs are expected to double if failed transformers are replaced reactively.

Reliability impacts: Should a power transformer's health decrease significantly, it may need to be off-loaded to reduce further stress while in-service. This in turn would increase the stress placed on other units. Additionally, the available capacity to deal with a system contingency is expected to decrease along with overall system reliability.

Safety: Transformer failure can be accompanied by fire or an explosion, which may result in collateral damage to other transformers, other station equipment, and, if staff are present, potential injury to personnel.

Applying this option to the general transformer population would lead to an anticipated increase in the frequency of transformer failures due to an increase in the number of transformers operating beyond end-of-life over the 2015 to 2019 period and beyond. Consequently, customers throughout Toronto Hydro's service territory will likely experience more transformer failures.

(2) Voltage Conversion of an MS : With this option, the transformer's need for replacement is addressed through a voltage conversion project, i.e. a project where all 4 kV distribution assets within the service area of an MS are replaced with assets that operate at 13.8 or 27.6 kV. Once the voltage conversion project is completed, the area's MS and power transformer are no longer needed, and are therefore decommissioned.

A voltage conversion project is inherently a distribution feeder project, and is therefore planned independently of transformer age or condition. However, if a voltage conversion project is planned for the service area of an MS whose transformer has reached end-of-life, then Toronto Hydro chooses to address the transformer's need for replacement by decommissioning after the voltage conversion project has been completed.

All of the transformers included in the Power Transformer Replacement program are located in areas which have not been planned for voltage conversion. Therefore, this option was not chosen as the preferred alternative for addressing the transformers of this program.

(3) Power Transformer Replacement: This option involves replacement of aging and/or poor condition transformers. This option is preferred if voltage conversion of an MS is not planned.

Power Transformer Replacement is more economical than the "No Transformer Intervention" option (Option 1). This option also reduces the risk to other MSs whose customers are served by these transformers under contingency. This option was chosen as Toronto Hydro's preferred alternative to address the transformers of this program.

The replacement of the power transformer assets in the first year of the program will result in an avoided estimated risk cost (ARC) of $2.66 million, as detailed in Table 7 This value represents the avoided cost of executing the first year of activities as scheduled as opposed to deferring these activities until 2020. These avoided costs include quantified risks, taking into account the probability of failure of the assets, and multiplying this by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement. For further details on the ARC approach is provided in Section D3.3.

TABLE 6: BUSINESS CASE EVALUATION FOR THE TRANSFORMER REPLACEMENT PROGRAM

Business Case Element	Cost (in Millions)
Asset Renewal	
Present Value of Net Cost in 2020 [PV(NET_COST(2020)]	$2.94
Net Cost for the First Year of Activity [NET_COST(First Year of Activity)]	$0.28
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - NET_COST(First Year of Activity))]	$2.66

E6.14.7 2015 Projects

Table 8 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

(a) previously filed projects that appeared as jobs in the OEB approved Stations Power Transformers segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 7: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	CIR Projects
0.55	1.13

Table 9 lists all projects that will be partially or completely executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 8: 2015 PROJECTS

Project Number	Project Name	Total Project Cost (K)	Start Date	Project Type (ICM or CIR)
S13168	Blaketon MS Replace TR1 Transformer	$165	2015	ICM
S13155	High Level MS Replace TR2 Transformer	$219	2015	ICM
S13463	Jane MS Install Oil Containment	$161	2015	ICM
S15096	Coronation Bennett MS: Replace Station Transformer TR1	$516	2015	CIR
S15186	Norseman MS Replace Transformer TR1	$616	2015	CIR

E6.14.7.1 S13168 Blaketon MS – Replace TR1 Transformer

Investment Category: System Renewal

Program: Stations Power Transformer Renewal

Project Title: Blaketon MS Replace TR1 Transformer

Project Number: S13168 (ICM)

Project Year: 2015

Estimated Cost: $164,570

(i) Objective

To replace the existing 7.5/10 MVA, 27.6/13.8 kV station transformer, TR1, with a new 7.5/10 MVA, 27.6/ 13.8 kV station transformer at Blaketon MS.

(ii) Scope of Work

TABLE 9: S13168 SCOPE OF WORK DETAILS

District Neighborhood	ETOBICOKE
Station(s)	BLAKETON MS
Transformer	TR1

The project is located at Blaketon MS. The scope of work for the replacement is described in Section E6.14.6. There is no overhead bus structure present.

(iii) Justification & Benefits

The transformer TR1 at Blaketon MS was manufactured in 1970 and will have reached the end of its useful life by 2015. Dissolved gas analysis (DGA) performed by Weidmann Diagnostic Solutions indicates that a medium-range thermal fault (between 300-700°C) and thermal decomposition of the cellulose paper insulation has occurred. The results of these tests are shown in Table 11.

TABLE 10: WEIDMANN DIAGNOSTIC SOLUTION'S SUMMARY OF DGA FOR BLAKETON MS TR1

Together with transformer TR2, TR1 at Blaketon MS supplies approximately 275 customers. If TR2 fails, it is possible TR1 will overload. Additionally, if TR2 were to fail and start a fire, there is a strong possibility that TR1 will be damaged and result in an outage to the 275 customers. Therefore, to improve the reliability of Blaketon MS and to avoid a significant customer outage, TR2 needs to be replaced.

E6.14.7.2 S13155 High Level MS Replace TR2 Transformer

Investment Category: System Renewal

Program: Power Transformer Renewal Program

Project Title: High Level MS Replace TR2 Transformer

Project Number: S13155 (ICM)

Project Year: 2015

Estimated Cost: $219,427

(i) Objective

To replace the existing 12/15 MVA, 13.8/4.16 kV station transformer, TR2, with a new 12/15 MVA, 13.8/4.16 kV station transformer at High Level MS.

(ii) Scope of Work

TABLE 11: S13155 SCOPE OF WORK DETAILS

District Neighborhood	TORONTO
Station(s)	HIGH LEVEL MS
Transformer	TR2

The project is located at High Level MS. The scope of work for the replacement is described in Section E6.14.6. There is no overhead bus structure present.

(iii) Justification & Benefits

The transformer TR2 at High Level MS was manufactured in 1947 (68 years old in 2015) and has reached the end of its useful life.

In addition, the transformer HI score, which is formulated based on a combination of oil leakage, corrosion, bushing, oil quality tests, age, and dissolved gas analysis is 48 out of 100. This score indicates that the transformer is in poor condition.

Together with transformers TR1 and TR3, TR2 at High Level MS supplies approximately 4,117 customers. If TR2 fails, it is possible TR1 and TR3 will overload. Additionally, if TR2 were to fail and start a fire, there is a strong possibility that TR1 and TR3 will be damaged and result in an

outage to the 4,117 customers. Therefore, to improve the reliability of High Level MS and to avoid a large-scale customer outage, TR2 needs to be replaced.

E6.14.7.3 S13463 Jane MS Install Oil Containment

Investment Category: System Renewal

Program: Power Transformer Renewal Program

Project Title: Jane MS Install Oil Containment

Project Number: S13463 (ICM)

Project Year: 2015

Estimated Cost: $160,758

(i) Objective

To install an oil containment system for the two power transformers at Jane MS.

(ii) Scope of Work

TABLE 12: SCOPE OF WORK DETAILS

District Neighborhood	NORTH YORK
Station(s)	JANE MS

The project is bound by Jane MS. The scope of work for the oil containment installation is described in Section E6.14.6, Step 3.

(iii) Justification & Benefits

Jane MS is in close proximity to large pipelines owned by other gas and petroleum utilities. If an oil leak should occur from either of the two transformers at Jane MS, it is possible that these pipelines may be damaged, as well as potential harm to the local environment. Therefore, to mitigate the risk of pipeline damage, an oil containment system needs to be installed at Jane MS.

E6.14.7.4 S15096 Coronation Bennett MS: Replace Station Transformer TR1

Investment Category: System Renewal

Program: Power Transformer Renewal Program

Project Title: Coronation Bennett MS : Replace Station Transformer TR1

Project Number: S15096

Project Year: 2015

Estimated Cost: $515,582

(i) Objective

To replace the existing 5 MVA, 27.6/4.16 kV station transformer, TR1, with new 5 MVA, 27.6 kV/4.16 kV, station power transformer at Coronation Bennett MS.

(ii) Scope of Work

TABLE 13: S15096 SCOPE OF WORK DETAILS

District Neighborhood	SCARBOROUGH
Station(s)	CORONATION-BENNETT MS
Transformer	TR1

The project is located at Coronation Bennett MS. The scope of work for the replacement is described in Section E6.14.6. There is no overhead bus structure present.

(iii) Justification & Benefits

The transformer TR1 at Coronation Bennett MS was manufactured in 1958 (57 years old in 2015) and has reached the end of its useful life.

In addition, the transformer HI score, which is based on a combination of oil leakage, corrosion, bushing, oil quality tests, age, and dissolved gas analysis is 36 out of 100. This indicates that the transformer is in poor condition.

If the transformer fails, it will result in a power outage to over 800 customers. Therefore, to improve the reliability of Coronation Bennett MS and to avoid a large-scale customer outage, TR1 needs to be replaced.

E6.14.7.5 S15186 Norseman MS Replace Transformer TR1

Investment Category: System Renewal

Program: Power Transformer Renewal Program

Project Title: Norseman MS Replace Transformer TR1

Project Number: S15186

Project Year: 2015

Estimated Cost: $615,921

(i) Objective

To replace the existing 5/6.7 MVA, 27.6/4.16 kV station transformer, TR1, with a new 5/6.7 MVA, 27.6 kV/4.16 kV, station power transformer at Norseman MS.

(ii) Scope of Work

TABLE 14: S15186 SCOPE OF WORK DETAILS

District Neighborhood	ETOBICOKE
Station(s)	NORSEMAN MS
Transformer	TR1

The project is located at Norseman MS. The scope of work for the replacement is described in Section E6.14.6. There is an overhead bus structure present.

(iii) Justification & Benefits

The transformer TR1 at Norseman MS was manufactured in 1958 (57 years old in 2015), and has reached the end of its useful life of 45 years. It will be in service 12 years beyond it useful life in 2015.

If the transformer fails, it will result in a power outage to over 500 customers. Therefore to improve the reliability of Norseman MS and to avoid a large-scale customer outage, TR1 needs to be replaced

E6.15 Circuit Breaker Renewal

TYPICAL EXISTING CIRCUIT BREAKERS

E6.15.1 Summary

Program Description

The Circuit Breaker Renewal program is a continuation of the activities previously presented in the OEB approved Stations Circuit Breakers segment of Toronto Hydro's 2012-2014 ICM application. The ongoing proactive replacement of circuit breakers through this program is required to mitigate the acute failure risks associated with functionally obsolete oil circuit breakers.

Toronto Hydro prioritizes its oil circuit breaker renewal plan based on asset condition and/or asset age. Those selected based on age and condition are further prioritized by the amount of load or the number of customers that would be impacted if the circuit breaker fails. Based on the above prioritization method, Toronto Hydro plans to replace 35 stand-alone outdoor oil circuit breakers with vacuum circuit breakers over the 2015-2019 period.

The following table summarizes the anticipated benefits of this program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Mitigation of significant reliability and system performance risks associated with circuit breaker failure and catastrophic failure.
Reliability	ƒ Mitigation of the reliability risk associated with oil circuit breakers, improving the reliability of power supply to the connected customers. ƒ Improved overall reliability of the terminal station by reducing the risk of catastrophic failure of the oil circuit breakers. ƒ Replacement of the associated feeder protection relay enables future feeder automation and other smart grid functionality, which is expected to further increase the reliability of power supply to customers.
Safety	ƒ Mitigation of safety risks associated with catastrophic failure of an oil circuit breaker.
Efficiency	ƒ The vacuum circuit breakers that Toronto Hydro plans to install have 50% less maintenance cost compared to the oil circuit breakers because the oil handling expenses associated with oil circuit breakers are eliminated, and vacuum circuit breakers have less moving parts to maintain.
Environmental Benefit	ƒ Replacement of the oil circuit breaker reduces the likelihood of oil with PCBs being spilled, which could contaminate the soil and groundwater and could entail high clean-up costs for the utility.

Program Drivers

The stand-alone oil circuit breakers currently in service are obsolete. Spare parts for these types of circuit breakers are no longer available and the technology is no longer supported by manufacturers. The combination of functional obsolescence, environmental risk (from leaking oil), reliability, and safety issues all indicate the need for these assets to be removed from Toronto Hydro's electrical distribution system as soon as possible. The trigger and secondary drivers for this program are summarized in the following table.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Procurement of replacement parts for legacy, stand-alone oil circuit breakers is becoming increasingly problematic, making it difficult to extend the life of these assets through maintenance ƒ A large number of these assets are at or beyond their useful lives and/or are in poor condition ƒ Catastrophic failure of end-of-life oil circuit breakers could release oil containing PCBs greater than 50 ppm into the environment.

Secondary Drivers	Reasoning
Failure Risk	ƒ Oil circuit breakers can fail catastrophically when they approach or exceed end-of–life. ƒ Catastrophic failure of oil circuit breakers can cause collateral damage that can result in expensive replacement costs and long outages to customers.
Safety	ƒ Catastrophic failure can result in flying debris and subsequent fire, creating a safety hazard to nearby personnel.

Preferred Alternative

Toronto Hydro considered the following alternatives for addressing the assets in this progam.

(1) Continue to maintain and repair oil circuit breakers currently in service.

(2) Increase maintenance to reduce failure risk of circuit breakers currently in service.

(3) Proactively replace these oil circuit breakers with vacuum circuit breakers.

Option III is the preferred alternative as it offer the best mitigation of the risks of unwanted outages, safety, and environmental concerns that can occur when an oil circuit breaker fails. Toronto Hydro also projects that under this option, maintenance costs would be lower than under the status quo scenario, as maintenance time of an oil circuit breaker is double than that of a vacuum circuit breaker.

The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $16.8 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.15.7 for details).

Timing and Pacing

The condition of the oil circuit breakers that are currently in service is deteriorating, as demonstrated by an increasing frequency of reactive circuit breaker repairs. Due to the potential reliability and safety risks posed by the failure of a circuit breaker, Toronto Hydro must continue its proactive replacement program during the 2015-2019 planning horizon. Toronto Hydro intends to replace 35 outdoor stand-alone oil circuit breakers over this period. This includes all outdoor

stand-alone oil circuit breakers that are in poor condition and/or that will have reached the end of their useful lives within the planning period.

Table C shows the historical and forecasted spending for the continuing activities in the Circuit Breaker Renewal program.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.00	0.91	0.22	1.02	2.09	1.66	1.80	1.79	2.11	1.78

E6.15.2 Program Description

The Circuit Breaker Renewal program is a continuation of the activities previously presented in the OEB approved Stations Circuit Breakers segment of Toronto Hydro's 2012-2014 ICM application. The ongoing proactive replacement of circuit breakers through this program is required to mitigate the acute failure risks associated with functionally obsolete oil circuit breakers.

Toronto Hydro prioritizes its oil circuit breaker renewal plan based on asset condition and/or asset age. Those selected based on age and condition are further prioritized by the amount of load or the number of customers that will be impacted if the circuit breaker fails. Based on the above prioritization method, Toronto Hydro is planning to replace 35 stand-alone outdoor oil circuit breakers with vacuum circuit breakers over the 2015-2019 period as summarized in Table 1. A typical existing stand alone KSO oil circuit breaker is shown in Figure 1.

TABLE 1: NUMBER OF CIRCUIT BREAKERS TO BE REPLACED

Assets (Units)	2015	2016	2017	2018	2019	Total
KSO Oil Circuit Breaker	10	6	6	7	6	35

FIGURE 1: TYPICAL EXISTING KSO OIL CIRCUIT BREAKER

These circuit breakers are distributed across the following group of stations, the geographical locations of which are shown in Figure 2:

- Bathurst TS: 7 circuit breakers
- Bermondsey TS: 3 circuit breakers
- Fairchild TS: 4 circuit breaker
- Finch TS: 9 circuit breakers
- Leslie TS: 11 circuit breakers
- Rosscowan Pharmacy MS: 1 circuit breaker

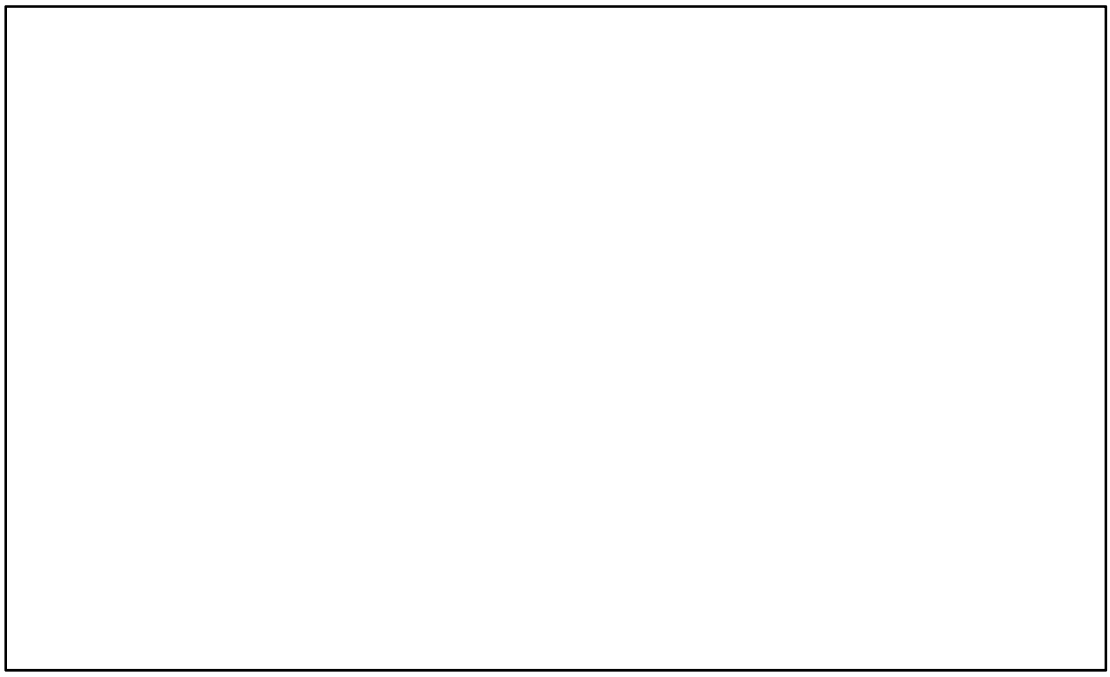


FIGURE 2: LOCATION OF CIRCUIT BREAKERS TO BE REPLACED (2015 – 2019)

Circuit breakers are switches designed to protect electrical circuits from damage caused by overloads, short circuits, or other contingency events. Their basic function is to interrupt current flow when a protective station feeder relay detects fault current or overload current in the circuit. The station feeder relay sends a signal to the circuit breaker to interrupt the current flowing through it in order to ensure the safety of upstream or downstream equipment. Unlike fuses, which must be replaced upon operation, circuit breakers can be reset to resume normal functioning once the fault is cleared.

Toronto Hydro currently utilizes three types of stand-alone outdoor circuit breakers in its distribution system:

(1) Oil circuit breakers

(2) SF_6-gas circuit breakers

(3) Vacuum circuit breakers

Circuit breaker technology has been continually evolving. Oil circuit breakers are the oldest technology of the three circuit breaker types listed above. Toronto Hydro no longer installs oil

circuit breakers in its distribution system due to the risks associated with their potential catastrophic failure (e.g., station fires), oil leaks, and the availability of better technology in terms of reliability, cost of ownership, and environmental stewardship. Toronto Hydro expects to have 46 outdoor stand-alone oil circuit breakers in service in 2015, 42 of which are 27.6 kV Kinetic Solenoid Operating (KSO) oil circuit breakers manufactured by General Electric and four of which are 13.8 kV oil circuit breakers manufactured by Montel.

Toronto Hydro has primarily used the KSO oil circuit breakers on the 27.6 kV outdoor open air transformer stations (TS) in the North York area, where it owns the feeder breaker and downstream assets. The other four outdoor stand-alone oil circuit breakers manufactured by Montel are found in Toronto Hydro-owned 13.8 kV municipal substations in the Scarborough area. All of the stand-alone oil circuit breakers, regardless of manufacturer, have the same obsolescence and end-of-life issues. Toronto Hydro also plans to replace the associated obsolete electromechanical feeder protection relays, which are more or less in the same vintage as the oil circuit breakers, with modern microprocessor relays.

Toronto Hydro plans to replace the existing stand-alone oil circuit breakers with modern stand-alone vacuum circuit breakers. A vacuum circuit breaker, illustrated in Figure 3, insulates its contacts by surrounding them in a vacuum as opposed to a medium such as oil. A vacuum exhibits strong insulating qualities as there is no possibility for the arc current to continue to flow through the open contacts of the vacuum circuit breaker, ensuring that the fault or overload current is completely interrupted. Fault current and overload current must be interrupted as fast as possible to prevent equipment damage.

FIGURE 3: STAND-ALONE OUTDOOR VACUUM CIRCUIT BREAKER

Toronto Hydro expects vacuum insulated circuit breakers to provide a number of additional benefits compared to the oil circuit breakers that are being replaced:

- Vacuum circuit breakers are environment friendly, since interruption takes place in a vacuum medium and does not require gas or liquid addition. This eliminates the possibility of leakage of gas (or any material) that can be harmful to the environment. The oil inside some of the existing stand-alone circuit breakers contains PCBs greater than 50 ppm, which Toronto Hydro has an obligation to remove from its distribution system in order to comply with Environment Canada regulations.
- Mitigation of the fire risk and risk of collateral damage associated with the existing oil circuit breakers.
- The ongoing maintenance cost of a vacuum circuit breaker is half of that of an oil circuit breaker.

- There are no gas decomposition products in the vacuum and hence the sealed vacuum interrupter mitigates environmental effects on the circuit breaker, which increases the asset life.

- There are fewer moving parts in vacuum circuit breakers compared to other types of circuit breakers, further increasing asset life.

Toronto Hydro's total estimated cost for this program is $9.13 million over the 2015-2019 period, which allows for the replacement of an estimated 35 circuit breakers and the associated mechanical feeder relays with modern vacuum circuit breakers and microprocessor feeder relays respectively. The following table summarizes the anticipated benefits of this program.

TABLE 2: PROGRAM BENEFITS

Customer Value	• Mitigation of significant reliability and system performance risks associated with circuit breaker failure and catastrophic failure. • The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $16.8 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.15.7 for details).
Reliability	• Mitigation of the reliability risk associated with oil circuit breakers, improving the reliability of power supply to the connected customers. • Improved overall reliability of the terminal station by reducing the risk of catastrophic failure of the oil circuit breakers. • Replacement of the associated feeder protection relay enables future feeder automation and other smart grid functionality, which is expected to further increase the reliability of power supply to customers.
Safety	• Mitigation of potential safety risks associated with catastrophic failure of an oil circuit breaker, which has the potential to send flying debris from the ruptured tank into the air, and can cause injury.
Efficiency	• The vacuum circuit breakers that Toronto Hydro plans to install have 50% less maintenance cost compared to the oil circuit breakers because the oil handling expenses associated with oil circuit breakers are eliminated, and vacuum circuit breakers have less moving parts to maintain.
Environmental Benefit	• Replacement of the oil circuit breaker eliminates the likelihood of oil with PCBs being spilled, which could contaminate the soil and groundwater and could entail high clean-up costs for the utility.

E6.15.3 Why the Program is Needed

The stand-alone oil circuit breakers currently in service are obsolete. Spare parts for these types of circuit breakers are no longer available and the technology is no longer supported by manufacturers. The catastrophic failure of a stand-alone oil circuit breaker can cause an explosion resulting in flying debris, which could injure workers on-site, and inflict collateral damage to adjacent equipment resulting in increased outage time for customers and environmental damage that necessitates costly cleanup. These circuit breakers are also connected to the 27.6 kV and 13.8 kV distribution feeders and therefore serve many customers over a large area. The combination of functional obsolescence, environmental risk (from leaking oil), reliability, and safety issues all indicate the need for these assets to be removed from Toronto Hydro's electrical distribution system as soon as possible.

E6.15.3.1 Program Drivers

Table 3 summarizes the trigger and secondary drivers for replacing outdoor stand-alone oil circuit breakers. This is a System Renewal initiative with a trigger driver of functional obsolescence.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Procurement of replacement parts for legacy, stand-alone oil circuit breakers is becoming increasingly problematic, making it difficult to extend the life of these assets through maintenance ƒ A large number of these assets are at or beyond their useful lives and/or are in poor condition ƒ Catastrophic failure of end-of-life oil circuit breakers could release oil containing PCBs greater than 50 ppm into the environment
Secondary Drivers	**Reasoning**
Failure Risk	ƒ Oil circuit breakers can fail catastrophically when they approach or exceed end-of–life ƒ Catastrophic failure of oil circuit breakers can cause collateral damage that can result in expensive replacement costs and long outages to customers
Safety	ƒ Catastrophic failure can result in flying debris and subsequent fire, creating a safety hazard to nearby personnel.

The critical function of circuit breakers is to interrupt the flow of current under normal and fault conditions. Under fault conditions, a fast response and complete interruption are essential to protect the rest of the power system from the faulted component in order to maintain grid

reliability. A failure of an oil circuit breaker is a very significant event in terms of customer impact, system performance, and personnel safety.

The trigger driver of this program is the functional obsolescence of the stand-alone outdoor oil circuit breakers. Toronto Hydro has had difficulty obtaining spare parts from the original manufacturers of these assets in order to properly maintain them. In some cases, these breakers are kept in service using salvaged second-hand parts from retired equipment, and at other times by purchasing custom made parts. As the in-service population of oil circuit breakers continues to age and deteriorate, this method of getting spare parts becomes less sustainable.

The secondary driver of this program is failure risk. As shown in Figure 6 in section E6.15.3.2, out of the total in-service stand-alone oil circuit breaker population, 61% are expected to be past the end of their useful lives of 45 years by 2015. If these oil circuit breakers are not replaced proactively, the likelihood that they may fail while in service is expected to increase. Toronto Hydro has recently started experiencing circuit breaker failures on units that are approaching, but have not reached, the end of their projected useful lives; for example, circuit breaker 80M3 at Fairchild TS and circuit breaker 51M6 at Leslie MS (both replaced in 2013) started failing when they were 39 and 44 years old, respectively. Similarly, the Hydro One owned circuit breaker that failed catastrophically at Manby TS in 2010 was only 32 years old.

There are also safety and environmental concerns associated with the stand-alone oil circuit breakers that have aged beyond their useful lives. A key safety risk associated with the failure of an oil circuit breaker, particularly under short circuit conditions, is a catastrophic failure and subsequent oil fire. Such an event can damage or destroy other electrical equipment in the vicinity to the extent that an entire station could be forced out of service. This, in turn, could cause a prolonged outage for all customers supplied by that station. A catastrophic failure of a circuit breaker is also a potential safety risk to any personnel on site.

A recent example of a catastrophic failure of a single circuit breaker was the July 2010 fire at the Manby Transformer Station (TS) owned by Hydro One Networks Inc. (HONI). As a result of this event, thousands of customers in the downtown and west-end of Toronto suffered long outages, while the area surrounding the station sustained extensive fire damage as shown in Figure 4.

FIGURE 4: CATASTROPHIC FAILURE OF AN OUTDOOR OIL CIRCUIT BREAKER AT MANBY STATION

The condition of stand-alone outdoor circuit breakers in Toronto Hydro's system continues to decline. This is demonstrated by the increasing trend in the number of stand-alone oil circuit breakers with major component malfunctions due to asset degradation (e.g., worn-out circuit breaker contacts, failure to close, flash over, and burnt potheads) all of which required immediate reactive repair in 2006 to 2013 as illustrated in Figure 5. As noted earlier, Toronto Hydro is facing increasing difficulty in obtaining spare parts for these circuit breakers to allow for continued operation. This overall increasing trend in repairs is consistent with the increasing proportion of oil circuit breakers approaching or exceeding end-of-life conditions.

FIGURE 5: QUANTITY OF STAND-ALONE OIL CIRCUIT BREAKERS REPAIRED PER YEAR (2006 TO 2013)

To mitigate the risks associated with catastrophic failure of the stand-alone oil circuit breakers, Toronto Hydro plans to proactively replace all stand-alone oil circuit breakers that have reached end-of-life and/or are in poor condition using a planned approach.

The oil circuit breakers are designed to normally carry 1200 A at 27.6 kV. However, fault current could go up to 9,000 A or more depending on the location of the fault. This substantial amount of uncontrolled energy could create a catastrophic failure event if the circuit breaker fails to interrupt the flow of this fault current. A catastrophic failure of oil circuit breakers would result in collateral damage leading to long outages, and potential injuries to personnel on site and environmental risks. To mitigate these risks, Toronto Hydro plans to continue the proactive replacement of its aging stand-alone oil circuit breakers.

As it replaces the existing stand alone oil circuit breakers, Toronto Hydro also plans to replace the associated obsolete electromechanical feeder protection relays which are more or less in the same vintage as the oil circuit breakers with modern microprocessor relays. Toronto Hydro is experiencing failure of the existing electromechanical feeder protection relays that were not replaced during the previous oil circuit breaker replacements. For example, on November 20th, 2012, the 53M25 SF_6 circuit breaker at Bermondsey TS was required to clear high fault current (9 kA). The circuit breaker failed to lockout as per its design and the upstream bus differential protection system had to operate to interrupt the fault current resulting in a substantial outage, with power interrupted to 2,390 customers for about 26 minutes. A similar event also occurred on

March 4, 2014 at Bermondsey TS with the SF_6 circuit breaker 53M8. This event interrupted 12,181 customers for 113 minutes. An investigation of the outage revealed that the feeder relay, associated with the SF_6 circuit breaker which is also part of the protection scheme was found to be defective and was at the end of life; the relay was replaced reactively.

Review of these events established that the electromechanical relays are also at the end-of-life. Toronto Hydro has concluded that it is more cost effective and operationally efficient to upgrade the existing feeder protection relays to microprocessor relays along with the associated oil circuit breaker replacement rather than retrofitting them with microprocessor relay at a later date or on a reactive basis to ensure the reliable operation of the protection scheme. The microprocessor relays will also enable future feeder automation and/or smart grid functionality. The cost of upgrading the feeder protection relays is included in the cost of each of the associated circuit breakers proposed to be replaced.

E6.15.3.2 Asset Details

(i) Asset Lifecycle

Figure 6 illustrates the age profile of the stand-alone oil circuit breakers deployed in Toronto Hydro's system. An oil circuit breaker has an expected useful life of 45 years. Toronto Hydro expects that 61% of its outdoor stand-alone oil circuit breakers will exceed their useful lives by 2015.

FIGURE 6: STAND-ALONE OUTDOOR OIL CIRCUIT BREAKER AGE PROFILE

(ii) Asset Failure Impacts

Table 4 tabulates the number of customers and the amount of load connected to each of the circuit breakers that Toronto Hydro proposes to replace over the 2015-2019 period. In the event of a circuit breaker failure, those customers would be without power for approximately two hours while power is re-routed from elsewhere on the network. For example, oil circuit breaker 51M6 at Leslie MS failed on May 17, 2006 and power supply to 1,735 customers was interrupted. It took an hour and 47 minutes to switch these customers to another source and restore their power. Another example is oil circuit breaker (80M4) at Fairchild TS, which failed on July 3, 2010. Power supply was interrupted for 9,901 customers for about 40 minutes until they were switched over to an alternate power source

TABLE 4: ASSET FAILURE IMPACT

Proposed Year	Station Name	Circuit Breaker name	Connected Load (MVA)	No of Connected Customers
2015	Bermondsey TS	53M1	5.3	69
	Bermondsey TS	53M9	6.0	22
	Bermondsey TS	53M11	3.1	273
	Finch TS	55M24	17.9	211
	Bathurst TS	85M4	17.9	693
	Bathurst TS	85M2	13.5	221
	Bathurst TS	85M27	8.4	1,443
	Bathurst TS	85M31	8.1	495
	Leslie TS	51M25	14.6	1,537
	Leslie TS	51M27	9.2	1,351
2016	Leslie TS	51M21	14	2,203
	Leslie TS	51M28	20.3	877
	Fairchild TS	80M2	12.1	1674
	Leslie TS	51M30	18.2	401
	Bathurst TS	85M30	13.4	115
	Finch TS	55M10	15.8	2,480
2017	Leslie TS	51M22	16.7	741
	Leslie TS	51M23	11.8	118
	Leslie TS	51M24	15	1,790
	Finch TS	55M31	16.9	167
	Finch TS	55M32	15.9	64
	Finch TS	55M29	13.9	775
2018	Leslie TS	51M26	9.5	987
	Leslie TS	51M29	15.5	492
	Leslie TS	51M32	9.7	43
	Finch TS	55M30	10.4	2,017
	Finch TS	55M7	15.9	2,533
	Finch TS	55M9	14.4	284
	Rosscowan Pharmacy MS	ScJG52T1	2.0	387
2019	Fairchild TS	80M10	12.4	1,236
	Fairchild TS	80M22	10	171
	Fairchild TS	80M4	15.5	1,947
	Finch TS	55M23	22.4	2,196
	Bathurst TS	85M3	19.4	288
	Bathurst TS	85M5	19	4,878

E6.15.4 Timing & Pacing of the Program

The condition of the oil circuit breakers that are currently in service is deteriorating, as previously demonstrated by the increasing frequency of reactive circuit breaker repairs in Figure 5. Due to the potential reliability and safety risks posed by the failure of a circuit breaker and the

obsolescence issues discussed earlier, Toronto Hydro must continue its proactive replacement program during the 2015-2019 planning horizon. Toronto Hydro intends to replace 35 outdoor stand-alone oil circuit breakers over this period. This includes all outdoor stand-alone oil circuit breakers that are in poor condition and/or that will have reached the end of their useful lives within the planning period.

Table 5 shows the historical and forecasted spending for the continuing activities in the Circuit Breaker Renewal program.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending ($Million)					Future Spending($Million)				
YEAR	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.00	0.91	0.22	1.02	2.09	1.66	1.80	1.79	2.11	1.78

The age profile of the eleven stand-alone oil circuit breakers that will remain in service in 2020 is illustrated in Figure 7. Four of these breakers will be past their useful life in 2020 and will require replacement in 2020, with additional replacements to be evaluated at the time.

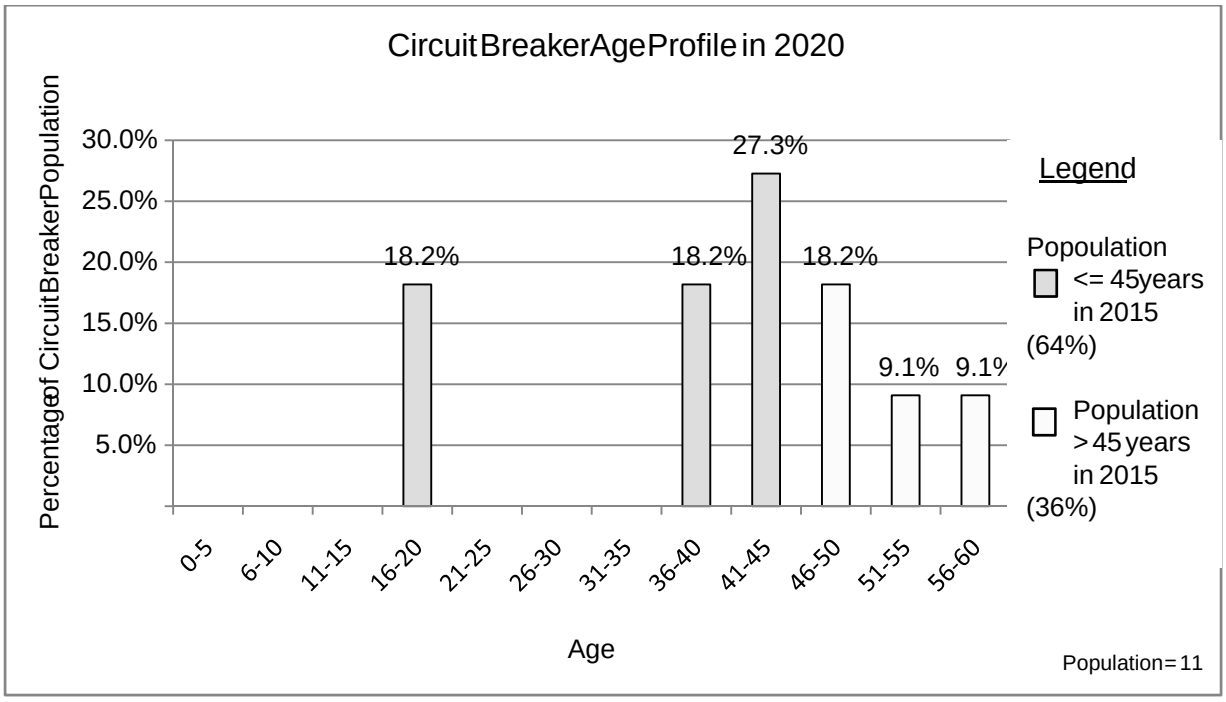


FIGURE 7: AGE PROFILE OF STAND ALONE OIL CIRCUIT BREAKERS IN 2020

E6.19.4.1 Ranking & Prioritization

The list of outdoor stand-alone oil circuit breakers proposed for replacement in 2015-2019 has been prioritized based on asset condition and asset age. Poor condition circuit breakers are of the highest priority for replacement, followed by circuit breakers prioritized according to age. Where more than one circuit breaker has the same health index score and age, Toronto Hydro further prioritizes the assets by the number of customers and the amount of load served by each. Circuit breakers with relatively higher loads or numbers of customers served will generally have a greater impact on customers if they fail.

E6.15.5 Program Execution

Toronto Hydro's proposed circuit breaker renewal program consists of a series of discrete projects. Field personnel coordinate a scheduled outage with Toronto Hydro's power system controllers before executing each project. Customers normally served by the circuit breaker being replaced would be temporarily served by another part of the network and would typically experience no interruption.

Individual projects must be coordinated with HONI, as circuit breakers need to be disconnected from the HONI-owned bus and new circuit breakers require testing once installed. Once the scheduled outage is agreed upon, Toronto Hydro installs the circuit breaker and test its functionality jointly with HONI. Once confirmed to be working according to specification, the circuit breaker is energized and customers are transferred back to the newly installed circuit breaker, completing the project.

E6.15.5.1 Proposed Work Plan

Table 6 summarizes the replacement plan for 2015 to 2019.

TABLE 6: 2017-2019 LONG TERM PLAN

Year	Feeder	Station
2015	53M1	Bermondsey TS
2015	53M9	Bermondsey TS
2015	53M11	Bermondsey TS
2015	55M24	Finch TS
2015	85M4	Bathurst TS
2015	85M2	Bathurst TS
2015	51M25	Leslie TS
2015	51M27	Leslie TS
2015	85M27	Bathurst TS
2015	85M31	Bathurst TS
2016	80M2	Fairchild TS

Year	Feeder	Station
2016	85M30	Bathurst TS
2016	51 M21	Leslie TS
2016	51M30	Leslie TS
2016	51M28	Leslie TS
2016	55M10	Finch TS
2017	55M32	Finch TS
2017	55M31	Finch TS
2017	51M22	Leslie TS
2017	51M23	Leslie TS
2017	51M24	Leslie TS
2017	55M29	Finch TS
2018	55M30	Finch TS
2018	55M9	Finch TS
2018	SCJG52T1	Rossocowan MS
2018	51M26	Leslie TS
2018	51M29	Leslie TS
2018	51M32	Leslie TS
2018	55M7	Finch TS
2019	85M3	Bathurst TS
2019	85M5	Bathurst TS
2019	55M23	Finch TS
2019	80M10	Fairchild TS
2019	80M22	Fairchild TS
2019	80M4	Fairchild TS

E6.15.5.2 Program Risks

The following are some of the risks/constraints that can impact the completion of this program:

System conditions may not allow the planned outages necessary to replace oil circuit breakers, especially during high season (summer or winter). At these times, most of the feeders are highly loaded and unable to accept additional load from the feeder on which the oil circuit breaker is to be replaced which could impact the replacement schedule. This risk can be mitigated through effective advance communication with system controllers to develop a workable and coordinated outage plan.

Potential work coordination issues with Hydro One could delay program completion. Hydro One is required to review the protection system of the new vacuum circuit breakers and associated feeder protection relays. Hydro One must also test the protection system for the circuit breakers together with Toronto Hydro to ensure that it is coordinated with the Hydro One protection system, since these circuit breakers will be connected to the Hydro One bus. Any delay in Hydro One's work could impact the timely completion of this program. This risk can be mitigated by

effective communication with Hydro One to ensure that the work requirements are known to Hydro One ahead of time so that the requirements can be included in their work plans.

E6.15.6 Evaluation of Alternatives

E6.15.6.1 Quantification/ Evaluation of Options

(i) Status Quo

Under the status quo scenario, Toronto Hydro would continue to maintain and repair oil circuit breakers currently in service. There would be no proactive replacement of these assets. This option is not preferred because it would not address the functional obsolescence, reliability, and safety risks noted earlier.

(ii) Increase Maintenance Activities

This option requires more frequent maintenance to be performed on the oil circuit breakers to reduce failure risk. While in theory this would be a viable alternative, the availability of spare parts is critical to this option. As previously explained, spare parts for the oil circuit breakers are increasingly difficult to procure, limiting the feasibility of this option.

(iii) Planned Replacement

This option involves the proactive replacement of 35 oil circuit breakers with vacuum circuit breakers over five years. This option mitigates the risks of unwanted outages, safety, and environmental concerns that can occur when an oil circuit breaker fails. Toronto Hydro also projects that maintenance costs would be lower than under the status quo scenario as maintenance time of oil circuit breaker is double that of a vacuum circuit breaker. The vacuum circuit breaker has less moving parts and therefore less components to maintain. The additional maintenance cost required to drain/maintain the oil in the oil circuit breakers is also eliminated.

The replacement of the circuit breakers in the first year of the program is expected to result in an avoided estimated risk cost (ARC) of $16.8 million, as detailed in Table 7. This value represents the costs avoided by executing the first year of activities as scheduled as opposed to deferring these activities until 2020. These avoided costs include quantified risks, taking into account the probability of failure of the assets, and multiplying this value by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions,

emergency repairs, and replacement. For further details on the ARC approach is provided in Section D3.3.

TABLE 7: BCE RESULTS

Business Case Element	Cost (in Millions)
Asset Renewal	
Present Value of Net Cost in 2020 [PV(NET_COST(2020)]	$19.68
Net Cost for the First Year of Activity [NET_COST(First Year of Activity)]	$2.88
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - (NET_COST(First Year of Activity))]	$16.80

E6.15.7 2015 Projects

Table 8 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

- previously filed projects that appeared as jobs in the OEB approved Stations Circuit Breakers segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and
- projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 8: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	CIR Projects
0.44	1.22

Table 9 lists all projects that Toronto Hydro plans to execute, partially or in fully, as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 9: 2015 PROJECTS

Project Number	Project Name	Total Project Cost ($M)	Start Date	Project Type (ICM or CIR)
21656	S13146 Bermondsey TS: Repl. KSO OCB's (53M1, 53M9 & 53M11)	0.18	2015	ICM
22693	S14052 Finch TS Replace 55M24 KSO Circuit Breaker	0.09	2015	ICM
22698	S14056 Bathurst TS Replace 85M4 KSO CB	0.09	2015	ICM
22699	S14057 Bathurst TS Replace 85M2 KSO Oil Circuit Breaker	0.09	2015	ICM
29633	S15103 Leslie TS Replace KSO Oil Circuit Breaker 51M25	0.30	2015	CIR
29634	S15104 Leslie TS Replace KSO Oil Circuit Breaker 51M27	0.30	2015	CIR
29636	S15105 Bathurst TS Replace KSO Oil Circuit Breaker 85M27	0.30	2015	CIR
29652	S15137 Bathurst TS Replace KSO Oil Breaker 85M31	0.32	2015	CIR

E6.15.7.1 S13146 Project Description

Investment Category: System Renewal
Program: Circuit Breaker Renewal
Project Title: Bermondsey TS Replace KSO Oil Circuit Breaker (53M1, 53M9 & 53M11)
Project Number: S13146
Project Year: 2015
Estimated Cost: $0.18

(i) Objective

The objective of this project is to replace the KSO oil circuit breakers 53M1, 53M9 and 53M11 at Bermondsey TS.

(ii) Scope of Work

TABLE 10: S13146 SCOPE OF WORK DETAILS

District Neighborhood	NORTH YORK
Station(s)	BERMONDSEY TS
Feeder(s)	53M1, 53M9 & 53M11

TABLE 11: S13146 ASSET REPLACED

Assets (Units)	2015
KSO Oil Circuit Breaker	3

(iii) Justification & Benefits

The 53M1, 53M9 and 53M11 KSO oil circuit breakers are in poor condition and are obsolete. Spare parts for this type of circuit breaker are no longer supported by manufacturers and, as a result, it is becoming difficult to keep the circuit breakers in good working condition. Replacement of the circuit breakers with a modern vacuum circuit breaker is necessary to mitigate reliability, environmental and safety risks, and possible collateral damage that could result from a potential catastrophic failure.

TABLE 12: BERMONDSEY TS CIRCUIT BREAKER 53M1, 53M9 & 53M11

Circuit Breaker Name	Connected Load (MVA)	No of Connected Customers	Age
53M1 CB	5.3	69	53
53M9 CB	6.0	22	53
53M11 CB	3.1	273	53

E6.15.7.1 S14052 Project Description

Investment Category: System Renewal Program: Circuit Breaker Renewal
Project Title: Finch TS Replace KSO Oil Circuit Breaker 55M24
Project Number: S14052
Project Year: 2015
Estimated Cost: $0.09

(i) Objective

The objective of this project is to replace the KSO Oil Circuit Breaker 55M24 at Finch TS.

(ii) Scope of Work

TABLE 13: S14052 SCOPE OF WORK DETAILS

District Neighborhood	FORMER NORTH YORK
Finch TS	FINCH TS
Feeder(s)	55M24

TABLE 14: S14052 ASSETS REPLACED

Assets (Units)	2015
KSO Oil Circuit Breaker	1

(iii) Justification & Benefits

The 55M24 KSO oil circuit breaker is in poor condition and is obsolete. Spare parts for this type of circuit breaker are no longer supported by manufacturers and, as a result, it is becoming difficult to keep the circuit breaker in good working condition. Replacement of the circuit breakers with a modern vacuum circuit breaker is necessary to mitigate reliability, environmental and safety risks, and possible collateral damage that could result from a potential catastrophic failure.

TABLE 15: FINCH TS CIRCUIT BREAKER 55M24

Circuit Breaker Name	Connected Load (MVA)	No of Connected Customers	Age
53M24	17.9	211	53

E6.15.7.1 S14056 Project Description

Investment Category: System Renewal
Program: Circuit Breaker Renewal
Project Title: Bathurst TS Replace KSO Oil Circuit Breaker 85M4.
Project Number: S14056
Project Year: 2015
Estimated Cost: $0.09

(i) Objective

The objective of this project is to replace the KSO Oil Circuit Breaker 85M4 at Bathurst TS.

(ii) Scope of Work

TABLE 16: S14056 SCOPE OF WORK DETAILS

District Neighborhood	FORMER NORTH YORK
Station(s)	BATHURST TS
Feeder(s)	85M4

TABLE 17: S14056 ASSETS REPLACED

Assets (Units)	2015
KSO Oil Circuit Breaker	1

(iii) Justification & Benefits

The 85M4 KSO oil circuit breaker is in poor condition and is obsolete. Spare parts for this type of circuit breaker are no longer supported by manufacturers and, as a result, it is becoming difficult to keep the circuit breaker in good working condition. Replacement of the circuit breakers with a modern vacuum circuit breaker is necessary to mitigate reliability, environmental and safety risks, and possible collateral damage that could result from a potential catastrophic failure.

TABLE 18: BATHURST TS CIRCUIT BREAKER 85M4

Circuit Breaker Name	Connected Load (MVA)	No of Connected Customers	Age
85M4	17.9	693	52

E6.15.7.1 S14057 Project Description

Investment Category: System Renewal
Program: Circuit Breaker Renewal
Project Title: Bathurst TS Replace KSO Breaker 85M2
Project Number: S14057
Project Year: 2015
Estimated Cost: $0.09

(i) Objective

The objective of this project is to replace the KSO Oil Circuit Breaker 85M2 at Bathurst TS.

(ii) Scope of Work

TABLE 19: S14057 SCOPE OF WORK DETAILS

District Neighborhood	FORMER NORTH YORK
Station(s)	BATHURST TS
Feeder(s)	85M2

TABLE 20: S14057 ASSETS REPLACED

Assets (Units)	2015
KSO Oil Circuit Breaker	1

(iii) Justification & Benefits

The 85M2 KSO oil circuit breaker is in poor condition and is obsolete. Spare parts for this type of circuit breaker are no longer supported by manufacturers and, as a result, it is becoming difficult to keep the circuit breaker in good working condition. Replacement of the circuit breakers with a modern vacuum circuit breaker is necessary to mitigate reliability, environmental and safety risks, and possible collateral damage that could result from a potential catastrophic failure.

TABLE 21: BATHURST TS CIRCUIT BREAKER 85M2

Circuit Breaker Name	Connected Load (MVA)	No of Connected Customers	Age
85M2	13.5	221	52

E6.15.7.1 S15103 Project Description

Investment Category: System Renewal
Program: Circuit Breaker Renewal
Project Title: Leslie TS Replace KSO Breaker 51M25
Project Number: S15103
Project Year: 2015
Estimated Cost: $0.30

(i) Objective

The objective of this project is to replace the KSO Oil Circuit Breaker 51M25 at Leslie TS.

(ii) Scope of Work

TABLE 22: S15103 SCOPE OF WORK DETAILS

District Neighborhood	FORMER NORTH YORK
Station(s)	LESLIE TS
Feeder(s)	51M25

TABLE 23: S15103 ASSETS REPLACED

Assets (Units)	2015
KSO Oil Circuit Breaker	1

(iii) Justification & Benefits

The 51M25 KSO oil circuit breaker is in poor condition and is obsolete. Spare parts for this type of circuit breaker are no longer supported by manufacturers and, as a result, it is becoming difficult to keep the circuit breaker in good working condition. Replacement of the circuit breakers with a modern vacuum circuit breaker is necessary to mitigate reliability, environmental and safety risks, and possible collateral damage that could result from a potential catastrophic failure.

TABLE 24: LESLIE TS CIRCUIT BREAKER 55M25

Circuit Breaker Name	Connected Load (MVA)	No of Connected Customers	Age
51M25	14.6	1,537	51

E6.15.7.1 S15104 Project Description

Investment Category: System Renewal
Program: Circuit Breaker Renewal
Project Title: Leslie TS Replace KSO Oil Circuit Breaker 51M27.
Project Number: S15104
Project Year: 2015
Estimated Cost: $0.30

(i) Objective

The objective of this project is to replace the KSO Oil Circuit Breaker 51M27 at Leslie TS.

(ii) Scope of Work

TABLE 25: S15104 SCOPE OF WORK DETAILS

District Neighborhood	FORMER NORTH YORK
Station(s)	LESLIE TS
Feeder(s)	51M27

TABLE 26: S15104 ASSETS REPLACED

Assets (Units)	2015
KSO Oil Circuit Breaker	1

(iii) Justification & Benefits

The 51M27 KSO oil circuit breaker is in poor condition and is obsolete. Spare parts for this type of circuit breaker are no longer supported by manufacturers and, as a result, it is becoming difficult to keep the circuit breaker in good working condition. Replacement of the circuit breakers with a modern vacuum circuit breaker is necessary to mitigate reliability, environmental and safety risks, and possible collateral damage that could result from a potential catastrophic failure.

TABLE 27: LESLIE TS CIRCUIT BREAKER 55M27

Circuit Breaker Name	Connected Load (MVA)	No of Connected Customers	Age
51M27	9.2	1,351	51

E6.15.7.1 S15105 Project Description

Investment Category: System Renewal
Program: Circuit Breaker Renewal
Project Title: Bathurst TS Re place KSO Oil Circuit Breaker 85M27.
Project Number: S15105
Project Year: 2015
Estimated Cost: $0.30

(i) Objective

The objective of this project is to replace the KSO Oil Circuit Breaker 85M27 at Bathurst TS.

(ii) Scope of Work

TABLE 28: S15105 SCOPE OF WORK DETAILS

District Neighborhood	FORMER NORTH YORK
Station(s)	BATHURST TS
Feeder(s)	85M27

TABLE 29: S15105 ASSETS REPLACED

Assets (Units)	2015
KSO Oil Circuit Breaker	1

(iii) Justificat ion & Benefits

The 85M27 KSO oil circuit breaker is in poor condition and is obsolete. Spare parts for this type of circuit breaker are no longer supported by manufacturers and, as a result, it is becoming difficult to keep the circuit breaker in good working condition. Replacement of the circuit breakers with a modern vacuum circuit breaker is necessary to mitigate reliability, environmental and safety risks, and possible collateral damage that could result from a potential catastrophic failure.

TABLE 30: BATHURST TS CIRCUIT BREAKER 85M27

Circuit Breaker Name	Connected Load (MVA)	No of Connected Customers	Age
85M27	8.4	1,443	45

E6.15.7.1 S15137 Project Description

Investment Category: System Renewal
Program: Circuit Breaker Renewal
Project Title: Bathurst TS Replace KSO Breaker 85M31.
Project Number: S15137
Project Year: 2015
Estimated Cost: $0.32

(i) Objective

The objective of this project is to replace the KSO Oil Circuit Breaker 85M31 at Bathurst TS.

(ii) Scope of Work

TABLE 31: S15137 SCOPE OF WORK DETAILS

District Neighborhood	FORMER NORTH YORK
Station(s)	BATHURST TS
Feeder(s)	85M31

TABLE 32: S15137 ASSETS REPLACED

Assets (Units)	2015
KSO Oil Circuit Breaker	1

(iii) Justification & Benefits

The 85M31 KSO oil circuit breaker is in poor condition and is obsolete. Spare parts for this type of circuit breaker are no longer supported by manufacturers and, as a result, it is becoming difficult to keep the circuit breaker in good working condition. Replacement of the circuit breakers with a modern vacuum circuit breaker is necessary to mitigate reliability, environmental and safety risks, and possible collateral damage that could result from a potential catastrophic failure.

TABLE 33: BATHURST TS CIRCUIT BREAKER 85M31

Circuit Breaker Name	Connected Load (MVA)	No of Connected Customers	Age
85M31	8.1	495	45

E6.16 Stations Control & Monitoring

TYPICAL RTUS AT ETOBICOKE STATIONS AND AT DOWNTOWN TORONTO SUBSTATIONS, RESPECTIVELY

E6.16.1 Summary

Program Description

The objective of the Stations Control and Monitoring program is to replace aging and obsolete remote terminal units (RTUs), install supervisory control and data acquisition (SCADA) systems at substations that currently do not possess SCADA capabilities, and upgrade obsolete pilot-wire relays and communication channels that supply large users.

RTUs, SCADA systems and pilot-wire configurations are tools that Toronto Hydro uses to clear and manage faults. Faults are hazardous if not cleared, as they can damage distribution equipment (prolonging and complicating repairs), customer equipment (possibly resulting in an outage to the customer), and Toronto Hydro's station equipment (which can result in long duration outages to large numbers of customers). Faults can also potentially set fire to the affected equipment. To prevent these serious risks, Toronto Hydro's distribution system must be capable of clearing all potential faults as designed.

This program addresses the following issues with the aforementioned assets.

- Existing RTUs and their associated communication systems are past their useful lives of 22.5 years and are now functionally obsolete. Spare parts for the existing RTUs are no

longer available in the market. With increasing RTU failures every year, the maintenance of these devices is becoming more difficult and expensive.

- The electromechanical relays and copper communication channels used for highly loaded customers with pilot-wire configurations are not technologically obsolete, lacking the capability to monitor the integrity of supply to pilot-wire customers outside of Toronto Hydro's equipment – a deficiency that can result in unnecessary outages or damage to customer equipment. The existing relays are also functionally obsolete, as the original suppliers no longer manufactures spare parts and/or new replacement parts for electromechanical relays. Another major disadvantage of electromechanical relays is the lack of accuracy of current and voltage measurements, which makes it difficult to recognize fault conditions within tight boundaries.

- Many of Toronto Hydro's municipal substations in Scarborough area are not connected to the SCADA system. These substations are technologically obsolete without the presence of SCADA connection. This prevents control room operators from having access to the real-time information and operation of the substation, such as breaker control, remote switching capabilities, alarm status and other distribution system parameters which can be analyzed and optimized to improve system efficiency.

Table A summarizes the anticipated benefits associated with the Stations Control and Monitoring program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	- Reduce the duration of station-related outages and the risk of extended outages - Allow customers to connect a Human Machine Interface (HMI) to the relays for data acquisition and load monitoring features
Reliability	- Reduce the risk of RTU failure and avoid potential prolonged station related outages - Enable Toronto Hydro to monitor and control feeder loading - Provide the ability to monitor the status of customer breakers, enabling Toronto Hydro to take immediate actions against pilot-wire faults
Efficiency	- Enable remote troubleshooting and switching capabilities that can result in labour cost savings by eliminating the need for station crews to go on-site to identify problems and perform manual switching - Automatic switching capability can help achieve maintenance efficiency by reducing the number of maintenance crew hours needed to complete the same work through a more effective

	streamlining of functions ƒ Can reduce costs associated with repairing obsolete RTUs and their supporting communication channels ƒ Allows control room operators to optimize power distribution system and improve data analysis through data obtained from SCADA system
Safety	ƒ Enhance safety by reducing the crews' exposure to safety hazards when they perform manual switching to restore power to customers
Cyber-security	ƒ New SCADA devices are built with stronger cyber security features than those currently deployed

Program Drivers

The trigger and secondary drivers for this program are summarized in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Large number of RTU assets are past their useful lives ƒ Replacement parts for RTUs and electromechanical relays are no longer available from the original manufacturer ƒ SCADA installations are required at Scarborough substations in order to bring these stations into alignment with modern control and monitoring standards
Secondary Drivers	**Reasoning**
Reliability	ƒ RTU failures have increased substantially over the past decade. ƒ SCADA technology is currently lacking at Scarborough substations. CHI would be reduced significantly if SCADA technology was introduced. ƒ Electromechanical relays used in current pilot-wire configuration do not have customer circuit breaker monitoring abilities, which may result in unnecessary customer outages.
Cyber Security	ƒ Cyber threats increasingly become more sophisticated for the existing SCADA system. ƒ Potential risk of compromising the RTU or communication channel device which can allow: shutting down entire or portion of a substation, stealing or altering metering data.

Preferred Alternative

Toronto Hydro considered the following options for addressing the end-of-life and obsolete assets in this program:

(1) Continue a "run to failure" approach where existing MOSCAD RTUs and associated DARCOM radio systems at Etobicoke substations and DACSCAN MDO-11 type RTUs in downtown Toronto are replaced only when the system completely fails.

(2) Replace or Install RTU and Communication System/Upgrade Pilot-Wire Relays

While the continuation of the status quo would allow Toronto Hydro to defer asset replacement temporarily, Toronto Hydro would incur additional costs to maintain these legacy units in the interim. Option II is the preferred option, as it cost-effectively addresses the failure risks associated with these obsolete communication and control assets while maximizing the value and performance of existing stations assets in Scarborough.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $0.1 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.16.7). Accounting for capital program costs, the first year's activities (approximately $80,000 in expenditures in first year) deliver a positive NPV of $0.02 million, confirming the economic prudence of the investments (see Section E6.16.7).

Timing and Pacing

Investment needs in this program did not arise before 2012 and thus, no projects were implemented in 2010 and 2011. Capital spending from 2012 to 2014 was fairly low because only five substations were targeted for RTU replacement. Since this program was a new initiative, the first of the five projects were used to adequately train Toronto Hydro personnel to quickly and efficiently complete the remaining RTU replacement projects. For this reason, the first project was designed to take longer to complete than the others. As a result, the first project was completed in 2013, and the remaining four are in-progress to be completed by the end of 2014.

Table C summarizes the historical and forecasted spending for this program.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0.12	0.46	0.24	0.08	0.94	1.11	1.49	1.44

For a detailed discussion of the pacing of investments in this program over the 2015-2019 period, please refer to Section E6.16.4

E6.16.2 Program Description

Toronto Hydro's substations feature control and monitoring assets that are essential to the efficient and reliable delivery of electricity. In particular, Toronto Hydro uses the supervisory control and data acquisition (SCADA) system to support the reliable functioning of substations and pilot-wire protection schemes (explained in detail in section E6.16.2.2 below) to provide a continuous supply of electricity to very large individual customers.

SCADA equipment automates the monitoring, command and control functions of critical substation equipment, enabling Toronto Hydro to remotely troubleshoot problems and respond to outages at substations. This is achieved by connecting station power equipment to remote terminal units (RTUs) via communication channels.

The pilot-wire feeder configuration automates feeder monitoring and troubleshooting to protect distribution equipment and to provide continuous load supply to large customers in the event of feeder faults. This configuration requires a pair of relays on each feeder to operate. Similar to RTUs, the relays are connected via communication channels. The relays and communication channels are the components responsible for the "intelligence" of the protection used in pilot-wire configuration. Without the proper functioning of the relays and communication channels on pilot-wire feeders, faults will not clear as intended.

The objective of the Stations Control & Monitoring program is to replace aging and obsolete remote terminal units (RTUs), install supervisory control and data acquisition (SCADA) systems at substations that currently do not possess SCADA capabilities, and upgrade obsolete pilot-wire relays and communication channels that supply large users.

Toronto Hydro plans to invest an estimated $5.05 million over the 2015 to 2019 period in this program. Table 1 summarizes the number of assets that are forecasted for replacement or installation over the 2015 to 2019 period.

TABLE 1: ASSETS TO BE REPLACED/INSTALLED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Etobicoke RTU Replacement	2	5	5	5	5	22
Scarborough SCADA Installation	0	2	2	2	1	7
Downtown RTU Replacement	0	1	1	2	2	6
Pilot-wire Relay Upgrade	0	6	10	12	12	40

Figure 1 shows a map of all the stations which are targeted by the Station Control & Monitoring program during the 2015-2019 period.

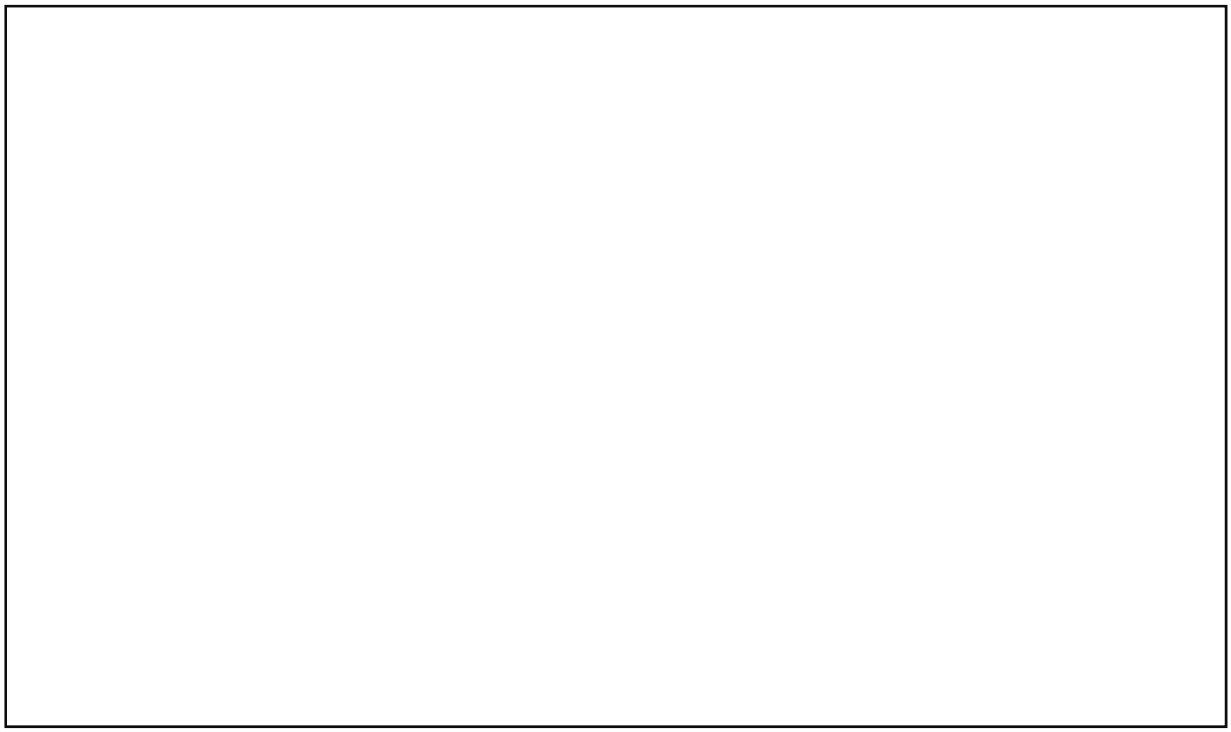


FIGURE 1: MAP OF STATION LOCATIONS SELECTED FOR THE 2015-2019 STATION CONTROL & MONITORING PROGRAM

The following sections describe the above mentioned activities in detail.

E6.16.2.1 SCADA RTU System

RTUs, SCADA systems and pilot-wire configurations are tools that Toronto Hydro uses to clear and manage faults. Faults are hazardous if not cleared, as they can damage distribution equipment (prolonging and complicating repairs), customer equipment (possibly resulting in an outage to the customer), and Toronto Hydro's station equipment (which can result in long duration outages to large numbers of customers). Faults can also potentially set fire to the affected equipment. To prevent these serious risks, Toronto Hydro's distribution system must be capable of clearing all potential faults as designed.

The Role of RTUs in the SCADA system

RTUs are installed at each monitored substation location. These units use a data concentrating device that connects to device sensors and relays to monitor and gather data on various types of substation equipment, including switchgear, circuit breakers and transformers. To be useful, this data must be communicated to the central SCADA console in Toronto Hydro's control room for real-time analysis. An RTU enables the communication channels to read the data that is then transmitted to the SCADA console. It also allows the central SCADA console to remotely control substation equipment by activating commands issued by the SCADA console to the station equipment. In the event of an outage, the SCADA system's data collection capabilities can help control room operators quickly identify the exact location of the outage without waiting for customer calls. The SCADA system then sends commands to SCADA-enabled switches to help operators isolate the outage and open adjacent automatic switches to reroute power quickly to unaffected sections. Absent a SCADA system, isolating the outage and rerouting power involves a time-consuming visual inspection by a line worker in the field to identify the exact nature and location of the problem.

Upgrading Obsolete RTUs

Toronto Hydro's existing station SCADA infrastructure includes two types of RTUs: Motorola SCADA (MOSCAD) RTUs at Etobicoke municipal substations and Motorola DACSCAN MDO-11 RTUs at downtown Toronto transformer substations, as illustrated in Figures 2 and 3, respectively. The different types of assets are a residual result of the amalgamation of Toronto Hydro and neighbouring utilities.

FIGURE 2 AND FIGURE 3: TYPICAL RTUS AT ETOBICOKE STATIONS AND AT DOWNTOWN TORONTO SUBSTATIONS, RESPECTIVELY

These two types of RTUs and their associated communication systems are past their useful lives of 22.5 years and are now functionally obsolete. Spare parts for the existing RTUs are no longer available in the market. With increasing RTU failures every year, the maintenance of these devices is becoming more difficult and expensive.

Aside from the current implementation becoming functionally obsolete, there are number of reliability and security issues associated with the RTU, including cyber security risks. As technology throughout the world continues to advance, and the level of technology in obsolete RTUs remains constant, it is becoming easier for cyber criminals to undermine the security of Toronto Hydro's existing obsolete RTUs. A successful cyber attack can cause significant damage to the utility's grid.

Toronto Hydro proposes to address these problems through a proactive RTU replacement program. Toronto Hydro's proposed solution is to replace the existing RTUs and supporting radio

communication channels at Etobicoke municipal substations and replace the obsolete RTUs at downtown Toronto transformer substations.

Expanding the SCADA System to Scarborough Municipal Stations

Many of Toronto Hydro's municipal substations in Scarborough area are not connected to the SCADA system. These substations are technologically obsolete without the presence of SCADA connection. This obsolescence prevents control room operators to have any access to the real-time information and operation of the substation such as breaker control, remote switching capabilities, alarm status and other distribution system parameters which can be analyzed and optimized to improve system efficiency. Currently, SCADA operators rely on customer calls to be made aware of any customer outages as a result of a failure at a non-SCADA substation. Toronto Hydro dispatches field crews to go on-site to perform extensive troubleshooting to resolve the problem. As a result, Toronto Hydro is unable to provide acceptable service to customers.

In addition to technological obsolescence, there are number of safety and efficiency issues associated with the non-SCADA substations. Station crews perform manual switching to isolate the problem during a customer outage. Manual switching is performed on live equipments and thus poses unforeseen safety hazards to station crews. Moreover, electrical distribution tasks such as manual switching or station maintenance takes longer and costs more without SCADA connection since remote operation is not available.

Toronto Hydro plans to mitigate these problems by expanding the existing SCADA system to non-SCADA Scarborough municipal substations.

E6.16.2.2 Pilot-Wire System

Pilot-wire configuration is a special power supply and protection scheme for individual customers whose load demand is 10 MVA or higher. Customers served by the pilot-wire configuration are generally those that cannot afford power outages for any period of time, like hospitals or large financial institutions. If the pilot-wire relay and communications equipment fails, a customer may experience an unnecessary outage and/or equipment damage.

Unlike the RTU system, the pilot-wire configuration is composed of several discrete components. As a result, understanding the pilot-wire system requires some background information. This section describes the composition of the pilot-wire system and its operation.

Pilot-wire Background

Pilot-wire configuration is made up of six basic components:

(1) feeders,

(2) current transformers (CTs),

(3) potential transformers (PTs),

(4) relays,

(5) communication channels, and

(6) circuit breakers (CBs).

A schematic diagram of the configuration is shown in Figures 4 and 5. Every pilot-wire configuration has at least two or more feeders for each customer, where one feeder continuously supplies electricity while the remaining feeder(s) act as backup(s). With this design, if one feeder experiences a fault, the customer will not experience a power interruption since there is at least one other feeder to continue supplying the customer. The feeders are the only components of pilot-wire configuration responsible for supplying customers with electricity; all other components are part of the protection scheme.

FIGURE 4: SIMPLIFIED OVERVIEW OF THE ARRANGEMENTS OF ELEMENTS IN PILOT-WIRE PROTECTION

FIGURE 5: TWO PILOT-WIRE LINES PER FEEDER BETWEEN THE SUPPLYING STATION AND CUSTOMER

Each feeder has two CTs and two PTs. A set, made up of one CT and one PT, is placed at the start of the feeder in one of Toronto Hydro's substations and the other set is placed at the end of the feeder in the customer's electrical room. The CTs and PTs are the measuring tools of the

protection system; the CTs measure the current on each feeder and the PTs measure the voltage on each feeder. The CTs and PTs then pass on their current and voltage measurements to the relays.

There are two relays for each feeder; and like the CTs and PTs, one relay is placed at the start of the feeder in one of Toronto Hydro's substations and the other relay is placed at the end of the feeder in the customer's electrical room. The relays are the "intelligence" of the protection system, because they are the components that recognize a fault in the feeder by analyzing the current and voltage measurements within a protection zone. This protection zone is the feeder region between Toronto Hydro's circuit breaker and customer circuit breaker. A pair of relays recognizes fault conditions by communicating with one another using the communication channel.

Each feeder is given a pair of communication channels that connect the pair of relays (see E6.16-2). The communication channel allows the pair of relays to communicate with one another. One communication channel is called a "main" and the other is called an "alternate".

The relays recognize a fault condition by the differential principle: if the pair of relays does not see the same measurements, then there is a fault. Each relay is connected to its own CT and PT, and using the communication channel, the relays compare their current and voltage measurements with one another. If there is a difference in the measurement seen by the relays (hence the "differential" principle), then there is a fault somewhere in the protection zone. If the relays recognize a fault condition in the feeder they are monitoring, then they will signal the feeder's circuit breakers to open (or "trip").

There are two circuit breakers in line with each feeder: one at the start of the feeder and one at the end of the feeder. The purpose of the circuit breakers is to stop electrical power flow through the feeder. When the relays detect a fault, they will signal the circuit breakers to open, which will completely isolate the feeder electrically and stop the fault. It is necessary that both circuit breakers open and not just the circuit breaker located at Toronto Hydro's substation; because otherwise, electricity will backflow from the customer into the faulting feeder, and the fault will continue.

Pilot-wire Upgrades

Toronto Hydro historically used now-obsolete GE Westinghouse CPD, Alston MBCI and ABB HCB or HCB-1 type electromechanical relays and copper communication channels for highly loaded customers with pilot-wire configurations. These technologically obsolete assets lack the

capability to monitor the integrity of supply to pilot-wire customers outside of Toronto Hydro's equipment – a deficiency that can result in unnecessary outages or damage to customer equipment. The existing relays are also functionally obsolete, as the original suppliers no longer manufactures spare parts and/or new replacement parts for electromechanical relays. Another major disadvantage of electromechanical relays is the lack of accuracy of current and voltage measurements, which makes it difficult to recognize fault conditions within tight boundaries.

Toronto Hydro proposes to address these problems through a proactive pilot-wire relay upgrade program. Toronto Hydro's proposed solution is to replace the existing electromechanical relays and the associated copper communication lines with microprocessor relays and fiber optic communication lines, respectively.

E6.16.2.3 Program Benefits

This program provides value to customers by reducing the duration of station-related outages and the risk of extended outages. These extended outages may occur as a result of SCADA system inoperability at stations or due to technical obsolescence of electromechanical relays as part of pilot-wire configuration. From 2008 to 2012, SCADA-enabled substations were, on average, responsible for far fewer customer hours interrupted (CHI) than stations without SCADA capabilities. Figure 6 and Figure 7 show a yearly comparison of CHI of stations with and without SCADA technology in the Etobicoke and downtown Toronto area, respectively. A significant contributor to this is the remote monitoring and control functions that SCADA devices provide to system controllers. SCADA system controllers can identify when an outage occurs and take immediate steps to address the problem, avoiding the need to wait for notification from an affected customer, as well as the need to send a crew to the substation to take remedial action. This typically reduces the amount of time that customers are without power during a station-related outage from three hours to thirty minutes.

Feeders with pilot-wire configurations supply individual customers whose load demands are much higher than average (10 MVA or more). Typically, the continued functioning of these customers is vital for keeping the City of Toronto running smoothly. For example, some pilot-wire customers include: hospitals, sewage treatment plants, public transit, large office towers, and stadiums. Generally, a power outage experienced by any of these customers has a significant and noticeable impact on the City of Toronto. This program is expected to enable faster relay operation and allow data acquisition. Customers may also be able to connect a HMI to the relays and use data acquisition and monitoring features for energy management purposes.

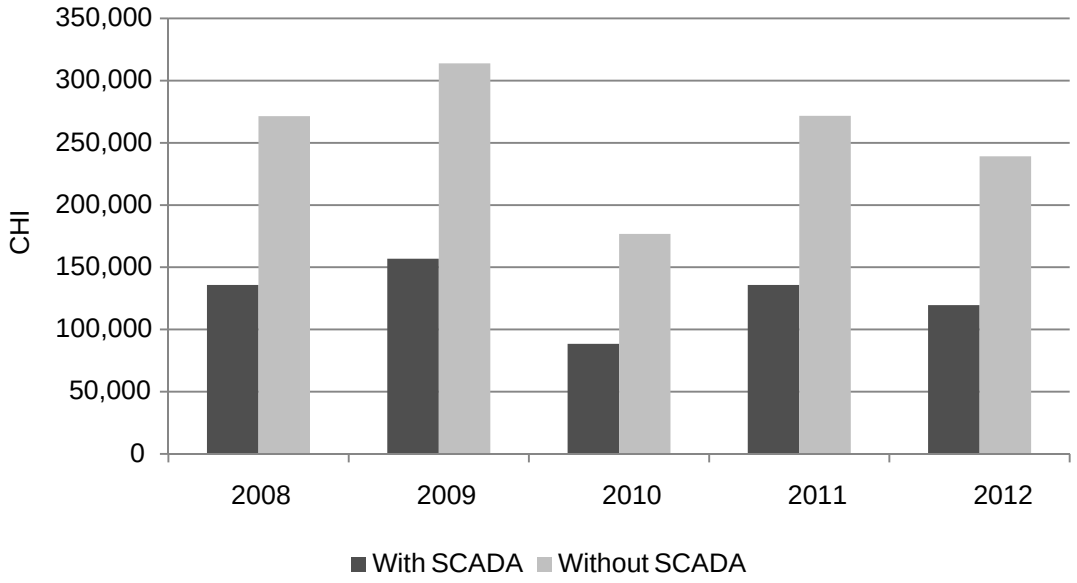


FIGURE 6: CHI WITH AND WITHOUT SCADA TECHNOLOGY IN ETOBICOKE SUBSTATIONS FROM 2008 TO 2012

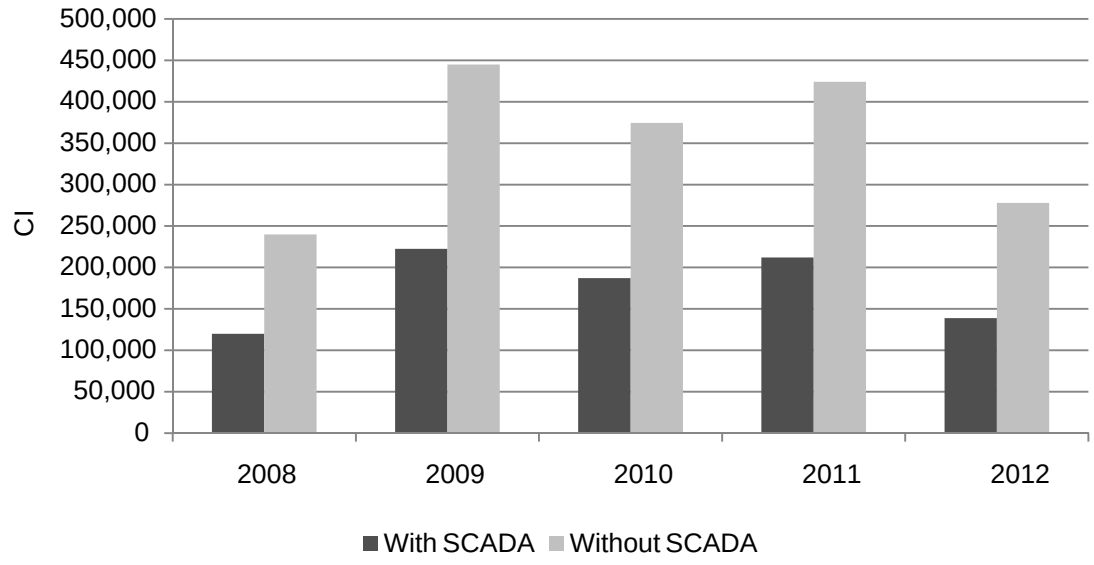


FIGURE 7: CHI WITH AND WITHOUT SCADA TECHNOLOGY IN DOWNTOWN TORONTO SUBSTATIONS FROM 2008 TO 2012

Investments made in this program are expected to improve reliability by reducing the risk of the RTU failure, which renders the SCADA system inoperative, and prolongs the duration of station-related outages.

By the end of 2015, all the RTU devices deployed at Toronto Hydro substations will have reached the end of their useful lives. Not coincidently, these assets have become more prone to failure in recent years. Figure 8 shows the number of RTU failures at Toronto Hydro as they age from 11 years to 19 years.

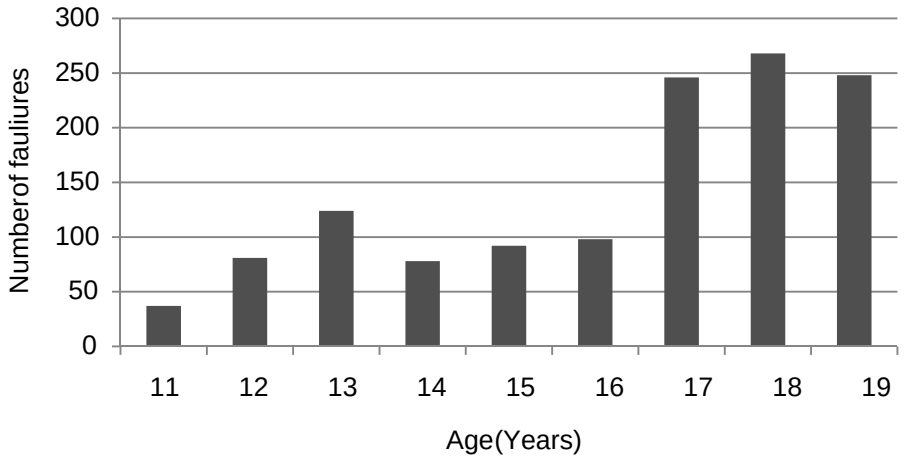


FIGURE 8: NUMBER OF RTU FAILURES WITH INCREASING AGE FROM 11 YEARS TO 19 YEARS

The failure rate will continue to increase in the absence of a replacement plan, which will result in a greater need for spare parts. But since the original manufacturer of the existing RTU devices no longer provides support and spare parts are no longer available in the market, maintaining these assets will become increasingly difficult for Toronto Hydro.

Toronto Hydro expects this program to improve reliability in the Scarborough area by enabling SCADA technology to be installed at a number of stations that currently do not have these capabilities. With this technology, Toronto Hydro will able to monitor and control feeder loading by re-routing electrical supply faster and more efficiently during planned outages and emergency situations

This program also plans to replace current electromechanical relays with digital relays, which will provide Toronto Hydro with the ability to monitor the status of customers' circuit breakers. This new ability allows Toronto Hydro to react to any pilot-wire faults (such as in Section E6.16.3.2ii) before an outage can occur. In this way, customers are likely to experience a greater level of reliability through pilot-wire upgrades.

The Stations Control & Monitoring program is expected to result in efficiencies relating to:

- labour cost,
- maintenance cost,
- optimize power distribution system, and
- maintain system parameters at desired level.

Toronto Hydro relies on manual labour to perform many of the electrical distribution tasks at sub-stations without SCADA capabilities. By replacing the obsolete RTUs and connecting additional substations to the SCADA system, Toronto Hydro expects to be able to automate many of the tasks such as problem troubleshooting and station equipment maintenance.

Remote troubleshooting allows SCADA console operators to identify the exact location of the outage and perform automatic switching to isolate the outage. Task automation is expected to result in labour cost savings by preventing the need for station crews to go to site and perform lengthy inspections and manual switching.

Automatic switching capability achieved through SCADA system installation is expected to help improve maintenance efficiency by reducing maintenance crew hours to complete the same work through harmonization of tasks and elimination of redundancies. As a result, planned maintenance outages and related maintenance cost would decrease. In addition, maintenance cost savings are also derived from SCADA monitoring data such as voltage deviation, hours of operation, number of breaker closures and transformer temperatures to extend useful life of the station assets. The analysis of these data enables Toronto Hydro to make adjustments and corrections, which may prevent an outage from occurring.

Toronto Hydro also expects this program to reduce the costs associated with repairing RTUs and their supporting communication channels. When obsolete RTUs fail, Toronto Hydro has to procure specialized support to repair them because spare parts and manufacturers' support are no longer available. There might be cases where repairing the asset would not work and

replacement is the only option. In this case, a like-for-like replacement would not be possible since the existing assets are obsolete and no longer available in the market. The only remaining option is replacing the existing asset with the new modern RTUs and communication channels. This requires planning and available spare resources. However, carrying out a big replacement job on a reactive basis is not feasible due to limited resource availability, difficulty of new asset procurement on short notice and system upgrade requirements to make the new asset compatible with the existing equipment. This program can help prevent the need for such expensive reactive replacement work.

SCADA system provides powerful analytical tools to operators that give real-time view into operations. This allows operators to optimize power distribution system in order to maximize efficiency. SCADA system also helps with data management to simplify data analysis. These recorded data provide comprehensive load profiles and growth planning to meet future demands. Similarly, microprocessor relays are capable of storing important data related to pilot-wire, which can be communicated to SCADA system for further analysis.

Furthermore, the ability to analyze trends and recorded historical data of substation operation helps maintain desired power factors, voltage levels and other system parameters at desired levels. With the evolution of power distribution system, these parameters are becoming more complex and difficult to maintain. Modern SCADA systems are developed to keep up with the increasing complexity that can be used to improve operational efficiency of substations.

SCADA system enhances safety of employees working in the distribution system, as they do not have to be physically exposed to electrical and operational hazards when they are troubleshooting and performing switching operations to re-route or restore power to a customer. Safety and operational hazards associated with not having a SCADA system are further magnified when crews have to set-up traffic protection in different types of weather just to be able to operate a switch. Switches, at times, are hard to operate causing muscular strain/ stress on workers legs, shoulders, back and hands. The SCADA system mitigates these safety risks by reducing the exposure of personnel to manual switching.

RTUs, communication channels and relays are all connected to a single SCADA console from where they are monitored and operated. Cyber security breaches of a SCADA system could result in wide-ranging adverse impacts. If a SCADA system is hacked, it may result in failure to transmit timely accurate commands to substation power equipment. As a result, the station equipment may fail or completely shut-down and compromise the safety of personnel working in

the station vicinity. Modern technologies in the new RTUs and communication channel are more resilient to cyber security risks. They help mitigate SCADA system vulnerabilities such as RTU spoofing or intruder eavesdropping. RTU spoofing involves intruders sending bogus status before a valid RTU response such as changing threshold of safety parameters. This can result in unpredictable outcomes including loss of confidential information, system disruption, or catastrophic failure. With a more secured system in place, electronic intruders will be less likely to be able to exploit vulnerabilities and gain access to SCADA system where they can gather sensitive and confidential information such as protection settings, circuit breaker position, metering data and more.

Table 2 summarizes the anticipated benefits of this program.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Reduce the duration of station-related outages and the risk of extended outages ƒ Enable faster relay operation to customers ƒ Allow customers to connect a Human Machine Interface (HMI) to the relays for data acquisition and load monitoring features ƒ The difference in the cost of ownership between existing and renewed assets (ΔCOO) for the first year of the program is $0.1 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.16.7). ƒ Accounting for capital program costs, the first year's activities (approximately $80,000 in expenditures in first year) deliver a positive NPV of $0.02 million, confirming the economic prudence of the investments (see Section E6.16.7).
Reliability	ƒ Reduce the risk of RTU failure and avoid potential prolonged station related outages ƒ Enable Toronto Hydro to monitor and control feeder loading ƒ Provide the ability to monitor the status of customer breakers, enabling Toronto Hydro to take immediate actions against pilot-wire faults
Efficiency	ƒ Enable remote troubleshooting and switching capabilities that allow labour cost savings by eliminating the need for station crews to go on-site to identify problems and perform manual switching ƒ Automatic switching capability enables maintenance efficiency by reducing the number of maintenance crew hours needed to complete the same work through a more effective streamlining of functions ƒ Analysis of SCADA monitoring data can help Toronto Hydro make adjustments and corrections, which may result in corrective maintenance cost savings ƒ Reduce costs associated with repairing obsolete RTUs and their

	supporting communication channels ƒ Allow control room operators to optimize power distribution system and improve data analysis through data obtained from SCADA system ƒ Help improve operational efficiency of substations by keeping up with the increasing complexity of maintaining desired substation system parameters such as power factors and voltage levels
Safety	ƒ Enhance safety by reducing the crews' exposure to safety hazards when they perform manual switching functions
Cyber-security	ƒ New SCADA devices are built with stronger cyber security features than those currently deployed

E6.16.3 Why the Program is Needed

This renewal program is needed to address several obsolescence issues affecting the reliability of stations control and communications infrastructure. The RTU equipment replaced in this program is no longer produced by the manufacturer, meaning that spare parts are not available and the supplier no longer provides operational support. Renewal of pilot-wire relay and communications equipment is needed as the equipment has aged and is technically obsolete. In addition, Toronto Hydro has substations in the Scarborough that lack SCADA capabilities. Automating the electrical distribution system at these Scarborough substations by the installing SCADA system is expected to improve system reliability, minimize power disruptions, and reduce outage times for customers.

E6.16.3.1 Program Drivers

Table 3 presents the trigger and secondary drivers for replacing and installing RTUs and pilot-wire electromechanical relays.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Large number of RTU assets are past their useful lives ƒ Replacement parts for RTUs and electromechanical relays are no longer available from the original manufacturer ƒ SCADA installations are required at Scarborough substations in order to bring these stations into alignment with modern control and monitoring standards
Secondary Drivers	Reasoning

Reliability	ƒ RTU failures have increased substantially over the past decade. ƒ SCADA technology is currently lacking at Scarborough substations. CHI would be reduced significantly if SCADA technology was introduced. ƒ Electromechanical relays used in current pilot-wire configuration do not have customer circuit breaker monitoring abilities, which may result in unnecessary customer outages.
Cyber Security	ƒ Cyber threats increasingly become more sophisticated for the existing SCADA system. ƒ Potential risk of compromising the RTU or communication channel device which can allow: shutting down entire or portion of a substation, stealing or altering metering data.

E6.16.3.1.1 SCADA RTU System

The trigger driver for this program is functional obsolescence. MOSCAD RTUs – along with the supporting communication channel – DACSCAN MDO-11 type RTUs are legacy equipment. The manufacturer of these units has discontinued production and no longer supply spare parts, which will soon be needed given that all RTUs will have passed their end of life by the end of 2014. Additionally, these manufacturers no longer supply the associated software, firmware, vulnerability patches or technical support for installed units. It is very expensive to custom make or track down rare parts for Toronto Hydro's equipment compared to purchasing mass-produced parts provided by manufacturers.

Toronto Hydro has moved towards integration of SCADA into substations to automate electrical distribution system. Scarborough substations without SCADA capabilities are now technologically obsolete and unable to provide acceptable service to customers. Power equipment and alarms at these stations cannot be remotely monitored, which would otherwise allow SCADA operators to quickly spot and address operational problems. Currently, Toronto Hydro relies on customer calls to be made aware of any customer outages as a result of a failure at these substations. Toronto Hydro also has monthly inspections and station crews ready to be dispatched to mitigate the risks associate with having no real-time monitoring capabilities. Moreover, in order to balance and co-ordinate Toronto Hydro's system, the control room must be aware of the load demand at each station. Without access to real-time load data at substations, controllers must send station personnel to determine the load on site at a specific time.

Intelligent Electronic Devices (IEDs) are critical SCADA components within Toronto Hydro's distribution system. An IED is a SCADA system component that collects information from sensors

and power equipment within SCADA operations. When an IED senses a fluctuation of these values from the desired range, it activates control function to correct the problem and bring the value to normal range. RTUs are interfaced with IEDs to collect the data and pass it to the master SCADA console. Since IEDs serve a number of important roles in the SCADA system, it is important to ensure that they are operating properly. Hence, RTUs monitor these IEDs and report alarm information to the master SCADA console to notify operators of any problem.

A physical cable connection is necessary to connect the existing RTUs to multiple newer IEDs at a station. Terminating multiple cables at a single RTU is labour intensive, costly and difficult to troubleshoot. The RTU models currently in use lack the ability to feasibly interface with newer IEDs.

Current RTUs cannot support modern communication channels and protocols. Legacy protocols used by the older RTUs have limitations that do not allow them to take advantage of the quantity, resolution and accuracy of modern data acquisition. This limits the existing SCADA system to improve its data security and data integrity in the future.

RTU failure rates have increased over the past eight years and are expected to continue to increase as the assets age. When a RTU fails, the communication between the central SCADA console and the substation is broken. In that situation, a substation with or without SCADA capabilities suffer the same consequences. Without SCADA control and monitoring, Toronto Hydro system control personnel cannot access critical information about the station assets, including alarms for circuit breaker trips, loss of transformer voltage, cable overloading, loss of battery power, and transformer pressure, oil level and temperature. This lack of real-time information can prolong the duration of outages associated with station asset failures. For example, at a substation without SCADA capabilities, the typical restoration time for a feeder outage is three hours because station field crews must attend the affected location to identify the problem and perform manual switching to end the outage. As a result, station crews are exposed to safety hazards associated with manual switching while trying to restore power to customers. With a SCADA system, the restoration time can be reduced to as little as thirty minutes by utilizing the remote diagnostic and switching capabilities of the system. Moreover, a SCADA system also enhances the safety of the station crews by reducing the need to perform manual switching.

Cyber security threats are another risk associated with obsolete RTU and its supporting communication channel design. As technology advances, cyber threats become increasingly

sophisticated, and as a result, obsolete RTUs and its communication system currently used by Toronto Hydro becomes more susceptible to cyber attacks. If an electronic intruder gains access to substation control or protective system they will be able to shut down the substation or any portion of the subsystem controlled by the compromised device and, steal or alter metering data gathered by SCADA system. Modern technologies in the new RTUs and supporting communication channel are equipped with complex encryption and additional safeguards, which makes them more resilient to cyber security risks. Installing the modern RTU devices and supporting communication channels will help Toronto Hydro to mitigate the risk of electronic intrusion and other system vulnerabilities.

E6.16.3.1.2 Pilot-Wire System

The trigger driver for this program is functional obsolescence. CPD, MBCI and HCB or HCB-1 type electromechanical relays are legacy equipment. The manufacturer of these units has discontinued production and no longer supplies spare parts, associated software, firmware, vulnerability patches or technical support for installed units. It is very expensive to custom make or track down rare parts for Toronto Hydro's equipment compared to purchasing mass-produced parts provided by manufacturers.

Electromechanical relays are technologically obsolete, consisting of mechanical parts that require routine calibration to stay within intended tolerances. They are not capable of providing many important features such as storage of fault current data and integration with other Intelligent Electronic Devices (IEDs).

Forty two percent (42%) of the pilot-wire distribution feeders in service are equipped with the GE Westinghouse CPD relays and one percent (1%) with Alston MBCI relay, while fifty one percent (51%) have the ABB HCB or HCB-1 relay. None of these relay models are equipped with real-time pilot-wire supervision. This lack of supervision can increase the risk of a customer outage (See Section E6.16.3.2ii). When modern pilot-wire equipment is installed, Toronto Hydro will be able to monitor the load of highly loaded customers, and make necessary provisions to minimize outage risks should part of the protection system fail. Accordingly, renewal of pilot-wire relay and communications channel will increase Toronto Hydro's reliability to its customers.

E6.16.3.2 Asset Details

(i) Asset Lifecycle

RTUs have a useful life of 22.5 years. The DACSCAN MDO-11 RTUs were installed in 1987. The MOSCAD RTUs and DARCOM radio communication system were installed in 1993. By the end of 2015, all of the RTUs will have reached the end of their useful lives.

The life expectancy of electromechanical relays is assumed to be approximately 30 years based on industry averages. The selected GE Westinghouse CPD, Alston MBCI and ABB HCB or HCB-1 type electromechanical relays and copper communication channel on pilot-wire feeders will be 30 years old by the end of 2015. The original manufacturer of these devices no longer produces them and thus, spare parts are not available in the market. While the HCB-1 relay model can still be custom made through ABB, the cost is substantially higher in comparison to a digital relay. The existing electromechanical relays are both functionally and technologically obsolete and prone to age related wear and tear.

The Stations Control & Monitoring program proposes to proactively replace these devices, as opposed to running them to failure, to mitigate the risk of equipment failure, prolonged outage duration and increased maintenance cost.

(ii) Asset Failure Impacts

The RTU is an integral part of the SCADA system. When an RTU fails, the communication link between the central SCADA console and Toronto Hydro substation assets is disrupted, causing power system controllers at the control centre to lose monitoring and controlling capabilities over Toronto Hydro's substation assets. Without the SCADA system in place, Toronto Hydro relies on customer calls to address feeder outages. Since Toronto Hydro personnel need to perform manual switching instead of remote switching to troubleshoot the problem, restoration time during a feeder outage increases from an average of thirty minutes to three hours. Since automatic switching eliminates the need for station crews to travel, SCADA installation will reduce CO_2 emission from trucks, ease traffic congestion as a result of vehicles being taken off the road and avoid many roadways blocking that is required to allow safe access to switching locations.

The pilot-wire relays and communication cables are vital components used for the protection of customer feeders, as described at the start of Section E6.16.3.2. When relays fail, circuit breakers aren't opened during a fault, which can potentially result in damage to feeders supplying customers and even customer equipment. If the communication channel between the relays fails,

then the relays are unable to communicate with each other, and this can also result in improper functioning of the circuit breakers. In worst-case scenario, the feeder fault can circle back to the station bus and take it offline. The consequences of such a scenario could be significant, resulting in a loss of load of up to 72MVA and thousands of customers.

In October 2013, electromechanical relays on a pilot-wire circuit failed to operate, which resulted in a four hour outage at one of the TD buildings located in the financial district of Toronto. The outage was the result of an accidental cut of the pilot-wire cable during a construction job in the City of Toronto. This customer was supplied by two feeders from Windsor Transformer Station (TS). When the relays lost communication with one another, the circuit breaker of one feeder opened on the customer side, but not at the supplying station. This left the customer to be supplied by only one feeder. Since the circuit breaker at the station did not open and Toronto Hydro does not have monitoring capabilities over customer breakers, Toronto Hydro's Control Room was unaware that the customer was being fed by one feeder instead of the usual two. Eventually, the second feeder supplying the customer failed while troubleshooting the communication channel, initiating the power outage. This outage could likely have been prevented if Toronto Hydro had monitoring capabilities of the customer's circuit breaker through the relays.

In the example above, the affected customer was a critical institution which is fed about 5 MVA of load. Multiple major businesses reside and operate from this building and cannot afford to experience an outage for any period of time.

E6.16.4 Timing & Pacing of the Program

Toronto Hydro plans to replace obsolete RTUs at substations that have SCADA technology and to install SCADA systems at substations that do not have this technology. Additionally, Toronto Hydro proposes to replace obsolete pilot-wire relays and communication cables. During the 2015-2019 period, Toronto Hydro plans to:

- replace the existing MOSCAD RTUs and supporting communication infrastructure at 22 Etobicoke substations,
- replace existing DACSCAN MDO-11 type RTU at six downtown Toronto stations,
- install SCADA system, which includes RTUs and communication channels, at seven Scarborough municipal stations; and

- replace the pilot-wire relays and communication channels for 22 feeders, which includes 44 relays and communication channel.

The total cost of the Stations Control & Monitoring program over the five year period from 2015-2019 is an estimated $5.05 million, as shown in Table 4 below.

TABLE 4: HISTORICAL AND FUTURE SPENDING

	Historical Spending ($M)					Future Spending ($M)				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0.12	0.46	0.24	0.08	0.94	1.11	1.49	1.44

Table 4 also shows the historical spending associated with the Station Control & Monitoring program. The need for this program was recognized in 2012 and thus no projects were implemented in 2010 and 2011. Capital spending from 2012 to 2014 was fairly low because only five substations were targeted for RTU replacement. These five substations were selected based on several factors as mentioned in section E6.16.4.1 Ranking & Prioritization. Since this program was a new initiative, the first of the five projects was used to adequately train Toronto Hydro personnel to quickly and efficiently complete the remaining RTU replacement projects. For this reason, the first project was designed to take longer to complete than the others. As a result, this project was completed in 2013, and the remaining four are in-progress and scheduled to be completed by the end of 2014. Toronto Hydro owns 70 substations in Etobicoke; out of these 70 substations, 46 are either included in the 2015 to 2019 Switchgear Replacement Program (See E6.13) or in system renewal programs that include load conversion plans such as Box Construction Conversion (E6.7), Overhead Circuit Renewal (E6.4), Underground Legacy Infrastructure (E6.3) and Load Demand (E5.4). A typical Switchgear replacement includes the replacement of an RTU and its supporting communication channel. In the case of load conversion, all the station assets are decommissioned. In both cases, RTU issues are addressed. Therefore, Toronto Hydro has excluded those stations from the Station Control & Monitoring program. Toronto Hydro proposes to replace the RTUs at the remaining 24 substations through this program.

Toronto Hydro has 66 substations located in the Scarborough, 44 of which are SCADA-enabled. Similar to RTU replacement in Etobicoke substations, SCADA installation in the Scarborough area is planned under the Station Switchgear Renewal program (E6.13) and other renewal

programs that include load conversion plans. The remaining substations without SCADA capabilities are planned to be fitted with RTUs and communication channel.

The work involved in Station Control & Monitoring program uses labour resources such as Station engineer, Station designer, certified substation electrician and Information Technology (IT) personnel. The same resources are required for Toronto Hydro's other station renewal programs such as Switchgear Renewal program (See E6.13), Power Transformer Renewal program (See E6.14) and Circuit Breaker Renewal program (E6.15). Based on limited availability of resources, Toronto Hydro can target only a certain number of substations every year for each program. To account for these constraints, Toronto Hydro plans to replace RTUs at five Etobicoke stations and to install SCADA systems at two Scarborough stations every year from 2016 to 2019. Given the available resources, Toronto Hydro plans to replace RTUs at only two Etobicoke stations in 2015.

The Stations Control & Monitoring program also targets Transformer Stations (TS) located in downtown Toronto. Because of the resource constraints mentioned above, Toronto Hydro plans to begin replacing RTUs at TS from 2016. Toronto Hydro plans to replace RTUs at one TS every year in 2016 and 2017 and then continue to replace RTUs at a rate of two TS every year in 2018 and 2019. Due to presence of higher volume of power equipments at TS, replacing SCADA RTUs and its supporting communication channel at TS is more difficult than doing it at MS. Moreover, the new RTUs use modern technology that requires training Toronto Hydro's station crews to install, operate and maintain these new devices. Therefore, the first two RTU replacement projects in 2016 and 2017 are planned to have resources allocated for training programs. Toronto Hydro plans to replace RTUs at two downtown Toronto stations every year from 2017 to 2019.

Toronto Hydro has approximately 67 distribution feeders equipped with pilot-wire protection in the downtown Toronto distribution system. These feeders serve 27 customers distributed across eight TS. Currently, three new customers have been installed with digital fibre optic line differential relays, while 64 feeders are equipped with the traditional electromechanical pilot-wire relays. Toronto Hydro plans to upgrade the electromechanical relays and its supporting copper communication channel on 22 highly loaded pilot-wire configured feeders from 2015 to 2019.

Additionally, the electromechanical relays and copper communication channels are critical to the protection of highly loaded pilot-wire feeders. These highly loaded feeders supply load to large buildings mostly located in the financial district of downtown Toronto. Many businesses operate from these buildings and rely on uninterrupted power supply. Any power disruption for even a small period of time may result in large loss of revenue for a customer. The existing relays and

communication channels on these feeders are obsolete. These relays are about 30 years old and have extensive wear and tear through chemical reactions as a result of aging. In addition, they do not possess the ability to monitor pilot-wire circuit or electronically store event information and transmit the data to remote location for analysis. Due to the risk of large impact, it is important for Toronto Hydro to implement this program starting 2015 in order to upgrade Toronto Hydro's protection equipment to modern standards, improve reliability and provide better analysis capabilities.

Similar to replacing RTUs at downtown Toronto TS, the pilot-wire relay and communication channel upgrade aspect of the program is a new project for Toronto Hydro. This project includes replacement of existing electromechanical relays and copper communication channels with modern digital relays and fibre optic communication, respectively. Toronto Hydro plans to replace these existing relays and communication channel at three pilot-wire feeders in 2016. Additional resources are planned to be allocated in 2016 for training station crews to perform the replacement work. Starting 2017, Toronto Hydro proposes to increase the pace of the program to target five feeders in 2017 and six in 2018 and 2019 (See Figure 1).

E6.16.4.1 Ranking & Prioritization

Identifying substations for RTU replacement and SCADA system installation are based on several factors. These include:

- Mitigate sub-station risks: Toronto Hydro's sub-stations for RTU replacement and SCADA installation were selected on the basis of on the immediate threat they inflict on customer value and the potential safety and operational risks they impose on the system. In order to mitigate these risks, stations that supply power to large number of customers and are highly loaded were selected to improve reliability and system efficiency at high impact stations.

- Coordination with Switchgear Replacement: The Switchgear Renewal program includes RTU replacement and SCADA system installation. The two programs are planned to be coordinated in order to avoid wasted resources and redundant work.

- Co-ordination with Maintenance Program: SCADA RTU replacement or installation work involves taking the bus offline on which the new RTU will be replaced or installed. Toronto Hydro plans to co-ordinate this work with the Maintenance program (Exhibit 4A, Tab 2, Schedule 1), so that RTUs can be replaced when stations are de-energized for regular maintenance tasks. Toronto Hydro expects that this will facilitate a more efficient

execution of the work program and reduce the effects on customers by minimizing the frequency of planned station outages.

- Avoiding replacing legacy 4.16kV station assets: 4.16kV Stations targeted for load conversion within the Box Construction Conversion (E6.7), OH Circuit Renewal (E6.4), UG Legacy Infrastructure (E6.3) and Load Demand (E5.4) programs are not included in this program. During load conversion, all station equipment is removed. Hence it is redundant to replace or install a RTU at 4.16kV station.

Toronto Hydro currently serves 26 pilot-wire customers using technically obsolete pilot-wire relay and communications technology. Toronto Hydro uses the following prioritization criteria to select customers for pilot-wire relay and communications upgrade (criteria weight in a descending order):

(1) Lack of an existing alternate pilot-wire circuit: The current Toronto Hydro standard is to have two pilot-wire lines per feeder. But, in a few cases, Toronto Hydro has customers with one pilot-wire line per feeder. These customers experience elevated outage risk. Therefore, they are targeted for upgrade before other customers. Toronto Hydro plans to take this opportunity to install two pilot-wire lines per feeder: both "main" and "alternate", while installing new digital relays.

(2) Customer criticality (nature of load): Toronto Hydro's customers include a variety of institutions which must receive uninterrupted power supply such as hospitals, sewage treatment plants and banks. Proper functioning of these institutions is critical to the operation of the City of Toronto. Any failure at these locations would have a high impact. Therefore, Toronto Hydro plans to mitigate high impact risks by targeting these critical customers.

(3) Customer peak load: Load characterizes the size of the customer. A customer with higher load tends to experience a greater impact in the event of an outage. Similar to customer criticality, Toronto Hydro plans to mitigate high impact risks by targeting these high load customers.

(4) Locations currently utilizing a leased communication circuit: Toronto Hydro has some customers whose pilot-wire communication lines are owned by an external source, rather than Toronto Hydro itself. Toronto Hydro plans to move away from this practice by replacing all these externally owned communication lines with lines

owned by Toronto Hydro. This allows Toronto Hydro to more efficiently monitor the status of these lines.

This prioritization method helps Toronto Hydro plan work in a manner that first addresses customers with the greatest reliability risk and greatest need for uninterrupted supply.

E6.16.5 Program Execution

The Stations Control & Monitoring program consists of multiple discrete replacement and installation projects over the 2015 to 2019 period. Sections E6.16.8 and E6.16.9 contain the full list of projects that make up this program. Toronto Hydro has identified a number of risks and constraints involved with the Stations Control & Monitoring program that need to be taken into consideration prior to executing this work. The work involved in replacing RTUs and their supporting communication infrastructure, installing SCADA systems and replacing existing pilot-wire relays is described below:

(i) Replacement of RTUs and Supporting Communication System

The replacement projects at both Etobicoke MS and Downtown Toronto TS consist of removing the existing MOSCAD RTU and DACSCAN MDO-11 RTU, respectively, and installing the new RTU along with the supporting communication channel. In addition, the following RTU supporting components will also be replaced with newer devices:

- Power supply
- CPU
- I/O Modules
- Housing and Chassis
- Software

(ii) SCADA System Installation

The work involved in SCADA system installation is similar to the replacement work discussed above, in the sense that both involve the same skill set for installing a new RTU, communication channel and other supporting components as mentioned in section E6.16.6(i). However, there will be additional work to prepare the substation for SCADA devices for the first time, namely the

installation of new cable connections. The cost of this additional work is incorporated into the estimates for this program.

(iii) Pilot-Wire Relay & Communication Line Replacement

The pilot-wire relay upgrade of Toronto Hydro's high load customers involve removing the existing electromechanical relays which include GE Westinghouse CPD, Alston MBCI and ABB HCB or HCB-1 type relays and their respective copper communication channel. Once removed, SEL411 microprocessor relays are installed along with fiber optic communication cables.

E6.16.5.1 Proposed Work Plan

TABLE 5: 2015-2019 LONG TERM PLAN

Year	Project Type	Station
2015	Etobicoke RTU Replacement	Blaketon MS
2015	Etobicoke RTU Replacement	Walney MS
2016	Etobicoke RTU Replacement	Albion MS
2016	Etobicoke RTU Replacement	Centre Drive MS
2016	Etobicoke RTU Replacement	Palmwood MS
2016	Etobicoke RTU Replacement	Annabelle MS
2016	Etobicoke RTU Replacement	Royalcrest MS
2016	RTU Installation	Ellesmere Kennedy T1 MS
2016	RTU Installation	Ellesmere Kennedy T2 MS
2016	Downtown RTU Replacement	Esplanade TS
2016	Pilot-wire Relay Upgrade	Terauley TS
2017	Etobicoke RTU Replacement	Fieldway MS
2017	Etobicoke RTU Replacement	Humberline MS
2017	Etobicoke RTU Replacement	Gunton MS
2017	Etobicoke RTU Replacement	Constellation MS
2017	Etobicoke RTU Replacement	Redcliff MS
2017	RTU Installation	Lawrence Mccowan MS
2017	RTU Installation	Progress Markham MS
2017	Downtown RTU Replacement	Main TS
2017	Pilot-wire Relay Upgrade	Windsor TS
2018	Etobicoke RTU Replacement	Dalegrove MS
2018	Etobicoke RTU Replacement	Burnhamthorpe MS
2018	Etobicoke RTU Replacement	Hunting Ridge MS
2018	Etobicoke RTU Replacement	Centennial MS
2018	Etobicoke RTU Replacement	Westmore MS
2018	RTU Installation	Brimley Shaddock T1 MS
2018	RTU Installation	Brimley Shaddock T2 MS
2018	Downtown RTU Replacement	Cecil TS

Year	Project Type	Station
2018	Downtown RTU Replacement	Duplex TS
2018	Pilot-wire Relay Upgrade	Windsor TS
2019	Etobicoke RTU Replacement	Marmac MS
2019	Etobicoke RTU Replacement	Meteor MS
2019	Etobicoke RTU Replacement	Dunsany MS
2019	Etobicoke RTU Replacement	York MS
2019	Etobicoke RTU Replacement	Windsor MS
2019	RTU Installation	Kennedy Eglington MS
2019	Downtown RTU Replacement	Charles TS
2019	Downtown RTU Replacement	George & Duke TS
2019	Pilot-wire Relay Upgrade	Windsor TS

E6.16.5.2 Program Risks

There are multiple risks associated with the execution of Stations Control & Monitoring program.

RTU replacement or SCADA installation requires planned station outages where the entire municipal station is taken offline since live cables are connected to the RTUs. In the case of replacing RTUs at transformer stations, transferring load to adjacent sub-stations would require the receiving TS to have spare capacity and sufficient feeder positions. The location of the receiving TS would also need to be sufficiently close to the load centre to avoid voltage drop. Since these conditions cannot be met for any of the TS addressed by this program, feeder outages would be performed instead of station outages in order to execute RTU replacement jobs. Similarly, relay and communication channel replacement on a pilot-wire feeder requires the feeder to be taken out of service. This leaves the customer to be fed by one less feeder. Even though they are being supplied by the remaining feeder(s), the customer could experience an outage in the event of an equipment failure or presence of fault current.

Both planned station and feeder outages are done through switching. Switching is expensive and requires significant Toronto Hydro resources. The switching process by its very nature is performed on live equipment, and despite best planning efforts, there is always a risk of unforeseeable safety issues or switching errors.

Toronto Hydro plans to mitigate these risks through careful advanced planning and coordination of the responsible parties. Toronto Hydro also expects to takes other precautions to mitigate the risks on customers being fed by highly loaded pilot-wire feeders. These measures include keeping dispatch crews on standby during the entire duration of the work or coordinating with customer equipment maintenance work. Moreover, stations maintenance programs also require planned station or feeder outages to perform maintenance work on station assets. To address the risks associated with planned outages, RTU replacement or installation projects will be scheduled in co-ordination with the maintenance plan, whenever possible.

E6.16.6 Evaluation of Alternatives

E6.16.6.1 Quantification/ Evaluation of Options

The value of proceeding with the Stations Control & Monitoring program proposed here can be quantified by comparing it to a "status quo" scenario on the basis of cost of ownership.

(i) Status Quo

The status quo scenario consists of maintaining a "run to failure" approach. In this case, the existing MOSCAD RTUs and its associated DARCOM radio system at Etobicoke substations and DACSCAN MDO-11 type RTU at downtown Toronto would be replaced only when the system completely fails. Similarly, the electromechanical relays and communication channels on pilot-wire feeders would be replaced only when they fail, meaning that Toronto Hydro would take on the large failure risks associated with these failures as described in section E6.16.3.2ii. In general, these obsolete devices would be regularly maintained or repaired, which includes testing the functionality of RTU communication system, relay settings, operation of communication channels and checking the wiring and connections for faults. Maintenance work also includes performing open/close operation on SCADA connected switches to ensure they are functioning up to standard. Any warning signal or malfunction of RTU, electromechanical relays, communication channels or any of their supporting components will be reported for follow-up repair. While the continuation of the status quo would allow Toronto Hydro to defer asset replacement temporarily, Toronto Hydro would incur additional maintenance costs to maintain these legacy units in the interim. The realization of the added benefits relating to reliability, efficiency and the mitigation of cyber security risks would also be delayed. Under the status quo scenario, substations in Scarborough would continue to operate without SCADA system

capabilities. As noted in earlier section of the evidence, this typically leads to longer outage times and additional expenditures due to the need for on-site troubleshooting and maintenance.

(ii) Replace or Install RTU and Communication System/Upgrade Pilot-Wire Relays

This option involves the proactive replacement of existing MOSCAD RTUs and DARCOM radio system with modern RTUs and communication channel at Etobicoke and downtown Toronto substations, as discussed above, and the installation of modern RTUs and communication channel system at Scarborough substations. It also includes the replacement of GE Westinghouse CPD, Alston MBCI and ABB HCB or HCB-1 type relays on pilot-wire feeders with SEL411 microprocessor type relays.

The cost of ownership (COO) and program net present value (NPV) associated with Station Control & Monitoring program is further detailed in Table 6. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned investments in this program. The cost of ownership (COO) of a state reflects the risk of asset failure including both direct and indirect costs. These costs include customer interruptions, emergency repairs, and asset replacements associated with that design. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first of activities, the Station Control & Monitoring program produces a NPV value of $0.02 million, as shown in Table 6 and Table 7.

TABLE 6: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	$0.19
Non Asset Risk [NAR_E]	$0
Maintenance Cost [MC_E]	$0
Additional Quantifiable Benefits [AQB_E]	$0
Cost of Ownership of Existing Assets [COO_E]	$0.19

TABLE 7: BOX CONSTRUCTION CONVER SION BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 2: Conversion to Standardized 13.8kV Feeders (N)	
Asset Risk [AR_N]	$0.09
Non Asset Risk [NAR_N]	$0
Maintenance Cost [MC_N]	$0
Additional Quantifiable Benefits [AQB_N]	$0
Cost of Ownership of New Assets (Conversion to 13.8kV) [COO_N]	$0.09
Option 2: Project Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_N)$]	$0.10
Program Cost [PC_1]	$0.08
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	$0.02

E6.16.7 2015 Projects

Table 8 lists the projects scheduled for completion as a part of the 2015 work program. Additional detail on projects for year 2015 is provided in the following sections.

TABLE 8: 2015 PROJECTS

Project Number	Project Name	Area	Cost
29869	S15248 Walney MS MOSCAD RTU Replacement	Etobicoke	$0.04M
29713	S16050 Blaketon MS MOSCAD RTU Replacement	Etobicoke	$0.04M

E6.16.7.1 S15248 Project Description

Investment Category: System Renewal

Program: Stations Control & Monitoring

Project Title: Walney MS MOSCAD RTU Replacement

Project Number: S15248

Project Year: 2015

Estimated Cost: $0.04M

(i) Objective

The objective of this project is to replace the obsolete MOSCAD RTU and DARCOM radio communication channel at Walney MS with SEL AXION RTU and MDS SD9 radio system to improve system reliability.

(ii) Scope of Work

TABLE 9: S15248 SCOPE OF WORK DETAILS

District Neighbourhood	ETOBICOKE
Station(s)	WALNEY MS

TABLE 10: S15248 ASSETS REPLACED

Assets (Units)	2015
RTU & Communication Channel	1

(iii) Justification & Benefits

The Motorola MOSCAD RTUs and supporting communication system used at Walney MS are past their useful life of 22.5 years. These legacy units are obsolete and spare parts are not available from the manufacturer. When these aging RTUs fail, control for switching restoration is unavailable, which can result in significantly longer customer outages. This program is expected to improve reliability by replacing these legacy units with newer and modern RTUs and communication channel. Replacing RTUs is expected to improve system reliability and reduce operational and maintenance cost as detailed in this exhibit.

E6.16.7.1 S16050 Project Description

Investment Category: System Renewal

Program: Stations Control & Monitoring

Project Title: Blaketon MS MOSCAD RTU Replacement

Project Number: S16050

Project Year: 2015

Estimated Cost: $0.04M

(i) Objective

The objective of this program project is to replace the obsolete MOSCAD RTU and DARCOM radio communication channel at Blaketon MS with SEL AXION RTU and MDS SD9 radio system to improve system reliability.

(ii) Scope of Work

TABLE 11: S16050 SCOPE OF WORK DETAILS

District Neighbourhood	ETOBICOKE
Station(s)	BLAKETON MS

TABLE 12: S16050 ASSETS REPLACED

Assets (Units)	2015
RTU & Communication Channel	1

(iii) Justification & Benefits

The Motorola MOSCAD RTUs and supporting communication system used at Blaketon MS are past their useful life of 22.5 years. These legacy units are obsolete and spare parts are not available from the manufacturer. When these aging RTUs fail, control for switching restoration is unavailable, which can result in significantly longer customer outages. This program is expected to improve reliability by replacing these legacy units with newer and modern RTUs and communication channel. Replacing RTUs is expected to improve system reliability and reduce operational and maintenance cost as detailed in this exhibit.

E6.17 Stations Ancillary Systems

ANCILLARY POWER SUPPLY LOCATED IN A STATION BASEMENT

E6.17.1 Summary

Program Description

Through the Station Ancillary Systems Program, Toronto Hydro plans to replace ancillary systems that are at risk of failure and functionally obsolete with more reliable, modern technologies. Examples include air compressor systems, station service power supply systems, fire alarm systems, and fire suppression systems. This program predominately targets stations that do not possess load transfer capabilities in order to mitigate the risk of prolonged outages for customers. The program is also intended to improve crew safety.

Table A summarizes the anticipated benefits associated with the Stations Ancillary Systems program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ The ancillary systems program mitigates risks to the reliability of power supply to 108,248 customers ƒ Proposed installation of the fire barrier system at Strachan B MS expected to mitigate fire hazards to customer property stemming from catastrophic failures of transformers ƒ A reliable fire alarm system notifies system controllers of a station fire so

	that preventive actions can be taken to control the issue before it migrates
Reliability	ƒ New air compressors planned mitigate risks to the reliable operation of the associated air blast circuit breakers, which isolate fault current and prevent damage to upstream or downstream equipment ƒ Reliable fire alarm systems report the presence of station fires to system controllers so that preventive action can be taken before a catastrophic event occurs ƒ Installation of fire barrier system helps to prevent catastrophic transformer failure from causing station outages ƒ Reliable station power supply helps to ensure the reliable operation of the station
Efficiency	ƒ Toronto Hydro expects the Stations Ancillary Systems program to minimize the time taken to acquire spare parts for deteriorating ancillary systems, freeing up maintenance time for other areas of need
Safety	ƒ A reliable fire alarm system notifies personnel on site of the presence of a station fire ƒ A reliable fire alarm system helps to prevent the spread of station fires reducing risks to customers and their property ƒ Proposed fire barriers at Strachan B MS expected to mitigate the fire hazard to customer property and customers' fire safety risk

Program Drivers

Toronto Hydro's proposed Station Ancillary Systems program plans to address ancillary systems that face a risk of failure and that are functionally obsolete. If left in service, a failure of these systems could have a negative impact on the safe and reliable operation of Toronto Hydro's transformer stations. The trigger and secondary drivers for this program are provided in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ Inspection data shows that the ancillary systems targeted in this program are at end-of-life and require frequent repairs ƒ Acquiring spare parts to maintain outdated station ancillary systems is becoming increasingly difficult ƒ Failure of ancillary systems has a potential to cause a failure of the associated station assets
Secondary Driver	**Reasoning**
Functional Obsolescence	ƒ Ancillary systems targeted to be replaced in this program are obsolete ƒ Spare parts are no longer supported by their

	manufacturers • Keeping these ancillary systems in service is increasingly difficult due to a lack of spare parts.
Safety	• Unreliable fire alarm system could impact the safety of personnel in the event of a station fire as they may not be notified early enough to leave the indoor stations • Public safety close to the stations could be at risk in the event of station fire as it is possible that a fire can migrate out of the station to nearby areas.

Preferred Alternative

Toronto Hydro evaluated the following options for addressing the ancillary systems in this program.

(1) Continue to utilize obsolete ancillary systems until they fail; or

(2) Replace existing ancillary systems with new equipment that will contribute to the safe and reliable operation of Toronto Hydro stations.

Option II is the preferred alternative because it mitigates risks to safe and reliable operation of Toronto Hydro stations in a cost-effective manner.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $2.22 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.17.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $1.53 million, confirming the economic prudence of the investments (see Section E6.17.7).

Timing and Pacing

The following table summarizes the historical and forecasted spending for this program.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.15	0.12	0.24	0.63	0.22	0.69	0.59	0.37	0.26	0.38

The air compressors planned for replacement in 2015 serve large customers in the downtown financial district. Fire suppression systems are planned for installation at Cavanagh TS in 2015 and Strachan B MS and Glengrove TS in 2016.

Relocation of a below grade station service power supply at George and Duke MS is planned for 2015 to mitigate the risk of failure that could be caused by flooding. Toronto plans to replace fire alarm systems in 2017-2019, beginning with those that are the oldest and most deteriorated.

E6.17.2 Program Description

In order to function effectively, Toronto Hydro's stations require a number of ancillary systems, including air compressor systems, fire alarm systems, heating and lighting systems, battery and charger systems, station service power supply systems, sump pump systems, and fire barrier or fire suppression systems. The ancillary systems that are addressed in this program are:

- air compressor systems,
- station service power supply systems,
- fire alarm systems, and
- fire suppression systems

These systems are vital to the safe and reliable operation of stations equipment. Toronto Hydro plans to invest $2.29 million over the 2015 to 2019 period to maintain the integrity of these systems at a number of distribution stations throughout the city, as illustrated in Figure 1.

FIGURE 1: LOCATIONS OF STATION ANCILLARY SYSTEMS TO BE REPLACED/INSTALLED

The following sections provide a detailed description of each of the ancillary systems addressed in this program.

E6.17.2.1 Air Compressor System

Toronto Hydro plans to replace functionally obsolete air compressors. A typical air compressor currently in use is shown in Figure 2.

FIGURE 2: TYPICAL EXISTING AIR COMPRESSOR SYSTEM

Reliable air compressors help to ensure that circuit breakers function as designed to clear faults when needed. If a circuit breaker fails to operate and interrupt a fault current due to a failure of the air compressors, the circuit breaker can be significantly damaged and power supply to customers associated with it will be disrupted. For example, a circuit breaker which failed to interrupt a fault current at George and Duke MS on July 5, 2012 was significantly damaged and as a result power was interrupted to 6,500 customers in the central Toronto area for 8 hours.

Toronto Hydro currently has twenty air compressors in service in some of its 4.16 kV and 13.8 kV stations where there are switchgears fitted with air blast circuit breakers which require air compressors to operate. Twelve out of the total are at the end of their lives and require frequent repairs and six out of these twelve air compressors are planned to be removed from service as a result of the Switchgear Renewal Program (see Section E6.13), and do not require replacement because the new switchgears use vacuum circuit breakers that do not require air compressors to operate. However, the remaining six air compressors must be replaced as they continue to operate the associated air blast circuit breakers. The locations of the stations that house these air compressors are shown in Figure 3.

TABLE 1: AGE OF AIR COMPRESSOR SYSTEM IN PROGRAM

Station Name	Air Compressor System Age in 2015 (years)
High Level MS	16
Windsor MS	17
Runnymede MS	18

FIGURE 3: LOCATIONS OF AIR COMPRESSORS TO BE REPLACED (2015 – 2019)

E6.17.2.2 Relocation of Below-Grade Service Equipment

The Station Ancillary Systems program includes investments to relocate below grade station service power supply, specifically the service transformer and associated secondary distribution panel and the battery and charger system of George and Duke Municipal Station (MS). The station service transformer and the associated secondary distribution panel (shown in Figure 4 and Figure 5, respectively) supply power to the lighting, heating and ventilation systems, fire alarm systems, battery charger systems and sump pump systems of George and Duke MS, which all provide essential services required for the station to operate safely and reliably.

The battery and charger system, shown in Figure 6 in turn supplies DC power to all protective relays of the station and their control circuits, alarms and the actuating of equipment such as circuit breakers, SCADA control system, and emergency lighting fire protection.

At George and Duke MS, the station service transformer and the associated secondary distribution panel and the battery and charger system are located in the basement of the station as shown in Figures 4 to 6.

FIGURE 4: STATION SERVICE TRANSFORMER LOCATED IN BASEMENT OF GEORGE & DUKE MS

FIGURE 5: STATION SERVICE SECONDARY DISTRIBUTION PANEL LOCATED IN BASEMENT OF GEORGE & DUKE MS

FIGURE 6: STATION BATTERY SYSTEM LOCATED IN THE BASEMENT OF GEORGE & DUKE MS

If the station basement is flooded due to heavy rain or a broken water main, and if the rate of water entering the basement exceeds the capability of its sump pump to drain the water, then the power supply to the station assets which provide essential services mentioned previously can be

severely impacted, which in turn would impact the ability of George and Duke MS to safely and reliably supply power to over 6,500 customers in the downtown area. Toronto Hydro has taken some measures such as plugging cable ducts, installing bigger size sump pump to reduce the risk of flooding; however, it is still possible that the basement can be flooded due to heavy storm rain or a broken water main. To mitigate this risk, Toronto Hydro plans to install a new station service transformer and associated secondary distribution panel and new battery and charger systems above ground to replace those which are currently located in basement. The location of the station where this power supply system is in service is shown in Figure 7.

FIGURE 7: LOCATIONS OF STATION POWER SUPPLY TO BE RELOCATED

E6.17.2.3 Fire Alarm System

Toronto Hydro plans to replace functionally obsolete, end-of-life fire alarm systems currently in service at a number of stations. Early detection of fire is critical to the safety of personnel on site and for the safety the general public in the surrounding area. It is also essential that fire events in station facilities be detected as early as possible to minimize operational disruptions and asset damage.

Toronto Hydro has fire alarm systems inside 32 stations whose load cannot be transferred to any other stations if the power supply to the initial station is disrupted. Consequently, a fire at any one of these stations could potentially be highly disruptive for customers. Of these 32 fire alarm systems, Toronto Hydro plans to replace five which have reached the end of their useful lives and are obsolete. Spare parts for this type of fire alarm system are no longer available from the manufacturers and it is becoming increasingly difficult to maintain the systems in service. A typical existing fire alarm control panel is shown in Figure 8.

The replacement of the fire alarm systems that are at end-of-life and obsolete will help ensure that fires initiated inside stations are reported to the control room so that fire authorities can be dispatched in a timely manner.

FIGURE 8: TYPICAL EXISTING FIRE ALARM CONTROL PANEL

FIGURE 9: NEW FIRE ALARM CONTROL PANEL

The new fire alarm system shown in Figure 9 contains improved detection technology: it has aspirating smoke detectors that quickly and reliably differentiate between smoke and other causes that previously may have led to false alarms. The new control panels and fire terminals are also easier to operate because they display important, customized intervention text right on

the control panel to facilitate appropriate action in the event of an alarm. In addition to smoke and heat, the new fire alarm systems are also able to detect carbon monoxide (CO).

TABLE 2: AGE OF FIRE ALARM SYSTEM IN PROGRAM

Station Name	Fire Alarm System Age in 2015 (years)
George & Duke MS	17
Dufferin TS	18
Charles TS	21
Glengrove TS	17
Terauly TS	17

The locations of the fire alarm systems requiring replacement in 2015-2019 are shown in Figure 10.

FIGURE 10: LOCATION OF FIRE ALARM SYSTEM TO BE REPLACED (2015 – 2019)

E6.17.2.4 Fire Suppression Systems

Toronto Hydro plans to install fire barrier systems in stations where there are multiple transformers that face the risk of collateral damage if any single transformer fails catastrophically. A catastrophic transformer failure occurs when an internal short-circuit arc takes place inside a

transformer resulting in a significant release of energy into the insulating oil and builds internal pressure which raptures the tank and burns the transformer oil. The fire caused by a catastrophic failure of a transformer can migrate to the adjacent transformers and can damage other equipment in the station.

Fire barriers can be passive or active. A fire barrier system is passive if it contains the fire within the boundary of a transformer so that a potential fire does not migrate and damage any other transformer(s) in the vicinity. Another method of preventing fire from damaging additional transformers is the installation of a fire suppression system. A fire suppression system is called an active fire barrier because it puts out fire actively. Fire suppression systems use a combination of dry chemicals and/or wet agents to suppress equipment fire. These systems are typically water sprinklers or foam spraying systems that can extinguish a fire before it spreads and potentially damages other transformers.

Toronto Hydro also plans to install a fire barrier wall between the station service transformers of Glengrove terminal station (TS) which are very close to each other as shown in Figure 11. A catastrophic failure of any one of them will impact the second one. In the even to catastrophic failure, the station essential services will interrupt and this could negatively impact the reliability of power supply to all the customers connected to Glengrove TS. Therefore, to mitigate the reliability risk, one of the station service transformers is to be relocated far enough so that space will be the fire barrier between the two transformers.

FIGURE 11: STATION SERVICE TRANSFORMERS AT GLENGROVE TS

The locations of these stations are shown in Figure 12.

TABLE 3: NUMBER OF CONNECTED CUSTOMERS

Station Name	Number of Customers Connected
Cavanagh TS	16,363
Strachan B MS	1,191
Glengrove TS	12,647

FIGURE 12: LOCATION OF FIRE BARRIER/SUPPRESSION SYSTEM INSTALLATION (2015-2019)

The assets that Toronto Hydro plans to replace/install under the ancillary system program are summarized by asset class in Table 4.

TABLE 4: ASSETS TO BE REPLACED/INSTALLED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Air Compressors	4			2		6
Station Service Power Supply		1				1
Fire Alarm System			2	1	2	5
Fire Barrier/Suppression System	1	2				3

In addition to addressing obsolete and aging assets, Toronto Hydro anticipates that the Stations Ancillary Systems program will offers a number of benefits as shown in Table 5.

TABLE 5: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Mitigates risks to the reliability of power supply to 108,248 customers ƒ Proposed installation of the fire barrier system at Strachan B MS mitigates fire hazards to customer property stemming from catastrophic failures of transformers ƒ A reliable fire alarm system notifies system controllers of a station fire so that appropriate steps can be taken to control the issue before it migrates ƒ The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $2.22 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.17.7). ƒ Accounting for capital program costs, the first year's activities are expected to deliver a positive NPV of $1.53 million, confirming the economic prudence of the investments (see Section E6.17.7).
Reliability	ƒ New air compressors mitigate risks to the reliable operation of the associated air blast circuit breakers, which isolate fault current and prevent damage to upstream or downstream equipment ƒ Reliable fire alarm systems report the presence of station fires to system controllers so that appropriate steps can be taken before a catastrophic event occurs ƒ Installation of fire barrier systems help to prevent catastrophic transformer failure from causing station outages ƒ Reliable station power supply helps to ensure the reliable operation of the station
Efficiency	ƒ Toronto Hydro expects the Stations Ancillary Systems program to minimize the time taken to acquire spare parts for deteriorating ancillary systems, freeing up maintenance time for other areas of need
Safety	ƒ A reliable fire alarm system notifies personnel on site of the presence of a station fire

	ƒ A reliable fire alarm system will help prevent the spread of station fires reducing risks to customers and their property ƒ Fire barriers at Strachan B MS mitigate the fire hazard to customer property and public safety risks

E6.17.3 Why the Program is Needed

Toronto Hydro's proposed Station Ancillary Systems program plans to address ancillary systems that face a risk of failure and that are functionally obsolete. A failure of these systems could have a negative impact on the safe and reliable operation of Toronto Hydro's transformer stations. This program also addresses the need for fire barriers and fire suppression systems in certain stations.

E6.17.3.1 Program Drivers

Table 6 specifies the trigger and secondary drivers for the Station Ancillary Systems program.

TABLE 6: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ Inspection data shows that the ancillary systems targeted in this program are at end-of-life and require frequent repairs ƒ Acquiring spare parts to maintain outdated station ancillary systems is becoming increasingly difficult ƒ Failure of ancillary systems has a potential to cause a failure of the associated station assets
Secondary Drivers	**Reasoning**
Functional Obsolescence	ƒ Ancillary systems targeted to be replaced in this program are obsolete ƒ Spare parts are no longer supported by their manufacturers ƒ Keeping these ancillary systems in service is increasingly difficult due to a lack of spare parts.
Safety	ƒ Unreliable fire alarm systems could impact the safety of personnel in the event of a station fire since personnel may not be notified early enough to leave the stations ƒ The safety of customers close to the stations could be at risk in the event of station fire since it is possible that fire can migrate out of the station to nearby areas.

(i) Failure Risk of Air Compressor Systems

In Toronto Hydro's distribution system, air compressor systems supply compressed air for air blast circuit breakers. The air compressor system of a station consists of two air compressors, two air receivers, a moisture separator, a drain system and an arrangement of pipes and valves, which together are designed to deliver compressed air to operate circuit breakers.

When the air blast circuit breaker is activated to clear a fault current, it uses the compressed air for both the opening of the arcing contacts and the quenching of the arc during interruption. The contacts close as soon as the air flow stops and are held closed by a spring. If the air compressor system fails, the breaker is unable to clear the fault and the fault current cascades upstream to the next protective device resulting in a sustained outage to the entire switchgear and all connected customers. Should the switchgear not be arc-resistant, adjacent cells and other nearby station equipment can face collateral damage risk, creating safety concerns for personnel on site.

Toronto Hydro has 20 air compressors currently in service in a number of its 4.16 kV and 13.8 kV stations. Inspection data shows that twelve of these air compressors are at the end of life. The number of major repairs performed on the air compressor population is shown in Figure 13. Toronto Hydro has kept these air compressors in service using spare parts from retired air compressors. However, these spare parts are finite and once Toronto Hydro runs out of them, it will be difficult to keep the air compressors in service to ensure a reliable operation of the existing air blast circuit breakers.

The air compressors are no longer being manufactured and spare parts are also no longer available. To address the risk of failure and functional obsolescence issues facing these air compressors, Toronto Hydro plans to proactively replace the obsolete air compressors with modern air compressors in order to mitigate the risk of a major failure which can cascade to a circuit breaker failure, which in turn can impact the switchgear it connected to it.

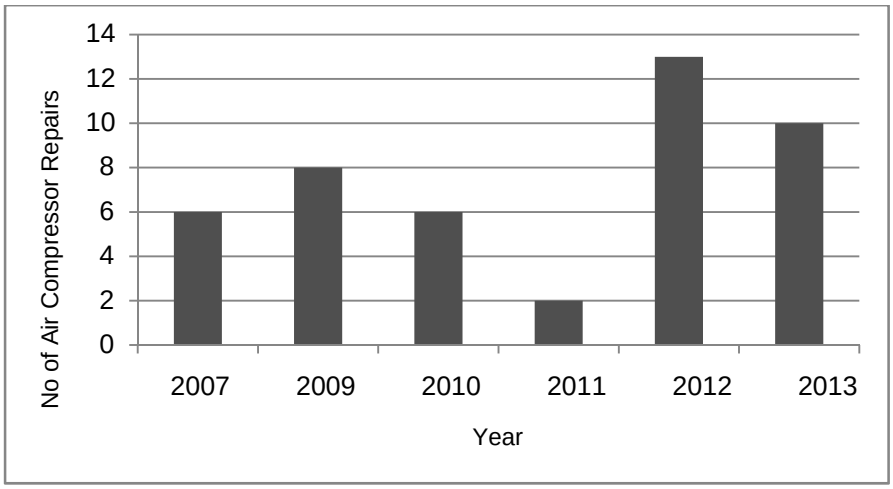


FIGURE 13: AIR COMPRESSORS REPAIR RATE

(ii) Flooding Risk to Below-Grade Service Equipment

Within the Toronto downtown core, station essential services (lighting system, heating and ventilation systems, fire alarm systems, battery charger systems and sump pump systems) are usually powered by two sources for contingency purposes. These sources could be two station service transformers connected to two different buses within the substation, or by one Toronto Hydro-owned station service transformer backed-up by either a Hydro One owned supply source or by Toronto Hydro's secondary network service connected to a different bus. In this arrangement, if one power source fails, the second source can still carry the load.

However, there are situations where the station service transformer and the associated secondary distribution panel, which supplies power to the station ancillary systems, are located in the basement, as is the case of George & Duke MS (see Figures 4 to 6), where the power supply to the station ancillary systems can be interrupted due to heavy rain that can flood the basement. If flooding occurs, the station service power supply system would fail. The failure of the station power supply would interrupt the functions of the ancillary systems of the station, impacting its safe and reliable operation. Failure of the essential station services can lead to long outages to 7,924 customers of George and Duke MS since the load cannot be transferred to adjacent station(s) because the station has no load transfer capability. This issue arose on July 8, 2013 when the City of Toronto received heavy rain that caused flooding, which impacted stations owned by Hydro One (HONI), resulting in long outages for up to 500,000 customers in the Etobicoke and downtown Toronto area. To avoid the risks associated with flooding, the station

service transformer and the associated secondary distribution panel and battery and charger system must be moved above grade. These assets were originally installed in the basement due to space constraints that existed in the station; however, as a result of load conversion and removal of station equipment, space is now available above ground level.

(iii) Fire-Related Risks

While Toronto Hydro takes precautions to prevent faults that can lead to a fire, the risk of station fires remains. Station fires can be initiated as a result of catastrophic failure of station equipment such as circuit breakers, oil insulated current transformers, and oil insulated pothead termination. To mitigate the risks of fire-related damage to station equipment and long outages for customers, Toronto Hydro has fire alarm systems installed in 32 stations. These stations have no load transfer capability, so that if a fire occurs in any one of these station and the power supply is disrupted as a result of the fire, the load cannot be transferred to adjacent station(s) as would be the case with other stations. As a result, fire alarm systems are installed to prevent or minimize the impact of fires initiated inside the station.

The fire alarm system detects fire at a very early stage, even before the presence of smoke, and notifies Toronto Hydro's power system controllers of the danger. System controllers can then take preventive actions such as sending personnel to the station to assess the situation and/or notifying the fire department. A functioning fire alarm system is therefore critical to preventing damage to station assets that could lead to catastrophic station failure, employee safety risks, and long outages for customers.

The affected stations are located in the congested downtown area of Toronto. Fire alarm systems were installed in these stations to not only protect Toronto Hydro's station assets and personnel on site, but to also enhance the safety of the general public in the area since it is possible for a fire to migrate off-site and impact the neighbourhood.

Out of the 32 fire alarm systems, Toronto Hydro plans to replace five which are functionally obsolete and at their end-of-life. Spare parts are no longer available from manufacturers, making it increasingly difficult to keep these alarm systems in service. The number of major repairs done on the fire alarm system population is shown in Figure 14, which supports the need for their replacement.

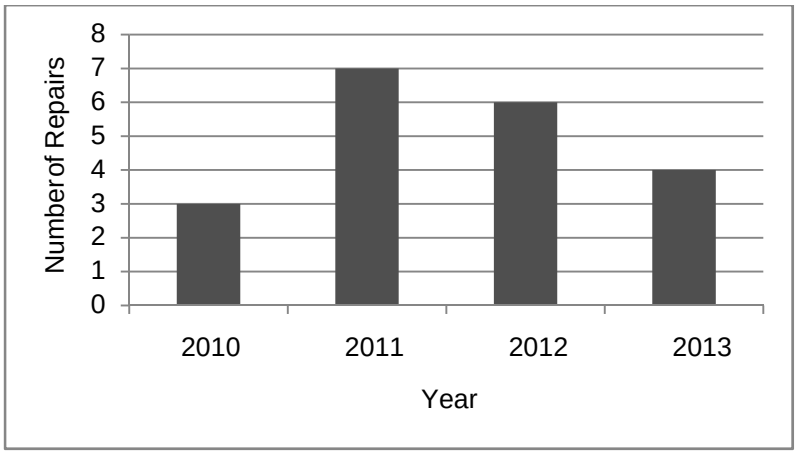


FIGURE 14: FIRE ALARM SYSTEM REPAIRS

TABLE 7: AGE OF FIRE ALARM SYSTEM IN PROGRAM

Station Name	Fire Alarm System Age in 2015 (years)
George & Duke MS	17
Dufferin TS	18
Charles TS	21
Glengrove TS	17
Terauley TS	17

Toronto Hydro also plans to install fire barrier system in stations with two or more transformers that do not have a fire barrier system to mitigate the risk of transformers being affected by a catastrophic failure of any neighbouring transformers.

Some of Toronto Hydro's municipal stations (MS) have no load transfer capability, and each is comprised of two or more transformer banks, which contain large volumes of flammable mineral oil. During a catastrophic transformer failure event, the transformer oil can be ignited by any number of sources including solid particles of insulation, internal component failure, or short circuit electrical arcing inside the tank. The energy released from the short circuit builds pressure inside the insulating oil and the tank raptures as a result of pressure build up. Once a rupture occurs, air rushes into the tank and the tank explodes, resulting in a blast scattering debris onto the surrounding area. This type of catastrophic failure can ignite neighbouring transformers. For example, in 2003, one of the transformers at Dupont MS failed catastrophically, causing a fire. The fire damaged the two adjacent transformers, as shown in Figure 15.

FIGURE 15: FIRE ALARM SYSTEM AGE PROFILE

Uncontained fires caused by catastrophic transformer failure can quickly result in the partial or total loss of the entire station, leading to lengthy outages to potentially thousands of customers. In addition, the cost of replacing damaged or burned station transformers ranges from $1.2 million to $3 million, depending on the size and voltage of the transformer.

Catastrophic transformer failures can be difficult to anticipate and prevent. Despite regular maintenance, transformers can fail catastrophically before warning signs are detected since the conditions that can create a catastrophic failure can develop in the transformer in between the maintenance cycles. However, collateral damage is preventable with the proper fire containment plan in place. Sound precautions include the installation of fire barrier systems or fire suppression systems.

Toronto Hydro plans to install fire suppression system at Cavanagh TS and a fire barrier wall at Strachan B municipal station to mitigate risk of collateral damage and long outages to the large number of affected customers as shown in Table 11.

The transformers at Cavanagh TS are two 125 MVA, transmission type transformers which step down voltage from 230 kV to 27.6 kV. A fire barrier wall was installed between the two transformers but a fire barrier wall could not be installed between the transformers and the

building where the switchgear is housed because of space limitations. However, according to the IEEE standard 979-1994, if large oil filled transformers are located between 20 and 50 ft of a building, the exposed walls of the building should constitute, or be protected by at least a 2 hour-rated fire wall. Even though the catastrophic failure of one of the transformers will not impact the second one due to the fire wall in place, it can impact the building where the switchgear of Cavanagh terminal station is located which can cause outages to all customers supplied by Cavanagh terminal station. Although the load of Cavanagh terminal station can be transferred to adjacent stations for a limited period of time, the transferred load will create an overload situation that can cause outage on the receiving stations during summer and winter peak time; this compounds the power outage issue. Toronto Hydro has no spare transformer to replace any of these transformers during emergency. The replacement cost of the affected switchgear will be at least $3M and it takes at least two years to replace them on a planned basis. Therefore, to avoid the risk associated with catastrophic failure of a transformer, it is necessary to install a fire suppression system that extinguishes any potential fire before it damages a transformer and spreads to the neighbouring switchgear building.

The City of Toronto formally asked Toronto Hydro to install fire barrier system between the Toronto Hydro owned transformers of Strachan B MS and the city owned Canadian National Exhibition (CNE) building which is very close to the transformers. The distance criteria between the transformers and the CNE building falls under the requirement of the IEEE standard 979-1994 mentioned earlier (see Figure 12) so fire barrier is necessary to protect the building from fire hazard caused by catastrophic failure of a transformer. Catastrophic failure of any of the transformers will impact the other two transformers and the CNE general building. Therefore, installation of fire barrier system in between the transformers and between transformers and the CNE general building is necessary to mitigate the reliability risk of Strachan B MS and the fire hazard to the CNE building.

Similarly the station service transformers of Glengrove terminal station are located very close to each other as shown in Figure 13 and if any one of them fails catastrophically, the second one will also be impacted hence, the power supply to all ancillary systems of Glengrove terminal station will be interrupted and this in turn will impact the safe and reliable operation of Glengrove terminal station. Therefore, to mitigate the risk, one of the transformers will be relocated to create space between each other so that if one of them fails catastrophically, the second one will not be impacted and will continue to supply power to the ancillary systems of the station.

E6.17.3.2 Asset Details

(i) Asset Lifecycle

The age profile for the in service air compressor population is shown in Figure 16.

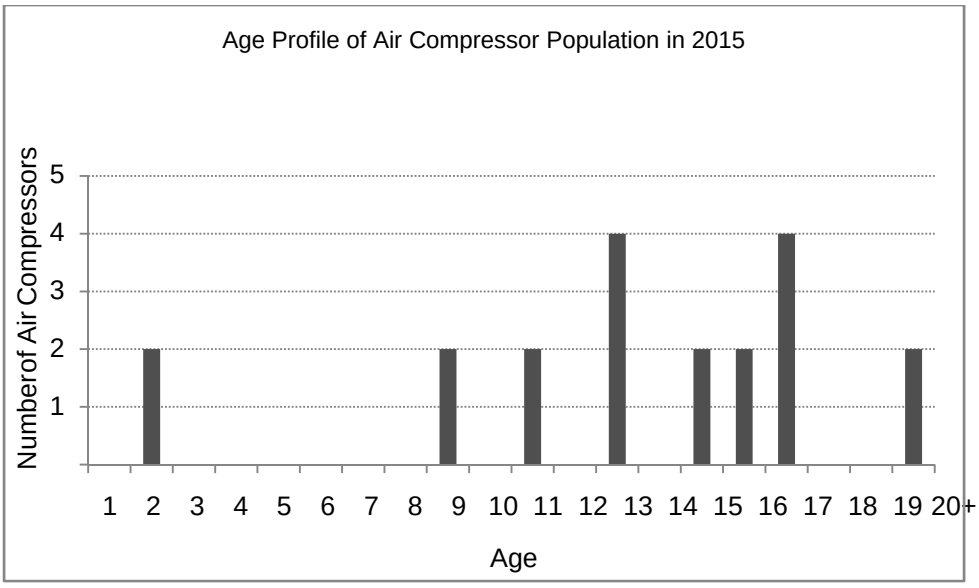


FIGURE 16: AGE PROFILE OF AIR COMPRESSOR POPULATION IN 2015

The age profile for the in-service fire alarm systems is shown in Table 8.

FIGURE 17: FIRE ALARM SYSTEM AGE PROFILE

(ii) Asset Failure Impacts

As discussed in Section E6.17.3.1, an air compressor system failure will result in a circuit breaker not being able to interrupt fault current, and therefore resulting in the fault cascading upstream and creating an outage to all customers connected to the switchgear. This type of outage can last for several hours. For example, in July 2012, an outage caused by the failure of a circuit breaker to clear a fault at George and Duke MS impacted over 6,000 customers connected to the switchgear for nearly eight hours.

TABLE 8: STATIONS REQUIRING AIR COMPRESSOR SYSTEM REPLACEMENTS

Station Name	Number of Customers Connected
High level MS	11,368
Windsor TS	5,536
Runnymede MS	4,025

If a station's fire alarm system fails, Toronto Hydro will not be notified of an actual fire unless (a) a member of the public reports the incident to emergency authorities or (b) damage to stations equipment caused by the fire triggers an alarm at the distribution control centre. In either case, there is substantial risk that fire damage to equipment will cause a significant power outage for customers since the load of any of these stations cannot be transferred to other adjacent station(s) like in the horseshoe areas.

In 2009 a fire occurred at Station J MS which had no load transfer capability. Since Station J MS had no fire alarm system and early intervention was not possible the fire consumed the station switchgear and the entire load was disrupted. (Fortunately in this case, most of the original Station J MS load had already been previously converted to a higher voltage supplied from another station, and the remaining load was converted and transferred to a higher voltage after the fire.) Reliable fire alarm systems are important for early intervention to minimize the impact of fire on the station equipment and on power supply to customers.

TABLE 9: STATIONS REQUIRING FIRE ALARM SYSTEM REPLACEMENTS

Station Name	No. of Connected Customers
George & Duke MS	7,924
Dufferin TS	20,013
Charles TS	7,851
Glengrove TS	11,298

Station Name	No. of Connected Customers
Terauley TS	1,151

The stations that require fire suppression systems to be installed either do not have load transfer capability or the transfer capability is limited. Typically, a station is supplied by two or three transformers such that if one fails, the remaining transformers carry the load. However, if one of the transformers fails catastrophically, impacting the remaining transformer(s), the station's entire load can be impacted and customers can experience long outages. For example, in 2003 one of the transformers at Dupont MS failed catastrophically causing a fire. The fire damaged the two adjacent transformers, as shown in Figure 15, and the entire station was lost due to collateral damage. Over 5,000 customers were without power for several hours because Dupont MS did not have load transfer capability. To prevent similar events from occurring, fire barrier or fire suppression systems are needed at Cavanagh terminal station.

TABLE 10: STATION REQUIRING FIRE BARRIER/SUPPRESSION SYSTEM INSTALLATION

Station Name	No. of Customers connected
Cavanagh TS	16,393
Strachan B MS	2,118
Glengrove TS	12,647

A failure of the power supply to ancillary systems will render those systems incapable of supporting the reliable operation of the distribution station. A failure of the power supply to the ancillary systems will cause the battery and charger system and the air compressor system, which are critical to the reliable operation of the station, to stop giving the operational support required by the station to provide a reliable power supply to customers.

TABLE 11: STATION REQUIRING STATION POWER SUPPLY IMPROVEMENT

Station Name	No. of Customers Connected
George & Duke MS	7,924

E6.17.4 Timing & Pacing of the Program

The ancillary systems that are targeted to be replaced and the new ancillary systems proposed to be installed over the next five years are shown in Table 4 and the associated estimated cost is shown in Table 12.

TABLE 12: HISTORICAL AND FUTURE SPENDING OF STATION ANCILLARY SYSTEMS

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.15	0.12	0.24	0.63	0.22	0.69	0.59	0.37	0.26	0.38

The air compressors planned for replacement in 2015 serve large customers in the downtown financial district. Inspection data shows that these air compressors are deteriorating and to secure their reliable operations, these air compressors must be given higher priority. The air compressors planned for replacement in 2018 are associated with lower risk, since the load of the station is expected to be reduced as a result of 4.16 kV to 13.8 kV load conversion, meaning that these air compressors will not operate as often as the air compressors planned for replacement in 2015.

The installation of the fire barriers is prioritized based on the magnitude of impact in terms of asset replacement cost and number of customers that will be impacted in the event of catastrophic failure of transformers. Fire suppression systems are planned for installation at Cavanagh TS in 2015 and Strachan B MS and Glengrove TS to in 2016.

Relocation of the below grade station service power supply at George and Duke MS is planned for 2015. These assets are currently vulnerable to flooding. Toronto plans to replace fire alarm systems from 2017 – 2019, beginning with those that are the oldest and most deteriorated.

E6.17.4.1 Ranking & Prioritization

Ancillary assets to be replaced were prioritized based on:

- asset failure risk – assets that are in poor condition and requiring frequent repair
- asset obsolescence – assets that are no longer manufactured and for which spare parts are no longer available
- number of customers that could be impacted due to asset failure
- level of flooding and fire risks

Ancillary systems in the stations where the load will be converted from 4 kV to 13.8 kV or that have scheduled switchgear replacement (in the case of air compressor replacement, the air blast

circuit breakers could be replaced with vacuum circuit breakers when switchgear is replaced) in the foreseeable future are not included as part of the program. Replacement of ancillary systems was prioritized based on the asset condition and magnitude of impact in the event of failure. Installation of new ancillary systems was prioritized based on the magnitude of impact if assets fail catastrophically.

E6.17.5 Program Execution

The projects planned under this program will be designed by Toronto Hydro station designers. After all necessary design drawings and documents are prepared, work will be issued for construction. Some of the jobs, such as fire alarm systems and fire barrier/suppression systems would typically be executed by external contractors, while the remainder (air compressor systems, power supply systems) would typically be completed by Toronto Hydro crews.

The replacement of the air compressors and fire alarm systems will require no station equipment outages, but the suppression system to be installed at Cavanagh TS will require temporary station outages, in which case the associated load will need to be transferred to adjacent stations. This load transfer will require coordination with HONI and will be completed during low load season to safeguard the reliability of the power supply under contingency. The relocation of station power supply at George & Duke MS requires that new station service power supply and distribution panel to be installed first, then the load will be transferred to the new power supply system followed by the decommissioning of the existing power supply system.

E6.17.5.1 2015-2019 Long Term Plan

The long term ancillary system replacement/installation program is shown in Table 13.

TABLE 13: 2015-2019 LONG TERM PLAN

Year	Station	Project Type
2015	High Level MS	Replacement of 2 Air compressors
2015	Windsor TS	Replacement of 2 Air compressors
2015	Cavanagh TS	Installation of Fire suppression system
2016	Strachan B MS	Installation of Fire barrier system
2016	Glengrove TS	Installation of Fire barrier system
2016	George & Duke MS	Relocation of below-grade ancillary system
2017	Dufferin TS	Replacement of Fire alarm system

Year	Station	Project Type
2017	George & Duke MS	Replacement of Fire alarm system
2018	Charles TS	Replacement of Fire alarm system
2018	Runnymede MS	Replacement of 2 Air compressors
2019	Glengrove TS	Replacement of Fire alarm system
2019	Terauley TS	Replacement of Fire alarm system

E6.17.5.2 Program Risks

The implementation of the Station Ancillary Systems Program, especially the installation of fire suppression system at Cavanagh TS, requires HONI's involvement. The load of Cavanagh TS which is owned by Toronto Hydro will need to be transferred to HONI owned station(s) so HONI needs to be closely involved during the load transfer. However, if HONI's work plan does not align with Toronto Hydro's, the execution of the program will be delayed. This issue can be mitigated by Toronto Hydro by discussing the project with HONI in advance and establishing a mutually agreed upon implementation plan at the early stages of the program.

E6.17.6 Evaluation of Alternatives

E6.17.6.1 Quantification/ Evaluation of Options

(i) Option 1: Status Quo

Maintaining the status quo involves utilizing existing obsolete ancillary systems until they fail. Since the condition of the ancillary systems are deteriorating, keeping them in service, especially as the availability of spare parts diminishes, presents a number of risks, including failure. Failure of the ancillary systems to provide support to the stations can lead to unreliable stations and increased safety risks. In turn, this could impact the reliability of the power supply to customers connected to those stations. Due to the potential high cost of equipment replacement and long outages to customers as a result of catastrophic transformer failure associated, this option is not recommended.

(ii) Option 2: Replace/Install Ancillary Systems

Replacing deteriorating ancillary systems and installing new ones where needed facilitates the safe and reliable operation of Toronto Hydro stations. It is prudent to take this course of action because it allows Toronto Hydro to be able deliver a consistent power supply to customers in an efficient and cost-effective manner, while also protecting the safety of its staff and the general public.

The cost of ownership (COO) and program net benefit (NPV) associated with ancillary systems program is further detailed in Table 14. The cost of ownership is established for both the existing state (COO_E), and the proposed new state (COO_N) based on the first year of planned activities in this program. The COO of a state reflects the risk of asset failure, including both direct and indirect costs. These costs include the customer interruptions, emergency repairs, and asset replacements associated with a given design. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3.

TABLE 14: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	$3.98
Non Asset Risk [NAR_E]	$0
Maintenance Cost [MC_E]	$0
Additional Quantifiable Benefits [AQB_E]	$0
Cost of Ownership of Existing Assets [COO_E]	$3.98

When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first of activities, the ancillary systems program produces a net benefit (NPV) value of $1.53 million, as shown in Tables 14 and 15.

TABLE 15: NEW CASE BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 2:	
Asset Risk [AR_N]	$1.76
Non Asset Risk [NAR_N]	$0
Maintenance Cost [MC_N]	$0
Additional Quantifiable Benefits [AQB_N]	$0
Cost of Ownership of New Assets [COO_N]	$1.76
Option 2: Project Net Benefit (NPV $_2$)	
Difference in Cost of Ownership [$\hat{u}COO_2 = (COO_E - COO_N)$]	$2.22
Program Cost [PC_1]	$0.69
Program Net Benefit [NPV $_1 = (\hat{u}COO_1 - PC_1)$]	$1.53

E6.17.7 2015 Projects

Table 16 lists the 2015 projects for the Stations Ancillary Systems program.

TABLE 16: 2015 PROJECTS

Project Number	Project Name	Cost	Start Date	Project Type (2014 Carry-over or 2015 New)
29860	High Level MS: Replace 2 Air Compressors	$0.11 M	2015	CIR
29857	Windsor TS: Replace 2 Air Compressors	$0.11 M	2015	CIR
30519	Cavanagh TS: Install Fire Suppression System	$0.31 M	2015	CIR
11491	Jane MS: Install Firewall barrier	$0.15 M	2015	CIR

E6.17.7.1 S15340 Project Description

Investment Category: System Renewal

Program: Stations Ancillary Systems

Project Title: High Level MS: Replace 2 Air Compressors

Project Number: S15240

Project Year: 2015

Estimated Cost: $0.11 million

(i) Objective

The objective of this project is to replace the two air compressors at High Level TS.

(ii) Scope of Work

TABLE 17: S15240 SCOPE OF WORK DETAILS

District Neighborhood	TORONTO
Station(s)	HIGH LEVEL MS
Feeder(s)	NA

TABLE 18: S15340 ASSETS REPLACED

Assets (Units)	2015
Air Compressor	2

(iii) Justification & Benefits

The existing air compressors at High Level MS are 15 years old and inspection and maintenance data shows that they are deteriorating and are obsolete. Spare parts for these air compressors are no longer available from the manufacturer and it is becoming increasingly difficult to maintain these units in good working condition. Therefore, the air compressors must be replaced in order to secure the reliable operation of the air blast circuit breakers.

E6.17.7.2 S15345 Project Description

Investment Category: System Renewal

Program: Stations Ancillary Systems

Project Title: Windsor TS: Replace 2 Air Compressors

Project Number: S15245

Project Year: 2015

Estimated Cost: $0.11 million

(i) Objective

The objective of this project is to replace the two air compressors at Windsor TS.

(ii) Scope of Work

TABLE 19: S15245 SCOPE OF WORK DETAILS

District Neighborhood	TORONTO
Station(s)	WINDSOR TS
Feeder(s)	NA

TABLE 20: S15245 ASSETS REPLACED

Assets (Units)	2015
Air Compressor	2

(iii) Justification & Benefits

The existing air compressors at Windsor TS are 16 years old and inspection data shows that they are at the end of their lives and are obsolete. Spare parts for these air compressors are no longer available from the manufacturer and it is becoming increasingly difficult to maintain these units in good working condition. Therefore, the air compressors need to be replaced in order to secure the reliable operation of the air blast circuit breakers.

E6.17.7.3 S15564 Project Description

Investment Category: System Renewal

Program: Stations Ancillary Systems

Project Title: Cavanagh TS; Install Fire Suppression System

Project Number: S15564

Project Year: 2015

Estimated Cost: $0.31 million

(i) Objective

The objective of this project is to install a fire suppression system at Cavanagh TS.

(ii) Scope of Work

TABLE 21: S15564 SCOPE OF WORK DETAILS

District Neighborhood	SCARBOROUGH
Station(s)	CAVANAGH TS
Feeder(s)	NA

TABLE 22: S15564 ASSETS REPLACED

Assets (Units)	2015
Fire Suppression System	1

(iii) Justification & Benefits

The power transformers at Cavanagh TS are unique to Toronto Hydro. Toronto Hydro does not have spare transformers to replace these transformers if they fail. As well, there is currently no fire suppression system in place to prevent fire from spreading and damaging the switchgear building and the switchgear inside it if any of the transformers fail catastrophically. To prevent a loss of service due to fire, it is necessary to install a fire suppression system.

E6.17.7.4 S11491 Project Description

Investment Category: System Renewal

Program: Stations Ancillary Systems

Project Title: Jane MS: Install Firewall barrier

Project Number: S11491

Project Year: 2015

Estimated Cost: $0.15M

(i) Objective

The objective of this project is to install firewall barrier at Jane MS.

(ii) Scope of Work

TABLE 23: S11491 SCOPE OF WORK DETAILS

District Neighborhood	TORONTO
Station(s)	JANE MS
Feeder(s)	NA

TABLE 24: S11491 ASSETS INSTALLED

Assets (Units)	2015
Fire suppression system	1

(iii) Justification & Benefits

Jane MS is located in the residential area and the transformers of Jane MS are very close to residential homes. In the event of a catastrophic transformer failure, fire could migrate to these residential houses. There is currently no firewall to protect the neighboring residents and their homes, so a fire wall must be installed between the transformers and these houses.

E6.18 Station Building Infrastructure

DETERIORATED STATION BUILDING

E6.18.1 Summary

Program Description

This program addresses 11 stations in the downtown Toronto area that are showing multiple signs of structural deterioration. Recent civil assessments revealed evidence of deteriorated foundations, cable pit areas and roof structures that require immediate intervention. Multiple examples of cracks in the brick masonry walls were also noted. These deficiencies present an increased risk of water infiltration, moisture ingress, compromised structural integrity, rodent infestation, building security deficiencies and other potential safety hazards. Toronto Hydro plans to repair and/or replace the identified critical structural and foundation issues in the stations to minimize the risks associated with water infiltration and to improve structural integrity.

Table A summarizes the benefits associated with this capital investment program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Mitigation of security, safety and reliability risks with respect to the valuable assets housed inside these buildings.
Reliability	ƒ Mitigation or elimination of substructure damage, cracked walls and ceilings, leaking roofs and other identified issues in the selected stations will improve the station buildings' ability to protect assets and the crew housed within.
Safety	ƒ Water infiltration can cause flooding in buildings and damage to electrical equipment, resulting in electrical short-circuit/arching, or equipment failure. ƒ Weak foundations, and/or cracked walls can cause buildings to collapse, resulting in equipment damage and risking both worker and public safety. ƒ Broken or damaged doors and windows expose the building to external elements, which can cause serious damage to the equipment housed within. ƒ Compromised doors and windows can also lead to increased incidents of unauthorized entry to premises, a definite security concern.
Efficiency	ƒ Cost containment - repair and resource costs can be proactively managed. ƒ Superior equipment efficiency and a reduction in equipment failure via improved HVAC systems that will allow equipment to operate as intended ƒ Improved building life expectancy via the integration of new and improved building materials and construction practices.
Other Benefits	ƒ The majority of the identified buildings are designated as historic structures by the City of Toronto. Accordingly, investment is designed to maintain the historic value of the designated building.

Program Drivers

The trigger driver of the Station Building Infrastructure program is the risk associated with the building's ability to protect and safeguard the equipment and crew housed within.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ Water infiltration into the station building, compromising the equipment housed within. ƒ Compromised building structural integrity. ƒ Building security deficiencies due to broken doors and windows.
Secondary Driver	**Reasoning**
Safety	ƒ Water infiltration can result in short circuit, arcing and/or catastrophic failure of electrical equipment, including electrical fires, which are hazardous to Toronto Hydro crews and the community/general

	public surrounding the building. ƒ Aged and deteriorating foundational/structural elements of the building may result in station building collapse, causing harm to the equipment, crew, and the public. ƒ Damaged/deteriorated building access stairs may cause a worker to trip and fall.

Preferred Alternative

Toronto Hydro considered two options in developing its plan: 1) maintain the status quo or 2) correct deficiencies. Maintaining the status quo with minimal maintenance and making reactive repairs was determined to be unsatisfactory. By pursuing this alternative, Toronto Hydro would see its facilities continue to age and deteriorate over time, ultimately leading to substantial issues requiring expensive solutions. The integrity of these stations cannot be adequately maintained without capital investment during the 2015-2019 period. Taking a proactive approach to improve existing station buildings is expected to extend their serviceable life and to cost less than other solutions considered.

The completion of the first year of activities in this program will result in an avoided estimated risk cost (ARC) of $0.65 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.18.7).

Timing and Pacing

Toronto Hydro has been able to prudently manage deterioration and/or damaged station building components on a reactive manner in the past. However, the average age and condition of the utility's station buildings has reached the point where a more robust renewal program is required. A steady investment program is required, beginning in 2015, so that the utility can pace the capital investments over a number of years and avoid the accumulation of a more difficult to manage backlog of renewal needs toward the end of the forecast period. Toronto Hydro proposes to repair and/or replace the identified structural deficiencies over the 2015 to 2019 period at a total cost of $11.1 million, as shown in Table C.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	$0	$0	$0.53	$0.003	$0.16	$0.5	$2.5	$2.3	$2.6	$3.3

E6.18.2 Program Description

The Station Building Infrastructure program proposed for 2015 to 2019 consists of work to correct noted deficiencies as identified in a civil assessment, which entails the required restoration of failing building components that are showing signs of deterioration. Since their construction in the early 20th century, the industry has seen improvements in building standards and materials used for construction. With the completion of the proposed work, Toronto Hydro expects to see an increase in overall building life expectancy by incorporating current standards and modern materials in their construction. As well, the proposed program is expected minimize, and in some cases eliminate, risks associated with the dilapidated condition of the stations.

This program focuses primarily on the structural integrity of station buildings, which, when deteriorated, can have a negative impact on the performance and safe operation of electrical equipment. Of particular concern are issues related to water infiltration, moisture ingress, structural integrity, rodent infestation, building security deficiencies and other potential safety hazards. Occurrence of any of these events has the potential to cause damage to impacted electrical equipment and can increase repair costs needed with respect to reactive work and loss of power to customers.

Pictures taken at Carlaw and High Level stations during a civil assessment (November and December 2013), illustrate some of the identified issues and concerns that Toronto Hydro plans to rectify:

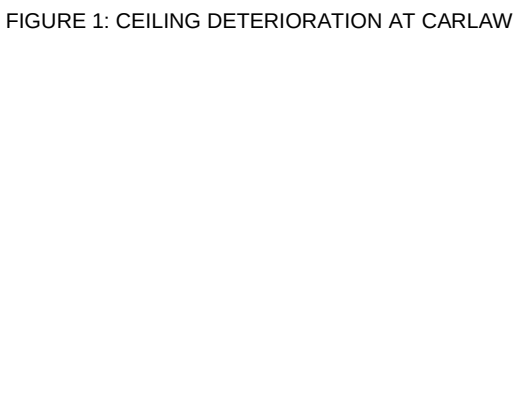


FIGURE 1: CEILING DETERIORATION AT CARLAW

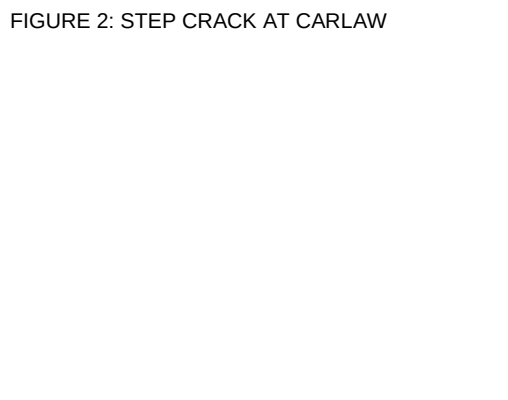


FIGURE 2: STEP CRACK AT CARLAW

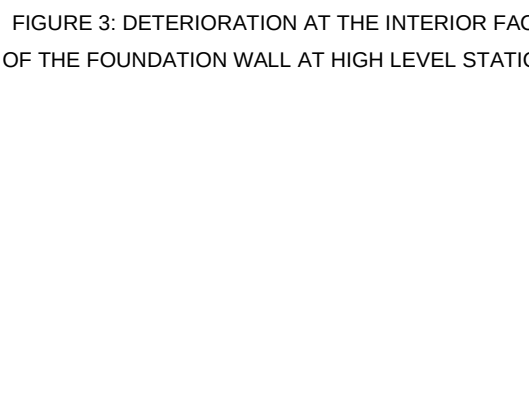


FIGURE 3: DETERIORATION AT THE INTERIOR FACE OF THE FOUNDATION WALL AT HIGH LEVEL STATION

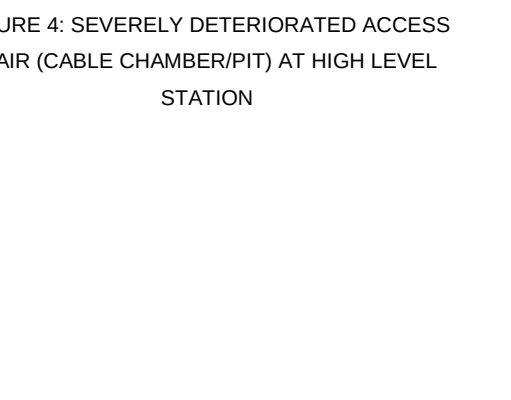


FIGURE 4: SEVERELY DETERIORATED ACCESS STAIR (CABLE CHAMBER/PIT) AT HIGH LEVEL STATION

FIGURE 5: DAMPNESS, PAINT PEELING, DELAMINATION AND SPALLING AT HIGH LEVEL STATION

FIGURE 6: GUTTER SECTIONS DAMAGED DUE TO SNOW AND ICE

Toronto Hydro's Station Building Infrastructure program targets eleven stations with critical deficiencies that require immediate attention. As buildings age, it is impractical and financially infeasible to replace them with new structures. Instead, maintenance and upkeep is needed to preserve structural integrity. By investing in and maintaining building infrastructure, critical electrical equipment is better protected against water ingress, rodent infestation and security breaches, which all can cause harm to electrical equipment. If the electrical equipment in stations is damaged, customers are likely to be directly impacted by prolonged outages across multiple feeders.

Well maintained building infrastructure and well-protected equipment keeps customers and the general community safe from various hazards that can arise if building infrastructure and/or equipment is compromised. Given that the identified station buildings are located in the former City of Toronto, a densely populated area, they are in close proximity to densely populated communities. Water and/or moisture ingress due to failed building infrastructure could easily cause a short circuit, resulting in a fire and/or a catastrophic equipment failure, posing a serious safety risk to workers, the public and nearby structures.

Through the Station Building Infrastructure program, Toronto Hydro plans to make investments to mitigate the risk of a potentially catastrophic failure and avoid costly reactive repair and restoration work. The following table summarizes the expected benefits of this program.

TABLE 1: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Mitigation of security, safety and reliability risks with respect to the valuable assets housed inside these buildings. ƒ The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $0.65 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.18.7).
Reliability	Mitigation or elimination of substructure damage, cracked walls and ceilings, leaking roofs, inefficient heating, ventilation and air-conditioning systems, damaged windows, and other identified issues improves the ability of stations buildings to protect assets and the crew housed within. Otherwise, the aforementioned issues can: ƒ lead to water ingress, resulting is damage to equipment, compromised crew safety, and corroding building structural elements such as support beams; ƒ invite rodent infestation due to broken and/or damaged doors and windows; ƒ impact crew safety due to uneven and/or deteriorating pavement and stairs; and ƒ create neighboring public safety concerns due to station building fires that might be caused by a short-circuit.
Safety	The following concerns will be addressed by the program, which will improve overall safety: ƒ Water infiltration can cause flooding in buildings and damage to electrical equipment, resulting in electrical short-circuit/arching, or equipment failure. These events risk worker safety and can potentially harm people and structures nearby. ƒ Weak foundations, and/or cracked walls can cause buildings to collapse, resulting in equipment damage and risking both worker and public safety. ƒ Holes and cracks in foundations and walls can allow rodent infestation to occur. Rodents create unsanitary conditions for workers and can damage cables/equipment. ƒ Broken or damaged doors and windows expose the building to external elements, which can cause serious damage to the equipment housed within. Compromised doors and windows can also lead to increased incidents of unauthorized entry to premises, a definite security concern. ƒ Settled and failed interlock paving and asphalt can cause water accumulation, increasing the risk of slip, trips, and falls.
Efficiency	The following efficiency benefits are generated by the program: ƒ Cost containment - repair and resource costs can be proactively managed. ƒ Superior equipment efficiency and a reduction in equipment failure via improved HVAC systems that allow equipment to operate as intended ƒ Improved building life expectancy via the integration of new and improved building materials and construction practices.

Other Benefits	ƒ The majority of the identified buildings are designated as historic structures by the City of Toronto. Accordingly, investment is designed to maintain the historic value of the designated building.

Figure 7 is a map showing the location of the identified stations that are addressed in the Station Building Infrastructure program.

FIGURE 7: STATION LOCATIONS

E6.18.3 Why the Program is Needed

Transformer stations (TS) and municipal stations (MS) serve a critical purpose in Toronto's distribution system; these stations contain power transformers, switchgear, station controls, fire protection and security systems, cable pits, racks and associated cable ingress/egress structures

– items that are essential to the safe and reliable delivery of electricity to customers throughout the system.

Electricity demand continues to increase along with the growing population of the City of Toronto. To meet the increasing demand efficiently and reliably, Toronto Hydro is relying largely on a diminishing amount of spare stations capacity, complimented by expansion of stations capacity where economical and the renewal of existing stations assets that are at or nearing end-of-life. In order to protect the value of these investments and to continue addressing the energy needs of a growing customer base, station buildings must be maintained in good working order throughout the useful life of the equipment contained within.

The goal of the Station Building Infrastructure program is to bring the identified stations – those with the most severely deteriorated infrastructure – to an acceptable industry standard by addressing the deficiencies noted as part of a civil assessment. The severity of deterioration as identified in the assessment can be seen in the Figures 8 to 19 below.

FIGURE 8: WINDOWSILL CRACK AT CARLAW

FIGURE 9: EFFLORESCENCE AND CORROSION OF THE FOUNDATION WALL AT TERAULEY STATION

FIGURE 10: SIGNS OF CORROSION DUE TO WATER INFILTRATION AT TERAULEY

FIGURE 11: EFFLORESCENCE AND CORROSION NOTED AT TERAULEY

FIGURE 12: SOUTH CABLE CHAMBERS/PITS SHOWING SIGNS OF WATER INFILTRATION AT HIGH LEVEL STATION

FIGURE 13: ROOF AT CARLAW. EXCESSIVE PONDING ON ROOF

FIGURE 14: WATER INFILTRATION IN CABLE PITS AT CARLAW SUBSTATION

FIGURE 15: FAILED MORTAR JOINTS AT CARLAW SUBSTATION

FIGURE 16: FOUNDATION WALL CRACKS NOTED AT CARLAW SUBSTATION

FIGURE 17: CONCRETE SOFFIT SPALLING AT CARLAW SUBSTATION

FIGURE 18: EXTENSIVE WALL DETERIORATION AT CARLAW SUBSTATION

FIGURE 19: CABLE CHAMBERS/PITS SHOWING SIGN OF WATER INFILTRATION AT CARLAW

By taking a proactive approach to addressing station building infrastructure deficiencies, Toronto Hydro can better plan and manage its workload and costs, and can reduce unexpected disruptions and issues relating to these assets. If steps are not taken to address the noted deficiencies, Toronto Hydro is likely incur higher costs associated with managing building or equipment failure and customers are likely to face an elevated risk of power disruptions due to failures. There are also potential worker and public safety risks. Toronto Hydro expects that this program faciliate improved safety, system reliability and efficiency. As can be seen in Figures 8 to 19 above, the identified work is complex and requires a proactive approach and planning.

E6.18.3.1 Program Drivers

The primary function of a station building is to provide protection from the elements, wildlife and intruders for station crews at work and the critical stations assets housed within. Components of the 11 station buildings targeted in this program are approaching a level of deterioration that could compromise the integrity of these essential building functions. The goal of the Station Building Infrastructure program is to proactively address the building infrastructure elements that are at risk of failure, thereby mitigating the associated risks to safety and reliability. The table below explains the trigger and secondary drivers of the program.

TABLE 2: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	x Many of Toronto Hydro's stations buildings we constructed in the early to mid-1900s, with some buildings currently over 100 years old. x An assessment of these buildings indicates the need to proactively address deficiencies in order avoid the risk of failure. x Deteriorated building infrastructure can result in: o water infiltration into the station building, compromising the equipment housed within, o electrical outages, o compromised building structural integrity, o rodent Infestation, and o building security deficiencies due to broken doors and windows.
Secondary Driver	**Reasoning**
Safety	The identified stations pose a heightened safety risk to workers, the community because: x water infiltration can result in short circuit, arcing and/or catastrophic failure of electrical equipment, including electrical fires, presenting a safety risk/hazard to Toronto Hydro crews and the general public surrounding the building, x aged and deteriorating foundational/structural elements could station buildings to collapse, and x damaged/deteriorated building access stairs increase the risks of trips and falls

The trigger driver of the Station Building Infrastructure program is the risk associated with the building's ability to protect and safeguard the equipment and crew housed within. The 11 stations covered by this program represent the highest risk stations in the fleet because of their respective conditions, age, loading, and impact to customers. The civil assessment provides evidence of deteriorated foundations, cable pit areas and roof structures. These deficiencies present an increased possibility of water infiltration, moisture ingress, compromised structural integrity, rodent infestation, building security deficiencies and other potential safety hazards. Water sources include seasonal snowmelt, heavy rains, high ground water levels and failure of adjacent municipal water pipes and storm sewers. The water related issues raise the risk of flooding and/or moisture in stations, which can cause the failure of station electrical equipment due to short-circuit events and ground faults. In short, water ingress, as seen in the pictures below, into the energized substation equipment could cripple the functioning of a station.

The civil assessment also provided Toronto Hydro with examples of severe structural deficiencies (for example Figure 18 shows damage to the windowsill at Carlaw station, which could cause severe damage, up to and including the wall collapsing, if not addressed). Foundation cracks noted in the civil assessment also point to the possibility of rodent infestation within station building, as they allow a pathway into the station building, and access to electrical equipment and cables housed within. Multiple signs of water ingress were also identified, e.g., Figures 20 and 21.

FIGURE 20: WATER PENETRATION THROUGH CABLE DUCK BANK AT HIGH LEVEL STATION

FIGURE 21: WATER PONDING, STAINING AND SEDIMENTATION AT HIGH LEVEL STATION

Toronto Hydro strives to maintain its existing station buildings and its components on an ongoing basis, but many of the station building components are approaching, and in some cases exceeding, their useful lives, thus increasing the burden and frequency of ongoing maintenance. These buildings require investments in the near-term so that Toronto Hydro can maintain system reliability, minimize unplanned outages and mitigate potential safety risks. The level of investment is intended to return the stations to a stable state where standard maintenance would keep them in good working order.

E6.18.3.2 Asset Details

Toronto Hydro assessed the current condition and expected service life of station buildings. Based on these inspections, the Station Building Infrastructure program was developed to target station buildings that are in the worst and/or most critical condition and those that pose substantial risk to Toronto Hydro's operations during the 2015-2019 period.

(i) Asset Lifecycle

The identified stations were constructed in the early and mid 1900s. Table 3 shows the year of construction and the age of the building as of 2014.

TABLE 3: YEAR OF CONSTRUCTION AND AGE OF STATION BUILDINGS

Station Name	Construction Year	Age in Years (as of 2014)
High Level MS	1910	104
Carlaw TS	1916	98
Terauley TS	1929	88
George & Duke MS	1929	85
Windsor TS	1950	64
Glengrove TS	1930	84
Junction MS	1910	104
Danforth MS	1967	47
Duplex TS	1967	47
Dufferin TS	1957	57
Wiltshire TS	1923	91

Each building is unique and has been assessed on an individual basis. The station buildings listed above have been selected for detailed assessment based on a number of factors, including: facility age, severe foundation deterioration, significant flooding risk and a potential for highest risk impact to customers. Even though ongoing maintenance has been performed, the station buildings each exhibit heightened degree of deterioration to their various components. These buildings retain certain components that date back to their original construction (e.g., foundation, walls, doors/windows, site work), and are showing signs of age and deterioration. The pictures below taken at Terauley and High Level stations, for example, show extensive signs of corrosion and damage at the foundation walls.

FIGURE 22: EFFLORESCENCE AND CORROSION AT THE FOUNDATION WALLS OF TERAULEY STATION

FIGURE 23: EFFLORESCENCE AND CORROSION AT THE FOUNDATION WALLS OF TERAULEY STATION

FIGURE 24: CORRODED SUPPORT STEEL POST AT HIGH LEVEL, SOUTH CHAMBER.

FIGURE 25: DAMAGED AND DETERIORATED TERRAZZO IN THE BASEMENT AT HIGH LEVEL STATION

(ii) Asset Failure Impacts

As identified in Table 3 above, the majority of the stations identified were constructed in the early 1900s and retain some of their original elements – elements that are showing signs of

deterioration, and that are in need of repair and/or restoration above and beyond ongoing reactive maintenance work. Water infiltration, flooding, and roof leaks have been identified at some of the stations, problems which are generally caused by failing building infrastructure components. These events increase the risk of station electrical equipment failure due to short-circuit events and ground faults, and pose a safety risk to employees and the public.

Water ingress occurred at Terauley Station in January 2005 and at Dufferin Station in January 2009, causing system outages, as further detailed below. These two recent examples demonstrate the damage that water ingress/flooding can cause to the equipment housed within the station building, the outages that can occur and the reactive work that needs to be performed, i.e., potential damage that flooding/water ingress can cause.

- Terauley Station Outage: On January 23, 2005 Terauley Station experienced water ingress that contributed to a station outage. Over 3,500 customers were affected for over a ten-hour period while the repairs were made, and the power restored. Further analysis into the cause pointed to a nearby ruptured water main, resulting in water ingress through the cable ducts. Terauley Station had to be removed from service for approximately 10 hours to pump the excess water out of the station, causing extensive and extended customer inconvenience, including the time and cost associated with reactive repair work incurred by Toronto Hydro.

- Dufferin Station Outage : In January 2009, Dufferin Station experienced a ruptured deluge system on the main level, causing damage to multiple switchgears in the basement of the station building. These events led to a substantial outage that affected 34,000 customers. Water was extracted from the basement in a timely manner, repairs made, and the power was restored, but this incident gave Toronto Hydro a good insight into the damage that can be caused by any form of water ingress into the station building.

Water infiltration into a station building occurs due to damaged or deteriorated building components, such as deteriorating roof and eaves trough conditions, broken or damaged doors and windows, cracked or damaged building and foundation walls, and may also be caused by uneven area paving and drainage system that fails to remove the water away from the building. This program plans to restore these station building components, as identified in the recently performed civil assessment.

FIGURE 26: WATER INFILTRATION AS NOTED AT HIGH LEVEL STATION

FIGURE 27: WALL AND ROOF SLAB SOFFIT DETERIORATION DUE TO WATER INFILTRATION AT HIGH LEVEL STATION

FIGURE 28: OVERVIEW OF THE COMPLETED REPAIR WHERE A ROOF LEAK HAS BEEN REPORTED. TERAULEY STATION ROOF.

FIGURE 29: TARGET MEMBRANE FLASHING FOR A DRAIN SEPARATING FROM THE FIELD. POTENTIAL FOR WATER INFILTRATION (HIGH LEVEL ROOF)

Substructure integrity, which includes building foundations and basement condition are vital to the overall strength of the building structure. Any signs of deterioration to this element of the station building needs immediate attention, as the safety and integrity of the entire building and its

contents are at risk. These are complex jobs, and require a proactive, planned approach to rectify the identified issues.

FIGURE 30: CABLE CHAMBER WALL AND ROOF FRAMING DETERIORATION AT HIGH LEVEL STATION

FIGURE 31: SETTLED SIDEWALK AND FAILED MORTAR JOINTS IN THE WALL/SIDEWALK JUNCTION AT HIGH LEVEL STATION

FIGURE 32: PAINT PEELING AT HIGH LEVEL STATION

FIGURE 33: DAMAGE TO THE CONCRETE STAIRS IN THE SOUTH CABLE CHAMBERS AT HIGH LEVEL STATION

Access to the building was studied to gain a better understanding of the safety issues facing the general public and workers. One specific point of emphasis was recessed and uneven ground that holds water; this condition can lead to improper drainage that can damage the building.

FIGURE 34: EXAMPLE OF FAILED MORTAR JOINTS AT THE EXTERIOR STEPS TO THE MAIN ENTRANCE AT HIGH LEVEL STATION.

FIGURE 35: FAILING MORTAR JOINTS, LEADING TO WATER INFILTRATION

The identified station buildings are located in the densely populated areas and serve a large number of customers. Any building component failure that has a potential of causing damage to equipment, such as water infiltration causing short circuits or collapsed support beams due to corrosion, can result in customer outages with long durations. Table 4 below shows the number of customers that could be affected by station building related outages. The costs associated with repair, both to the equipment and building can be substantial.

TABLE 4: NUMBER OF CUSTOMERS AND LOAD

Station Name	Station Address	Number of Customers	Peak Load (MVA)
High Level	292 MacPherson	7,010	144
Carlaw	369 Carlaw Avenue	10,600	75
Terauley	532 Bay Street	1,148	190
George & Duke	233 Adelaide St. East	6,330	311
Windsor	253 Wellington Street West	3,749	311
Glengrove	2829 Yonge Street	9,830	66
Junction	20 Ruskin Avenue	4,976	18.6
Danforth	2357 Danforth Ave	3,254	17
Duplex	390/400 Duplex Ave	9,286	109
Dufferin	1047 Dufferin St	29,038	141
Wiltshire	39 Wiltshire Ave	541	51

Collectively, these stations serve 85,762 customers and 1433.6 MVA of peak load.

Generally, any repair work due to water ingress in a station building requires the entire station to be deactivated due to safety concerns. While Toronto Hydro plans to attempt to restore power to all affected customers by transferring load during repair work, it is important to note that load transfer may not always be possible.

E6.18.4 Timing & Pacing of the Program

Toronto Hydro has been able to prudently manage deterioration and/or damaged station building components on a reactive manner in the past. However, the average age and conditions of the utility's station buildings have now reached a point where a more robust renewal program is required. As noted above, the recently conducted civil assessment gave Toronto Hydro a more comprehensive look at station building conditions, and has highlighted elements that need to be addressed in a planned fashion (e.g., foundational and/or structural repair work) so as to minimize the impact to customers. A steady investment program is required, beginning in 2015, so that the utility can pace the capital investments over a number of years and avoid the accumulation of a more difficult to manage backlog of renewal needs toward the end of the forecast period.

Toronto Hydro plans to address the identified deficiencies associated with each of the eleven targeted stations over the 2015-2019 planning horizon. Station building repair work entails

extensive planning, including contractor and city permit coordination prior to implementation, and load transfers (where feasible) to ensure minimal customer service disruptions during execution.

Station work has been prioritized based on the degree of deterioration and the severity of the possible impact to customers, the crew and the assets housed within each station. Table 5 below shows Toronto Hydro's historical and forecasted future spending.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending ($M)					Future Spending ($M)				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	$0	$0	$0.53	$0.003	$0.16	$0.5	$2.5	$2.3	$2.6	$3.3

E6.18.4.1 Ranking & Prioritization

In a recent review, Toronto Hydro identified the station buildings that need immediate attention based on age, failure risk (i.e., potential impact of failure), and field observations. The eleven stations identified in this program (see Table 3) were selected because they ranked poorly in these three areas.

Following the initial selection, a detailed civil assessment of the station buildings was performed. The objective of the assessment was to document the condition of the station buildings and to identify specific tasks necessary to ensure that the facilities are in compliance with all applicable industry standards, and to minimize risks to equipment reliability and worker safety. Of particular concern were any issues related to moisture/water ingress, structural integrity, rodent infestations, building security deficiencies and any potential safety hazards.

The civil assessment allowed Toronto Hydro to review the station buildings' infrastructure condition (pictures and engineering notes), which included cost estimates to perform the repair work. The magnitude and risk of deterioration in addition to the complexity of work (to ensure pacing of work) was used to further prioritize the sequence of work to be performed in 2015 and beyond.

E6.18.5 Program Execution

Toronto Hydro plans to address each of the identified station buildings as separate projects because the degree and severity of deterioration varies from one station building to another. As well, the identified station building components that need attention also vary from one station to

another. Where possible, Toronto Hydro plans to advantage of efficiencies that may be available by retaining contractors or procuring materials for multiple projects.

Toronto Hydro plans to manage and coordinate the required work and approvals amongst all parties involved, including external contractors, City authorities, and Hydro One Networks Inc. (HONI). During construction, extensive coordination may be required to isolate equipment in order to properly de-energize electric equipment as required and transfer load to adjacent station buildings, if necessary. In addition, if the construction work impacts HONI systems and/or equipment, coordination with HONI is required.

In terms of involvement with the City of Toronto, Toronto Hydro and its assigned contractors are responsible for initiating and completing any coordination work with city authorities.

E6.18.5.1 Program Risks

- External Contractor: Building infrastructure repair and maintenance work is generally sub-contracted to external vendors rather than being performed by Toronto Hydro employees. Usually, multiple vendors need to be engaged over the duration of the project including roofers, painters, foundation repairers, brick layers, etc. Accordingly, external contractor availability, timelines and expertise will impact the scope and timeline of the project. Proactive planning, including scheduling based on contractor selection and availability should minimize the risk associated with prolonged and/or slipped timelines. Upfront identification of contractor dependencies will be scheduled accordingly.

- Load Transfer: During construction, it may be necessary to transfer load between busses in order to manage load and electricity requirements. In some cases this load transfer might not be possible, resulting in temporary outages. In all cases, Toronto Hydro would know beforehand if load transfers are required, and appropriate actions would be taken off prior to any work being performed in the station building. In instances where load transfer is not possible, scheduled outages must be planned and communicated to all impacted customers and/or mitigated accordingly.

- City of Toronto: Prior to undertaking any major construction repair/maintenance project Toronto Hydro is required to obtain building permits from the City of Toronto. Delays to receiving permits are common and at times, alterations to original plans are required in order to obtain approval. The assigned project manager is typically aware of the timelines

as outlined by City, and tries to reflect them as accurately as possible in the project schedule.

- Community: Construction may cause inconveniences to the general community. In order to minimize impact, Toronto Hydro would typically undertake community engagement activities to inform the general public of its work and to seek valuable feedback.

E6.18.5.2 External Constraints

Formal agreement with HONI is required for certain building infrastructure repair work since it might affect their equipment. It is also important to take into account scheduling conflicts, since HONI's schedule may not align with Toronto Hydro's. Additionally, HONI may own a portion of the property/station building, thus requiring coordination between Toronto Hydro and HONI.

E6.18.6 Evaluation of Alternatives

E6.18.6.1 Quantification/ Evaluation of Options

Toronto Hydro considered two options to mitigate the reliability and safety risks associated with the deteriorated state of the eleven priority stations that are addresses by this program:

- Option 1: Maintain status quo
- Option 2: Correct Deficiencies

(i) Maintain Status Quo

Toronto Hydro considered maintaining the status quo and taking action only when the stations building components fail, i.e., a "run-to-fail" approach. Generally, station building components have specific useful lives that can be extended with ongoing maintenance work and improvements up to a point. If Toronto Hydro were to choose this alternative for the duration of the forecast period, some station building components would inevitably fail or reach a point beyond repair, and the cost associated with failure and repair could far outweigh the costs of maintaining the stations on an ongoing basis, due to the potential impact that a failed station building component could have on the equipment housed within or the crew working in the station. Also, a station outage would negatively affect customer service and the associated crumbling infrastructure would represent a potential risk to worker and public safety.

Past facility improvement and maintenance work on these stations has been minimal, as outlined in the historical spend table, Table 5. Less than $0.7 million a year has been invested in facility repair and improvement across Toronto Hydro's major downtown stations between 2010 and 2014. This past work has been directed to emergency and/or minimal repair work only. The status quo approach of minimal and reactive repairs it is now insufficient given the degree of deterioration.

(ii) Correct Deficiencies

The alternative choice involves addressing the identified deteriorating components of the station buildings proactively, by replacing and repairing older worn out components with newer, improved components. While this approach involves up-front costs, over the long term, it is the most cost-effective approach. For example, repairing the deteriorating roof of a station building proactively is cheaper than the cost associated with repairing a roof once it is completely damaged. In addition, a leaked/failed roof at a station building can cause water damage to other components, such as walls and ceilings, which would also require costly repairs. Additionally water infiltration due to a failed roof can cause flooding, damage and/or the destruction of equipment and poses safety risks for workers and the public in the surrounding area. Also, potential outages during repair work can be substantial.

As demonstrated, the chain reaction of a failed building infrastructure can be costly and can pose serious safety risk. By employing a proactive approach, existing electrical equipment and feeder arrangements can be maintained with minimal disruption achieved if the work is carefully planned out. Work can be compartmentalized and individual bus/feeders can be transferred while the balance of the station remains operational.

The proposed work is to be completed over a period of five years, from 2015 to 2019, at an average cost of $2.2 million per year, for a total of $11.1 million over the five years.

The first year of Stations Building Infrastructure investments is expected to results in avoided estimated risk cost (ARC) of $0.65 million, as detailed in Table 6. This value represents the avoided cost of executing the first year of activities as scheduled as opposed to deferring these activities until 2020. These avoided costs include quantified risks, taking into account the probability of failure of the assets, and multiplying this by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement. Further details on the ARC approach is provided in Section D3.3.

TABLE 6: AVOIDED RISK COST BUSINESS CASE EVALUATION

Business Case Element	Cost (in Millions)
Asset Renewal	
Present Value of Net Cost in 2020 [PV(NET_COST(2020)]	$0.65
Net Cost for the First Year of Activity [NET_COST(First Year of Activity)]	$0
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - (NET_COST(First Year of Activity))]	$0.65

E6.18.7 2015 Projects

Table 7 list the project that Toronto Hydro has planned for completion in 2015. Detail on this project ar provided in the following subsection.

TABLE 7: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date
S15371	High Level TS Shell and Roofing Improvements	$549,751	2015

E6.18.7.1 High Level TS She ll and Roofing Improvements

Investment Category: System Renewal

Program: Stations Building Infrastructure

Project Title: High Level TS Shell and Roofing Improvements

Project Number: S15371

Project Year: 2015

Estimated Cost: $ 549,751

(i) Objective

The objective of the High Level TS shell and roofing improvement project is to correct deficiencies in the roofing and outer shell at High Level TS to mitigate the risk of damage to critical station electrical equipment. This project is expected to bring the shell and roof of this facility up to an acceptable condition. Deficiencies include a degraded sacrificial layer on the roof, split stones on the surface of the station, degraded windows and a rear loading door in poor condition.

(ii) Scope of Work

TABLE 8: HIGH LEVEL TS CIVIL INFRAS TRUCTURE SCOPE OF WORK DETAILS

Station(s)	HIGH LEVEL TS
Feeder(s)	N/A

The scope of this project involves completion of the following tasks:

- Repaint roofing with a new aluminum reflective coating to seal the open laps in the sacrificial layer. It will be necessary to eliminate debris and vegetation from the roof drains before painting. Installation of a new membrane and flashings is necessary to complete the work.
- Repaint all stonework or faux-stone concrete masonry units. Prior to painting, it is necessary to wash the surfaces of the building to clean them of stains and dirt. Split stones and gaps in mortar joints, feature bandings, and sills are to be repaired with mortar.
- Replace the windows on two sides of the skylights. While replacing the windows, clear the corrosion of the steel window well grilles and repaint.

(iii) Justification & Benefits

The above deficiencies were identified through a condition assessment of the building. Completion of the identified improvements is necessary to prevent damage to critical station infrastructure housed within the station. In particular, water ingress is a significant concern since it can damage to electrical equipment.

Failure to complete this work as planned could result in a continued and increasing risk to system reliability, and eventually necessitate more extensive and costly improvements. Addressing these issues is expected to extend the life of the station building and to mitigate significant safety and reliability risks. The proposed repairs are expected to increase the safety of individuals in or around the station by removing potential slip or trip hazards and by minimizing the amount of water around electrical equipment.

E6.19 Stations DC Battery System Renewal

LEGACY TYPE BATTERY BANK

E6.19.1 Summary

Program Description

The Stations DC Battery System Renewal Program plans to replace aging direct-current (DC) batteries and chargers at various Municipal Stations (MS) and Transformer Stations (TS) to maintain operational effectiveness, minimize potential outages to customers, and comply with provisions within the Transmission System Code. Toronto Hydro currently has 194 battery and charger sets at various MS and TS locations. The DC battery system becomes a critical component when main power to the station itself is lost, as it continues to provide the necessary power supply to control and operate the associated circuit breaker assets.

Sixty-five of the 67 battery systems proposed for replacement during 2015-2019 are at least ten years old. Two of the battery systems are less than ten years old, but are planned for replacement in order to take advantage of work efficiencies by coordinating with transformer replacements planned at the same stations (Flemingdon MS and Oberon MS – refer to section E6.14 for details on planned power transformer replacements).

Table A summarizes the anticipated benefits associated with this capital investment program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Mitigation of the risk of long duration outages for approximately 137,000 customers supplied from the stations addressed in this program.
Reliability	ƒ Improved system reliability by mitigating the risk that SCADA and protection systems will be inoperable. Inoperable protection and control systems can result in lengthier and more widespread outages than would otherwise be necessary. ƒ Prevention of the propagation of feeder faults to a larger supply grid, and mitigation of the reliability risk introduced to the larger supply system by battery failures. ƒ Mitigation of the risk that the collection of system data (e.g. current, voltage and kVA readings on transformers, busses and feeders) by associated SCADA systems will be interrupted. These data points are important to Toronto Hydro planners for analysis of historical events and for future planning considerations.
Safety	ƒ Reduced likelihood that manual switching activities will be required as a result of battery system failure. Manual switching is one of the most electrically hazardous activities performed by field crews. ƒ Reduction in the potential risk of exposure to acid and fumes that may cause harm by eliminating the need to refill VLA batteries with distilled water.
Efficiency	ƒ Potential cost savings can be realized by planning replacements proactively as opposed to making reactive replacements following battery failure.

Program Drivers

The trigger and secondary drivers are summarized in the following table.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ 65 of the 67 batteries identified for renewal have exceeded their ten-year useful lives and require replacements to ensure proper operation of circuit breakers during contingencies. ƒ When a battery fails, the SCADA system cannot isolate feeder faults, which can cause prolonged outages and propagation of faults to the upstream supply grid. Replacement of end-of-life batteries is expected to mitigate the battery failure risk. ƒ Battery replacements are required to maintain alignment with the Transmission System Code Section 10.7.1, which specifies that customers (e.g., local distributors) must maintain battery systems capable of operating for at least eight hours per single battery bank.
Secondary Drivers	**Reasoning**
Safety	ƒ When the DC battery system fails to provide sufficient energy to

	operate breakers to isolate feeder faults through SCADA remotely, manual switching is required to isolate feeder faults to restore power to customers. Manual switching work is one of the most hazardous electrical activities performed by field crews because of the potential for electrical arc flash.

Preferred Alternative

Toronto Hydro considered two options in developing its plan: 1) maintain the status quo (run-to-fail) or 2) planned replacements. A run-to-failure approach would involve replacing these assets reactively when they fail.

Maintaining the status quo is likely to result in higher replacement costs, an increased risk of significant station-level outages to customers, and potential diversion of resources from planned capital work to replace the failed battery reactively. With the increasing percentage of batteries exceeding their expected useful lives, there is a heightened risk that battery failures could occur at any time in an unpredictable manner. Taking a proactive approach to replace the targeted battery systems that are beyond end-of-life is expected facilitate optimal planning of resources and materials allowing for replacements to be carried out in an effective and efficient manner at the lowest possible cost.

The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $5.10 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program.

Timing and Pacing

As shown in Table C, Toronto Hydro proposes to spend $3.14 million over the 2015 to 2019 period for this program.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.19	0.17	0.39	0.31	0.58	0.27	0.67	0.71	0.74	0.73

Based on the age of the battery population and the selection criteria described in Section E6.19.4.1, Toronto Hydro plans to replace DC battery systems at a pace that will maximize the

use of the remaining life of existing battery assets while mitigating the risk of untimely and potentially high-impact failures. The program also allows flexibility for selective replacements to coordinate with other asset replacements, such as stations power transformers or switchgear, to minimize the number of outages required for planned work at a station.

With approximately 14 battery replacements per year, Toronto Hydro's proposed program is intended to substantially reduce the growing backlog of batteries operating beyond end-of-life by 2019. The utility estimates that a slower rate of battery replacements would result in increased risk of additional outages associated with failed batteries and higher life-cycle costs due to replacements of the failed batteries on a reactive basis.

E6.19.2 Program Description

Direct current (DC) battery systems are installed in distribution stations to provide the DC power supply required to operate and control stations circuit breakers. The circuit breakers are used to isolate feeder faults and to restore service to customers during outages. Toronto Hydro's Stations DC Battery System Renewal program will replace battery systems (i.e., batteries and chargers) that have reached or exceeded their expected useful lives of ten years, at which point the potential risk of failure increases. Toronto Hydro also plans to replace two non end-of-life systems in coordination with planned station power transformer replacements.

Toronto Hydro anticipates that adopting a proactive replacement approach will minimize the likelihood of battery system failure, mitigating the risk that DC power supply from the battery system will be unavailable when needed. A reliable battery system allows isolation of feeder faults in an effective manner, whereas an unreliable battery system raises the potential risk of lengthy outages. Proactive replacement is also expected to lower replacement costs by enabling the relatively efficient organization of replacement activities compared to replacement during emergency situations.

The proposed battery replacement work involves removal of the old battery system and installation of a new battery system on a 'like-for-like' basis. Figure 1 illustrates the locations of the 67 battery systems that Toronto Hydro proposes to replace during the 2015-2019 period.

FIGURE 1: MAP OF 67 BATTERY SYSTEM REPLACEMENTS

Toronto Hydro plans to install modern valve-regulated lead-acid (VRLA) batteries when replacing the existing vented lead-acid (VLA) battery systems. The advantages of the VRLA battery are as follows:

- maintenance free (i.e. unlike VLA batteries, VRLA batteries do not require refilling with distilled water);
- less stringent ventilation requirements compared to VLA batteries as the VRLA battery does not release chemical fumes under normal operating conditions;
- lower potential safety risks from exposure to chemicals – specifically the risk of potential eye injuries during maintenance of the flooded acid type batteries. (Exposure to chemical fumes is also reduced.)

Figure 2 illustrates a typical set up of the new battery system for a 300 Amp-hour (Ah) VRLA battery and charger.

FIGURE 2: TYPICAL SET UP OF 300AH VRLA BATTERY SYSTEM (BATTERY BANK ON LEFT AND CHARGER ON RIGHT)

Figure 3 illustrates the older, flooded type 330 Ah battery bank.

FIGURE 3: 330AH FLOODED TYPE BATTERY BANK (THE OLDER TYPE)

The battery system size used at various Toronto Hydro stations varies depending on station requirements such as the load requirements of the different alarm systems, emergency lights, SCADA protection system and RTUs, the number of circuit breakers, etc. Table 1 below shows the number of battery systems proposed for replacement broken down by size and proposed replacement year.

TABLE 1: PROPOSED DC BATTERY SYSTEM REPLACEMENTS

Assets (Units)	2015	2016	2017	2018	2019	Total
Battery System 50 Ah	2	8	5	6	5	26
Battery System 80 Ah					1	1
Battery System 100 Ah	3	8	7	5	7	30
Battery System 200 Ah			1			1
Battery System 300 Ah		1	2	2		5
Battery System 400 Ah	1	1			2	4

Table 2 below summarizes the anticipated benefits of the Stations DC Battery System Renewal program.

TABLE 2: STATION DC BATTERY SYSTEM RENEWAL PROGRAM BENEFITS

Customer Value	ƒ Mitigation of the risk of long duration outages for approximately 137,000 customers supplied from the stations addressed in this program. ƒ The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $5.10 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.19.7).
Reliability	ƒ Improved system reliability by mitigating the risk that SCADA and protection systems will be inoperable. Inoperable protection and control systems can result in lengthier and more widespread outages than would otherwise be necessary. ƒ Prevention of the propagation of feeder faults to a larger supply grid, and mitigation of the reliability risk introduced to the larger supply system by battery failures. ƒ Mitigation of the risk of interruption to the collection of system data (e.g. current, voltage and kVA readings on transformers, busses and feeders) by associated SCADA systems. These data points are important to Toronto Hydro planners for analysis of historical events and for future planning considerations.
Safety	ƒ Reduced likelihood that manual switching activities will be required as a result of battery system failure. Manual switching is one of the most electrically hazardous activities performed by field crews. ƒ Reduction in the potential risk of exposure to acid and fumes that may cause harm by eliminating the need to refill VLA batteries with distilled water.
Efficiency	ƒ Potential cost savings can be realized by planning replacements proactively as opposed to making reactive replacements following battery failure.

E6.19.3 Why the Program is Needed

Of Toronto Hydro's 194 battery systems currently in service, 27% are expected to be past their useful lives of ten years in 2015 (as shown in Figure 6 in Section E6.19.3.2(i)), with an additional 33% of the current population expected to reach end-of-life by 2020. The Stations DC Battery System Renewal program is required to mitigate the potential failure and safety risks associated with this growing backlog of end-of-life battery systems. A functional DC power supply is vital to the reliable operation of critical station level protection and control systems.

E6.19.3.1 Program Drivers

Table 3 below provides a summary of the trigger and secondary drivers for the Stations DC Battery System Renewal program. This program is System Renewal initiative with a trigger driver of failure risk.

TABLE 3: STATIONS DC BATTERY SYSTEM RENEWAL PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ 65 of the 67 batteries identified for renewal have exceeded their ten-year useful lives and require replacements to ensure proper operation of circuit breakers during contingencies. ƒ When a battery fails, the SCADA system cannot isolate feeder faults, which can cause prolonged outages and propagation of faults to the upstream supply grid. Replacement of end-of-life batteries is expected to mitigate the battery failure risk. ƒ Battery replacements are required to maintain alignment with the Transmission System Code Section 10.7.1, which specifies that customers (e.g., local distributors) must maintain battery systems capable of operating for at least eight hours per single battery bank.
Secondary Drivers	**Reasoning**
Safety	ƒ When the DC battery system fails to provide sufficient energy to operate breakers to isolate feeder faults through SCADA remotely, manual switching is required to isolate feeder faults to restore power to customers. Manual switching work is one of the most hazardous electrical activities performed by field crews because of the potential for electrical arc flash.

The risks described in the table above are further detailed below.

(i) End-of-Life Failure Risk

Based on historical data on battery failures, the average useful lifespan of existing DC batteries is approximately ten years, as represented in Figure 4 in section E6.19.3.2 (i). As the batteries age

beyond their useful lives, the risk of battery failure increases and the battery systems can eventually fail in the field if not replaced. Toronto Hydro plans to replace the batteries that are at or beyond their useful lives because of the increased risk of battery failure. The reliability impacts associated with failed batteries are discussed in section E6.19.3.2 (ii).

(ii) Alignment with the Transmission System Code

The Transmission System Code (TSC) sets out the obligations between a transmitter and its customers, including distributors.. With respect to battery banks and DC supply, section 10.7.1 of the TSC specifies that customer batteries must have enough capacity to operate for at least eight hours for a single battery system (or at least six hours for each of the batteries in a two battery system). For batteries that are operating beyond end-of-life, there is a higher potential risk that these units will not be able to supply necessary power for the minimum amount of time specified in the TSC. As previously mentioned, failure of the battery system can render the protection and control systems inoperable, which, during a Loss of Supply event, can have reliability impacts on the larger supply grid.

(iii) Safety Risk

If a battery system fails to provide sufficient energy to operate the circuit breaker to isolate the feeder fault, the Control Center has dispatch a field crew to perform manual switching by opening (tripping) the circuit breaker to isolate the fault. Manual switching work is one of the most hazardous electrical activities performed by field personnel due to the potential for electrical arc flashes.

E6.19.3.2 Asset Details

(i) Asset Lifecycle

Battery failure data from 2011 through to 2013 (Figure 4) demonstrates that the average age of battery failure has historically been approximately ten years. On this basis, Toronto Hydro considers its existing stations DC battery systems to have reached end-of-life at ten years of age.

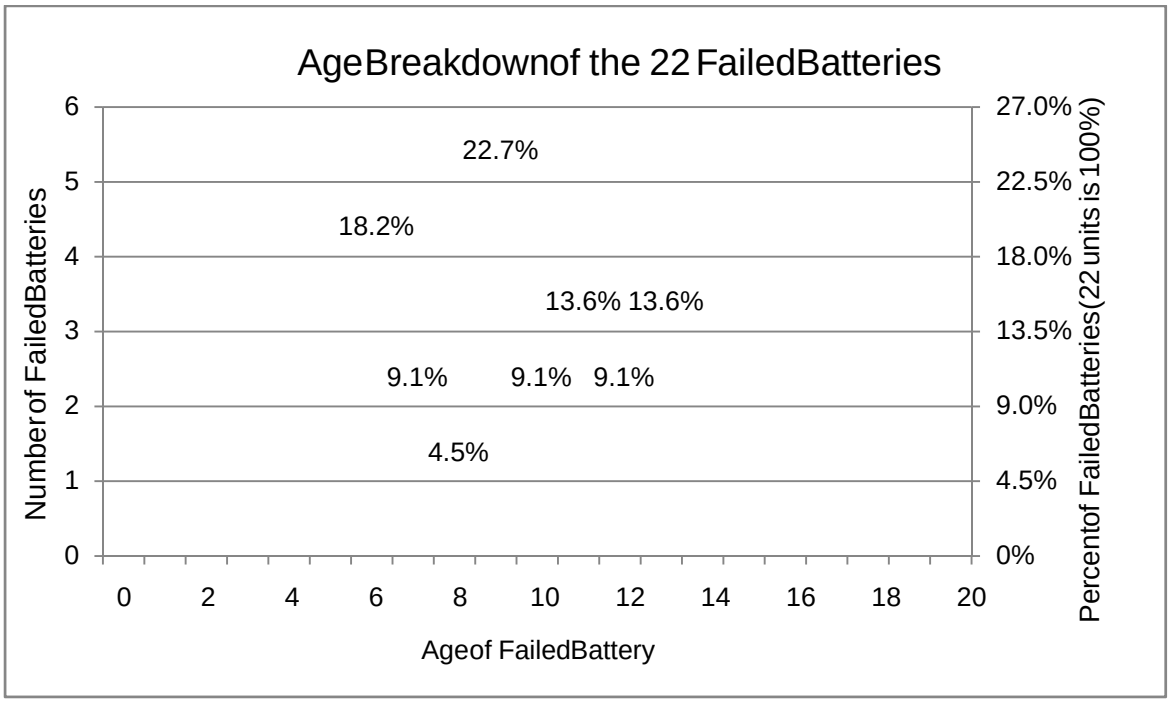


FIGURE 4: AGE OF BATTERIES THAT FAILED FROM 2011 TO 2013

A number of factors can lead to the failure of station batteries. A battery is essentially failed when the total capacity of the battery is significantly reduced, or when abrupt losses of power frequently occur. Typical factors contributing to the failure of VRLA and VLA batteries include: elevated operating temperature, excessive discharge-recharge cycling, improper floating voltage, and improper installation.

VRLA and VLA batteries operate at optimal temperatures of 25ºC, and operation above this temperature can cause the float charge current at float charge voltage to increase. This contributes to an increased rate of grid corrosion and is a frequent source of battery failure. At higher operating temperatures than 25ºC, the acceptable float charge voltage needs to be decreased, and operation at the manufacturer specified voltage can cause damage to the battery grid structure. Lastly, excessive discharge-recharge cycling of the battery causes repeated expansion and contraction of $PbSO_4$, which can accelerate grid corrosion in the cell.

Low capacity failures normally develop slowly over time due to a combination of the factors described above. Therefore, they do not generally cause sudden or expensive outages. In

contrast, abrupt "power cuts", caused, for example, by severely corroded grids, require immediate attention and replacement of the battery.

Figure 5 below illustrates the percentage of the total DC battery population that is currently more than ten years old as of 2015 and also provides a projection to 2020 that shows how the number of batteries beyond ten years old is projected to grow. If Toronto Hydro doesn't replace any battery systems between now and 2019, a high percentage (59.8%) of the battery population is expected to be more than ten years old by 2020.

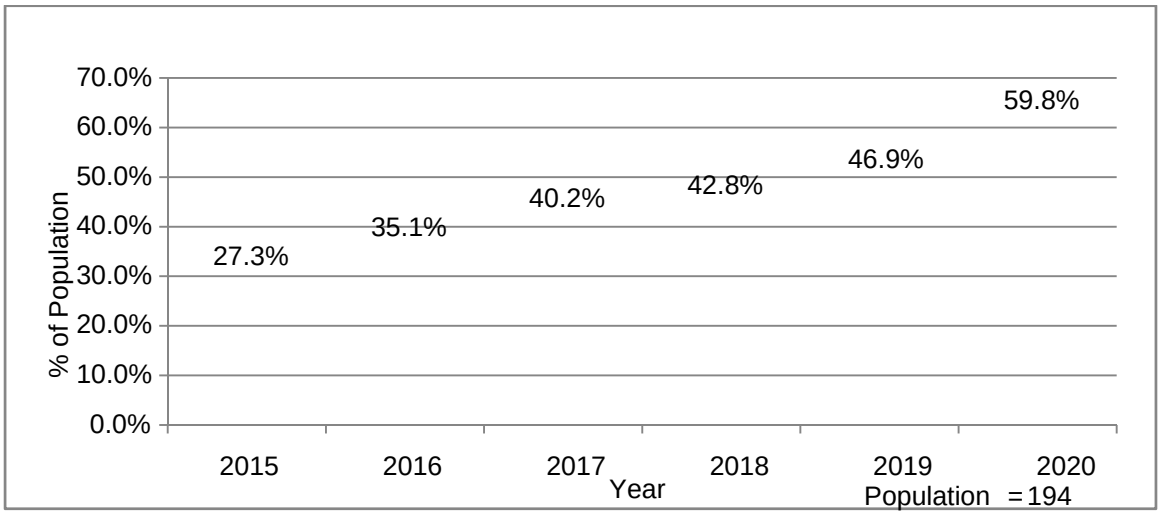


FIGURE 4: PERCENTAGE OF BATTERY POPULATION AT OR BEYOND 10 YEARS OF AGE FROM 2015 TO 2020 (IN ABSENCE OF A RENEWAL PROGRAM)

Figure 6 below shows the age profile of the 194 in-service battery systems as of 2015, where 27.3% (53 battery systems) are at or beyond the ten-year age threshold.

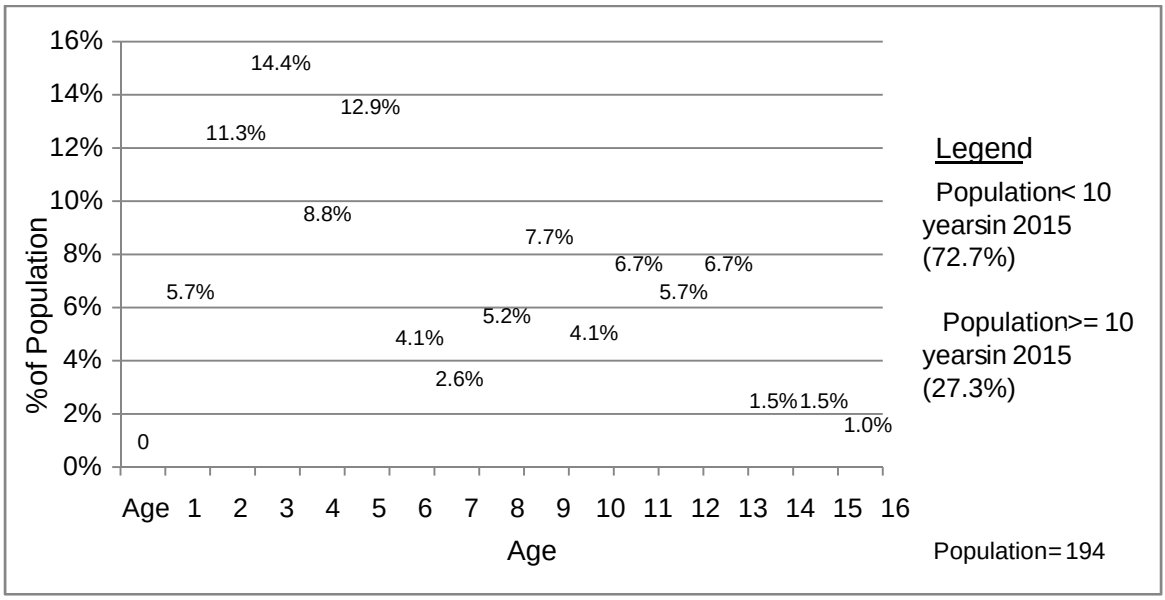


FIGURE 5: AGE PROFILE OF BATTERY POPULATION IN 2015

To help ensure that the battery system population remains in working order, Toronto Hydro proposes to replace a total of 67 battery systems, or about 14 battery systems per year from 2015 to 2019 inclusively. Figure 7 below shows the age profile of the 67 battery systems (with their sizes in Amp-hours (Ah)) identified for replacement during the 2015-2019 period.

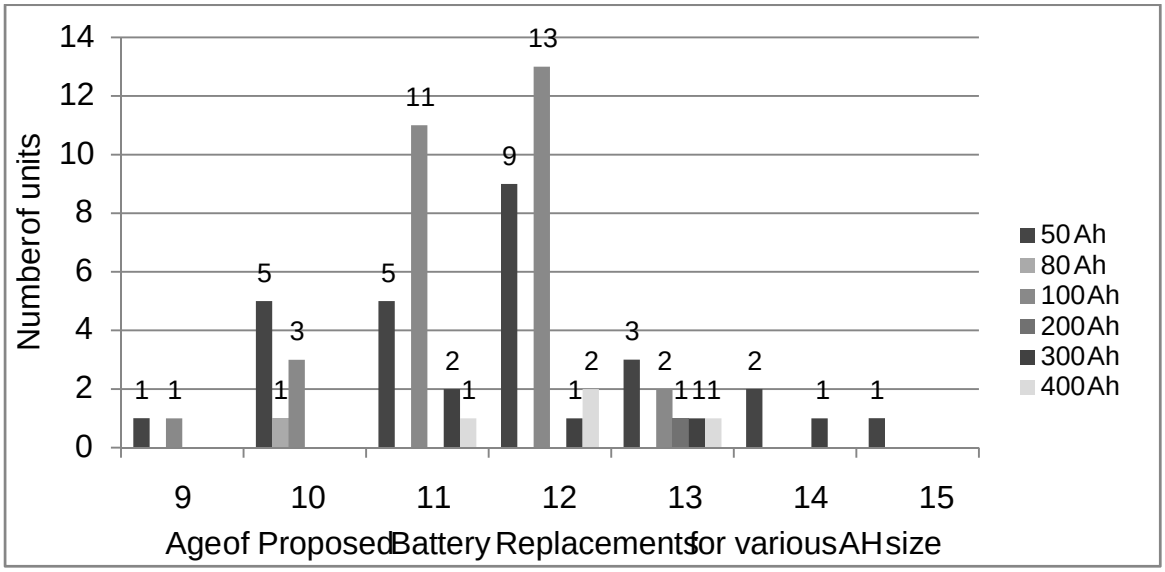


FIGURE 6: AGE OF THE PROPOSED 67 BATTERY SYSTEM REPLACEMENTS

As shown above, 65 of the 67 battery systems proposed for replacements are at least ten years old. Two of the battery systems are less than ten years old, but are planned for replacement in order to take advantage of work efficiencies by coordinating with transformer replacements planned at the same stations (Flemingdon MS and Oberon MS – refer to section E6.14 for details on planned power transformer replacements).

(ii) Asset Failure Impacts

The impact of a failed DC battery system depends on operating conditions of the grid at the time of the failure. For example, if a tree branch made contact with a feeder emanating from a station with a deteriorating DC battery system, the battery may still possess sufficient voltage to permit the breaker to open and isolate the fault. If the battery functions as required, the breaker would then be closed remotely by the power system controller at the control centre, and therefore only a momentary outage would occur. However, if the DC battery supply does not have sufficient voltage to close the circuit once the tree branch is no longer in contact with the feeder, customers would experience a substantially longer outage, as Toronto Hydro would be required to dispatch field crews to perform manual switching in order to restore power to the affected customers. This manual switching process could take anywhere from one to three hours.

In a more severe case, where the DC battery system has insufficient voltage to open the circuit breaker to isolate the initial fault, the fault could cascade to the upstream supply system, resulting in a wider outage, affecting customers beyond those on the immediately affected feeder and station. At that point, significantly more time would be required to restore service to a much larger number of customers.

The worst case outage scenario with the greatest impact to customers would occur if the upstream power supply to the station was completely lost (i.e. a Loss of Supply outage event), and the battery system failed to function properly, which would disable the protection system. This combination of events could cause a wide-spread outage impacting a very large number of customers.

One of the most severe impacts due to failure of a protection system occurred on July 8, 2013 at Manby TS, resulting in a widespread outage to the Greater Toronto Area (GTA). A storm caused severe flooding at Manby TS and Richview TS, rendering the protection system and SCADA inoperable. To minimize upstream damages, a total of 3,770 MW load was interrupted, causing a wide spread outage to the GTA area that affected up to 500,000 customers for at least eight hours, with some customers experiencing outages of more than 48 hours. While the outage in

this instance was not caused by a failed battery system, it is nonetheless indicative of the magnitude of the potential impact (i.e., the number of customers interrupted) that could result from a battery failure during a Loss of Supply event, which would similarly render the protection system and SCADA inoperable for a period of time until the battery could be replaced.

E6.19.4 Timing & Pacing of the Program

Table 4 below shows the historical spending and the proposed annual investment for the Stations DC Battery System Renewal program.

TABLE 4: STATION DC BATTERY SYSTEMS RENEWAL PROGRAM HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending ($M)				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0.19	0.17	0.39	0.31	0.58	0.27	0.67	0.71	0.74	0.73

Based on the age of the battery population and the selection criteria described in section E6.19.4.1, Toronto Hydro plans to replace DC battery systems at a pace that maximizes the use of the remaining life of existing battery assets while mitigating the risk of untimely and potentially high-impact failures. The program also allows flexibility for selective replacements to coordinate with other asset replacements, such as stations power transformers or switchgear, to minimize the number of outages required for planned work at a station.

With approximately 14 battery replacements per year, Toronto Hydro's proposed program is intended to substantially reduce the growing backlog of batteries operating beyond end-of-life by 2019. The utility estimates that a slower rate of battery replacements would result in increased risk of outages associated with failed batteries and higher life-cycle costs due to replacements of the failed batteries on a reactive basis.

Table 5 shows relatively lower spending in 2010 and 2011. This is due to the fact that failed batteries were previously replaced under the Reactive Capital program (refer to section E6.20 for details on this program).

E6.19.4.1 Ranking & Prioritization

Projects within this program are prioritized according to the following criteria:

- Age: the batteries addressed are ten years or older, with the oldest batteries being the most urgent.

- Coordination (i.e., opportunistic replacement): a battery is replaced when other activities are also occurring at the same station. For example, there are two stations where the batteries are less than ten years old, but replacement is warranted to coordinate with transformer renewal at the same station.

- Prudence: Toronto Hydro avoids proactive replacement of battery systems at stations that are scheduled for decommissioning due to conversion of station load to a higher voltage.

The ranking and prioritization process consists of sorting the battery population in an ascending order based on age and then checking the list against the list of scheduled voltage conversion projects to ensure battery replacements only take place at stations that will remain in service in the long-term. Once this is done, Toronto Hydro cross-references the resulting list with the switchgear replacement list and the power transformer replacement list to coordinate work execution efficiency and avoid multiple outages, as discussed in Section E6.19.5.

E6.19.5 Program Execution

Execution of Stations DC Battery System Renewal projects involves design and planning, procurement of materials, request for station outages, work to remove the old battery and charger systems, and the installation of new battery and charger systems with appropriate capacity. The work may involve the installation of additional switches, where necessary, to bring the installation up to the current standard of battery system design for easy isolation and replacements in future. Once the design is up to standard, future replacements of battery systems are less likely to require an outage at the station.

If a station has multiple assets requiring replacement (e.g. switchgear, transformers, battery systems, etc.) within the same timeframe, Toronto Hydro plans to schedule a single station outage to efficiently replace all the targeted assets simultaneously. Taking a station offline is a major undertaking and can only be carried out within certain windows of time during low load seasons (i.e. spring and fall).

E6.19.5.1 Program Risks

A significant complexity associated with the Stations DC Battery System Renewal program is the requirement that all associated station assets be de-energized to allow the battery system to be replaced safely. Before the station can be taken offline, the control center must determine that the adjacent stations have sufficient capacity and the distribution system has adequate availability to

transfer the loads from the interrupted station to adjacent stations. Toronto Hydro is unable to de-energize stations during high load seasons (i.e. summer and winter). Toronto Hydro mitigates this program risk by scheduling projects during the low load seasons.

E6.19.6 Evaluation of Alternatives

E6.19.6.1 Quantification/ Evaluation of Options

Toronto Hydro considered two alternatives for battery system replacement as described below.

(i) Run-to-Fail

Under this option, Toronto Hydro would replace battery systems reactively when they fail. This alternative is likely to result in higher replacement costs, an increased risk of significant station-level outages to customers, and potential diversion of resources from planned capital work to replace the failed battery reactively. With the increasing percentage of batteries exceeding their expected useful lives, there is a heightened risk that battery failures could occur at any time in an unpredictable manner.

(ii) Planned Replacement

The preferred option is to proactively replace the targeted battery systems that are beyond end-of-life. This alternative facilitates more efficient planning and use of resources and materials and allows for replacements to be carried out in an effective manner at the lowest possible cost. This alternative also minimizes the potential for lengthy customer outages, reduces the safety risks to personnel who may otherwise be required to perform manual switching, and ensures alignment with distributor-specific requirements in the Transmission System Code.

The replacement of the station DC battery systems planned for the first year of the program is expected to result in an avoided estimated risk cost (ARC) of $5.10 million, as detailed in Table 5. This value represents the cost avoided by executing the first year of activities as scheduled, rather than deferring these activities until 2020. These avoided costs include quantified risks, taking into account the probability of failure of the assets, and multiplying this by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement. Further details on the ARC approach are provided in Section D3.3.

TABLE 5: AVOIDED RISK COST OF DC BATTERY SYSTEM RENEWAL PROGRAM FOR 2015 PROJECTS

Business Case Element	Cost (in Millions)
Asset Renewal	
Present Value of Net Cost in 2020 [PV(NET_COST(2020)]	$5.83
Net Cost for the First Year of Activity [NET_COST(First Year of Activity)]	$0.74
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - (NET_COST(First Year of Activity))]	$5.10

E6.19.7 2015 Projects

Table 6 lists the Stations DC Battery System Renewal projects that Toronto Hydro plans to execute in 2015.

TABLE 6: 2015 PROJECTS

Project Number	Project Name	Battery System Age (years)	Total Project Cost	Project Start Date
28185	S14578 Porterfield MS replace battery system	13	$33,142	2015
29823	S15171 Brimley Shaddock MS replace battery system	13	$31,455	2015
30386	S15524 Cavanagh TS replace UPS battery system	11	$24,538	2015
29815	S15172 Coronation Bennett MS replace battery	12	$17,511	2015
29861	S15243 Dufferin B MS replace battery system	13	$31,006	2015
29877	S15258 Dufferin TS replace battery system	12	$136,305	2015

E6.20 Reactive Capital

TORONTO HYDRO CREW MEMBERS MAINTAINING POLES

E6.20.1 Summary

Program Description

The Reactive Capital program accounts for unplanned, non-discretionary capital expenditures required to repair or replace assets. Reactive expenditures are comprised of replacing failed or failing overhead, underground, stations, and metering assets. With proper budgeting and resource allocation, timely reactive work improves safety, lowers the backlog of assets waiting to be maintained, avoids depriving other planned capital programs of resources and reduces strain on the distribution system from failed assets.

A summary of the anticipated benefits for this investment program are provided in Table A.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Reduced customer interruptions and durations by replacing all failed assets immediately
Reliability	ƒ Maintaining and indirectly improving system performance and reliability through enhancements that occur when assets that have failed are replaced
Safety	ƒ Mitigation of the risk of catastrophic asset failure events from the replacement of high-risk assets approaching imminent failure

Efficiency	ƒ Projected 2015-2019 expenditures are in line with historical levels, despite the projection of higher asset failures, thanks to increased emphasis on assets being addressed proactively opposed to reactively across Toronto Hydro's planned capital and maintenance programs. The overall cost-efficiency of greater amounts of proactive renewal is expected to be higher than a more reactive approach.
Other	ƒ Reducing the possibility of greenhouse gases, harmful chemicals, waste, or debris being released in the environment as a result of a catastrophic asset failure ƒ Economic benefits derived from the mitigation of outages to businesses through the replacement and enhancement of assets in a timely manner

Program Drivers

The Reactive Capital program is primarily driven by Failure, and as such, is categorized as a System Renewal investment. The program's purpose is to fund capital expenditures that are non-discretionary and need to happen in a moment's notice mainly due to asset failures. By having the capital funds available, Toronto Hydro is better able to maintain system performance and reliability and can manage or eliminate certain potential safety risks to the public and Toronto Hydro employees. The secondary drivers of this program are safety and reliability. Both the trigger and secondary drivers for the Reactive Capital program are outlined in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure	ƒ High population of assets in poor condition and beyond their useful lives, requiring replacements as they fail ƒ Timely replacements are required to avoid running the system on contingency (i.e. with any number of feeders or assets interrupted and unable to provide backup supply in the event of an outage) ƒ Asset failure presents environmental risk; common environmental risks include the release of greenhouse gases into the atmosphere, and oil spilling into ground water
Secondary Drivers	**Reasoning**
Safety	ƒ Electrical and civil asset failures can create injury and health risks to the public and Toronto Hydro employees ƒ Common safety risks associated with the risk of faulted/failed equipment include electrical contacts, arc flashes, and fires that could have serious consequences
Reliability	ƒ Asset failures generally have a direct impact on system reliability performance and customer service. To mitigate reliability impacts, resulting in reduced customer service and system performance

	reliability.

Preferred Alternative

Toronto Hydro considered the following options for addressing failed and about to fail assets:

(1) Performing reduced reactive capital work

(2) Performing no reactive capital work

(3) Performing the Reactive Capital program as set out in this narrative

Option III is the preferred alternative as it accounts for sufficient capital funding to effectively replace and repair failed assets over the 2015-2019 planning horizon. Accounting for the amount of aging distribution infrastructure in Toronto, anticipated reactive capital expenditures are expected to maintain system performance, improve reliability, increase customer satisfaction and eliminate safety risks.

Timing and Pacing

The total forecasted spending for the Reactive Capital program from 2015 to 2019 is $165.5 million. As seen in Table C, the future spending from 2015 to 2019 is relatively constant and aligned with projected corrective work requests as further discussed in Section E6.20.3.2 (iii).

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	25.1	28.6	29.2	37.4	32.1	31.9	32.7	33.1	33.6	34.2

E6.20.2 Program Description

The Reactive Capital program is comprised of expenditures made to overhead, underground, secondary network, stations and metering assets. The purpose of reactive work is to restore service to customers and maintain system reliability by addressing failed assets. Reactive work is unplanned, and either occurs in response to an asset failure or to the detection of a severe asset deficiency (e.g., a severely cracked pole) that cannot be addressed by planned capital replacement procedures and timelines and must be reactively replaced to ensure the safety of the public and Toronto Hydro employees. Reactive work is usually executed on the same day, following the detection of an asset requiring replacement. The scope of all reactive work covers Toronto Hydro's entire distribution system and affects all asset classes.

Within Toronto Hydro's predictive and preventive maintenance programs[3], crews designate a rating of one to five on their inspection forms to indicate the state of an asset. An asset identified as having a Level 4 deficiency exhibits major deterioration, operates at a lower efficiency and requires replacement soon. An asset is given Level 5 deficiency if it requires replacement in response to both a failure or if the asset is causing a significant safety, environmental or reliability risks. Based on the severity of the situation, Level 4/5 deficiencies are issued corrective work requests to be performed immediately, which are funded from the reactive capital budget.

Overhead reactive work includes the replacement of poles, primary and secondary conductors, transformers, switches and overhead line hardware equipment. Underground reactive work includes the replacement of cables, installation of splices for direct buried cables, joints, transformers, switches and civil infrastructure. In addition, grounding compliance issues related to both non-conforming submersible transformer vaults and pole-top transformers are covered. Secondary network assets, including automatic transfer switches, reverse power breakers, network protectors and network transformers are combined with underground reactive work. Stations reactive work includes all system components between the demarcation point at the Hydro One Networks Inc. (HONI) supply point and the line disconnect device on the distribution feeder circuit. Reactive metering work includes meter asset replacements, including smart meters.

[3] Exhibit 4A, Tab 2, Schedule 1

Although Toronto Hydro has performed trending analysis based on past unplanned reactive capital work, by its very nature, this type of work is inherently difficult to anticipate. As well, reactive capital work cannot be deferred and addressed by other programs at a later date because of the immediate safety, environmental and reliability risks associated with this work as described above.

Table 2 summarizes the expected benefits of the Reactive Capital program.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Reduced customer interruptions and durations by replacing all failed assets immediately
Reliability	ƒ Maintaining and indirectly improving system performance and reliability through enhancements that occur when assets that have failed are replaced
Safety	ƒ Mitigation of the risk of catastrophic asset failure events from the replacement of high-risk assets approaching imminent failure
Efficiency	ƒ Projected 2015-2019 expenditures are in line with historical levels, despite the projection of higher asset failures, thanks to increased emphasis on assets being addressed proactively opposed to reactively across Toronto Hydro's planned capital and maintenance programs. The overall cost-efficiency of greater amounts of proactive renewal is expected to be higher than a more reactive approach.
Other	ƒ Reducing the possibility of greenhouse gases, harmful chemicals, waste, or debris being released in the environment as a result of a catastrophic asset failure ƒ Economic benefits derived from the mitigation of outages to businesses through the replacement and enhancement of assets in a timely manner

E6.20.3 Why the Program is Needed

An increasing percentage of Toronto Hydro's asset population is either approaching or is already beyond its useful life. As shown in Table 3, the total number of corrective work requests within Toronto Hydro's asset population is projected to steadily increase every year through 2015 to 2019, primarily due to the growing trend of assets beyond their useful lives as explained in Section E6.20.3.2 (i).

TABLE 3: HISTORICAL AND PROJECTED NUMBER OF CORRECTIVE WORK REQUESTS TO ADDRESS OVERHEAD, UNDERGROUND, SECONDARY NETWORK & STATIONS DEFICIENCIES

	Historical				Forecast					
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of Corrective Work Requests (in thousands)	10.1	10	6.5	8.3	9.2	9.4	9.6	9.9	10.1	10.3

The number of asset failures requiring reactive intervention varies from year to year. For example, Toronto Hydro experienced fewer asset failures and instances of defective equipment in 2012, signified by the lower number of corrective work requests as compared to 2011. Due to the unpredictable nature of asset failures, there may be volatile swings in the number of corrective work requests from year to year, as further discussed in Section E6.20.4. Catastrophic failures[4] of assets can require very large investments by Toronto Hydro – investments that, in the absence of a dedicated reactive capital budget, would deprive other capital and operational programs of resources and hinder the planned modernization and growth of the utility as a whole. As such, Toronto Hydro requires the Reactive Capital program to manage unavoidable asset failures and address high-risk assets approaching imminent failure, in order to continue to provide reliable, safe, and environmentally sound service to customers from 2015 to 2019 and beyond.

E6.20.3.1 Program Drivers

The purpose of the Reactive Capital program is to fund capital expenditures that are non-discretionary and that may need to be made at a moment's notice in order to maintain system performance and reliability, maintain customer satisfaction, eliminate safety risks to the public and Toronto Hydro employees, mitigate environmental risks and maintain accurate billing through the replacement of failed assets. The trigger and secondary drivers for this program are shown in Table 4 below.

[4] Defined in Section E6.20.3.2 (ii).

TABLE 4: PROGRAM DRIVERS

	Program Drivers	Reasoning
Trigger Driver	Failure	ƒ High population of assets in poor condition and beyond their useful lives, requiring replacements as they fail ƒ Timely replacements are required to avoid running the system on contingency (i.e. with any number of feeders or assets interrupted and unable to provide backup supply in the event of an outage) ƒ Asset failure presents environmental risk such as contamination
Secondary Drivers	Safety	ƒ Electrical and civil asset failures can create safety risks to the public and Toronto Hydro employees ƒ Common safety risks associated with the risk of faulted/failed equipment include electrical contacts, arc flashes, and fires that could have serious consequences
	Reliability	ƒ Asset failures generally have a direct impact on system reliability performance and customer service. Timely replacements mitigate reliability impacts, resulting in increased customer service and system performance reliability.

(i) Failure

The trigger driver of the Reactive Capital program is equipment failure. As a whole, Toronto Hydro's distribution system has experienced improved reliability; however, despite this improvement, a substantial number of assets continue to fail each year. Continued asset failure is mostly attributed to a significant percentage of Toronto Hydro's assets being beyond their useful lives; as they continue to age, their failure probabilities increase.

In addition to the safety and reliability risks of failure discussed below, the failure of assets can also be harmful to the environment. Leaking transformers or cables in underground structures pose a serious environmental risk. Asset failures can also result in the release of harmful contaminants and greenhouse gases into the environment. Timely reactive capital replacements can mitigate the environmental risks associated with asset failure.

(ii) Safety

Another important driver of the program is the safety and health of both the public and Toronto Hydro employees. In order to protect the public and Toronto Hydro employees, the company has systems in place to detect failure incidents, and ensure coordination with all third parties before any replacements occur. Failure modes of equipment, depending on their nature, can have

immediate and serious safety and health consequences. Electrical equipment failures can lead to electrical arcs and arc flashes, which can lead to fires and pose serious risk to workers and the public. Civil failures and the collapse of equipment such as poles and underground vaults can put the public and Toronto Hydro employees at risk.

A reactive capital program can mitigate safety and health risks by replacing assets approaching imminent failure. An example of safety risk mitigation is the replacement of failed network protectors. The failure of a network protector to operate can lead to network vault fires, which poses significant safety risks for firefighters, the public and Toronto Hydro employees. In addition to replacing an asset that has failed, harmful debris and contamination caused by a failed asset, such as asbestos in the case of fibertop network units, are removed and cleaned up. Examples of the effects of an underground network vault fire and asbestos cleanup crews working on removing all asbestos contaminants from a vault are shown in Figures 1 and 2.

FIGURE 1: (LEFT) FAILED PROTECTOR. (RIGHT) BURNT AILC SECONDARY CABLES.

FIGURE 2: ASBESTOS CLEANUP OF VAULT

(iii) Reliability

Finally, reliability is an important driver of the program. Depending on the asset and its location within the distribution system, system reliability will be impacted to varying degrees by an asset failure. Asset failures affect the supply of power to Toronto Hydro's customers and strain the system. See Section E6.20.3.2 (iii) for more information of historical and projected system reliability impacts.

E6.20.3.2 Asset Details

Due to the unplanned nature of reactive work, it is difficult to project the total number of assets that will need to be replaced in a given year through the Reactive Capital program. However, as discussed in Section E6.20.3.2 (iii), assets are continuing to deteriorate as demonstrated by the number of outages caused by failed equipment, and the severe deficiencies and corrective work requests generated by inspectors and work crews. Other factors that are taken into account to help project the number of assets that may fail in a given year include asset age, condition, location, configuration and loading, all of which can affect longevity. Approximately 26% of all assets in the distribution system will be beyond their useful lives by 2015.

(i) Asset Lifecycle

The useful life of an asset is defined as the estimated range in years that it is expected to operate as designed without the need for repair or replacement. Depending on an asset's complexity, operational stress, location and configuration, its useful life will vary. Figure 3 illustrates the assets that will reach end-of-life by 2015, distributed between overhead, underground, network, station and civil categories. Nearly a third of the assets approaching end-of-life in 2015 are stations assets, which pose a significant risk to reliability and customer satisfaction. Due to their location within the distribution system, outages on station assets have the potential to affect a large number of customers.

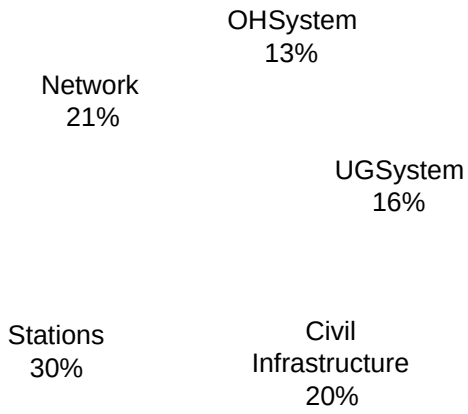


FIGURE 3: DISTRIBUTION OF ASSETS BEYOND THEIR USEFUL LIFE BY 2015

Degradation processes, such as corrosion, water ingress and heavy loading can expedite various failure modes of an asset. Toronto Hydro has maintenance programs in place to address various degradation processes and prevent asset failures; however, all assets, even those that have

been properly maintained, are at risk of failure at any time, whether it is from age related issues or problems beyond the control of maintenance. As such, reactive capital programs play a pivotal role in addressing failed assets.

Figures 4 and 5 illustrate some of the structural deficiencies associated with underground vaults and pole equipment.

FIGURE 4: UNDERGROUND VAULT STRUCTURAL DEFICIENCIES

FIGURE 5: INFRARED (IR) SCAN OF HOT SPOT DEFICIENCY ON POLE EQUIPMENT (INDICATED BY RED ARROW ON RIGHT IMAGE)

(ii) Asset Failure Impacts

Each asset has two or more distinct failure modes that result in a certain consequence cost. Typically, the two modes of failure are a normal failure and a catastrophic failure, as defined below.

Normal Failure

A "normal" failure mode is defined as a typical asset failure, where the outage is only experienced by local, connected customers and where there are usually no further associated events and/or collateral damage that results in "indirect" costs. A typical example of a "normal" failure would be an internal winding fault within a transformer, which would result in an outage to all connected customers and would necessitate replacement of the transformer.

Catastrophic Failure

A "catastrophic" failure mode (Figures 6 and 7) is defined as an extraordinary failure of the asset, where the outage is typically on a larger scale, affecting a greater number of customers up the line fuse or feeder circuit breaker. These failures would typically result in associated events and/or collateral damage, ultimately leading to the incurrence of "indirect" costs. Safety and environmental risks may result from catastrophic failures due to the explosive failure modes of certain asset classes.

FIGURE 6: UNDERGROUND VAULT FIRE ON ST. CLAIR AVE

FIGURE 7: POLE COLLAPSING ONTO A RESIDENCE

The figures above provide examples of two catastrophic asset failures. These asset failures not only reduce system reliability, but may also pose significant safety and environmental risks to the public and Toronto Hydro employees.

(iii) Reliability Impacts

As stated in Section E6.20.3.2 (i), a high number of assets within Toronto Hydro's distribution system are projected to reach end-of-life within the next five years. This will likely result in a greater number of asset failures. Adequate proactive budgeting and resource allocation for reactive work lowers the risk of creating a backlog of failed assets requiring replacement, and depriving other programs of capital resources. Through immediate replacements of failed assets, impact costs to customers (outages and events) and Toronto Hydro (lost revenue) can be reduced, and system reliability can be maintained and improved.

Information presented in the following graphs is derived from historical data of Toronto Hydro's corrective work requests, outages, and defective equipment demographics.

Figure 8 shows that the total number of corrective work requests issued in a given year has been increasing and Toronto Hydro expects this trend to continue in 2015-2019. In 2012, a lower amount of corrective work requests were issued, which resulted in the sharp decline from the previous year, as explained in Section E6.20.3; this reasoning applies to all of the following figures in this section.

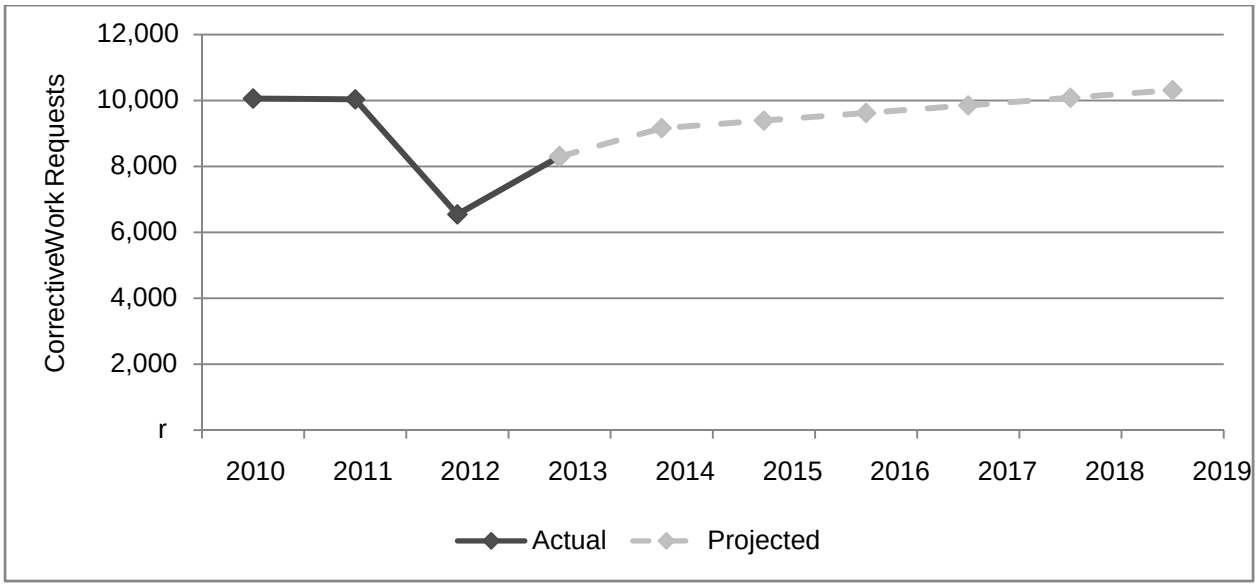


FIGURE 8: TOTAL NUMBER OF CORRECTIVE WORK REQUESTS TO ADDRESS OVERHEAD, UNDERGROUND, SECONDARY NETWORK & STATIONS DEFICIENCIES

Figure 9 shows the total number of asset failures across all systems, recorded by Toronto Hydro's Defective Equipment Tracking System (DETS). Assets tallied here only include those that were found during operational procedures or scheduled maintenance tasks. Over 700 asset failures were detected in 2010 and 2011. While there was a decrease in 2012, the number of failures increased by 12% in 2013.

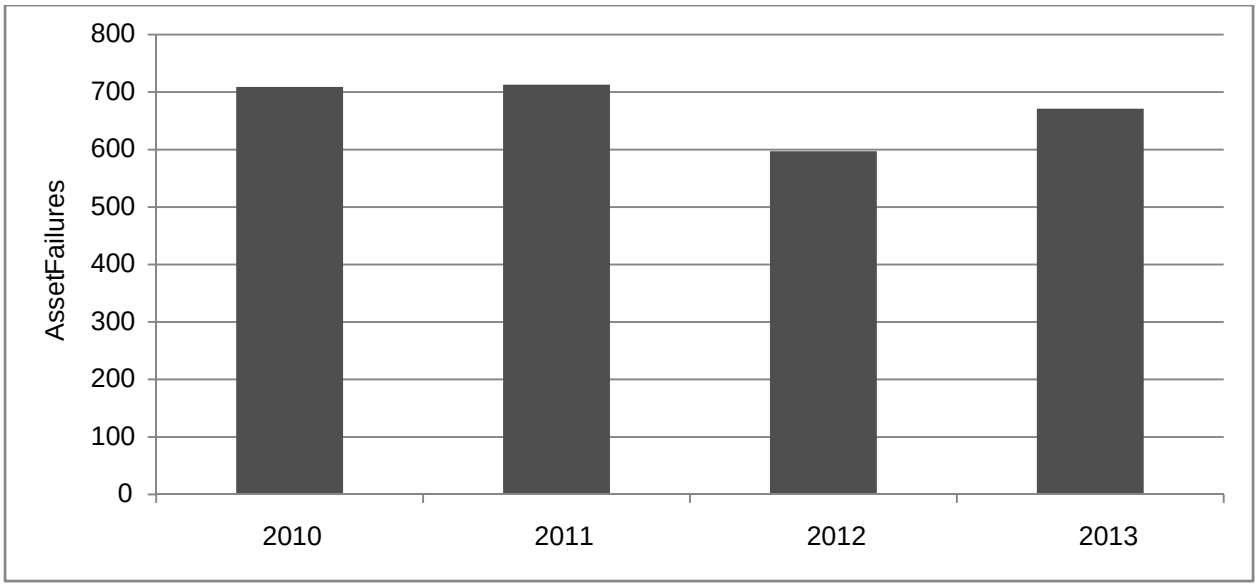


FIGURE 9: TOTAL NUMBER OF ASSET FAILURES ACROSS OVERHEAD, UNDERGROUND, SECONDARY NETWORK & STATION SYSTEMS (DETS)

Figure 10 illustrates the historical trend of the total number of asset failures resulting in outages across all systems; recorded from Toronto Hydro's Interruption Tracking Information System (ITIS). Over 1,000 failures occurred in 2010 and 2011. While there was a decrease in 2012, the number of failures increased by 14% in 2013. Approximately 19% of all failures during the 2010-2013 period in Figure 10 were caused by external factors including adverse weather, tree contacts, animal contacts and foreign interference.

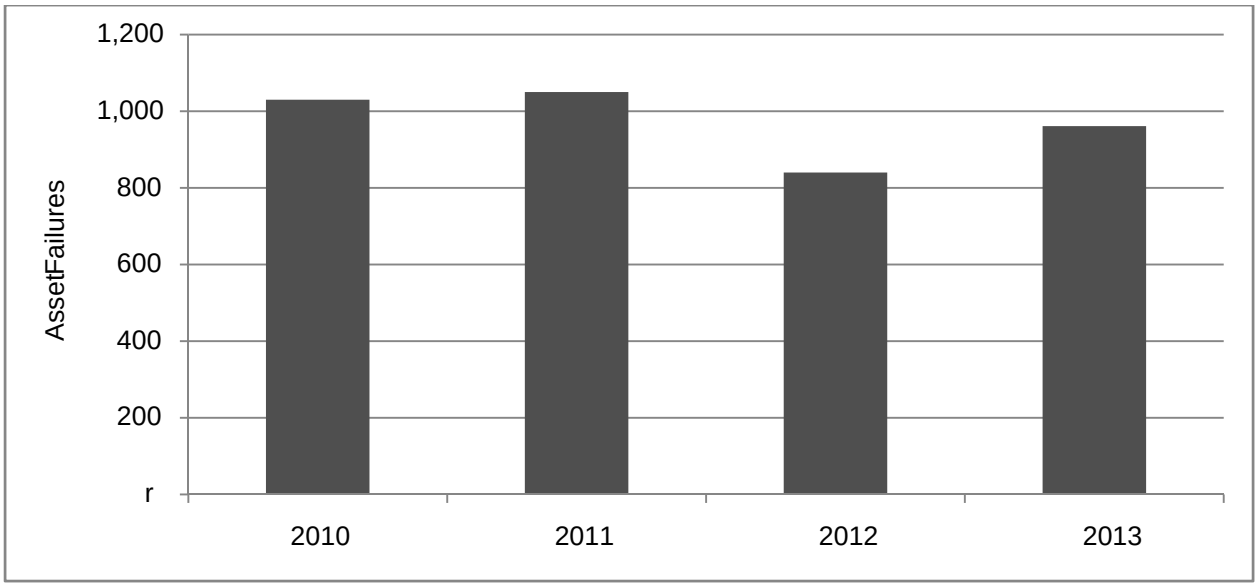


FIGURE 10: TOTAL NUMBER OF ASSET FAILURES RESULTING IN OUTAGES ACROSS OVERHEAD, UNDERGROUND, SECONDARY NETWORK & STATION SYSTEMS (ITIS)

(a) Overhead Assets

The overhead system includes overhead conductor wire, utility poles and their corresponding attached equipment, transformers and switches. Approximately 21% of all overhead assets will reach their end-of-life by 2015, without considering planned capital investments to be completed by then. Overhead assets are much more susceptible to non-asset related deficiencies such as animal/insect/tree contacts, weather and vegetation related incidents. These factors accelerate degradation processes. Figure 11 shows an example of a catastrophic failure of a wood pole collapsing onto neighbouring poles.

FIGURE 11: MULTIPLE POLE COLLAPSE

Figure 12 illustrates the number of overhead asset failures resulting in outages to the system, recorded by ITIS. Toronto Hydro has consistently experienced at least 250 failures annually during the 2010-2013 period. The main overhead assets responsible for the outages illustrated in Figure 12 consist of switches, transformers, lightning arresters, conductor wire, insulators and poles.

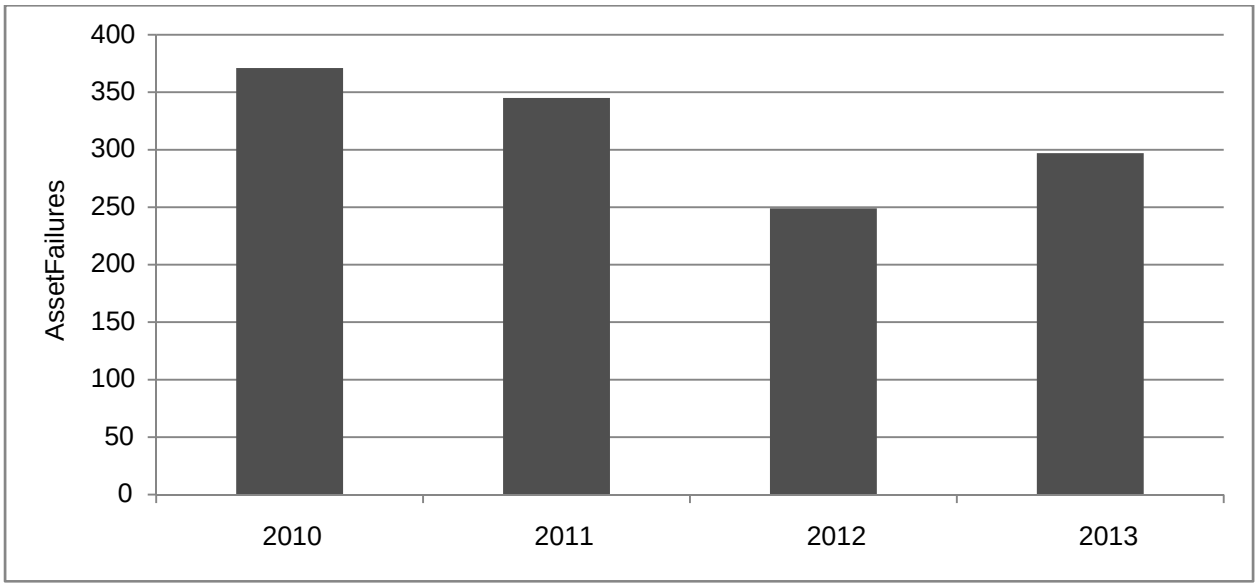


FIGURE 12: NUMBER OF OVERHEAD ASSET FAILURES RESULTING IN OUTAGES (ITIS)

Figure 13 shows a trend of overhead asset failures, recorded by DETS. Assets tallied here only include those that were found during operational procedures or scheduled maintenance tasks. Over 60 asset failures have been found annually during the 2010-2013 period.

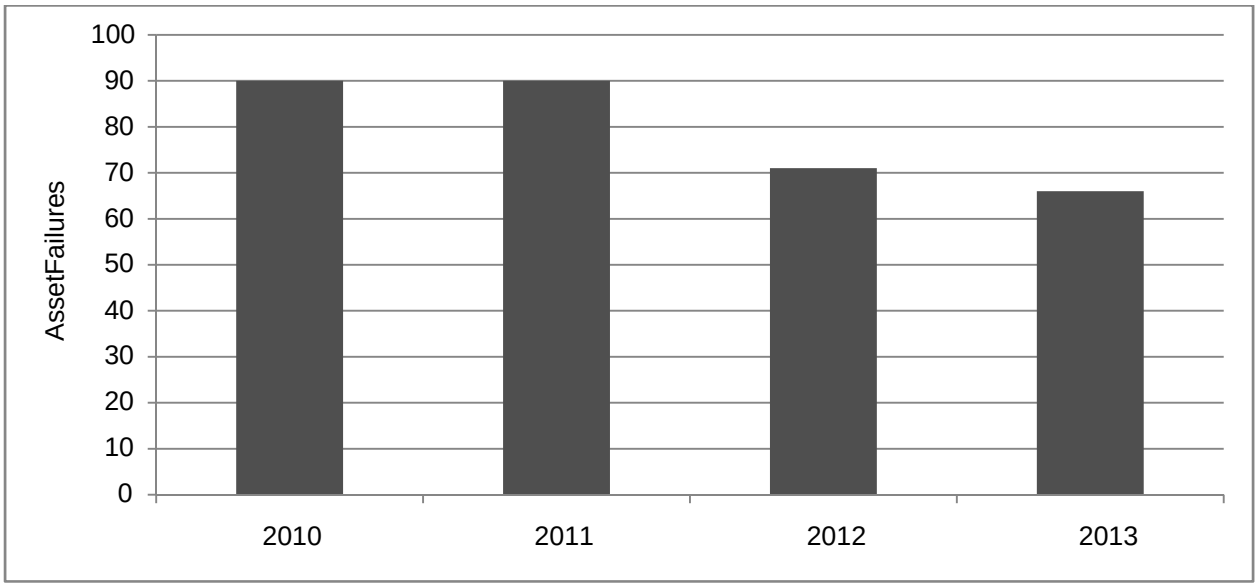


FIGURE 13: NUMBER OF OVERHEAD ASSET FAILURES (DETS)

Figure 14 shows the historical trend for the number of overhead corrective work requests. The number of work requests exceeded 2,500 in 2010 and 2011. Although the number of work requests declined in 2012, there is an increase in 2013. Toronto Hydro projects this increase to continue during the 2015-2019 period as a greater population of overhead assets exceed their useful life.

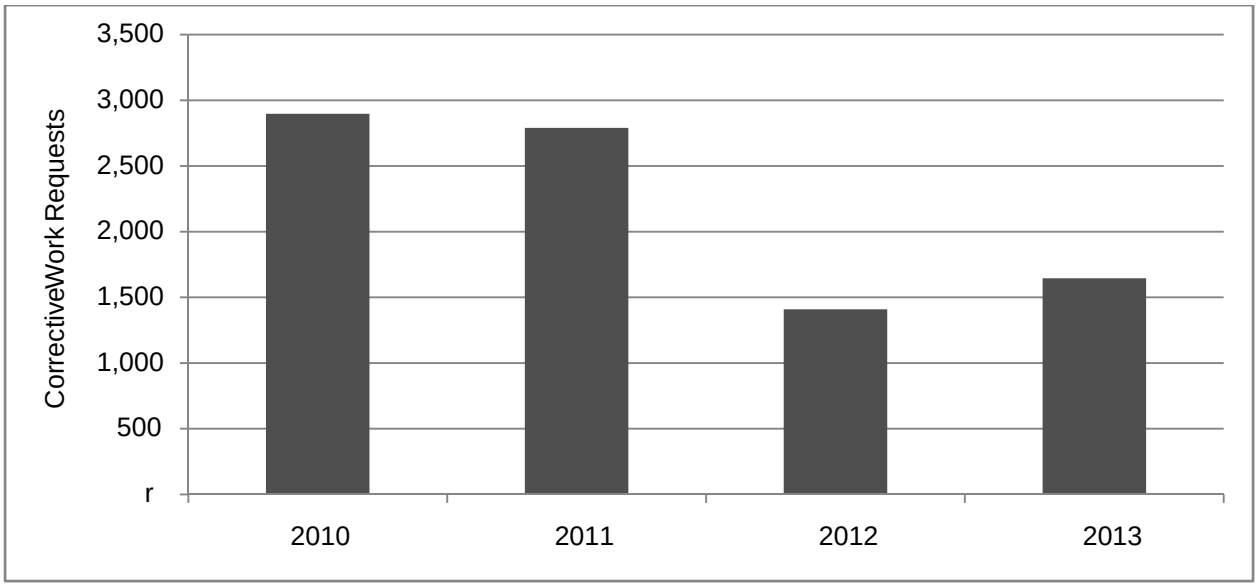


FIGURE 14: NUMBER OF OVERHEAD CORRECTIVE WORK REQUESTS

(b) Underground & Secondary Network Assets

Both the underground distribution system and secondary network system primarily consist of below-grade vaults and cable chambers, and the assets housed within them including cables, splices, joints, transformers and switches. Approximately 26% of underground assets, 35% of secondary network assets and 32% of all civil infrastructure will reach end-of-life by 2015, without considering planned capital investments to be completed by then.

Structural failures of vaults can lead to failures of all the assets inside them. Higher asset failure rates for vaults will reduce system reliability and cause longer outages. The damage to internal electrical equipment as a result of a vault failure (Figure 15) can be significant and replacement costs add to the costs normally required for power restoration. In addition, vault fires can occur when internal protection devices fail to prevent potentially unsafe backfeed conditions (reverse flow of power). These conditions may pose safety and health risks in the case of a network vault fire with fibertop units inside, which are often connected to the secondary grid using asbestos-insulated lead covered (AILC) secondary cables.

Approximately 60% of all network vault enclosures are expected to reach end-of-life within the next 10 years or less, while over 80% of all network vault roofs, which experience greater

exposure to external degradation factors, are already past end-of-life. A single vault can cost $1 million to rebuild.

FIGURE 15: (LEFT) VAULT WITH ROOF SLABS OFF. (RIGHT) TWO FIBERTOP UNITS DAMAGED BY A VAULT FIRE.

Faulted direct-buried cross-linked polyethylene (XLPE) cables are costly to repair due to the high number of labour hours required to locate and repair the fault. Segments of cables with high failure rates may require reactive work to install a standard concrete-encased duct bank to permanently replace the faulted cable segment. This reactive capital work is costly but necessary to remove consistently problematic direct-buried XLPE cable assets from the system, which improves system reliability.

Figure 16 illustrates the number of underground and secondary network asset failures resulting in outages to the system, recorded by ITIS. The number of asset failures has exceeded 400 annually during the 2010-2013 period. The main underground and secondary network assets responsible for the outages in Figure 16 are underground cable, transformers, elbows, switchgears, terminators, joints/splices and potheads.

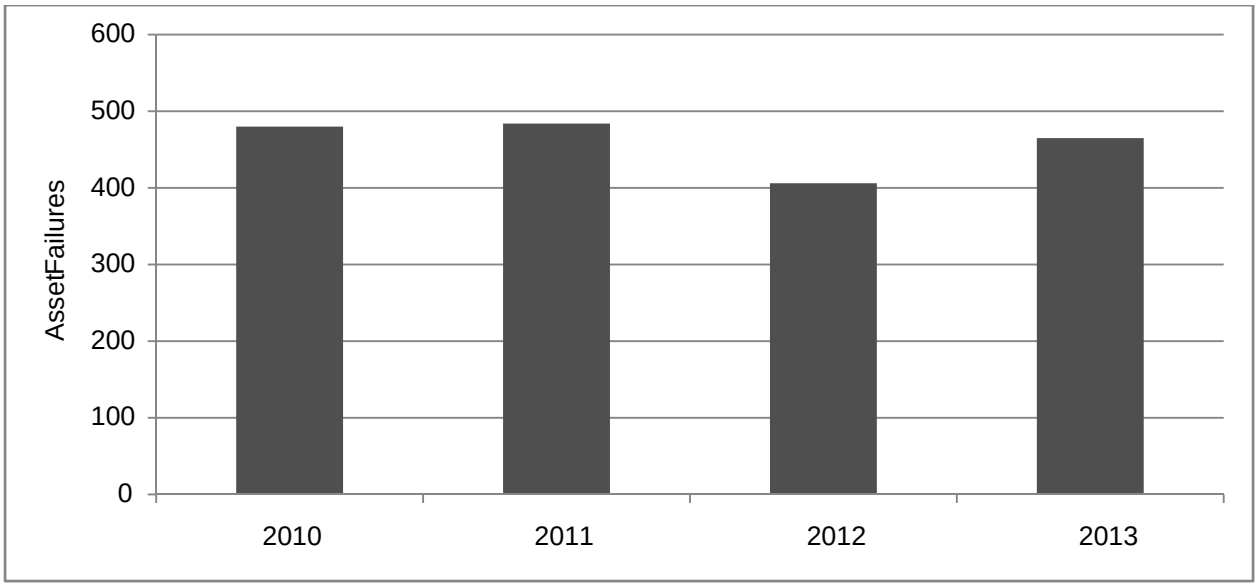


FIGURE 16: NUMBER OF UNDERGROUND & SECONDARY NETWORK ASSET FAILURES RESULTING IN OUTAGES (ITIS)

Figure 17 shows a trend of underground and secondary network asset failures, recorded by DETS. Assets tallied here only include those that were found during operational procedures or scheduled maintenance tasks. Over 200 asset failures have been found annually during the 2010-2013 period. The detection of underground and secondary network asset failures is shown to be on the rise as of 2013.

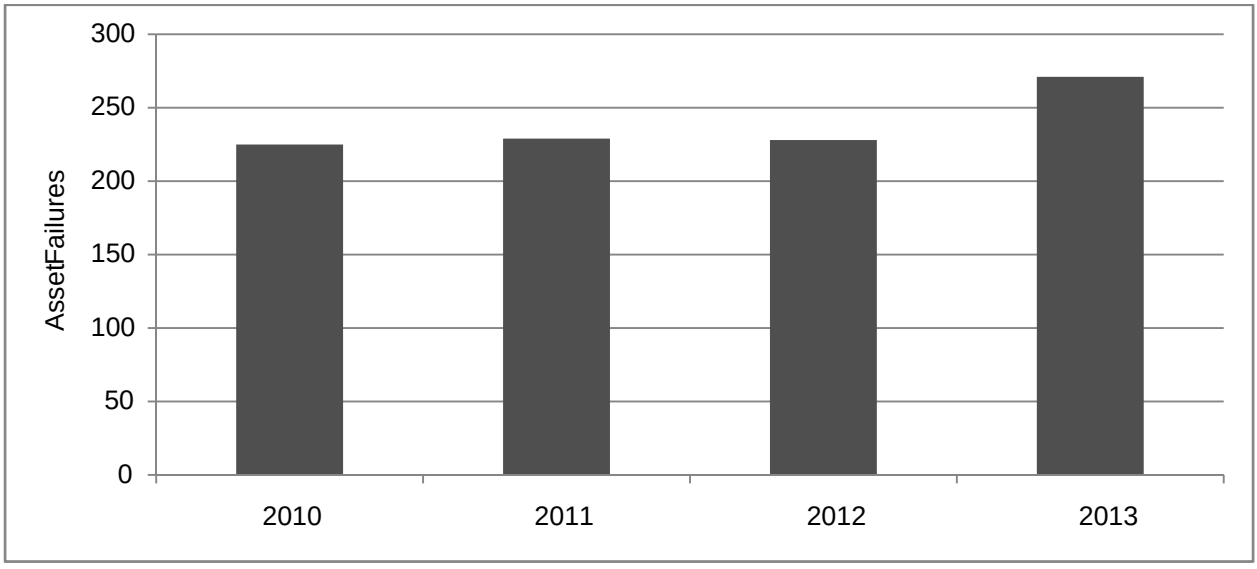


FIGURE 17: NUMBER OF UNDERGROUND & SECONDARY NETWORK ASSET FAILURES (DETS)

Figure 18 shows the historical trend for the number of underground and secondary network corrective work requests. The number of work requests exceeded 5,000 in 2010 and 2011. Although the number of work requests declined in 2012, there was a 53% increase in 2013, bringing the number up to 2010 and 2011 levels. Toronto Hydro projects this increase to continue during the 2015-2019 period, as more underground and secondary network assets exceed their useful life.

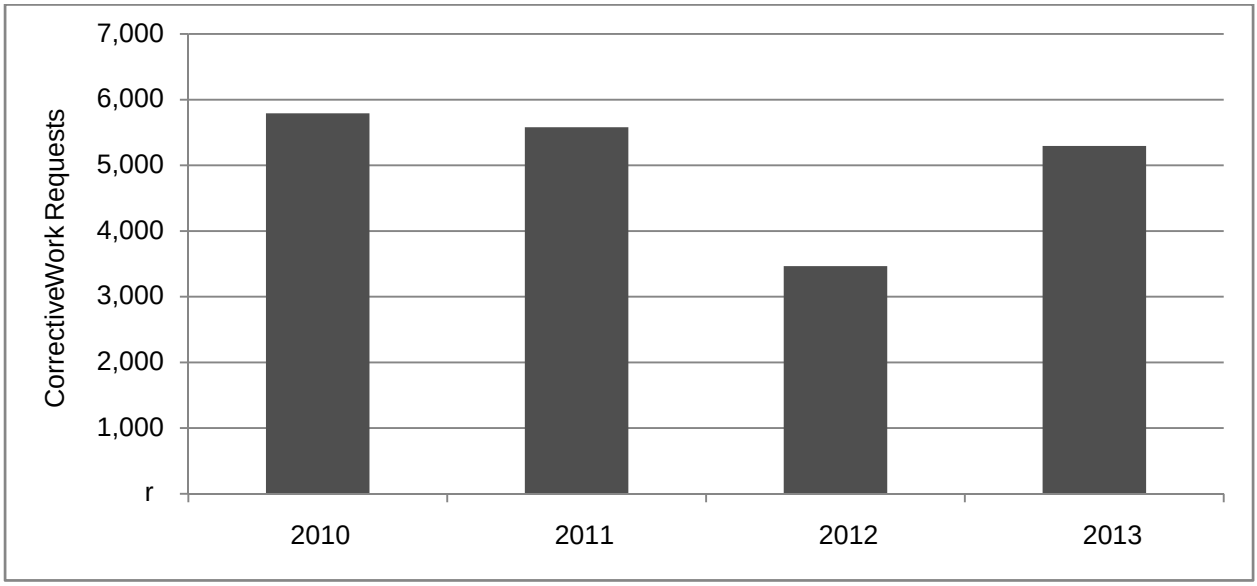


FIGURE 18: NUMBER OF UNDERGROUND & SECONDARY NETWORK CORRECTIVE WORK REQUESTS

(c) Station Assets

Station assets include power transformers, circuit breakers, relays, batteries/chargers, SCADA telemetry and/or control equipment, station alarms, DC panels, station heating, ventilation systems and sump pumps, which are installed across Toronto Hydro's 164 municipal stations and 35 transformer stations. Approximately 50% of all stations assets will reach end-of-life by 2015, without considering planned capital investments to be completed by then.

Figure 19 illustrates the number of station asset failures resulting in outages to the system, recorded by ITIS. The number fluctuates between 10 and 20 assets annually. The number of outages caused by failed station assets is much lower than the number caused by overhead and

underground assets, however station assets have higher failure impact costs to customers (outages and events) and Toronto Hydro (lost revenue). The main station assets responsible for the outages illustrated in Figure 19 are power transformers, cabling/terminations, switchgears, circuit breakers and other protection and control equipment.

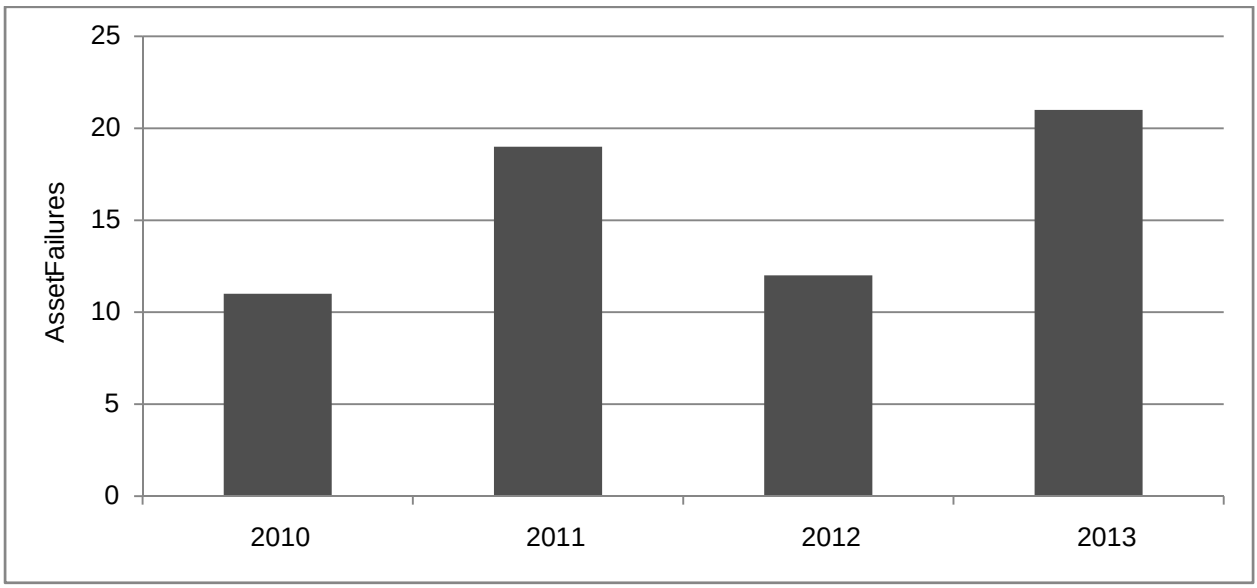


FIGURE 19: NUMBER OF STATION ASSET FAILURES RESULTING IN OUTAGES (ITIS)

Figure 20 shows a trend of station asset failures, recorded by DETS. Assets tallied here only include those that were found during operational procedures or scheduled maintenance tasks. At least 300 failures have been found annually during the 2010-2013 period. The detection of station asset failures are shown to be on the rise as of 2013.

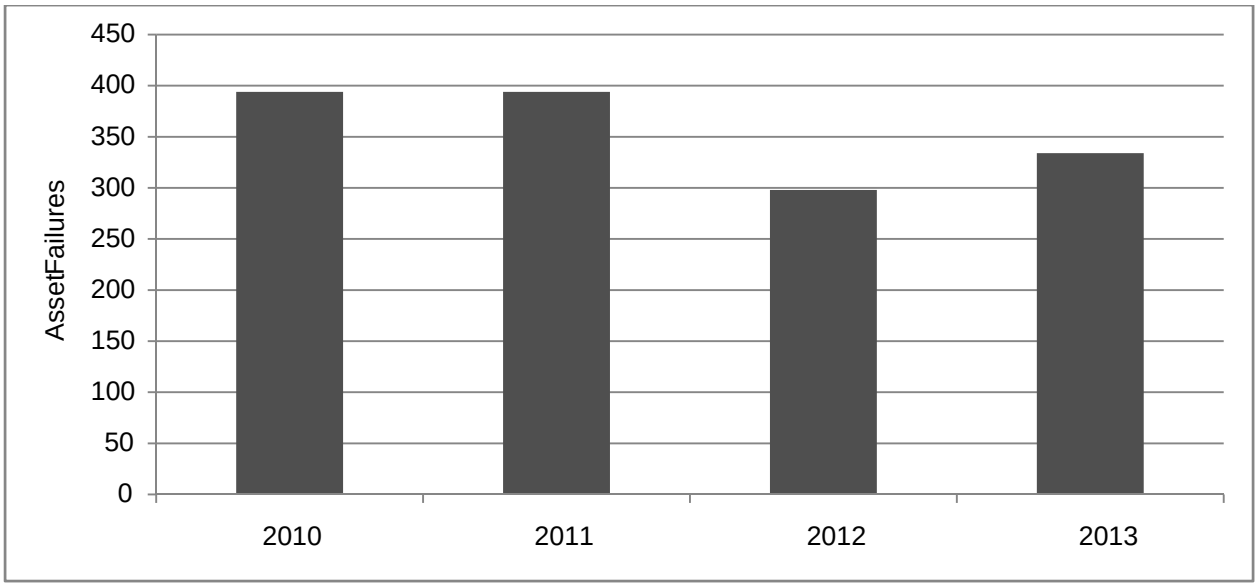


FIGURE 20: NUMBER OF STATION ASSET FAILURES (DETS)

Figure 21 shows a historical trend of the number of stations corrective work requests. The number of corrective work requests averaged over 1,500 in 2011 and 2012. The number of work requests is shown to be on the decline as of 2013, however it is expected the trend will increase again, as a greater population of station assets exceed their useful life.

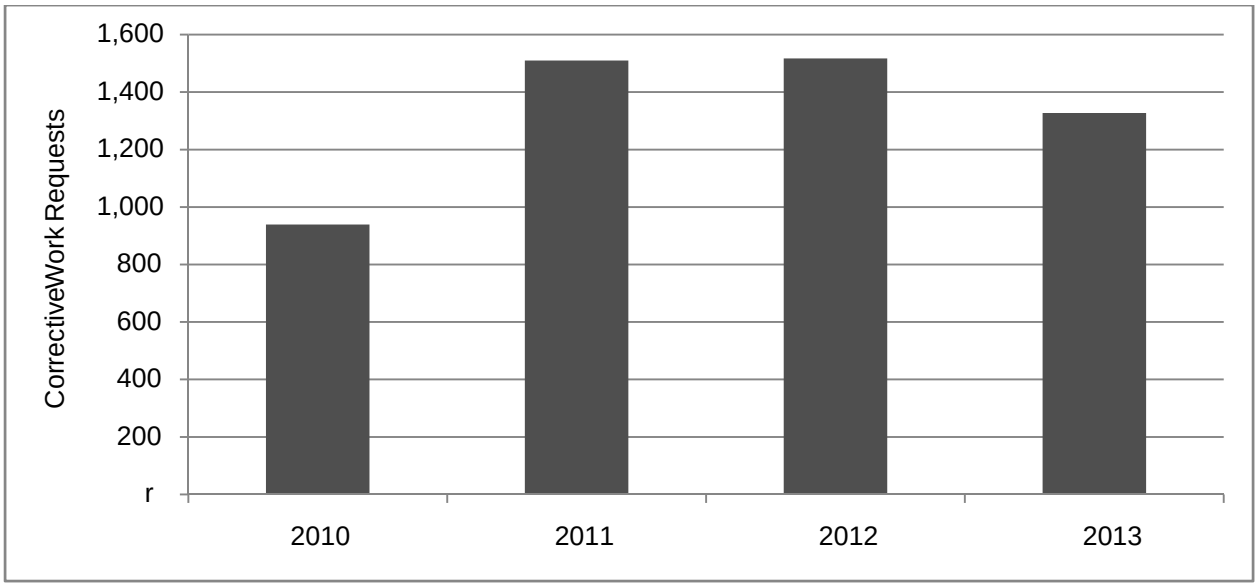


FIGURE 21: NUMBER OF STATIONS CORRECTIVE WORK REQUESTS

(d) Metering Assets

Metering reactive capital work includes replacement jobs for defective Smart Meters, Suite Meters, Interval Meters and Primary Metering units (Current Transformers/Potential Transformers). The failure of the communication module is a primary cause for meter replacements, where data is unable to be received or transmitted. Primary metering unit failures may be due to blown primary current transformer or potential transformer fuses. Meter replacement work is usually performed after hours and requires an outage for the affected customer. Failed smart meters that aren't replaced quickly can result in delayed billing and the need to estimate power consumption.

Table 5 summarizes the total number of meter replacements for each meter type from 2014-2019. The number of Smart Meters, Remotely Interrogated Meters (RIMS) and Quadlogic's requiring replacement is projected to increase significantly in 2015-2019. This is due to the larger population of non-mechanical metering assets now installed. Today's smart meters are configured to perform a self diagnosis every 24 hours and report any potential errors, statuses or warnings. These checks are designed to ensure that the meters are measuring energy accurately. Non-mechanical meters on the other hand provide only one reading every 30 or 60 days for troubleshooting and determining their health. In addition to the smart meters own

diagnostics, Toronto Hydro receives 720 hourly interval and 120 electronic register reads which are validated and checked for anomalies. This level of scrutiny and volume of data has lead to the discovery of meter issues and failures before they impact billing and result in higher meter replacements.

In order to provide this information, smart meters have additional components such as circuit and memory boards, LCD displays, batteries and communication modules, which are susceptible to errors and issues unlike mechanical meters. New meters are required to transmit interval data in five, 15 or 60 minute intervals for time sensitive billing. Billing is based on thousands of reads per month versus conventional meters with demand registers which only use a maximum of three readings. This data is used to bill customers based on time of use rates and provides customers with the ability to have a granular view of their energy use by 8:00 am the following day. Understanding their hourly energy use empowers customers to control their energy costs.

TABLE 5: REACTIVE METER REPLACEMENTS FOR 2014-2019

Meter Type	Projected						
	2014	2015	2016	2017	2018	2019	Total
Smart Meters	1,186	3,930	3,930	3,930	3,930	3,930	23,101
RIMS	10	88	88	88	88	88	470
Quadlogic	287	1,057	1,157	1,257	1,357	1,457	7,022
Total	1,483	5,075	5,175	5,275	5,375	5,475	30,593
Primary Metering Units	8	10	10	10	10	10	50
Total	1,491	5,085	5,185	5,285	5,385	5,485	30,643

TABLE 6: METER ASSET REPLACEMENT COSTS ($ MILLIONS) FOR 2014-2019

Meter Type	Projected						
	2014	2015	2016	2017	2018	2019	Total
Smart Meters	$.45 M	$1.2 M	$1.23 M	$1.25 M	$1.27 M	$1.3 M	$7.14 M
RIMS	$.01 M	$.12 M	$.13 M	$.13 M	$.13 M	$.13 M	$.67 M
Quadlogic	$.09 M	$.26 M	$.29 M	$.31 M	$.34 M	$.36 M	$1.73 M
Total	$.55 M	$1.59 M	$1.64 M	$1.69 M	$1.74 M	$1.8 M	$9.54 M
Primary Metering Units	$.25 M	$.26 M	$.27 M	$.27 M	$.28 M	$.28 M	$1.35 M
Total	$ 0.8 M	$ 1.9 M	$ 1.9 M	$ 2 M	$ 2 M	$ 2.1 M	$ 10.9 M

As explained above, the higher volume of non-mechanical meter failures are expected to result in higher replacement costs in 2015-2019, as shown in Table 6 above. The primary metering category includes one third of 1% of the largest customers who represent approximately 45% of Toronto Hydro's gross revenue. There have been 8-10 failures in this group per year costing up to $35,000 per replacement.

In addition to the increased failure rate of metering assets, Toronto Hydro is regulated by Measurement Canada (sections 9, 11 and 12 of the Electricity and Gas Inspection Act[5]) to ensure that all customers are metered and billed accurately. All meters failing to comply with the act risk being taken out of service, which will result in additional spending and allocation of resources to remove all affected meters.

Replacements of defective primary metering units also ensures Toronto Hydro's customers have accurate data to meet the requirements for Hourly Ontario Energy Price (HOEP) spot market pricing, and OPA programs such as DR3, where accurate internal data is required as part of their contractual obligations.

E6.20.4 Timing & Pacing of the Program

Reactive capital work is generally unplanned and only executed in response to an asset failure or asset approaching imminent failure and requiring immediate replacement. Reactive capital jobs are prioritized for assets that pose the greatest risk to system reliability, customer satisfaction, safety of the public and Toronto Hydro employees, and the environment.

Table 7 below provides historical and forecasted reactive capital spending. The total forecasted spending from 2015 to 2019 is $165.5 million. The projected budgets are relatively constant and aligned with projected corrective work requests as further discussed in Section E6.20.3.2 (iii).

TABLE 7: HISTORICAL AND FUTURE SPENDING (2010-2019)

	Historical Spending					Future Spending				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	25.1	28.6	29.2	37.4	32.1	31.9	32.7	33.1	33.6	34.2

[5] R.S.C., 1985, c. E-4. ["Electricity and Gas Inspection Act"]

Planned capital investments during the 2015-2019 period aimed at eliminating obsolete legacy assets and assets at their end-of-life such as fibertop network units, RPBs, ATSs, and porcelain insulators reduce the risk of these assets resulting in catastrophic failures, requiring replacement. Some of the proposed changes to Toronto Hydro's distribution maintenance programs during the 2015-2019 period focus on improving the detection and correction of deficiencies and move more towards condition based maintenance. These changes include: reduced vegetation management cycles; PCB testing at below-grade structures, pad-mounted equipment locations and customer locations; the use of new technologies, tools and testing methods such as ultrasonic testing to detect partial discharge (corona), infrared scanning to detect faulted components (Figure 8) and oil testing to monitor transformer health; increased proactive maintenance activities at customer locations and substations; the inclusion of street lighting maintenance and cable testing; and increased reactive maintenance activities.

As shown in Table 8 below, the majority of reactive capital expenditures have historically been allocated to overhead and underground distribution system assets. Despite Toronto Hydro having fewer corrective work requests in 2012, reactive expenditures still increased; this is not an inconsistent result, as the expenditures required to address corrective work requests can vary considerably depending on the nature and scope of the work request (e.g., replacement of an overhead switch versus the replacement of a station power transformer); this is also evident for years 2010 and 2011, which differed by 26 work requests and $3.5 million in reactive expenditures. In 2013, $3.6 million was spent on the overhead system to address the December 21st ice storm. Due to the unplanned nature of reactive work, spending varies each year.

TABLE 8: HISTORICAL ALLOCATION OF REACTIVE CAPITAL SPENDING ($ MILLIONS)

Historical Reactive Capital Summary	2010 Actual	2011 Actual	2012 Actual	2013 Actual
Underground Assets	12.9	17.6	17.6	22
Overhead Assets	11.7	10.7	10.2	13.2
Station Assets	0.5	0.3	1.1	1.6
Metering Assets	-	-	0.3	0.7
Total	25.1	28.6	29.2	37.4

E6.20.4.1 Ranking & Prioritization

Reactive capital work takes precedence above all other capital work and may be executed immediately, following the detection of an asset failure or asset approaching imminent failure and posing high safety, environmental and reliability risks. If an asset exhibiting a Level 5 deficiency is

detected within the system, whether it is from planned capital or maintenance work, crews notify Toronto Hydro of the high-risk asset and remain at the site until reactive crews arrive to replace it. In terms of prioritization, Toronto Hydro dispatches crews to address those assets that pose the greatest safety and environmental risks first, followed by assets that have had the greatest impact on system reliability. Toronto Hydro maximizes resources and crew efficiency by strategically dispatching crews to those locations with the highest number of asset failures and customers impacted.

E6.20.5 Program Execution

Work under the Reactive Capital program is not pre-planned or scheduled. All asset replacements are made in response to either an asset failure or corrective work requests indicating high-risk assets that require immediate replacement and cannot be addressed during planned capital replacement.

Based on corrective work requests generated from Toronto Hydro's maintenance programs, assets may be scheduled for immediate replacement if Level 4/5 deficiencies are found, which pose serious potential safety or environmental risks to the public and Toronto Hydro employees. Before reactive capital work can be executed, Toronto Hydro must consider the timing, scheduling and approval of the work, as well as the asset type, its location and the nature of the failure. Once the failed asset is located, and proper coordination with all required third parties is made, crews are dispatched to the site to perform the replacement.

E6.20.5.1 Program Risks

As touched upon in Section E6.20.5, depending on the type of asset and the nature and scope of an asset failure, there are various risks that can delay the completion of reactive work such as resource and logistics constraints, and major storm events. In addition, depending on the location and nature of an asset failure, additional design, planning and approval may be required before the work can be executed.

E6.20.5.2 External Constraints

Depending on the nature, severity and location of an asset that has failed, coordination with third parties may be required to ensure replacement work can be performed in an efficient and safe manner.

E6.20.5.3 Standard & Regulation Adherence

Toronto Hydro must comply with the Minister of Energy's directive on smart meter installation and the metering requirements set out by Measurement Canada and in the Electricity and Gas Inspection Act. Toronto Hydro is responsible for ensuring that all customers are accurately billed and metered. In order to adhere to these requirements, Toronto Hydro must budget reactive capital work for meter replacements. In addition, Toronto Hydro must undertake reactive capital work to address asset failures and maintain compliance with relevant environmental, health and safety legislation.

E6.20.6 Evaluation of Alternatives

Toronto Hydro considered three alternatives for addressing failed assets:

(4) Performing reduced reactive capital work

(5) Performing no reactive capital work, or

(6) Performing the Reactive Capital program as set out in this narrative.

E6.20.6.1 Performing Reduced Reactive Capital Work

This option involves using a lower reactive capital budget to address all reactive capital work in 2015-2019, without taking into consideration Toronto Hydro's aging distribution infrastructure and incremental asset failure rates. Implementing this option would result in inadequate funding to meet the demands of required reactive capital work. A backlog of work would arise and deprive planned capital or maintenance programs of required resources. Inadequate funds would also increase safety risks to the public and Toronto Hydro employees and environmental risks.

Figure 12 shows that the total number of corrective work requests have been increasing, a trend which is projected to continue in 2015 to 2019, while Figures 13 and 14 show the number of asset failures annually across the distribution system have remained relatively constant. These trends are consistent with the fact that the overall asset population is aging, and together, indicate that a reactive capital budget in line with 2014 spending is necessary to address asset failure issues over the 2015 to 2019 period. Thus, the option of allocating a lower budget for reactive capital is not recommended.

E6.20.6.2 Performing No Reactive Capital Work

This option involves no reactive capital budgeting for 2015-2019. The consequences of implementing this option are similar to the previous option above (reduced reactive work), but far more severe. With no reactive capital budget allocated, a significant backlog of work would result in very high capital costs, putting the system in contingency mode, severely limiting system growth and modernization. A consistent reactive capital budget in line with 2014 spending levels is necessary to address emerging problems within the distribution system. Therefore this option is not preferred. .

E6.20.6.3 Proposed 2015-2019 Reactive Capital Work

The proposed Reactive Capital program is necessary to address anticipated reactive capital expenditures. These expenditures are necessary to maintain system performance and reliability, support customer satisfaction, eliminate safety risks to the public and Toronto Hydro employees, mitigate environmental risks and maintain accurate billing. This budget is relatively constant and aligned with corrective work requests as further discussed in Section E6.20.3.2 (iii). This option is recommended.

E6.21 Worst Performing Feeders

TORONTO HYDRO CLEARING EXTREME WEATHER DEBRIS AFFECTING EQUIPMENT FUNCTIONALITY

E6.21.1 Summary

Program Description

The Worst Performing Feeder program is part of Toronto Hydro's effort to improve overall service reliability for customers supplied from poorly performing feeders. The program involves the identification of feeders that have experienced seven or more sustained, unplanned and/or long duration interruptions over a 12-month rolling period. Based on these results, projects are created to determine the root cause of the outages and to resolve the issue in a targeted, timely manner to improve reliability in the short-term.

Table A summarizes the anticipated benefits associated with this program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Reduces the frequency of power interruptions for customers on feeders that are experiencing especially poor reliability performance
Reliability	ƒ Improved reliability on a small number of feeders (less than 50) that nonetheless contribute to approximately one third of annual customer interruptions (CI) and one quarter of annual customer hours interrupted (CHI). Refer to section E6.21.3 for additional details.
Efficiency	ƒ Mitigates the risk of future unplanned reactive work required to restore power to customers on poor performing feeders.
Safety	ƒ Removal of porcelain hardware mitigates the risks of potential catastrophic failure, whereby the hardware could shatter explosively,

	sending debris into the surrounding area.

Program Drivers

The Worst Performing Feeder program's trigger driver is summarized in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ Failure of assets and foreign interference can result in power outages for customers connected to the feeder. As demonstrated in Figures 9 and 10, WPF feeders have contributed more than 30% of the annual customer interruptions (CI) and 28% of customer hours interrupted (CHI) over the past five years. ƒ The WPFs on Toronto Hydro's distribution system typically require short-term intervention to mitigate the risk of additional asset failures.

Preferred Alternative

The Worst Performing Feeder program analyzed and evaluated the following options:

(1) Replace all assets proactively as part of a longer term, planned capital rebuild program

(2) Target those feeders experiencing seven or more interruptions for improvement with short term mitigation investments

Option II is the preferred alternative as it provides immediate, targeted reliability improvements to customers experiencing especially poor electrical service.

Timing and Pacing

Table C summarizes the historical and forecasted costs for this program.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	16.7	19.3	6.7	1.2	4.8	1.8	1.8	1.8	1.8	1.8

In 2010 and 2011, Toronto Hydro spent $16.7 million and $19.3 million respectively on its WPF program, which included large rebuild projects designed to renew assets on poorly performing feeders (e.g., direct-buried cable rebuilds). In 2012, Toronto Hydro recalibrated the program to focus on targeted, short-term mitigation work that would yield immediate reliability improvement. Substantial rebuild projects that were previously included in the worst performing program were reallocated to either the planned Overhead or Underground Circuit Renewal programs. This change took effect mid-year, meaning that certain rebuild projects were charged to the WPF program, which resulted in actual spending of $6.7 million in 2012. Using the new, more focused approach in 2013, Toronto Hydro conducted mostly short term, small scale asset installation or replacement work, resulting in total spend of $1.2 million. Spending in 2014 is forecasted to increase to $4.8 million due to a number of projects that were previously delayed but that are still expected to provide considerable reliability improvements in poor performing areas.

As the assets in the field continue to age and deteriorate, Toronto Hydro anticipates ongoing random failures and interruptions. To address these failures, Toronto Hydro has forecasted investments of $1.8 million yearly from 2015 to 2019 for WPF projects.

E6.21.2 Program Description

Toronto Hydro's ongoing Worst Performing Feeder program targets feeders that are at risk of experiencing seven or more sustained power interruptions over a 12-month rolling period (excluding planned outages, major event days and outages caused by loss of supply). This includes feeders that have already experienced seven outages in a previous 12-month period (i.e., FESI-7 feeders[1]) as well as feeders that are trending towards FESI-7 status. This program funds small-scale mitigation measures executed in the short-term to reduce the risk of additional outages on feeders already causing reliability issues. The maps below outline the locations of FESI-7 feeders from 2010 to 2013. Toronto Hydro is plans to allocate a budget of $8.5 million to this program during the 2015 to 2019 forecast period.

FIGURE 1: 2010 FESI FEEDERS

[1] The FESI acronym stands for 'feeders experiencing sustained interruptions'

FIGURE 2: 2011 FESI FEEDERS

FIGURE 3: 2012 FESI FEEDERS

FIGURE 4: 2013 FESI FEEDERS

The WPF program is comprised of relatively quick, targeted actions that yield immediate reliability improvements. Toronto Hydro makes best efforts to constantly monitor the reliability performance of every feeder throughout the distribution system. Feeders that experience a high number of outages or are trending towards increased outages are selected for analysis to determine the cause of outages. As well, possible solutions are examined.

Based on the result of the analysis, field crews perform feeder patrols to assess the condition of equipment in the field. If the crew is examining an overhead feeder, they may carry-out basic mitigation work simultaneously, as required. Mitigation work may include the following (further detailed in this section below):

- animal guard installation,
- bare transformer drop wire replacement,
- metal switch bracket replacement, and
- glass or porcelain insulator replacement.

Animal Guard Installation, Bare Transformer Drop Wire Replacement and Metal Switch Bracket Replacement

Issue

Figure 5 depicts a pole without animal protection that contains a metal bracket, bare transformer drop wire and exposed live connection on the transformer primary bushing termination. In this case, there is a high risk for animal contact at the point between the bare live conductor and the metal bracket or the transformer enclosure that can result in power outages.

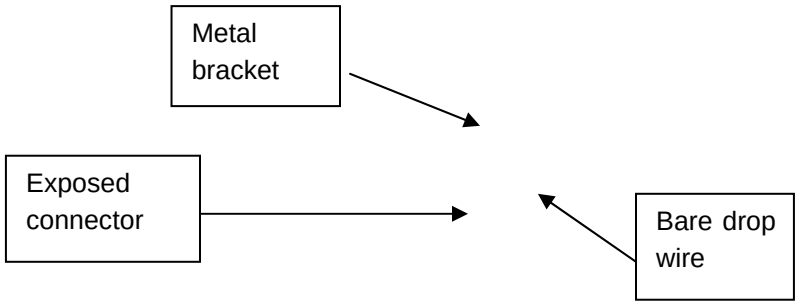


FIGURE 5: POLE WITHOUT ANIMAL PROTECTION

Solution

Figure 6 shows a pole after mitigation work has been completed. It contains a fiber-glass switch bracket, insulated drop wire and animal guard. These remedies insulate live conductors on the pole and prevent contact by animals minimizing the likelihood of power outages.

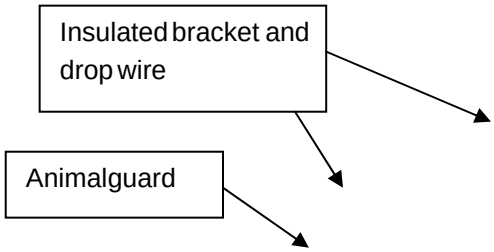


FIGURE 6: POLE WITH PROPER ANIMAL PROTECTION

Insulator Replacement

Issue

Figure 7 shows a pole with porcelain insulator. These assets are susceptible to tracking and flashover that would lead to power outages after sufficient contaminants and moisture accumulate on the insulator surface.

FIGURE 7: POLE WITH PORCELAIN INSULATOR

Solution

Figure 8 shows a pole with polymer insulator after mitigation work has been completed. Polymer insulators have a self-washing feature that minimizes contaminant build up on the insulation surface. In addition, polymer material contains an anti-beading function that naturally prevents water from forming a continuous path over its surface. This prevents the flow of leakage current between live conductor and the grounding point on the pole, which greatly reduces the risk of tracking and flashover over the insulation surface that could lead to power outages.

FIGURE 8: POLE WITH POLYMER INSULATOR

Follow-up Work

Feeder patrol results may also necessitate additional follow-up projects under the Worst Performing Feeder program. This follow-up work can consist of small scale capital replacement work that the crew could not perform during their initial patrol, including "like for like" replacements of select assets in the problem area, such as underground cable, transformers, or overhead conductor and ancillary equipment.

Relationship with Renewal Projects

In some cases, where a majority of assets on a feeder have aged or are in poor condition, a large-scale renewal project may be undertaken to refresh assets on the feeder. In these instances, the small-scale capital replacement performed to mitigate immediate failure risk pursuant to the WPF program would serve as a necessary bridge to provide interim reliability relief before full scale renewal projects are planned and carried out in the field. In addition, the WPF program is complementary to large-scale renewal projects as results from the feeder reliability analysis may be used to re-prioritize existing planned capital rebuild projects to respond to emerging and evolving reliability issues in the field.

Relationship with Maintenance Work

For assets that have not reached the end of their useful service lives or that are in good condition but are installed in areas with exposure to trees and/or excessive environmental contaminants that can cause outages, tree trimming or equipment washing may be required to reduce outage risks. This routine maintenance work is not part of this WPF program but is covered in the operating expenditures part of the WPF budget

The following table is a summary of the anticipated benefits of the WPF program. A detailed discussion of program drivers can be found in the following section.

TABLE 1: PROGRAM BENEFITS

Customer Value	Reduces the frequency of power interruptions for customers on feeders that are experiencing especially poor reliability performance
Reliability	Improved reliability on a small number of feeders (less than 50) that nonetheless contribute to approximately one third of annual customer interruptions (CI) and one quarter of annual customer hours interrupted (CHI). Refer to section E6.21.3 for additional details.
Efficiency	Mitigates the risk of future unplanned reactive work required to restore power to customers on poor performing feeders.
Safety	Removal of porcelain hardware mitigates the risks of potential catastrophic failure, whereby the hardware could shatter explosively, sending debris into the surrounding area.

E6.21.3 Why the Program is Needed

E6.21.3.1 Program Drivers

Toronto Hydro has classified the Worst Performing Feeder (WPF) program as a System Renewal activity because it deals primarily with failure risk on poor performing feeders, as further described in Table 3 below.

TABLE 2: PROGRAM DRIVERS

Trigger Driver	Reasoning
Failure Risk	ƒ Failure of assets and foreign interference can result in power outages for customers connected to the feeder. As demonstrated in Figures 9 and 10, WPF feeders have contributed more than 30% of the annual customer interruptions (CI) and 28% of customer hours interrupted (CHI) over the past five years. ƒ The WPFs on Toronto Hydro's distribution system typically require short-term intervention to mitigate the risk of additional asset failures.

Toronto Hydro's distribution system contains more than 1,600 feeders that supply power to over 700,000 customers in the City of Toronto. While any one of these feeders is subject to random equipment breakdown and foreign interference (e.g., tree and animal contacts) that can cause unplanned outages, certain feeders experience a disproportionate number of problems and cause an unacceptably high number of sustained interruptions. Customers on these feeders experience unreliable service that can lead to frustration and material financial losses. These are the feeders that the WPF program is designed to address.

The WPF program complements Toronto Hydro's general capital program in two ways. Firstly, with respect to feeders that are experiencing poor reliability performance due to contact with foreign objects, but where the majority of assets are not reaching the end of their useful lives and are still in fair working condition, WPF mitigation work is carried out in the form tree trimming and the installation of animal guards to increase service reliability. Secondly, with respect to feeders that contain a large quantity of assets that are operating near or beyond their useful service lives or in poor condition, a large scale planned renewal project may be needed to refresh these assets to reduce reliability risks and provide long-term improvements. Given that these rebuild projects typically take more than one year to complete, the WPF program is designed to provide interim reliability relief until the long-term rebuild program is completed.

Generally, the WPF program deals with probabilistic outcomes that are not entirely mitigated by planned maintenance and capital activities. The bulk of Toronto Hydro's planned activities are carefully designed and paced to address the highest risk assets and the most frequent outage causes in a cost-efficient manner and based on sophisticated risk-based models. Nevertheless, Toronto Hydro anticipates that there will continue to be a relatively small number of feeders that are statistical outliers in terms of the exceptionally poor performance that they exhibit in a 12-month period. These feeders continue to have an outsized impact on system reliability and customer value, and must be managed through the responsive, efficient and targeted interventions described in this program.

Figures 9, 10 and 11 show the historical count of FESI-7 feeders per year and their contribution to overall system reliability in terms of CI and CHI.

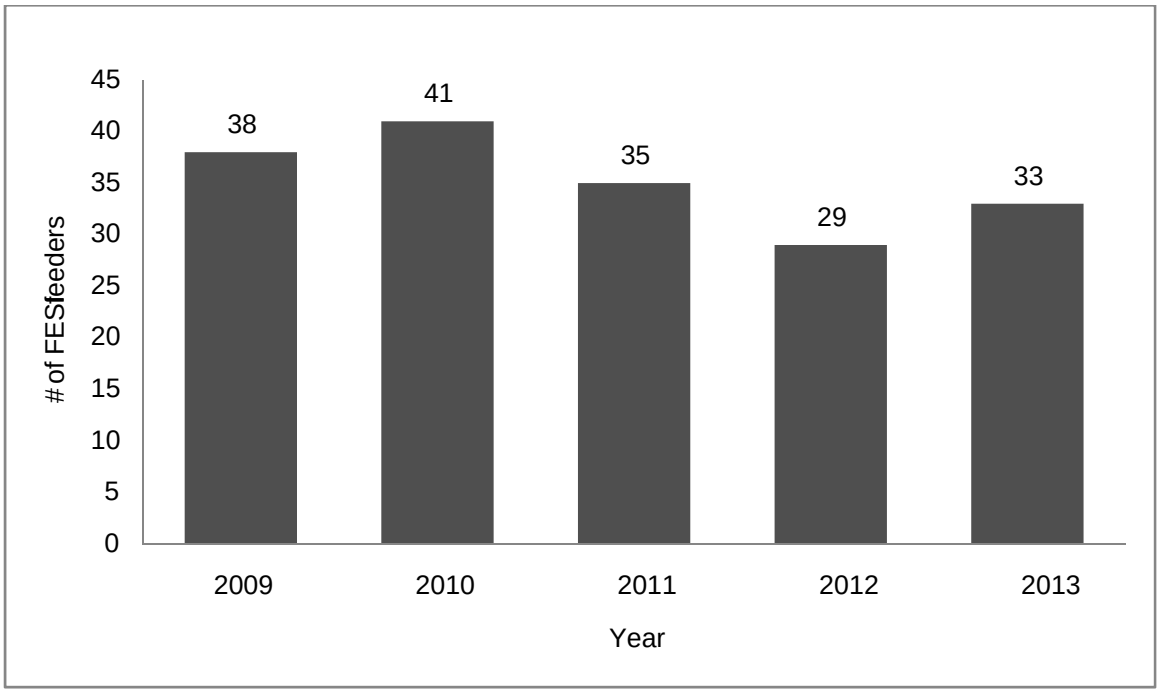


FIGURE 9: HISTORICAL WORST PERFORMING FEEDERS

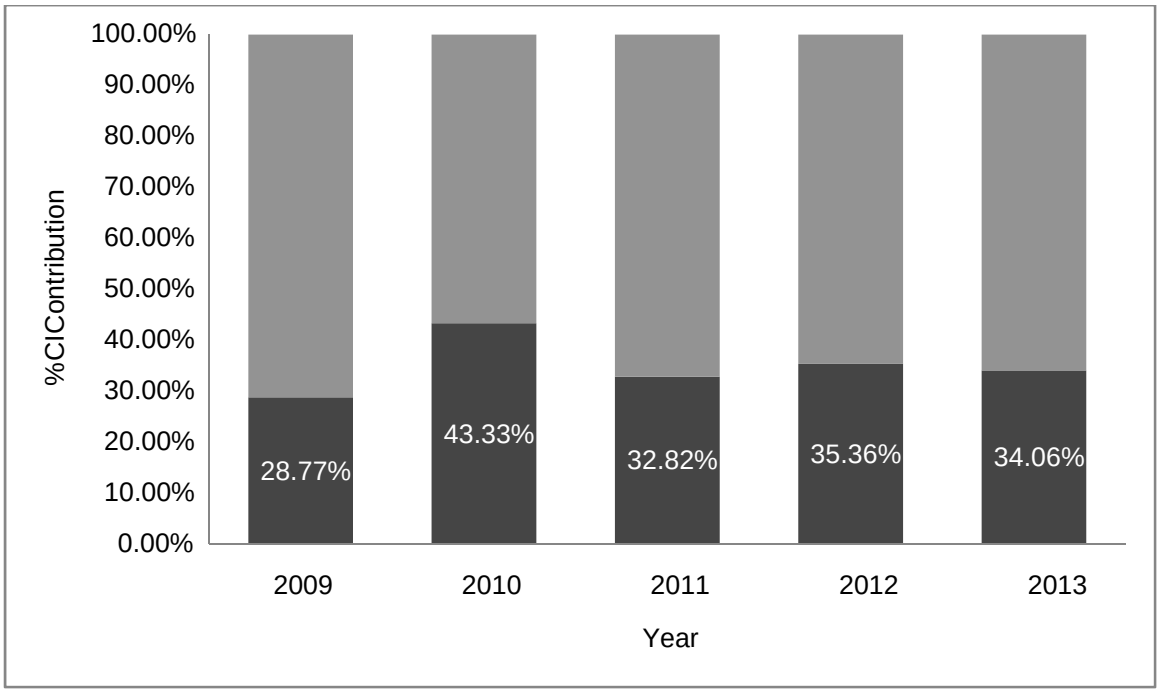


FIGURE 10: CUSTOMERS INTERRUPTED (CI) CONTRIBUTION OF WORST PERFORMING FEEDERS

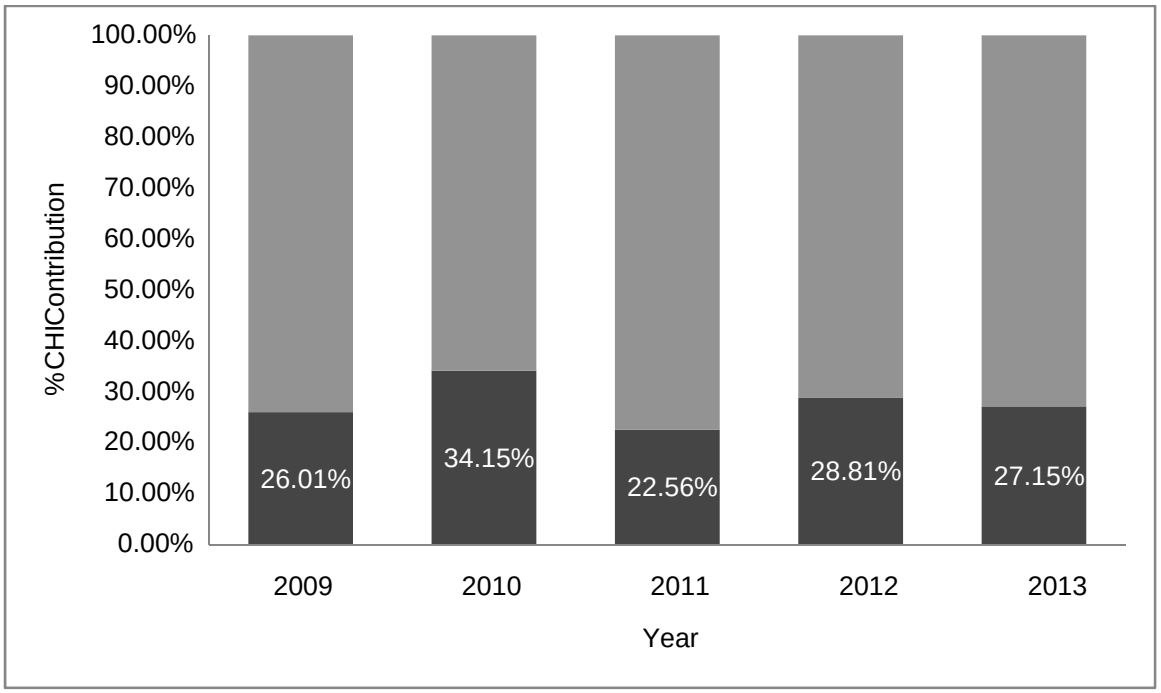


FIGURE 11: CUSTOMER HOURS INTERRUPTED (CHI) CONTRIBUTION OF WORST PERFORMING FEEDERS

The above figures show that while the annual number of WPFs is small (less than 50) relative to over 1,600 feeders that make-up Toronto Hydro's distribution system, they have a disproportionately negative effect on the system's overall reliability performance. As shown previously in Figure 11 and Figure 9, FESI-7 feeders have contributed to more than 34% of the system's annual CI and 27% of CHI in 2013.

Toronto Hydro anticipates that the WPF program will immediately improve system reliability, as demonstrated in Figure 12. The bar on the left shows the cumulative outages on FESI-7 feeders for the 2011 year. The bar on the right shows the cumulative outages on the same set of feeders in 2012. There was an improvement of approximately 50% from 2011 to 2012. Similarly in Figure 13, the bar on the left shows the cumulative outages of FESI-7 feeders in 2012r. The bar on the right shows the cumulative outages on the same set of feeders in 2013. There was an improvement of approximately 37% from 2012 to 2013.

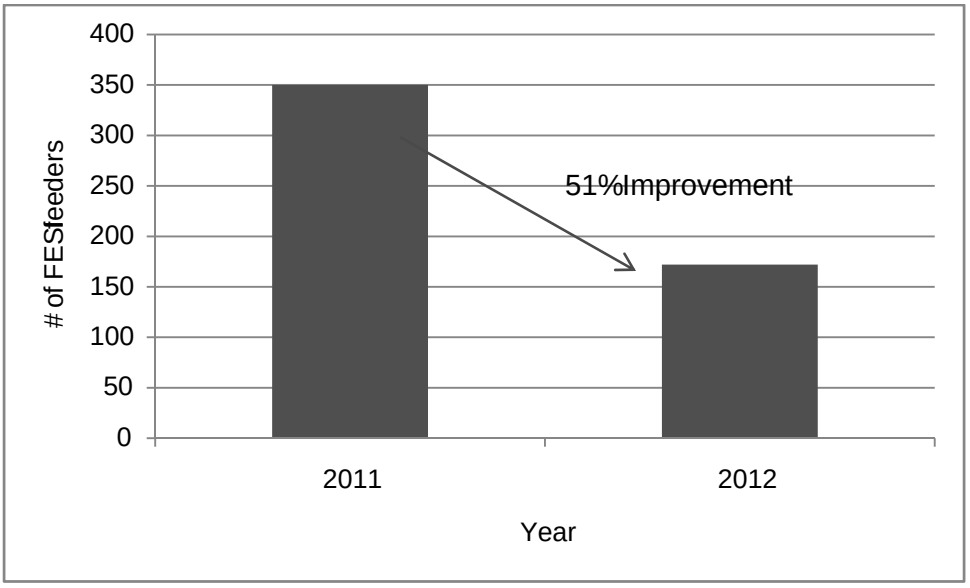


FIGURE 12: 2011 FESI FEEDER CUMULATIVE OUTAGES IN 2012

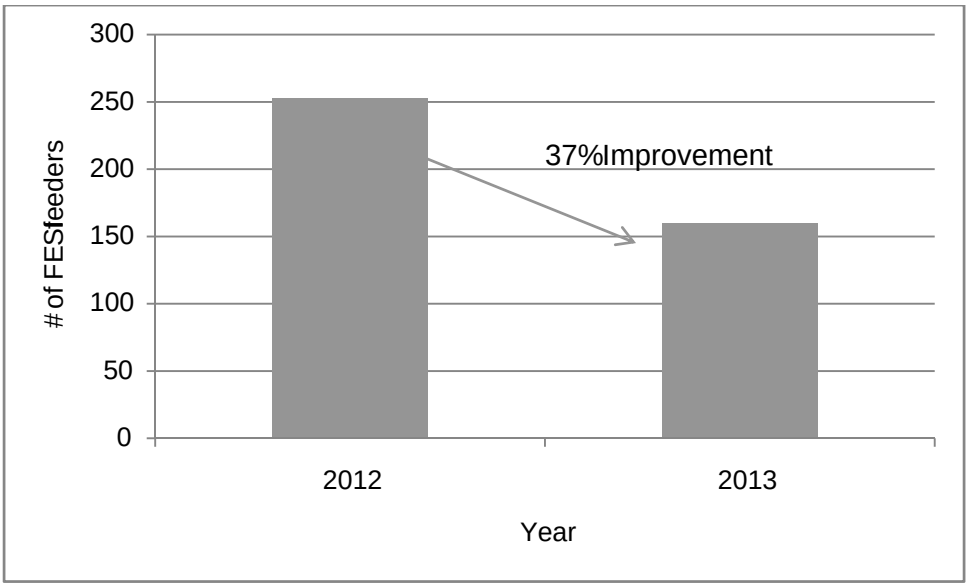


FIGURE 13: 2012 FESI FEEDER CUMULATIVE OUTAGES IN 2013

It is evident that past FESI mitigation work has provided noticeable improvements in the number of interruptions that a group of feeders will experience in a given year. However, as the WPF program is designed be a short term mitigation measure, it is not designed to perform full rebuild of assets on the troubled feeders as the planned asset renewal projects do. As a result, feeders that are addressed by the WPF program still experience random failure and power outages, albeit at a less frequent rate, until permanent, long-term solutions are implemented.

E6.21.3.2 Asset Details

Assets addressed in this program are mostly legacy installations that did not possess some of the features that the current standards require, such as animal protection and insulated overhead accessories. The FESI program studies feeders that are performing poorly to determine necessary mitigation work to strengthen these legacy components in order to prevent future failures. Some of the common components involved in WPF mitigation work are the following:

Transformer drop wire replacement : Transformer drop wire connects the load side of the transformer disconnect switch to the high voltage bushing of the overhead transformer as shown in Figure 5. Traditionally, a bare conductor is used for this connection. However, there is a risk of animal contact between the live conductor on one side of the transformer bushing and the grounded transformer enclosure on the other side, which can result in a short-circuit fault leading to an outage. Replacement of existing bare drop wire with an insulated conductor can prevent animal contact between the energized wire and ground, mitigating the risk of this type of outage.

Toronto Hydro's current standard for transformer drop wire calls for the use of insulated conductor.

Animal guard installation: Animal guards are frequently installed on the top portion of the transformer bushing unit to cover the live conductor connection point. Animal guards can reduce the risk of animal contacts between the live connection points on the bushing and the transformer enclosure. Toronto Hydro's current standard for overhead transformer calls for the use of animal guards.

Metal switch bracket replacement: Metal brackets are used to mount the disconnect switch on the pole as shown in Figure 5. Similar to the area around the transformer bushing, there is a risk of animal contact across the live side of the switch and the grounded metal bracket, which can cause an outage. Proactively replacing these brackets with a non-conductive bracket made of fiber glass material can eliminate the risk of live-to-ground contacts.

Glass or porcelain insulator replacement: Aged glass or porcelain insulators are susceptible to dirt accumulation over the insulator surface. When combined with a sufficient amount of moisture over time, tracking or flashover will occur, which can lead to failure of the insulator and a power outage on the feeder. Replacing these insulators with polymer insulators removes the risk of tracking as the polymer insulator has the anti-beading feature that cuts off the electrical tracking path over the insulator surface.

Underground cable replacement: Aged or poor conditioned underground cables can fail due to deterioration in insulation strength as a result of water ingress or soil contamination, leading to power outages. They can be installed both directly buried or in conduit. Small scale replacement of unreliable segments of cable would eliminate the risk of additional failure from the asset.

Underground transformer replacement: Submersible transformers that are aged or in poor condition can fail, resulting in power outages. Spot replacement of unreliable underground transformer will lower the risk of failure.

(i) Asset Failure Impacts

Assets that are targeted for replacements under the WPF program present various failure impacts. For instance, a lack of animal guards coupled with bare transformer drop wires and metal transformer switch brackets will subject the overhead conductor to the potential risk of animal contact between the live and grounding point connections. On the other hand, dirty

porcelain and glass insulators create the risk of electrical flashover across its surface. One common thread is that asset failures can and will likely lead to customer outages.

E6.21.4 Timing & Pacing of the Program

In 2010 and 2011, Toronto Hydro spent $16.7 million and $19.3 million respectively on its WPF program, which included large rebuild projects designed to renew assets on poorly performing feeders (e.g., direct-buried cable rebuilds). In 2012, Toronto Hydro recalibrated the program to focus on targeted, short-term mitigation work that would yield immediate reliability improvement. Substantial rebuild projects that were previously included in the worst performing program were reallocated to either the planned overhead or underground rebuild programs. This change took effect mid-year, meaning that certain rebuild projects were charged to the WPF program, which resulted in actual spending of $6.7 million in 2012. Using the new, more focused approach in 2013, Toronto Hydro conducted mostly short term, small scale asset installation or replacement work, resulting in total spend of $1.2 million. Spending in 2014 is forecasted to increase to $4.8 million due to a number of projects that were previously delayed but that are still expected to provide considerable reliability improvements in poor performing areas.

As the assets in the field continue to age and deteriorate, Toronto Hydro anticipates ongoing random failures and interruptions. To address these failures, Toronto Hydro has forecasted investments of $1.8 million yearly from 2015 to 2019 for WPF projects.

TABLE 3: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	16.7	19.3	6.7	1.2	4.8	1.8	1.8	1.8	1.8	1.8

E6.21.4.1 Ranking & Prioritization

The WPF program is highly dynamic compared to other, typical planned work programs. Feeder and project prioritization can change quickly and often depending on emerging FESI conditions in the field. As a result, mitigation work is normally placed on high priority and scheduled for field execution based on available resources. Emphasis is placed on feeders that have experienced a high number of outages in a 12-month rolling window. Some feeders may require patrolling to identify components that need to be replaced.

E6.21.5 Program Execution

In order to execute the work under this program, first an initial analysis of locations and root causes of FESI-7 feeder outages must be completed. Depending on the need as revealed by the analysis, field crews may perform field patrols to determine the condition of equipment. In order to be as efficient as possible, field crews may also carry out mitigation work simultaneously with the patrol. Typical mitigation work that would be undertaken during field patrols includes the installation of animal guards, insulator replacement, transformer drop wire replacement and switch bracket replacement. As well, follow up small-scale construction project may be issued by under the WPF program when work is determined to be feasible and required. Small scale construction projects involve the replacement of assets such as underground cable, transformers or overhead conductor to remove immediate failure risks.

E6.21.5.1 Program Risks

The primary program risk is limited resource availability. As the WPF program is a short term measure in nature, delay in timely intervention may result in additional outage. Feeder scheduling/restriction and road work moratoriums may also pose risks to the completion of work in a timely manner.

E6.21.5.2 Standard & Regulation Adherence

All assets installed in this program are approved by Toronto Hydro's Standards Department in compliance with Ontario Regulation 22/04, Electrical Distribution Safety.

E6.21.6 Evaluation of Alternatives

Toronto Hydro considered two alternatives for addressing poor performing feeders.

(i) Option 1: Planned Capital Rebuild

Addressing worst performing feeders through planned capital rebuilds is the optimal long-term solution. However, rebuild projects take time to plan, design, schedule and execute, and are not typically feasible within a period that would allow for the timely mitigation of worsening reliability trends on poor performing feeders. Without targeted, short-term interventions for poor performing feeders, customers would likely continue to experience a high frequency of interruptions, and Toronto Hydro anticipates that the number of worst performing feeders would most likely increase, negatively impacting system SAIFI and SAIDI over time and harming customer

satisfaction. Accordingly, pursuing long-term capital rebuilds without a complementary WPF program is not recommended.

(ii) Option 2: Continue WP F Program (Preferred Option)

The status-quo and preferred option is to perform mitigation work pursuant to the WPF program, as this will help provide immediate reliability improvements to customers served by poor performing feeders at a reasonable cost. This approach acts as a "bridge" solution until planned capital rebuilds can be executed.

E6.22 Distribution System Communication Infrastructure

COMMUNICATION HARDWARE EQUIPMENT

E6.22.1 Summary

Program Description

The objective of the Distribution System Communication Infrastructure (DSCI) program is to install the telecommunication infrastructure that is needed to operate and maintain a safe and reliable distribution system. The execution of the DSCI program allows Toronto Hydro to move away from obsolete legacy technologies and transition to an updated system that enables greater SCADA penetration throughout the system.

The program is divided into three main areas: (1) Distribution System Communication Technology Upgrade; (2) Distribution System Fiber-optic Plant Replacement and Expansion; and (3) Wireless SCADA Infrastructure.

(1) Toronto Hydro currently relies on SONET communication technology at substations on the 13.8 kV system for SCADA communication to operate Remote Terminal Units (RTUs), which provide automated control of station assets such as circuit breakers. There are approximately 200 RTUs at about 45 substations sites in the downtown core that are connected to the SONET ring for RTU communication.

(2) SONET is a legacy communication technology that is no longer supported by the manufacturer and has limited capacity to support increased automation at additional substations. In order to address the limitation of this system, Toronto Hydro plans to install Coarse Wavelength Division Multiplexing (CWDM) technology to decouple SONET technology and Internet Protocol (IP) traffic, preventing the need to upgrade the legacy SONET platform. Toronto Hydro plans to implement CWDM technology at all 45 SONET sites in the system during the 2015-2019 period in order to address the obsolescence of the SONET system.

A fiber-optic cable plant is used to connect the various in-field communication technologies to Toronto Hydro's control room. There is approximately 300 km of fiber-optic cable within Toronto Hydro's communication system. Currently, 225 km, or 75% of all fiber-optic cable, is jointly owned between Toronto Hydro and Cogeco Data Services (CDS). This arrangement limits Toronto Hydro's ability to route diverse fiber-optic cables as required to ensure that there are no overlaps geographically in fiber-optic cable routes which may lead to a single point of failure.

Toronto Hydro plans to replace 117 km of fiber-optic cables, or approximately 50% of the CDS fiber within the existing plant by targeting areas of fiber that are prone to failure. This work will enable Toronto Hydro to reduce dependency on CDS through gradual migration to a Toronto Hydro owned fiber-optic plant.

(3) Toronto Hydro operates five wireless SCADA technologies, including GE TransIt, MOSCAD, DACSCAN, GE SD9, and SpeedNet. Three out of these five technologies – GE TransIt, MOSCAD, and DACSCAN – are legacy systems that are now functionally obsolete. To cost-effectively address these obsolescence issues, Toronto Hydro plans to (1) install four new SCADA SD9 "High-Sites" and (2) migrate GE TransIt SCADA radios, which have reached the end of their useful lives and are functionally obsolete, to GE SD9. [1]

For additional details on these investments, refer to section E6.2.2.2 below.

The anticipated benefits of this program are outlined in Table A.

[1] This program specifically excludes radio replacement for MOSCAD and DACSCAN technology, as they are being handled through radio replacements covered in the Overhead Circuit Renewal program at Exhibit 2B, E6.4.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Upgrade in technology to maintain a reliable and secure communication system to support substation monitoring and control, which results in quicker restoration of power to customers during an outage. ƒ Monitoring and control supported by the proposed upgrade is expected to provide sufficient protection for DG in the event of a power outage, which protects DG customers' assets as well as provides them with undisrupted revenue.
Reliability	ƒ Prevent SCADA communication outages so that Toronto Hydro can remotely operate equipment; this leads quicker restoration times and shorter outages, including during increasingly frequent major storm events. ƒ Allows for increased RTU installations for substations and additional capability to remotely monitor and control circuit breakers.
Safety	ƒ Enables SCADA monitoring at substations and allows power controllers to constantly monitor substation assets, reducing the possibility of equipment failures and related worker and public safety risks. ƒ The updated technology provides increased protection against cyber-security threats and reduces potential safety impacts.
Efficiency	ƒ Efficiency cost saving of approximately $4.5 million that would have been required for the expansion of the existing network system. ƒ Conversion allows for three legacy wireless SCADA infrastructures to be decommissioned, reducing the cost of maintenance.

Program Drivers

The trigger and secondary drivers for this program are provided in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Obsolete, non-standard, and non-ruggedized LAN equipment is required by the SONET technology. ƒ Continued investment in SONET is costly and strategically limiting due to growing technology, asset obsolescence, and declining availability of qualified support personnel. ƒ Capacity limit with current SONET system has been reached, further expansions (e.g. adding new locations) are very complex and costly. ƒ Obsolete wireless SCADA infrastructure requires upgrades to remain functional, supporting critical portions of the distribution system. ƒ Obsolete MOSCAD and DACSCAN systems have no redundancy while supporting large SCADA presence. ƒ Existing fiber-optic plant exhibits a large number of single points of failure. Joint ownership of Fiber-optic plant with CDS further

	complicates the issue.
Secondary Drivers	Reasoning
System Capital Investment Support	ƒ Upgrading station services by migrating devices from being reliant on legacy SONET to Ethernet/IP networks supports the Stations Monitoring and Control program to upgrade/install RTUs at substations for better monitoring and control of substation assets. ƒ Implementing additional GE SD9 high-sites allows for the migration and consolidation of end-of-life MOSCAD/DACSCAN/GE TransIt wireless SCADA systems to GE SD9. ƒ Increasing the footprint of both fiber-optic plant as well as the coverage of GE SD9 within the system allows for the expansion of the SCADA.
System Maintenance Support	ƒ Communication supports the remote monitoring of stations assets such as circuit breakers and power transformers to alert of issues that may require maintenance or intervention. ƒ Upgrading SONET allows Toronto Hydro to maintain security measures such as access card readers, CCTV cameras and supports in-office work at substations.
Safety	ƒ Communication infrastructure supports monitoring of stations assets to ensure failures do not escalate. ƒ Obsolete communication does not provide the encryption provided by the new Ethernet/IP system to protect against cyber-security threats.

The SONET system was built at a time when monitoring and control functionality were limited. The SONET system can no longer support stations requiring monitoring and control due to its limited capacity. There are approximately 45 SONET sites in the system, which is beyond the number of maximum sites recommended by the manufacturer, and additional sites cannot be added to the SONET backbone. In addition, the legacy SONET multiplexers can cause communication outages that may render SCADA functionality of RTUs in stations inoperable and increase the number of outages that last 30 minutes to three hours. Customers on an entire feeder can be impacted during extended outages. Over the last five years, there were a total of 90 SONET communication outages. In order to rectify these issues associated with the existing SONET infrastructure, the work proposed in this program must be executed as soon as possible.

Preferred Alternative

This program is the preferable to the alternative of maintaining the status quo state of the system. The DSCI program provides the infrastructure required to maintain reliable control and monitoring capability for power controllers such that critical asset performance information will continue to be accessible. Also, without the DSCI program Toronto Hydro may not be able to support other high

value initiatives, such as Generation Protection, Monitoring and Control (Section E5.5), Downtown Contingency (Section E7.7), or Stations Control and Monitoring (Section E6.16).

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $17.01 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.22.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $6.83 million, confirming the economic prudence of the investments (see Section E6.22.7).

Timing and Pacing

As can be seen in Table C below, Toronto Hydro plans to complete the work proposed in this program by the end of 2017 so that the communication system will be available to support advances in monitoring and control within the distribution system.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)		-	-	$1.03	$0.85	$6.06	$6.02	$3.95	-	-

E6.22.2 Program Description

The Distribution System Communication Infrastructure (DSCI) program addresses the foundational technology that underlies and enables distribution operational activities that depend on data and voice communications. This program aims to achieve a balance between functionality, scalability, and operating cost. The DSCI program proposes work that is critical to the business operation of the distribution system at an estimated cost of approximately $16 million during the 2015-2019 period.

There are approximately 1100 SCADA switches within the distribution system, which allow for rapid restoration of customers in un-faulted sections of the feeder during a power outage or provide tie points to transfer load to adjacent feeders. There are approximately 800 distributed generation (DG) connections currently operating on the distribution system and Toronto Hydro estimates that there will be approximately 2,000 new connections over the next five-year period. The increase in connections necessitates additional SCADA capacity and a reliable wireless communication network to enable adequate protection and monitoring as part of the Generation Protection Monitoring and Control initiative (Section E5.5).

The execution of the DSCI program allows Toronto Hydro to move away from obsolete legacy technologies and transitioning to an updated system that enables greater SCADA penetration throughout the system. In addition, performing this work is expected to facilitate operational efficiency, through the decommissioning of obsolete or overlapping communication systems. By enabling SCADA, this program is integral to several of Toronto Hydro's distribution system initiatives, such as:

- Station Control and Monitoring (Section E6.16),
- Stations Switchgear Renewal (Section E6.13),
- Generation Protection Monitoring and Control (Section E5.5),
- Feeder Automation (Section E7.3),
- SCADA-Mate R1 Renewal (Section E6.8),
- Overhead Circuit Renewal (Section E6.4), and
- Downtown Contingency (Section E7.7).

The DSCI program is comprised of three key areas of investment: (1) Distribution System Communication Technology Upgrade; (2) Distribution System Fiber-Optic Plant Replacement and Expansion; and (3) SCADA Wireless Infrastructure.

SCADA technology plays a critical role in reducing restoration times during an outage by allowing power controllers to remotely operate in-field switches to isolate faulted areas and restore customers on unaffected sections of the feeder. In addition, SCADA technology allows for the monitoring of assets, especially at substations, to determine their operating conditions such as transformer oil levels, alarms for pressure and voltage loss, or loss of battery power. Therefore, the lack of SCADA can limit the visibility controllers have on the operating conditions of Toronto Hydro's assets and severely impact their ability to remotely isolate faults during an outage.

E6.22.2.1 Distribution System Communication Technology Upgrade

Toronto Hydro currently relies on SONET technology at substations on the 13.8 kV system for SCADA communication to operate Remote Terminal Units (RTUs), which provide automated control of station assets such as circuit breakers. There are approximately 200 RTUs at about 45 substations sites in the downtown core that are connected to the SONET ring for RTU communication. An example of SONET equipment is shown in Figure 1.

FIGURE 1: SONET TECHNOLOGY – HARDWARE EQUIPMENT

The SONET system connects multiple substations using a ring topology (SONET Ring) as shown in Figure 2 below. This is a legacy communication technology that is no longer supported by the manufacturer and has limited capacity to support increased automation at additional substations.

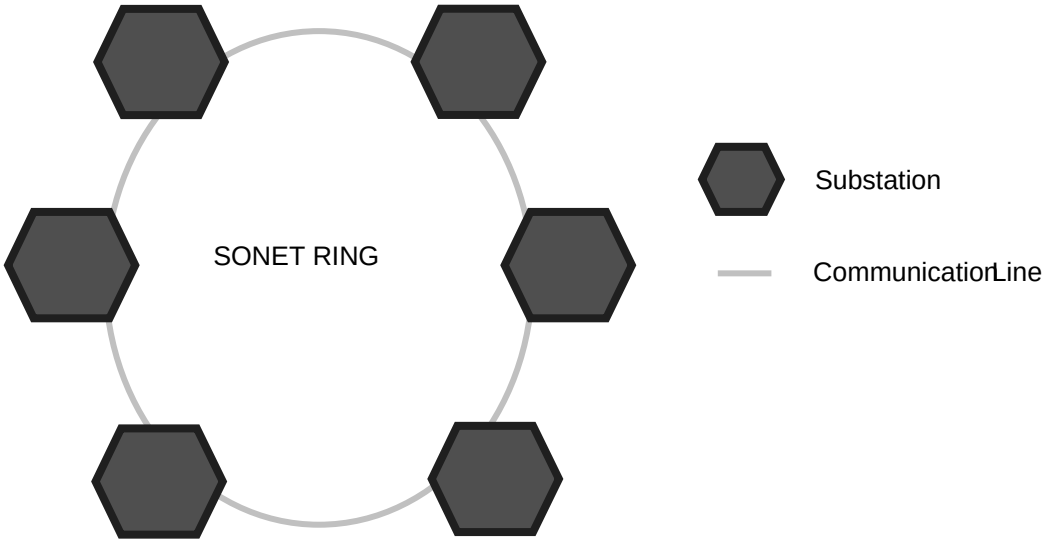


FIGURE 2: SONET RING STRUCTURE WITH SUBSTATIONS

In order to address the limitation of this system, Toronto Hydro plans to install Coarse Wavelength Division Multiplexing (CWDM) technology to decouple SONET technology and Internet Protocol (IP) traffic, preventing the need to upgrade the legacy SONET platform. This involves the installation of CWDM multiplexers as a means of migrating from the legacy SONET system to Ethernet, thereby providing communication through the internet. By taking this action, Toronto Hydro expects to limit the investment required to upgrade the capacity of legacy SONET technology and to allow the utility to eventually decommission the SONET ring, which is functionally obsolete.

Toronto Hydro plans to implement CWDM technology at all 45 SONET sites in the system during the 2015-2019 period in order to address the obsolescence of the SONET system. In addition, this work will enable dedicated 1 Gigabits per second (Gbps) path for Ethernet/IP signal on CWDM multiplexers. Toronto Hydro plans to retain SONET functionality to maintain compatibility

with existing assets; however, the Ethernet/IP based system will be used for all new RTU installations, such that once existing RTUs on the SONET system reach end-of-life, the obsolete SONET technology can be eliminated from the system. Once existing sites with SONET technology are addressed, Toronto Hydro will install Ethernet/IP technology at 34 additional sites to enable greater SCADA presence at substations. Once this work is completed, using IP routers, Toronto Hydro can support high-bandwidth applications at substations, including supporting internet bandwidth for in-office work, closed circuit television, and wireless communication. The routed network allows for maximum performance and to easily expand the capacity of the network as required for additional SCADA connections.

E6.2.2.2.2 Distribution System Fiber-Optic Replacement & Expansion

A fiber-optic cable plant is used to connect the various in-field communication technologies to Toronto Hydro's control room. As such, the fiber-optic cable plays a key role in enabling active communication and control between power controllers and in-field assets. There is approximately 300 km of fiber-optic cable within Toronto Hydro's communication system. Currently, 225 km, or 75% of all fiber-optic cable, is jointly owned between Toronto Hydro and Cogeco Data Services (CDS). This arrangement limits Toronto Hydro's ability to route diverse fiber-optic cables as required to ensure that there are no overlaps geographically in fiber-optic cable routes which may lead to a single point of failure.

Fiber-Optic Plant Replacement and Expansion removes limitations posed by the inadequate availability of fiber-optic connections in the existing fiber-optic network by eliminating fiber-optic cable strands owned by CDS and replacing them with Toronto Hydro owned fiber-optic cables. Taking this action is expected to eliminate single points of failure, which can cause significant SCADA outages.

Toronto Hydro plans to replace 117 km of fiber-optic cables, or approximately 50% of the CDS fiber. within the existing plant by targeting areas of fiber that are prone to failure. This work would enable Toronto Hydro to reduce dependency on CDS through gradual migration to a Toronto Hydro owned fiber-optic plant. In order to achieve this goal, Toronto Hydro plans to selectively replace problematic spans of the existing fiber-optic plant provisioned inside of CDS fiber-optic bundles with fully-diverse configurations where the fiber-optic cable and backup communication

lines do not overlap. This routing ensures the elimination of "flat/folded"[2] sections in the fiber-optic plant that contribute to the potential of concurrent, large-scale SCADA outages.

In addition, Toronto Hydro plans to expand the fiber-optic footprint to provide redundancy to wireless SCADA and substations that require fiber-optic network connectivity for activities such as in-office work or closed circuit television (CCTV). Toronto Hydro proposes to install an additional 238 km of fiber-optic cable. Expanding fiber-optic presence to new locations will enable additional synergies, such as the ability to migrate away from costly third party service providers for communication purposes. This work is expected to reduce Toronto Hydro's dependency on third parties to provide the communication infrastructure by integrating CCTV/Access card and Office LAN functionality with the upgraded Ethernet/IP technology, which in turn is expected to result in future cost avoidance of third party Service Provider fees.

E6.22.2.3 SCADA Wireless Infrastructure

Toronto Hydro operates five wireless SCADA technologies, including GE TransIt, MOSCAD, DACSCAN, GE SD9, and SpeedNet. Three out of these five technologies – GE TransIt, MOSCAD, and DACSCAN – are legacy systems that are now functionally obsolete. Within the distribution system, there are approximately 1,100 in-field overhead or vault RTUs and 800 DG connections that rely on the existing wireless SCADA communication network. By eliminating these legacy technologies, the SCADA wireless infrastructure activities are expected to reduce operational risks such as the reliance on assets with limited support from manufacturers and the lack of redundancy for SCADA systems in western Toronto.

This work includes the addition of four new wireless SCADA SD9 "High-Sites" in addition to the seven existing SCADA High-Sites, as shown in Figure 7 in section E6.22.7 2015 Project Details.

High-sites are installations in the distribution system that communicate with in-field SCADA radios wirelessly and transmit the information back to the control center through fiber-optic cable lines. Figure 3 shows one such site in Toronto's distribution system.

[2] Flat/Folded section - A section of fiber-run is non redundant. An example would be primary and backup fiber-path on a fiber-optic SONET ring that are provisioned inside of the same conduit and failure of the conduit will impact both cables.

FIGURE 3: SCADA WIRELESS HIGH SITES – HARDWARE EQUIPMENT

Toronto Hydro plans to migrate GE TransIt SCADA radios, which have reached the end of their useful lives and are functionally obsolete, to GE SD9. This migration includes the replacement of 483 GE TransIt radios to GE SD9 radios out of the 675 GE TransIt devices still in service. The remaining GE TransIt radios would be replaced as part of other programs targeting SCADA switches such as Overhead Circuit Renewal (Section E6.4) and SCADA-Mate R1 Renewal (Section E6.10). Once migration is complete, the GE TransIt technology will be decommissioned, eliminating any technology overlap. This program specifically excludes radio replacement for MOSCAD and DACSCAN technology, as they are being handled through radio replacements covered in the Overhead Circuit Renewal (Section E6.4) program.

The deployment of four additional GE SD9 high-sites is expected to improve wireless SCADA coverage and enable SCADA capability for in-field assets via greater area coverage. This capacity expansion is necessary for wireless SCADA dependent initiatives such as Generation Protection Monitoring and Control (Section E5.5). The SCADA wireless infrastructure enables SCADA functionality to in-field distribution assets such as small municipal substations and pole-top RTUs that are outside the reach of the current and planned fiber-optic plant. The importance of SCADA are detailed in Section E6.22.2. In addition, this program plans to consolidate wireless SCADA platforms into a single GE SD9 connectivity standard.

The proposed program also allows updated communication networks that have encryption to protect the networks and ensure cyber-security. This is needed in particular for applications such as those proposed under the Station Control and Monitoring (section E6.16) program or

Generation Protection Monitoring and Control (section E5.5) program where protection equipment can be tampered with or breached.

The breakdown of the assets to be addressed from 2015 to 2019 is outlined in Table 2 below.

TABLE 1: ASSETS TO BE RENEWED OR INSTALLED AS PART OF DSCI PROGRAM

Assets (Units)	2015	2016	2017	2018	2019	Total
IP Data Network Retro-fit (SONET Multiplexers to be augmented with CWDM Multiplexers) (Number of Sites)	34	11	-	-	-	45
IP Data Network Installation (Without SONET technology Present) (Number of Sites)	-	34	-	-	-	34
Fiber-Optic Ring Fiber replacement in Toronto (km)	72	-	-	-	-	72
Fiber-Optic Ring Fiber replacement in Scarborough (km)	45	-	-	-	-	45
Fiber-Optic Ring Expansion in Toronto (km)	-	54	48	-	-	102
Fiber-Optic Ring Expansion in Scarborough (km)	-	64	72	-	-	136
New Wireless SCADA SD9 High-Site Deployment (# of Sites)	3	1	-	-	-	4
Wireless SCADA GE TransIt to GE SD9 Endpoint Radio Equipment Migration (# of Radios)	-	194	289	-	-	483

The pacing of the work in this program is based on: (1) the various dependencies of each component as outlined in section E6.22.4.1; and (2) the dependency of other programs and assets on the communication infrastructure. As a result, the pace of replacement is within the first three years due to the urgent nature of this program as discussed in section E6.22.4. Table 3 provides a summary of the benefits that are expected to be attained through the implementation of the DSCI program.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Upgrade in technology to maintain a reliable and secure communication system to support substation monitoring and control, which results in quicker restoration of power to customers during an outage. ƒ Monitoring and control supported by the proposed upgrade is expected to provide sufficient protection for DG in the event of a power outage, which protects DG customers' assets as well as provide them with undisrupted revenue. ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $17.01 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.22.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $6.83 million, confirming the economic prudence of the investments (see Section E6.22.7).
Reliability	ƒ Prevent SCADA communication outages so that Toronto Hydro can remotely operate equipment; this leads quicker restoration times and shorter outages, including during increasingly frequent major storm events. ƒ Allows for increased RTU installations for substations and additional capability to remotely monitor and control circuit breakers.
Safety	ƒ Enables SCADA monitoring at substations allows power controllers to constantly monitor substation assets, reducing the possibility of equipment failures and related worker and public safety risks. ƒ The updated technology provides increased protection against cyber-security threats and reduces potential safety impacts.
Efficiency	ƒ Efficiency cost saving of approximately $4.5 million that would have been required for the expansion of the existing network system. ƒ Conversion allows for three legacy wireless SCADA infrastructures to be decommissioned, reducing the cost of maintenance.

E6.22.3 Why the Program is Needed

As detailed above, the DSCI program is essential to the maintenance of an updated telecommunication system (both physical and wireless) that supports the safe, efficient, and reliable supply of electricity to Toronto Hydro customers. From 2009 to 2013, Toronto Hydro's aging, legacy SONET technology – relied upon by substation RTUs – experienced 90 failures. Any failure of this system will result in the lack of visibility of assets within the distribution system for power controllers and therefore is unacceptable. Furthermore, these types of failures can result in the loss of SCADA functionality, meaning that power controllers cannot remotely operate in-field assets which can extend outages from 30 minutes in length up to three hours. A sound telecommunication system is also a crucial component of cost-effective service delivery for

Toronto Hydro. As well, a large number of capital programs rely on a functional and reliable communication system both at substations and at dispersed locations on the distribution system.

E6.22.3.1 Program Drivers

Table 4 presents the trigger and secondary drivers for the DSCI program. As this program will mitigate critical risks to the continued operations of the electrical distribution system by upgrading the foundational communications infrastructure, it falls within the System Renewal category. The activities within this program are primarily driven by the functional obsolescence of the current communications plant.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Obsolete, non-standard, and non-ruggedized LAN equipment is required by the SONET technology. ƒ Continued investment in SONET is costly and strategically limiting due to growing technology, asset obsolescence, and dwindling qualified support personnel. ƒ Capacity limit with current SONET system has been reached, further expansions (e.g. adding new locations) are very complex and costly. ƒ Obsolete wireless SCADA infrastructure requires upgrades to remain functional, supporting critical portions of the distribution system. ƒ Obsolete MOSCAD and DACSCAN systems have no redundancy while supporting large SCADA presence. ƒ Existing fiber-optic plant exhibits a large number of single points of failure. Joint ownership of fiber-optic plant with CDS further complicates the issue.
Secondary Drivers	**Reasoning**
System Capital Investment Support	ƒ Upgrading station services by migrating devices from being reliant on legacy SONET to Ethernet/IP networks supports the Stations Monitoring and Control program to upgrade/install RTUs at substations for better monitoring and control of substation assets. ƒ Implementing additional GE SD9 high-sites allows for the migration and consolidation of end-of-life MOSCAD/DACSCAN/GE TransIt wireless SCADA systems to GE SD9. ƒ Increasing the footprint of both fiber-optic plant as well as the coverage of GE SD9 within the system allows for the expansion of the SCADA.
System Maintenance Support	ƒ Communication supports the remote monitoring of stations assets such as circuit breakers and power transformers to alert of issues that may require maintenance or intervention. ƒ Upgrading SONET allows Toronto Hydro to maintain security measures such as access card readers, CCTV cameras and supports in-office work at substations.

Safety	ƒ Communication infrastructure supports monitoring of stations assets to ensure failures do not escalate. ƒ Obsolete communication does not provide the encryption provided by the new Ethernet/IP system to protect against cyber-security threats.

This program addresses the Functional Obsolescence of the existing communication infrastructure and provides the required System Capital Investment Support and System Maintenance Support to allow programs aimed at increasing SCADA usage to obtain full benefits by providing a sound communication backbone.

(i) Functional Obsolescence

In recent decades, a number of grid automation technologies have become available to enable remote monitoring and control of distribution system assets. These technologies include electronic sensors and RTUs that require a means of communicating with Toronto Hydro control centers.

Obsolete Fiber-Optic System

Toronto Hydro maintains a substantial SONET technology presence to provide connectivity between substations and control centers. SONET is a technology from the 1980s that is being rapidly phased out in modern communication space in favour of the simpler, cheaper, and more scalable Ethernet and IP networks. Toronto Hydro's current system continues to rely on the original 155 Mbps OC-3 specifications to support legacy grid automation systems that rely on obsolete technologies. Insufficient network bandwidth on the SONET ring has resulted in the deployment of a number of costly and suboptimal stop-gap solutions to overcome network capacity issues and has hindered the proliferation of alternative Ethernet/IP technologies. The SONET system is very limited with support or technical expertise, making all maintenance work with the system more costly (on average $150,000 annually) due to the need for customized solutions from the manufacturer.

In addition, Toronto Hydro has deployed a large fiber-optic presence in the City of Toronto to support the SONET environment. The fiber-optic cabling underlying the SONET network is plagued with folded sections and non-diverse building entrances, where both fiber-optic cable runs to a premise converge to a single path or conduit resulting in multiple potential points of failure across the infrastructure. Depending on the position of the folded section, a single fiber cut may result in a concurrent outage to multiple sites on the same ring, causing unacceptable loss of

SCADA service. The loss of SCADA service can last, on average, three hours as compared to thirty minutes when SCADA services are not lost. Figure 4 illustrates the difference between the logical SONET network topology and the actual physical routing of the underlying fiber cabling.

FIGURE 4: CONCEPTUALIZATION OF IDEAL AND ACTUAL FIBER-OPTIC CONNECTIONS BETWEEN SITES

The existing SONET equipment provides limited 10 Mbps support for Ethernet/IP services. However, with technology evolving and continuous load growth in the system, the device count related scalability limitations prevent further growth for control and monitoring connectivity. The obsolete, non-standard and non-ruggedized LAN equipment required by the SONET technology's limitations and the flat LAN segments that span long-distances are inherently unstable and unreliable, increasing the probability of network outages. The continued investment into a 25-year old legacy technology with aging hardware and rising support costs is disadvantageous to Toronto Hydro's customers from the perspective of delivering value for money over the life of this asset class. Furthermore, bandwidth limitations prevent deployment of 100 Mbps/1Gbps Ethernet/IP services that are needed to support evolving business requirements such as:

- Control Room Network Infrastructure,

- Station Network Infrastructure,
- Station/Field RTU Connectivity, and
- In-field Device Communications.

Further gaps include the fact that there are no gradual migration paths to modern Ethernet/IP technologies; rigid vendor tie-in due to the highly proprietary nature of the solution; and complex, niche technology with a shrinking qualified resource pool in the market.

The installation of Ethernet/IP station LAN will allow for the connectivity to IP enabled distribution grid devices at the substations stations such as Ethernet based RTUs for circuit breakers, switchgears and SCADA switches. Furthermore, it supports IP-based Wireless SCADA communication and support in-office functions at the stations.

Obsolete SCADA Systems

Toronto Hydro currently operates five overlapping wireless SCADA systems, three of which (Motorola DARCOM, Motorola DACSCAN and GE MDS TransIt) are considered legacy systems. The technology within the MOSCAD/DACSCANs platforms is completely unsupported and obsolete with no redundancy supporting the large SCADA presence of Etobicoke. Consolidating these diverse Wireless SCADA technologies on a single, supported platform standard - GE SD9 technology - allows Toronto Hydro to eliminate the need for legacy radio systems, reduces the risk associated with the obsolete and unsupported communication technologies and can prevent large scale SCADA outages.

(ii) System Capital Investment Support

The DSCI program is essential to providing the communication backbone required to monitor and operate major assets such as circuit breakers via the use of RTUs or distribution feeder switches with SCADA functionality.

SCADA Technology at Substations

The use of modern optical technologies, such as Wavelength Division Multiplexing (WDM), enables Toronto Hydro to transition from the legacy SONET multiplexers to a modern, cost-efficient Ethernet/IP based infrastructure. This in-turn allows for the expansion of monitoring and control by allowing for the increased penetration of SCADA technology within the distribution system, including the increased installation of RTUs in substations through initiatives such as

Stations Control and Monitoring (Section E6.16). Under the legacy SONET network, only seven concurrent Ethernet/IP stations can be supported, severely restricting the ability to realize the full benefits of the Stations Control and Monitoring (Section E6.16) program since it must rely on third party communication connections. Furthermore, without the upgrade of the SONET system, RTU technology lock-in with legacy and obsolete serial communications technology (SONET) will occur as RTUs that function on SONET will need to be used even in new installations. The RTU technology lock-in results directly from the obsolescence of the SONET technology. Only a single manufacturer still offers a SONET compatible RTU and as long as Toronto Hydro remains reliant on a SONET system, it remains locked-in to the RTUs provided by that specific manufacturer. This results in vendor dependence which limits Toronto Hydro's ability to use commercially available RTUs from other vendors.

SCADA Technology on Feeders

The installation of remote SCADA switches and RTUs may be limited due to lack of expansion in the fiber-optic plant, thereby limiting the benefits of programs such as Generation Protection Monitoring and Control (Section E5.5) and Stations Control and Monitoring (Section E6.16). The renewal and expansion of the fiber-optic plant is required to ensure a reliable SCADA system for power controllers and to further increase the penetration of SCADA technology into the distribution system.

The functionality of the wireless SCADA systems is to provide monitoring and control to in-field assets outside of the fiber-optic plant perimeter. Furthermore, it enables rapid SCADA connection for in-field assets and ensures security and availability of the data communications network. This program also supports the Overhead Circuit Renewal (Section E6.4) program, which replaces MOSCAD RTUs and DARCOMM radios. These technologies are vintage communication systems and thus need to be migrated to the new standard S&C 6801 RTU and SD9 Radio. Expanded SD9 coverage is required for this to happen. Increased SCADA availability is required for the protection schemes for distributed generation (DG) assets, which are being installed as part of the Generation Protection Monitoring and Control (Section E5.5). A stable and reliable GE SD9 system also allows Toronto Hydro to increase monitoring and implementing advanced initiatives, such as Stations Control and Monitoring (Section E6.16) or Feeder Automation (Section E7.3), to drastically reduce power outage durations.

(iii) System Maintenance Support

The work proposed in this program ensures reliable communication for SCADA functionality. Without SCADA monitoring and control, Toronto Hydro power system controllers do not have access to critical information such as alarms for circuit breaker trip, loss of transformer voltage, loss of battery power, alarms on transformer pressure, oil level, and temperature. This information is critical to ensure that assets are utilized appropriately and to prevent conditions that may rapidly degrade an assets life, thereby allowing Toronto Hydro to maintain its stations assets.

In addition, the program's expansion of the outside fiber-optic plant to select locations expands the communication footprint to better support services such as Voice Radio/Wireless SCADA, Station office facilities, and remote CCTV cameras, allowing for increased security. This infrastructure helps to support security cameras monitoring stations as well as to support access card reader connectivity.

(iv) Safety

Station Asset Monitoring

The lack of reliable communication networks within an area limits the installation of RTUs in substations which provide important information about substation assets. This information is integral in ensuring that a problem on these assets does not escalate into a catastrophic failure that may pose a threat to the station surroundings. By alerting power controllers of key issues with station assets such as circuit breaker trips, low oil levels in power transformers, loss of battery power etc., a flashover or explosion can be avoided.

Failure due to Cyber-security events

For reasons that the utility cannot disclose, the existing systems are more vulnerable to cyber-security threats such RTU spoofing, system disruption, or theft of system data. RTU spoofing occurs and can result in tampering of information such as changes to threshold levels set for safety parameters. Tampered SCADA systems at substations can lead to catastrophic failure of power system assets, and can compromise the safety of Toronto Hydro employees, the public, and station surroundings. This program provides advanced security measures to mitigate these risks.

E6.22.3.2 Asset Details

(i) Asset Lifecycle

The DSCI program contains assets that are functionally obsolete and have passed their useful lives.

- SONET multiplexers have a useful life of 10 years. The assets currently in service range from 10 to 12 years of age.
- Fiber-optic cables have a useful life of approximately 25 years, and given that the existing fiber-optic plant was installed in the 1980s, these cables are well beyond their useful life. Moreover, CDS and Toronto Hydro jointly own major fiber-optic cables, with CDS owning the conduit and many of the strands of fiber-optic cabling within the conduits, and Toronto Hydro owning only the pair of fiber-optic strands that it utilizes within the fiber bundle. The joint ownership limits Toronto Hydro's ability to remediate severe issues with routing, single points of failure, and availability of fiber-optic cabling plant.
- Similarly, the GE TransIt wireless SCADA system is approximately nine years old and has passed its useful life of five years. This system is unable to meet the increasing demands for monitoring and control on the distribution system. GE SD9 is the successor and the natural migration path for the GE TransIt system.

(ii) Asset Failure Impacts

Over the past five years, the existing SONET system experienced a total of 90 communication outages. A communication outage impacting the SCADA system can limit the ability for power controllers to operate substation equipment remotely, and may extend the outage duration from 30 minutes to three hours. The failure of the communication assets within this program, such as the SONET equipment, fiber-optic cables, or obsolete wireless SCADA technology, can impact a multitude of programs as listed in Table 5, preventing the programs from achieving their full benefits.

TABLE 4: THE IMPACTS OF FAILURE ON THE DISTRIBUTION SYSTEM

Areas	Related Programs	Description	Consequences
Distribution System Communication Technology Upgrade	Stations Control & Monitoring (Section E6.16)	ƒ Introduce CWDM technology and decouple SONET multiplexers from IP/Ethernet equipment ƒ Increase the presence and capacity of Ethernet/IP at the stations ƒ Allow for SONET technology to be decommissioned once migration to Ethernet/IP is complete	ƒ Failure of obsolete equipment would result in Toronto Hydro having to rely on customer calls to learn about feeder outages and having to perform manual switching instead of remote switching to troubleshoot problems
	Stations Switchgear Renewal (Section E6.13)		ƒ Visibility and control of installed switchgear would be constrained without this program. Toronto Hydro would be dependent on customer calls to report outages due to operational constraints on the SCADA system
	Generation Protection Monitoring and Control (Section E5.5)		ƒ With current communication equipment, the distribution system is at risk to operate within design and station available short circuit capacity limits ƒ With failure occurring, all inverter-based generators will not be able to cease power production well before the station breaker begins to open, thereby not mitigating the short circuit impact.
Distribution System Fiber-Optic Replacement and Expansion	Stations Control & Monitoring (Section E6.16)	ƒ Will remediate single points of failure, flat/folded sections and suboptimal quality cabling within the existing fiber-optic plant to drastically improve the availability	ƒ Limitation in full monitoring and control of station outages with current system ƒ Concurrent multi-station SCADA outages due to fiber cuts and single points of failure

	Feeder Automation (Section E7.3)	of the core SCADA station network • Will expand the perimeter of the existing fiber-optic plant to provide better coverage • Expand the fiber-optic footprint to provide redundancy to wireless SCADA substations that require fiber-optic network connectivity	• Concurrent outages in the backhaul infrastructure for Feeder Automation due to fiber cuts and single points of failure
	SCADA-Mate R1 Renewal (Section E6.8)		• Interruption of SCADA may render newly installed SCADA-Mate R2 switches useless during power outages, thereby foregoing their benefits
SCADA Wireless Infrastructure	Feeder Automation (section E7.3)	• Will eliminate legacy wireless SCADA technologies that are now obsolete and no longer supported by the manufacturer and thus will reduce the operational risks • Additional GE SD9 high-sites will be installed to improve wireless SCADA coverage and facilitate rapid SCADA provisioning for in-field assets via greater area coverage	• Failure of the infrastructure could affect overhead SCADA and SF_6 URD switches- large customer impact would result since switches are located on the feeder trunk and will limit the ability for restoration • The automation of the system would fail, resulting in FA and URD not operating as intended and failure to deliver the reliability and efficiency benefits it provides • Failure of infrastructure will affect RTUs having the same effect as overhead SCADA - crews would need to be dispatched for manual switching
	SCADA-Mate R1 Renewal (Section E6.8)	• Will allow SCADA functionality to in-field distribution assets such as substations that are outside the fiber-optic backhaul telecom	• If there is no remote connection to SCADA-Mate switches then the function of the SCADA switches is compromised

	Overhead Circuit Renewal (Section E6.4)	perimeter	ƒ A failure of MOSCAD RTUs and DARCOMM radios can lead to the loss of remote functionality of SCADA switches in a large part of Toronto
	Downtown Contingency (Section E7.7)		ƒ Obsolete assets raise the risk of partial or complete station outages, limited visibility and increase of outage duration to three hours on average ƒ Limited operational response capabilities will exist should failure of these assets occur
	Generation Protection Monitoring and Control (Section E5.5)		ƒ Real time monitoring for safety and feeder management for bi-directional distribution grid flows via communications with Toronto Hydro's SCADA system will be strictly limited with the failure of SCADA equipment ƒ Monitoring, control, and generation forecasting of remote distributed generation sites will difficult to do with the failure of SCADA

E6.22.4 Timing & Pacing of the Program

The program's spending forecast for the five year period starting in 2015 is shown below in Table 6, along with the historical spending on communication systems.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)		-	-	$1.03	$0.85	$6.06	$6.02	$3.95	-	-

As can be seen in Table 6, Toronto Hydro plans to complete the work proposed in this program by the end of 2017 so that the communication system will be able to support advances in monitoring and control within the distribution system.

The SONET system was built at a time when monitoring and control functionality were limited. The SONET system can no longer support stations requiring monitoring and control due to its limited capacity. There are approximately 45 SONET sites in the system, which is beyond the number of maximum sites recommended by the manufacturer and therefore, additional sites cannot be added to the SONET backbone. In addition, the legacy SONET multiplexers can cause communication outages that may render SCADA functionality of RTUs in stations inoperable and increase the outage durations from 30 minutes to three hours. Customers on an entire feeder can be impacted for the extended duration. Over the last five years, there were a total of 90 SONET communication outages. In order to rectify these issues associated with the existing SONET infrastructure, the work proposed in this program must be executed as soon as possible.

The work is also urgent because it is needed to improve both the resiliency of the communication network and to allow for increased penetration of SCADA. As detailed in Section E6.5.4.1, Toronto Hydro plans to complete renewal of the existing plant to ensure a resilient communication backbone before expanding the fiber-optic network to allow for increased coverage for SCADA within the distribution system. Deferring this work would limit Toronto Hydro's fiber-optic plant capability and constrain programs such as Station Control and Communication (Section E6.16), Overhead Circuit Renewal (Section E6.4), and Feeder Automation (Section E7.3).

In order to increase the capability of the communication infrastructure to support an increasing trend in control, monitoring, and automation, Toronto Hydro must also create additional SCADA high-sites immediately. SCADA high-sites extend the reach of the communication network and allow for SCADA installation on distribution feeders. As shown in Section E6.5.4.1, once the SCADA high-sites are installed, the obsolete GE TransIt radios must be replaced with GE SD9 radios in order to address the functional obsolescence of the wireless SCADA infrastructure. GE TransIt technology is obsolete and is no longer supported, Toronto Hydro must move to the GE SD9 system to maintain support. Currently, there are five overlapping wireless SCADA technologies in use within the system. This work allows a single technology to be established to support wireless SCADA thereby leading to efficiency savings via the decommissioning of the obsolete systems, as further discussed in Section E6.22.5.3.

E6.22.4.1 Ranking & Prioritization

The program is structured to accommodate the various dependencies outlined in Figure 5.



FIGURE 5: RANKING AND PROCESS OF IMPLEMENTATION OF THE DSCI PROGRAM

Three key aspects of the program must be completed before subsequent work can take place:

- CWDM/IP/Ethernet introduction to the SONET substation network as part of the Distribution System Communication Technology upgrade,
- Fiber-optics plant single point of failure remediation as part of the Distribution System Fiber-Optic Plant Replacement and Expansion, and

- New wireless SCADA high-site deployments must be completed as part of the wireless SCADA infrastructure activities.

Completing the above three activities allows for the strategic expansion of fiber-optic plant to the SCADA high-sites and to substations allowing for increased SCADA presence in the distribution system and IP/Ethernet to be introduced at substations respectively. Once all communications enabled assets have been replaced or upgraded to support Ethernet/IP connectivity, overlapping communication service provider technology will no longer be required and can be eliminated. In parallel with this activity, the migration from the legacy GE TransIt to the GE SD9 technology can be conducted.

E6.22.5 Program Execution

(i) Distribution System Communication Technology Upgrade

Work executed under the Distribution System Communication Technology Upgrade initiative includes the design and implementation of CWDM multiplexers at substations connected to the SONET rings. Concurrently, enablement of support for Ethernet on existing fiber using CWDM will be executed. This will allow for the migration of all IP based station services into the new Ethernet/IP networks, eliminating overlapping service provider solutions. The program will facilitate the migration of stations devices and services from SONET to IP.

The Technology Upgrade project is completed with the following steps:

- Detailed network architecture and design
- Network equipment vendor selection
- Equipment procurement and logistics
- Facilities preparations (space/racks/HVAC/power)
- Equipment installation and testing
- Promotion to production (subject to fiber-optic availability)
- System migration to the new network infrastructure

(ii) Distribution System Fiber-Optic Plant Replacement and Expansion

Work executed within the Fiber-Optic Plant Replacement and Expansion area involves the identification and remediation of single points of failure by designing new fiber-optic plant sections. Furthermore, identification of strategic sites in the distribution system without fiber-optic connectivity would allow these sites to be added to the fiber-optic communication segment through plant expansion. The Fiber-Optic Plant Replacement and Expansion needs to be completed prior to the promotion to production of infield SCADA equipment, since the fiber-optic cables are required to provide the communication network between the equipment and the control room.

The Fiber-Optic Plant Replacement and Expansion project is completed with the following steps:

- Prioritization of key sites and fiber-optic spans
- Fiber contractor selection (competitive bidding)
- Detailed telecom architecture and fiber plant route design
- Fiber route preparation (rodding and roping, “make-ready’s”, etc.)
- Fiber-optic plant installation, splicing and testing
- Demarcation (building entrance and facilities) preparation
- Telecom equipment migration to the new fiber-optic plant

(iii) Wireless SCADA Infrastructure

Work executed within the Wireless SCADA Infrastructure area involves the identification of locations and deployment of four new wireless SCADA high-sites for GE SD9 to improve the coverage radius. Concurrently, all GE TransIt wireless SCADA endpoints are to be upgraded to GE SD9, as well as the decommissioning of legacy wireless SCADA systems (GE TransIt, MOSCAD, and DACSCAN) are executed.

The Wireless SCADA Infrastructure project is completed with the following steps:

- Potential high-site identification and lease negotiation
- Equipment procurement and logistics

- Facilities preparations (space/racks/HVAC/power)
- High-site radio equipment installation and testing
- Promotion to production (subject to fiber-optic availability)
- Planned replacement of RTU TransIt radios with SD9 (no dependencies)

E6.22.5.1 Program Risks

The key risk associated with the DSCI program is that the project schedule may be impacted by the City permit process as well as attaining permission for high-site locations, which may cause delays in program execution. In order to mitigate this risk, the applications for permits and permissions are prepared well in advance such that any issues that arise can be addressed in a timely manner.

E6.22.6 Evaluation of Alternatives

E6.22.6.1 Quantification/ Evaluation of Options

The DSCI program is critical to maintaining the communication backbone of a safe and reliable distribution system. There are two alternatives to this program: (i) maintaining the current practices and legacy infrastructure or (ii) implementing the proposed program.

(i) Status Quo

With the status quo option, Toronto Hydro will simply maintain the platform and bandwidth requirement. This will result in very little new functionality and capability as the emphasis will be on addressing single points of failure and architectural deficiencies.

Maintaining the current state poses a variety of risks including vendor/technology sprawl created by multiple overlapping technologies and vendors, unpredictable availability of capacity on existing communication infrastructure, obsolescence, and lack of technical support. Although the capital investment is low for this particular option, the operational cost has and will continue to rise due to the need to maintain an obsolete system with declining manufacturer support and expertise.

This option would severely limit Toronto Hydro's ability to improve its distribution system through increased monitoring and control. For example, due to capacity issues with the SONET system,

the current state limits Toronto Hydro's ability to connect RTUs at additional substations in the downtown core, thereby limiting the benefits achieved through the execution of programs such as Stations Control and Monitoring (Section E6.16) or Stations Switchgear Renewal (Section E6.13). This limitation affects the amount of control that can be exercised on station assets, which increases the restoration time when a circuit breaker operates, extending the outage to the customer.

Fiber-optic cables now in use are past their useful life and experience outages, impacting the SCADA capability of both substation RTUs as well as distribution feeder SCADA switches, thereby reducing the benefits of increased SCADA penetration introduced by programs such as Overhead Circuit Renewal (Section E6.4), Feeder Automation (Section E7.3), and Generation Protection Monitoring and Control (Section E5.5). Due to interruptions on the fiber-optic network, power controllers lose the ability to see and operate on faults quickly, which can lengthen the time to needed to respond to an outage from 30 minutes to three hours on average. Similarly, on the distribution feeder, SCADA switches are used to restore power to customers quickly when a fault occurs by remotely isolating the fault and restoring power to customers on sections that are not affected by the fault. However, there are many portions of the distribution system where SCADA capabilities are not supported due to the lack of high-sites to communicate with the SCADA switches, impacting Toronto Hydro's ability to delivery this technology to reduce the outage restoration time. This problem is further aggravated by the fact that the GE TransIt system is past its useful life and these radios have become functionally obsolete, thus not providing the intended SCADA capability. A functionally obsolescent communication infrastructure compromises safety by exposing Toronto Hydro to cyber-security threats and limiting the visibility on asset performance and operating condition. Given the impact on the distribution system of an aging communication system, this option is not preferred.

(ii) Implement the Distribution System Communication Infrastructure program

This option involves performing the work outlined in Section E6.22.6 to improve the resiliency and performance of the communication system, while also enabling business initiatives, such as remote control and increased system monitoring. With fiber-connectivity, 1 Gbps Ethernet/IP will be available at all sites. The investment would eliminate single points of failure in the outside fiber-optic plant by running new fiber and will expand outside fiber-optic plant footprint to improve availability and provide high-speed connectivity to strategic sites. The implementation would also standardize and consolidate the wireless SCADA environment to GE SD9 from the obsolete GE

TransIt. In addition, carrying out the proposed program would allow Toronto Hydro to avoid costly investments in obsolete systems (SONET) and to decommission legacy communication technologies and infrastructure, thereby introducing efficiency savings in the communication system. This option is also a foundational enabler technology for various initiatives, including programs like Generation Protection Monitoring and Control (Section E5.5), Overhead Circuit Renewal (Section E6.4), SCADA-Mate R1 Renewal (Section E6.8), and Stations Monitoring and control (Section E6.16), which are essential to increasing the protection, monitoring, and control of the distribution system.

The cost of ownership (COO) and program net benefit (NPV) associated with the Distribution System Communication Infrastructure program is further detailed in Figure E6.22-11. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities within this program. The COO of a state reflects the risk of asset failure including both direct and indirect costs; these costs include customer interruptions, emergency repairs, and asset replacements associated with a given design. For further details on the COO approach, please refer to Section D3.3. The implementation of the DSCI program is critical for enabling the penetration of SCADA technology when SCADA switches are installed on feeders in the affected region. In order to reflect this requirement, the business case takes into account for the installation cost of SCADA switches (SC) to establish the required number of switching regions on feeders in this region in addition to the program cost (PC) of this program. The total cost that is applied is then equal to (SC) and (PC). When the difference in cost of ownership (ûCOO) is compared to the associated total cost, the Distribution System Communication Infrastructure produces a net benefit (NPV) value of $6.83 million, as shown in Tables 7 and 8.

TABLE 6: EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	$ 106.18
Non Asset Risk [NAR_E]	$ 0
Maintenance Cost [MC_E]	$ 0
Additional Quantifiable Benefits [AQB_E]	$ 0
Cost of Ownership of Existing Assets [COO_E]	$ 106.18

TABLE 7: DISTRIBUTION SYSTEM COMMUNICATION IN FRASTRUCTURE BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 2: Implementation of DSCI (N)	
Asset Risk [AR_N]	$ 89.18
Non Asset Risk [NAR_N]	$ 0
Maintenance Cost [MC_N]	$ 0
Additional Quantifiable Benefits [AQB_N]	$ 0
Cost of Ownership of New Assets (Conversion to 13.8kV) [COO_N]	$ 89.18
Option 2: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_N)$]	$ 17.01
Program Cost [PC_1]	$ 6.06
Switch Replacement Cost [SC_1]	$ 4.12
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	$ 6.83

E6.22.7 2015 Project Details

As part of the 2015 project year, Toronto Hydro plans to remove the limitations posed by the current CDS owned fiber by replacing the cable with Toronto Hydro owned cable. The proposed locations, in downtown Toronto and Scarborough, for replacing existing CDS fiber are listed in Tables 9 and 10, respectively.

TABLE 8: PROPOSED PLANT OPTICAL FIBER CABLE REPLACEMENT FOR 2015: DOWNTOWN TORONTO

Station/Node A	Station/Node B
60 Eglinton (Control Centre)	Highlevel TS Station
Highlevel TS Stn.	Terauley TS Station
Charles TS Stn.	Gerrard TS Stn.
Charles TS Stn.	Carlaw TS Stn.
Carlaw TS Stn.	Main TS
Cecil TS Stn.	Dufferin TS Stn.
Dufferin TS Stn.	Wiltshire TS Stn.
George & Duke MS Stn.	Duncan MS Stn.
Defoe MS Stn.	Windsor TS Stn.
Wilshire TS Stn.	Bridgman d TS Stn.
Fairbank TS	60 Eglinton
George & Duke MS Stn.	Ontario MS Stn.
Finch TS Stn.	Runnymede TS Stn.

TABLE 9: PROPOSED PLANT OPTICAL FIBER CABLE REPLACEMENT FOR 2015: SCARBOROUGH

Station/Node A	Station/Node B
Cavanagh TS Stn.	Fairchild TS Stn.
Cavanagh TS Stn.	Malvern TS Stn.
Marvern TS Stn.	Warden TS Stn.

Toronto Hydro plans to install 34 Coarse Wavelength Division Multiplexing (CWDM) technology units which will decouple SONET technology and Internet Protocol (IP) traffic, preventing the need to upgrade the legacy SONET platform. Table 11 provides the location for the existing

SONET nodes to be augmented with CWDW deployment. Figure 6 presents a map of these same locations.

TABLE 10: LIST OF SONET MULTIPLEXER NODES FOR REPLACEMENT WITH CWDM MULTIPLEXERS

No.	Name of the Node/Station	Ring	Category	Address
1	14 Carlton	Toronto	Corporate office	14 Carlton St.
2	Terauley Stn.	Toronto	TS	532 Bay St.
3	George & Duke Stn.	Toronto	MS	233 Adelaide St. E
4	Esplanade Stn.	Toronto	TS	106 Lower Sherbourne St.
5	Windsor Stn.	Toronto	TS	253 Wellington St. W
6	Duncan Stn.	Toronto	CS	29 Nelson St.
7	Strachan Stn.	Toronto	TS	10 Strachan Ave.
8	Charles Stn.	Toronto	TS	83 Charles St. E
9	Bridgman Stn.	Toronto	TS	391 Davenport Rd.
10	High Level Stn.	Toronto	MS	290 Macpherson Ave
11	Control Centre	Toronto	Office building	60 Eglinton Ave W
12	Glengrove Stn.	Toronto	TS	2829 Yonge St.
13	Fairbank Stn.	Toronto	TS	5760 Yonge St.
14	Leaside Stn.	Toronto	TS	5733 Leslie St.
15	500 Commissioners	Toronto	Office building	500 Commissioners St.
16	Basin Stn.	Toronto	TS	23-25 Basin St.
17	Cecil Stn.	Toronto	TS	38 Cecil St.
18	Dufferin Stn.	Toronto	TS	1045 Dufferin St.
19	Junction Stn.	Toronto	MS	26 Ruskin Ave.
20	Runnymede	Toronto	TS	99 Woolner Ave.
21	Witshire Stn.	Toronto	TS	39 Wiltshire
22	Bathurst Stn.	Toronto	TS	155 Goddard St.
23	Forest Laneway	Toronto	Hub site	6 Forest Laneway
24	Finch Stn.	Toronto	TS	2150 Finch West

25	Copeland	Toronto	TS	25 Ress St.
26	Carlaw Stn.	Toronto	TS	369 Carlaw Ave.
27	Gerrard Stn.	Toronto	TS	20 Blackburn str.
28	Main Stn.	Toronto	TS	131 Stephenson Ave.
29	Copeland Stn.	Toronto	TS	25 Ress St.
30	Fairchild Stn.	Scarb.	TS	5760 Yonge St.
31	Warden Stn.	Scarb.	TS	682 Warden Ave.
32	Scarborough Stn.	Scarb.	TS	2411 Lawrence Ave E.
33	Malvern Stn.	Scarb.	TS	1702 Neilson Rd.
34	Cavanagh Stn.	Scarb.	TS	105 Miliken Boulv.

FIGURE 6: MAP OF 34 SONET MULTIPLEXER NODES FOR REPLACEMENT WITH CWDM MULTIPLEXERS FOR 2015

Additionally, Toronto Hydro proposes to install three additional SD-9 High-Sites in 2015. High-sites are installations in the distribution system that communicate with in-field SCADA radios

wirelessly and transmit the information back to the control center through fiber-optic cable lines. The proposed SD-9 High-Sites locations for 2015 are shown in Figure 7.

FIGURE 7: MAP OF THE NEW SD-9 HIGH-SITE LOCATIONS FOR 2015

TABLE 1: TRIGGER DRIVERS FOR SYSTEM SERVICE CATEGORY

Driver	Description
Safety	ƒ Assets are exposing known safety-related hazards/risks to crew workers or the general public, or assets are an integral part of maintaining safe work practices, and the failure of those assets would likely result in safety-related hazards or risk exposure
Reliability	ƒ Maintain or improve reliability at a local, feeder-wide or system-wide level
System Efficiency	ƒ The need to improve restoration capability, ultimately resulting in substantial reliability and customer experience improvements ƒ The need to reduce losses in distribution lines
Capacity Constraints	ƒ Expected changes in load that will constrain the ability of the system to provide consistent service delivery ƒ Current or potential incapability of the system to handle demand requirements

Table 2 provides a brief description for each investment program within the System Service narrative along with total expenditures for each program from 2015 onwards to 2019. Individual section numbers for each investment program are also provided in this table.

TABLE 2: DESCRIPTION OF SYSTEM SERVICE INVESTMENT PROGRAMS

Program Index and Name		Description	Total (5 years)
E7.1	Contingency Enhancement	Make improvements to feeders in the existing distribution systems that are currently unable to quickly restore power to affected customers under a contingency situation.	$48.9 M
E7.2	Design Enhancement	Implementing fusing enhancements to resolve the issues of undersized fuses, mis-coordinated fuses and redundant trunk sections that lack fusing. Replacement and strategic location of fuses and the implementation of tree proof conductors to mitigate sustained interruptions caused by tree contact outages.	$7.27 M
E7.3	Feeder Automation	Facilitating faster and less labour intensive system restoration procedures by replacing existing switches with autonomously operating Supervisory Control and Data Acquisition (SCADA) switches, reducing the impact of trunk outages to customers and isolating the faulted section of the feeder in less than a minute.	$54.1 M

Program Index and Name		Description	Total (5 years)
E7.4	**Overhead Momentary Reduction**	Installation of reclosers to provide flexibility to the system, fault protection and improve the distribution feeder reliability performance by limiting outage times and containing the outage to a minimum area.	**$1.91 M**
E7.5	**Handwell Upgrades**	Replacing the remaining legacy handwells with new standard handwells made from non-conducting composite materials to remove the risk of contact voltage to the public.	**$4.98 M**
E7.6	**Polymer SMD-20 Fuses**	Targets SMD-20 switches that were installed between 2006 and 2011, as breakages inhibit these switches from functioning safely as designed. New switches utilize a fiberglass core that has five times the strength of the previous design. Replacement of the switches eliminates the known safety risk to the public and Toronto Hydro employees.	**$4.84 M**
E7.7	**Downtown Contingency**	Providing distribution load transfer capability between stations in the downtown Toronto area by tying feeders from one station with feeders from an adjacent station. This program addresses a risk in the downtown area where no back-up is provided for certain low probability, high impact events.	**$3.36 M**
E7.8	**Customer Owned Station Protection**	Installation of utility-owned protection devices upstream of customer-owned substations to isolate any faults occurring at customer owned substations.	**$4.04 M**
E7.9	**Stations Expansion (including HONI contributions)**	Upgrades to either Toronto Hydro or Hydro One Networks Inc. owned transformer stations. These upgrades address recent trends in customer connection requirements and loading, by mitigating system limitations imposed by existing station equipment.	**$188 M**
E7.10	**Local Demand Response**	Providing medium-term capacity relief to Cecil TS by implementing a targeted and localized demand response strategy which primarily leverages new and existing demand response resources.	**$4.06 M**
E7.11	**Energy Storage Systems**	To provide a conventional support for local capacity constraints and service reliability issues throughout Toronto Hydro's distribution system. These systems are also categorized as a renewable enabling improvement to accommodate the increasing numbers of renewable energy generation (REG) connections.	**$10.8 M**

/C

The following Sections E7.1 though to E7.10 contain the details and justification for each capital investment program within the System Service investment category.

E7.1 Contingency Enhancement

TORONTO HYDRO CREW MEMBER REPAIRING OVERHEAD INFRASTRUCTURE

E7.1.1 Summary

Program Description

The objective of the Contingency Enhancement program is to make improvements to feeders in the existing electrical distribution system that are currently unable to quickly restore power to affected customers under a contingency situation. Distribution feeders can be interrupted due to equipment failure and weather-related events. These interruptions can impact the supply of power along either a portion or the entire feeder. Several feeders in Toronto Hydro's overhead and underground distribution systems lack the ability to restore power to customers in a timely manner during emergencies. The program aims to reduce the risk of long duration outages for customers by ensuring that crews and system controllers have full capability to re-route affected customers to nearby feeders.

Toronto Hydro plans to address the situation by establishing sufficient tie and sectionalizing points, upgrading under-sized loop conductors and upgrading undersized trunk egress cable capacities. These targeted upgrades and installations will equip the distribution system to better meet the needs of customers in contingency scenarios, effectively maximizing the customer value of existing feeders by minimizing unnecessary failure risk.

Table A summarizes the expected benefits related to the Contingency Enhancement Program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Reduces the length of customer outages. ƒ Increases the number of customers that can be restored during an outage
Reliability	ƒ Enhances reliability through improved load transfers and upgraded equipment. ƒ Faster response with SCADA controlled switches. ƒ Improved system performance during high impact events, including major storms.
Safety	ƒ Eliminates manual switching, which reduces Toronto Hydro crew exposure to energized equipment.
Efficiency	ƒ Eliminates manual switching, allowing Toronto Hydro to utilize resources for other matters.

Program Drivers

The trigger and secondary drivers for this program are provided in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Reliability	ƒ Certain feeder configurations and assets on the 27.6 kV distribution systems limit the system controller's ability to restore electrical service to customers when a feeder experiences a fault or requires maintenance. By undertaking this program, Toronto Hydro will reduce the duration of outages during contingency situations, including high impact events such as major storms.
Secondary Drivers	**Reasoning**
System Efficiency	ƒ Manually operated switches require Toronto Hydro crew members to physically travel to the site and perform switching operations during faults, which prolongs the duration of outages for customers. By deploying SCADA-enabled tie point and sectionalizing switches, Toronto Hydro will reduce its need to send crews to perform switching activities. ƒ Undersized conductor restricts Toronto Hydro's ability to transfer load during fault repair or maintenance activities ƒ Aluminum trunk egress cable exists at 10 transformer stations and is not rated to deliver the full capacity of a 27.6 kV feeder circuit, preventing Toronto Hydro from fully utilizing feeder capacity to deliver load to adjacent feeders during a contingency scenario.

Safety	*f* Installation of SCADA enabled switches in the field eliminates manual switching, which reduces Toronto Hydro crew exposure to energized equipment. This is especially important during contingency condition when most of the outages occur during poor weather condition which may result in access to the switch location difficult and crew forced to work near faulty equipment.

Preferred Alternative

Toronto Hydro evaluated the following options for addressing the system design deficiencies considered by this program.

(i) Do nothing and accept the anticipated degradation of reliability due to aging assets and forecasted increases in load growth and the frequency of major storms.

(ii) Increase the contingency capabilities within the system to mitigate anticipated degradation of reliability.

Option II is the preferred alternative as it strengthens Toronto Hydro's distribution system in contingency conditions, thus mitigating a degradation of reliability as the system ages, load growth continues and environmental conditions evolve due to climate change. Enabling feeders to be segmented into smaller sections gives system controllers greater ability to transfer loads and minimize the number of customers impacted during power outages. Upgrading the aluminum egress cable to copper also increases the capacity of feeders, thus allowing them to supply more load, which can benefit reliability under contingency situations.

Timing and Pacing

The Contingency Enhancement program takes into account other renewal projects and will work in conjunction with them to upgrade assets while the renewal project is taking place. This will keep the renewal work costs lower and will reduce the number of planned outages for customers during the renewal process.

Details of the historical and future spending for Contingency Enhancement are outlined below in Table C. There was no historical spending prior to 2015 as these projects were typically undertaken as part of other asset renewal projects.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Annual Spend ($M)	0	0	0	0	0	$9.97	$5.88	$9.71	$9.68	$13.53

E7.1.2 Program Description

Distribution feeders can be interrupted by a number of incidents, including equipment failure and weather-related events. A feeder may also need to be taken out of service for scheduled maintenance or repair work. The interruption of a feeder can stop the supply of power along a portion or event the entire feeder. Under either contingency scenario, Toronto Hydro must be able to transfer customers normally supplied by the out-of-service feeder to adjacent feeders to minimize the duration of outages for customers that are dependent on the affected feeder.

A number of feeders in Toronto Hydro's overhead and underground distribution systems lack the ability to restore power to customers quickly during contingency scenarios. The Contingency Enhancement program will make targeted improvements so that customers experiencing an outage can receive re-routed power during contingency scenarios. These investments will help shorten the duration of power outages for customers that are dependent on failing, aging assets. The total cost of the program from 2015 to 2019 is $48.8 million. The program consists of the following distinct but related elements:

(1) Establishing additional tie and sectionalizing points,

(2) Upgrading under-sized loop conductors, and

(3) Upgrading the capacity of trunk egress cable.

E7.1.2.1 Establishing additional tie and sectionalizing points on looped feeders

Toronto Hydro plans to install additional SCADA-enabled[1] tie and sectionalizing points on underground and overhead feeders so that customers can be quickly switched to alternate feeders in the event of a contingency condition, reducing the duration of outages. Initial analysis will be performed on feeders that lack a sufficient number of tie or sectionalizing points to determine the reliability impact. Toronto Hydro will take into account the feeders' configurations and number of customers each serves in determining the optimal location of tie or sectionalizing switches. In addition, overhead line or underground cable extension work will be performed to establish new tie connection points between feeders; this work may involve the installation and removal of poles, lines and switches for the overhead plant. Additional civil infrastructure may be needed for the placement of new pad mounted switches and cable in the underground distribution

[1] SCADA switches are capable of being remotely controlled to perform switching operations from the control room.

system. Also, the utility plans to convert the existing manually operated sectionalizing and tie switches to SCADA-controlled switches where feasible.

Figure 1 shows the locations of feeders in the looped distribution system with insufficient tie points. Toronto Hydro plans to either install new switches or convert existing manually operated switches to SCADA controlled type to address these deficiencies. If the switches are located within the boundary of the rebuild project, they may be included as a renewal project under the System Renewal program. Otherwise, the switches are targeted under this Contingency Enhancement program.

FIGURE 1: MAP OF FEEDERS WITH INSUFFICIENT TIE POINTS

E7.1.2.2 Upgrade existing undersized loop conductors

Toronto Hydro plans to upgrade undersized conductor in lateral loops to ensure that they are properly rated to carry the load of the entire loop under contingency condition. If the existing cable is installed in concrete encased duct, the only work that would be required is the replacement of cable and transformer vault ancillary. However, if the existing cable is direct-buried or if the existing duct structure has collapsed, before replacement work can be undertaken, Toronto Hydro would have to conduct civil construction work to build new concrete encased duct and splice boxes.

Figure 2 shows the location of undersized loop conductors in the distribution system.

FIGURE 2: LOCATION OF UNDERSIZED LOOP CONDUCTOR

E7.1.2.3 Upgrade capacity of trunk egress cable

Toronto Hydro plans to replace existing aluminum cable on feeder trunk egress sections with copper cable to match the 600 A rated capacity of the breaker. The capacity of aluminum cable is limited to 500A/530A in the summer/winter, which means that the full breaker capacity cannot be realized under contingency situations if necessary. The normal rating of copper cable is 630A/680A in the summers/winter, which is sufficient to carry the full continuous load of a 27.6 kV feeder circuit breaker. With the appropriately rated cable, feeders can be used to provide safe and reliable relief to adjacent feeders under a contingency condition. If the existing cable is installed in concrete encased duct, Toronto Hydro will only need to make cable replacements. However, as with the undersized loop conductors, if the existing cable is direct-buried or if the

existing duct structure has collapsed, before replacement work can be undertaken, Toronto Hydro will have to conduct civil construction work to build new concrete encased duct and splice boxes.

The following is a list of Transfer Stations (TS) with under-rated trunk egress cables:

- Leslie TS
- Bathurst TS
- Fairchild TS
- Fairbank TS
- Horner TS
- Runnymede TS
- Finch TS
- Scarborough East TS
- Scarborough West TS
- Sheppard TS

Error! Reference source not found. Table 1 summarizes the assets that are forecast to be replaced through the Contingency Enhancement program during the 2015-2019 period.

TABLE 1: ASSETS TO BE REPLACED (BY ASSET CLASS)

Assets (Units)	2015	2016	2017	2018	2019	Total
Primary cable (meter)	27,397	16,158	26,683	26,600	37,180	134,017
Underground Transformers	23	14	22	22	31	113
Underground switchgear	11	6	11	11	15	54
Poles	157	93	153	152	213	768
Overhead Transformer	28	17	27	27	38	137
Overhead switch	46	27	45	45	62	225

The following table summarizes the anticipated benefits of this program. A detailed discussion of program drivers can be found in the following section.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Reduces the length of customer outages. ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $59.79 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.1.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $49.82 million, confirming the economic prudence of the investments (see Section E7.1.7).
Reliability	ƒ Enhances reliability through improved load transfers and upgraded equipment. ƒ Faster response with SCADA controlled switches. ƒ Improved system performance during high impact events, including major storms.
Safety	ƒ Eliminates manual switching, which reduces Toronto Hydro crew exposure to "live" equipment.
Efficiency	ƒ Eliminates manual switching, allowing Toronto Hydro to utilize resources for other matters.

E7.1.3 Why the Program is Needed

Certain sections of Toronto Hydro's distribution network cannot effectively respond to contingency conditions in order to deliver reliable service to customers. The Contingency Enhancement program is needed to minimize the effect maintenance activities and faults have on outages during contingency situations.

E7.1.3.1 Program Drivers

The Contingency Enhancement program is designed to ensure that Toronto Hydro can efficiently and effectively restore power to customers during contingency scenarios. Table 3 presents the trigger and secondary drivers for the Contingency Enhancement program. This program is a System Service initiative because the trigger driver is reliability.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Reliability	ƒ Certain feeder configurations and assets on the 27.6 kV distribution systems limit the system controller's ability to restore electrical service to customers when a feeder experiences a fault or requires maintenance.

	By undertaking this program, Toronto Hydro will reduce the duration of outages during contingency situations, including high impact events such as major storms.
Secondary Drivers	Reasoning
System Efficiency	ƒ Manually operated switches require Toronto Hydro crew members to physically travel to the site and perform switching operations during faults, which prolongs the duration of outages for customers. By deploying SCADA-enabled tie point and sectionalizing switches, Toronto Hydro expects to reduce its need to send crews to perform switching activities. ƒ Undersized loop conductor restricts Toronto Hydro's ability to transfer load during fault repair or maintenance activities. ƒ Aluminum trunk egress cable exists at 10 transformer stations and is not rated to deliver the full capacity of a 27.6 kV feeder circuit, preventing Toronto Hydro from fully utilizing feeder capacity to deliver load to adjacent feeders during a contingency scenario.
Safety	ƒ Installation of SCADA enabled switches in the field eliminates manual switching, which reduces Toronto Hydro crew exposure to "live" equipment. This is especially important during contingency condition when most of the outages occur during poor weather condition which may result in access to the switch location difficult and crews potentially forced to work near faulty equipment.

(i) Establishing additional tie and sectionalizing points on a looped feeder

When a segment of, or the whole feeder, loses power during a contingency scenario, customers connected to the failed segment receive power from an alternate feeder using feeder tie points and sectionalizing switches. In the underground distribution system, the switching equipment used is SF_6-insulated pad-mounted switches equipped with SCADA capability; the overhead system uses SCADA controlled switches mounted on poles.

If a feeder is not sufficiently equipped with sectionalizing or tie points that can divide the load into smaller sections, re-routing of power may not be possible for all customers during peak loading times. Issues arise because the amount of lost load may be too large for the adjacent feeder to supply without causing an overloading condition. In some cases, load growth and the addition of new developments onto feeders have created this problem. However, this program is not triggered by the challenge of new load added to the system – that driver is addressed in the Load Demand program. The intent of this program is to allow the distribution system to respond adequately to contingency conditions, rerouting affected customers to alternate feeders.

In addition to a lack of tie-points in some areas, an additional issue is that many existing tie and sectionalizing switches in the field that are manually operated, the problems of which are discussed below. Table 4 provides an overview of the switch types found in the distribution system.

TABLE 4: TIE AND SECTIONALIZING SWITCHES

Switch type	Manual	SCADA	Total
Tie	527	395	922
Sectionalizing	3,605	448	4,053

Manual switches were installed before SCADA-controlled devices were available and considered standard equipment by Toronto Hydro. To restore customers using manual switches, a crew must travel to the switch location to perform the switching work on-site. Depending on the location of the fault and accessibility of the switches, it may take anywhere from 30 minutes to a few hours to perform the switching work. On the other hand, with SCADA controlled switches, this switching operation can be performed remotely by system controllers in a matter of minutes. In addition to the time savings, remotely controlling switches is safer than manually performing switching activities because crews are not exposed to live equipment. SCADA controlled switches also send back instant loading information to the control room, enabling controllers to reroute power to adjacent feeders more efficiently and reducing the duration of power outages during a feeder contingency condition.

An illustration of the situation described above is demonstrated in Figure 3 below. Although there are two individual tie points, T1 and T2, connected to the feeder, customers in section C may not have their power restored under a fault condition if section C's load is greater than T1's available spare capacity at the time. As a result, even though tie point T2 has enough capacity to restore power to customers in section B, customers in section C would be without power until repair work is completed and power is restored through the feeder breaker itself.

FIGURE 3: FEEDER WITH INSUFFICIENT NUMBER OF TIE POINTS

Figure 4 illustrates a solution to the problem above. By adding an additional tie point (T3) and a new sectionalizing switch (F) to split the original section "C" into two sections ("C1" and "C2"), an additional source of supply can be used to restore the lost load.

FIGURE 4: AFTER ADDITION OF TIE AND SECTIONALIZING SWITCH

An example of location that required a tie point is project W15391: Bathurst Bridge Tie Point (35M4-35M9), illustrated in Figure 5. Through this project, Toronto Hydro plans to extend overhead 27.6kV conductor on Bathurst St. between Heathdale Rd. and Ridgewood Rd. to connect feeders 35M4 and 35M9 via a new SCADA controlled switch. This project is needed because the south-east most portion of 35-M9 has one of the highest load densities in the area; this section of 35-M9 supplies 3500 residents, including 14 large condominium developments, a 400 resident long-term care facility, and St. Michael's College School. In all, this section accounts for 50% of the total feeder load; however, it is in an isolated corner of the feeder that currently does not possess effective tie points to transfer its load to in the event of feeder failure. As a result, this section had a history of long outages. By installing a new tie switch, this section of the feeder will be able to be supplied by feeder 35M4 in the event of failure, greatly enhancing the reliability of power supply to customers.

FIGURE 5: SCOPE W15391

To provide appropriate backup supply, a feeder should have at least three strategically located tie points connected to three unique back up feeders:

(1) The first tie point connects to another feeder from the same substation bus.

(2) The second tie point connects to another feeder on a separate bus located at the same substation.

(3) The third tie point connects to another feeder from a different substation.

This design is illustrated in Figure 6.

FIGURE 6: THREE TIE POINT DESIGN

By arranging the tie points in such a fashion, a contingency power source is made available for the faulted feeder regardless of whether the fault occurs at the feeder, bus or station level. This increases the flexibility of the switching options available to reroute power quickly to the affected customers from a failed feeders, thus reducing the duration of a power outage. It should be noted that the number of additional sectionalizing switches and tie points that need to be installed for each feeder under this program will vary depending on the amount of load that is connected to the specific feeder and availability of tie feeders in the area.

E7.1.3.2 Undersized loop conductor

In a looped distribution system, a group of transformers is connected in a loop formation from two fused points that are connected to the trunk portion of the feeder, as shown in Figure 7. There is typically an open-point near the middle of the loop so that, under normal operating conditions, about half of the load in the loop is supplied from one lateral or the other. The loop can be a single phase circuit (connecting single phase transformers) or a three-phase circuit (connecting three-phase transformers).

FIGURE 7: LOOPED DISTRIBUTION

If there is an equipment failure at any point along the loop, the faulty asset can be isolated by opening removable connectors in the transformer vault on both sides of the failed equipment. Power to customers on the undamaged portion of the loop can then be restored by closing the open point.

Generally, the conductor on either lateral is, by design, large enough to handle the load of the entire loop if necessary. In a situation where a fault occurs, on the first section downstream of the fuse, the restored load must be supplied entirely from the other side of the loop, as shown in Figure 8. This situation is analogous to the circumstances where Toronto Hydro must electrically isolate an asset for maintenance purposes.

FIGURE 8: POWER RESTORATION IN LOOP AFTER FAULT

Over time, new customers are added to the loop. In some situations, this gradual increase in load has resulted in existing conductors no longer being able to supply the load of the entire loop. A contingency situation in these locations would cause cascading power outages to the entire loop because the conductor is not rated to deliver the total load demand in the loop. This situation is illustrated in Figure 9. In the end, prolonged repair work is required and customers would face long power outages. Although controllers do monitor the conductor size and number of transformers that are transferred to the circuit under contingency, the actual load of each transformer may not be known by the controller. Therefore, even in instances where a conductor withstood a high current during repair work without failing, this overloading situation may have already caused degradation of the integrity of the conductor and could lead to premature failure of the loop conductor and reactive repair work in the future.

Toronto Hydro plans to upgrade undersized conductor in lateral loops to ensure that they are rated to carry the load of the entire loop under contingency conditions.

FIGURE 9: POWER LOST DUE TO UNDERSIZED CONDUCTOR

E7.1.3.3 Insufficient Capacity of Trunk Egress Cable

Feeders in the looped distribution system are connected to one another using tie switches installed at various locations along each feeder. The tie-points are designed to transfer load from one feeder to another under a contingency condition. The initial section of the feeder between the station breaker and the first distribution switch (i.e. the section upstream from any load connections) is called the "egress" section of the feeder. The egress can carry the entire load of the feeder at any time. The trunk egress cable must be adequately sized to be able to supply the load of the feeder as well as additional load from adjacent feeders under contingency, up to the maximum capacity of the feeder breaker.

When stations were initially constructed in the 1960's and 1970's, several factors were considered in choosing which feeders to install, including known or anticipated load, contingency requirements and the material cost of cable. Some existing underground 27.6 kV feeders contain legacy 1000 kcmil aluminum trunk egress cable, a cable that is de-rated (i.e. its current carrying capacity is lowered) when installed in an underground environment to 500 A and 530 A in the summer and winter seasons respectively.

In some areas, demand growth has exceeded the capacity of this existing configuration, so a higher rated trunk egress cable is needed to utilize the full capacity of certain feeders. In addition, the existence of a large quantity of aging assets in the distribution system raises the risk of asset failures, which may ultimately result in multiple feeders in contingency condition at a same time. In some circumstances, a feeder may be forced to carry the load of more than one feeder under contingency. This is a high risk situation, as failure of the load carrying feeder to deliver power to its maximum capacity may ultimately result in loss of power to two other feeders, causing power outages to a very large area for an extended period. It is therefore critical that the egress portion of the feeder be fully rated to effectively utilize the rated capacity of the breaker, which is rated 600A, in order to supply load to customers on its own and to adjacent feeders under contingency. Due to the limitation of current carrying capability of these trunk egress cables, customers that would otherwise be served by those feeders under a contingency condition would experience an outage until the work on their normal feeder has been completed.

Under a contingency condition, controllers may not be able to utilize feeders with 1000 kcmil aluminum egress trunk cable to pick-up load lost on adjacent feeders during fault or planned maintenance. As a result, customers will experience prolonged power outage until the faulty asset is repaired or replaced on the normal supply feeder. Toronto Hydro may also be required to defer important scheduled maintenance work until the load on feeders is low enough to be re-routed, resulting in the deterioration of asset conditions, further reducing reliability.

An example of a project to upgrade undersized trunk conductor is “W11147: Cable Replacement Bathurst Stn M4, M24, M25” (addition details can be found in section E7.1.9). Through this project, Toronto Hydro plans to upgrade existing 1000 kcmil Al trunk egress cable to 1000 kcmil Cu to fully utilize the rated capacity of feeders 85M4, 85M24 and 85M25. Figures 10, 11 and 12 show the loading profile of feeders 85M4, 85M24 and 85M25 from May 2011 to May 2014. The loading charts show that the normal seasonal peak loading for all three feeders is in excess of 450 A. The maximum peak loading that these feeders have experienced, although short in duration, has exceeded the normal rating of the 1000 kcmil Al conductor. While the existing aluminum cable can withstand a small amount of additional load of 80 A, over time, the frequent overloading of cable would eventually cause the cable to fail prematurely, causing power outages to the entire feeder. The small size of the cable and overloading accelerates the physical degradation of the conductor insulation integrity. It is for this reason that the legacy aluminum trunk cable is no longer sufficient to be used as the trunk cable and must be upgraded to Cu conductor

FIGURE 10: FEEDER LOADING 85M4

FIGURE 11: FEEDER LOADING 85M24

FIGURE 12: FEEDER LOADING 85M25

Similar situations also exist in the following stations with aluminum trunk egress cable:

- Leslie TS
- Bathurst TS
- Fairbank TS
- Horner TS
- Runnymede TS
- Finch TS
- Scarborough East TS
- Scarborough West TS
- Sheppard TS

E7.1.4 Timing & Pacing of the Program

Contingency readiness is an essential component of electrical distribution operations. Without it, customers are subject to the risk of lengthy power outages any time there is a disturbance on a feeder. The majority of Toronto Hydro's distribution assets are equipped to properly respond to contingency conditions. In certain areas however, load growth and feeder extension has resulted in sections of the distribution system that are inadequately equipped to handle contingency conditions to restore power to customers in a timely manner. Due to the fact that Toronto Hydro is operating with a large quantity of aged assets in the field, there is an increasing risk of random asset failures that could result in power outages and contingency scenarios. As a result, it is critical that the contingency enhancement work be performed where needed to ensure the impact of feeder failure to customer is minimized.

This program is required to upgrade the distribution system's ability to effectively manage contingency situations in order to minimize customer interruptions. Deferring this program would likely prevent Toronto Hydro from being able to effectively restore power to certain feeder segments that have experienced failure, leading to potentially lengthy power outages. In addition, Toronto Hydro will not be able to perform proactive repair or maintenance work on certain feeders to prevent assets from deteriorating.

Toronto Hydro has taken into account the timing of other planned asset renewal projects that may be taking place in timing the projects under the Contingency Enhancement program. If a switch that needs to be addressed is within the boundary of a renewal project, it will be upgraded in conjunction with the system renewal work since the renewal of overhead lines or underground cable and transformer will usually require that existing switches be temporarily removed to allow for the construction work to be done. As such, it is more efficient and cost effective to upgrade the switch while the renewal project is taking place. If the switch is not located in any planned rebuild project area, Toronto Hydro will assess the urgency to install or upgrade the switch based on the historical reliability, age and condition of the switch and its impact on customer outages. As a result, some projects will be performed from 2015 to 2019 while other, non-urgent projects will take place beyond 2019. Similar logic applies to undersized loop conductor and trunk egress cable.

Contingency readiness is a key element in Toronto Hydro's asset management and engineering function. As indicated in the Table 5 below, there was no historical spending solely dedicated to contingency enhancement prior to 2015. Typically, these projects were undertaken as part of asset renewal or plant upgrade projects and as such, their spending figures can be found under

those respective projects. Although some contingency enhancement projects will continue to be classified under asset renewal projects going, a portion will be performed as standalone work. To align with the new program categorization commencing in 2015, these project are grouped together as part of the Contingency Enhancement program.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	$9.97	$5.88	$9.71	$9.68	$13.53

E7.1.4.1 Ranking & Prioritization

For the tie point and sectionalizing switch work, projects will be ranked and prioritized by feeder loading, reliability and available feeders in the nearby vicinity for new tie switch installations. Some feeders lack a sufficient number of tie points because there is no other feeder in the area that is within reasonable reach. In these cases, work will be required to extend overhead or underground infrastructure to complete the connection and work may need to be staged in phases for completion.

Undersized loop conductor upgrades will be ranked and prioritized based on reliability statistics as well as the age and condition of the existing assets. Aging or unreliable assets can signal a risk of failure, increasing the urgency of the work.

Aluminum to copper conversion of egress cable will primarily be ranked and prioritized based on feeder loading and the reliability of adjacent feeders. A feeder that consistently experiences high loading with insufficient egress trunk cable rating is at risk of not being able to deliver the capacity needed to relief adjacent feeder under contingency. These feeders will be prioritized.

E7.1.5 Program Execution

The underground system uses SF_6-insulated pad-mounted switches equipped with SCADA capability. The overhead system uses SCADA-controlled switches mounted on poles. Installing new switches may require new poles, lines for the overhead plant, or civil infrastructure for the placement of new pad mounted switches in the underground distribution system. Cable replacement may also be required where existing cable must be spliced to accommodate a new switch. Fuses on both the overhead and underground systems may also be replaced.

Replacing undersized lateral loop conductors is required for underground cable only. Cable is either directly buried in the ground or is encased in a concrete duct. In cases where cable is directly buried, concrete duct encasements are also installed.

Feeder trunk cable upgrades are only required on the underground system. Similar to lateral loop conductors, if trunk cable is direct-buried, concrete ducts are installed in advance of the cable replacement. For all underground cable replacement, Tree Retardant Cross Link Polyethylene (TRXLPE) cable is used.

If a planned overhead or underground renewal project overlaps with work from this program, the work to install tie and sectionalizing switches will be included as a part of the larger scale renewal projects (as executing such work together is more cost effective). For locations where work in this program is not associated with any larger-scale renewal work, projects are individually scoped and executed.

E7.1.5.1 Proposed Work Plan

Work in this program covers mainly the 27.6kV looped distribution outside of the downtown core.

E7.1.5.2 Program Risks

Unforeseen site conditions, such as the presence of foreign infrastructure (such as gas, sewer or water pipes), can necessitate scope changes and can result in cost increases and/or delays in the completion of the underground work. In these situations, Toronto Hydro would reprioritize and/or reschedule work after taking all factors into consideration.

As well, Toronto Hydro must take into account city road moratoriums that may be imposed after the scope is issued, which could result in delays. However, Toronto Hydro can mitigate this risk by ensuring that it maintains open communication with the City of Toronto and coordinates its activities with those of the city.

Finally, weather-related events can impact system loading conditions, which may prohibit feeder work (e.g., summer heat wave). In the same way, emergency work may also alter Toronto Hydro's planned work schedule.

E7.1.5.3 Evaluation of Alternatives

E7.1.5.3.1 Quantification/Evaluation of Options

(i) Status Quo

Maintaining the status quo involves forgoing the Contingency Enhancement program. Customers served by troubled feeders would continue to experience lengthy outages during contingency conditions. In addition, Toronto Hydro would incur high costs with respect to performing reactive work to replace equipment that was damaged due to overloading and manual switching work.

For these reasons, the status quo option is not preferable.

(ii) Proposed Program

Executing the proposed program strengthens Toronto Hydro's distribution system in contingency conditions, improving reliability for affected customers. The addition of SCADA controlled tie and sectionalizing switches would enable Toronto Hydro to segment a feeder into smaller sections so that load could transferred to alternate feeders to reduce the duration of power outages. In the end, customers would be expected to experience improved service reliability and Toronto Hydro would gain efficiency advantages by extending the reach of the SCADA system. As well, upgrading aluminum egress cable to copper would allow feeders to utilize the full rated capacity of the circuit in order to deliver power during a contingency condition.

The cost of ownership (COO) and program net benefit (NPV) associated with the Contingency Enhancement program is further detailed in Figure 10 and Figure 11. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities in this program. The cost of ownership (COO) of a state reflects the risk of asset failure including both direct and indirect costs, including the costs of customer interruptions, emergency repairs, and asset replacements associated with that design. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NARE) and proposed (NARN) state. Non-asset risks are further explained in Section D3.3. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership ("COO) is compared to the associated program costs (PC) for the first year of activities, the

Contingency Enhancement program produces a net benefit (NPV) value of $49.82 million, as shown in Tables 6 and 7.

TABLE 6: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo / Existing State of Infrastructure	
Asset Risk [AR_E]	$ 274.66
Non Asset Risk [NAR_E]	$ 719.30
Maintenance Cost [MC_E]	$ 0
Additional Quantifiable Benefits [AQB_E]	$ 0
Cost of Ownership of Existing Assets [COO_E]	$ 993.96

TABLE 7: CONTINGENCY ENHANCEMENT PROGRAM BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Contingency Enhancement (N1)	
Asset Risk [AR_N]	$ 221.67
Non Asset Risk [NAR_N]	$ 712.51
Maintenance Cost [MC_N]	$ 0
Additional Quantifiable Benefits [AQB_N]	$ 0
Cost of Ownership of New Assets [COO_N]	$ 934.17
Option 2: Project Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\Delta COO_1 = (COO_E - COO_N)$]	$ 59.79
Program Cost [PC_1]	$ 9.97
Program Net Benefit [$NPV_2 = (\Delta COO_1 - PC_1)$]	$ 49.82

E7.1.6 Program Projects

Table 8 list the projects that Toronto Hydro plans to execute beginning in 2015. Detail on projects for years 2015 is provided in the following sections.

TABLE 8: PROGRAM SCOPES

Project Number	Project Name	Total Project Cost	Start Date
E14136	E14136 OH Upgrade R43M24 Hollis Milne Birchmount (Electrical) - Map Area 1	$871,476.78	2015
E11672	E11672 Midland Distbn Rebuild/Relocate/VC Ph1 (EJF2 to E5-M27	$109,420.64	2015
E11673	E11673 Midland Distbn Rebuild/Relocate/VC Ph2 (EJF3 to E5-M27)	$95,988.77	2015
E11637	E11637 Civil works for rebuild of NY51M4 Gordon Baker and Hazelnut Crescent	$209,013.26	2015
W13478	P03 SCADA Switch Installation on NY55M5	$178,176.43	2015
W11147	Cable Replacement Bathurst Stn M4, M24, M25	$1,181,568.15	2015
W11148	Cable Replacement Bathurst Station M6, M7, M2, M32	$1911519.44	2015
W15228	W15228 P01 Canarctic & Wildcat Phase 2 Tie to 55M24 CIVIL NY85M32	$427,591.59	2015
W15229	W15229 P01 Canarctic & Wildcat Phase 2 Tie to 55M24 ELECTRICAL 85M32	$554,460.13	2015
W15394	W15394 - Overhead Sectionalizing points on 55M31	$137,017.06	2015
W15391	W15391 Overhead Tie Point at St.Clair and Spadina RD TO35M6 YK35M9	$649,885.63	2015
W15402	W15402 Underground Tie and Sectionalizer on feeder 55M3	$348,713.32	2015
W15398	W15398 Underground and Overhead ties to 55M30	$719,149.92	2015
W15450	W15450 P1473 The Queensway - Install Scada OH tie between 38M21 and 38M27	$105,504.65	2015
E14136	E14136 OH Upgrade R43M24 Hollis Milne Birchmount (Poles Only)	$162,861.44	2015
E15460	E15460 Morningside Neilson Install SCADA PMH 47M3 SCNT47M3	$689,424.28	2015
W15459	W15459 Sectionalizing / Installing Tiepoints on the overhead trunk of 38M29	$1,063,446.93	2015
E13272	E13272 Upgrade UG trunk E51M21 Brimley Rd	$228,034.21	2015
W15517	W15517-P05-SCADA for Sectionalization on 88M46, Richview TS	$69,509.96	2015
E14136	E14136 OH Upgrade R43M24 Hollis Milne Birchmount (Electrical) - Map Area 2	$258,117.42	2015

E7.1.6.1 Project Detail

E11637 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: E11637 Civil works for rebuild of NY51M4 Gordon Baker and Hazelnut Crescent

Project Number: E11637

Project Year: 2015

Estimated Cost: $209,013.26

(i) Objective

This project provides necessary civil structures for when direct buried cables are removed from the feeder and replaced with those enclosed concrete encased ducts.

(ii) Scope of Work

TABLE 9: SCOPE OF WORK DETAILS

District Neighbourhood:	Don Valley East
Station(s):	Leslie 1 TS
Feeder(s):	NY51M4

(iii) Justification & Benefits

With respect to reports filed on the ITIS databases, feeder NY51M4 has experienced six outages within the last 12 months. The WPF rank deteriorated from 19 to 16. Aged cable in the loop is the primary cause of failure. This project will upgrade cable to current standard.

E11672 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: E11672 Midland Distribution Re-build/Relocate/VC Ph1 (EJF2 to E5-M27)

Project Number: E11672

Project Year: 2015

Estimated Cost: $109,420.64

(i) Objective

The objective of this project is to rebuild, with voltage conversion, the old distribution at 1710 Midland Ave and to relocate a pad mounted transformer for safety reasons.

(ii) Scope of Work

TABLE 10: SCOPE OF WORK DETAILS

District Neighbourhood:	Scarborough Centre
Station(s):	Canadine Midland (4.16kV)
Feeder(s):	SCEJF2

(iii) Justification & Benefits

The distribution at 1710 Midland Ave is currently operating at 4kV and consists of aged assets. This lateral of EJ-F2 was installed in 1968 according to GEAR.

Routine maintenance inspection determined that assets at this location need to be replaced. This project is needed to upgrade the asset to current standard and supply the customer from 27.6kV distribution in order to improve system reliability.

TABLE 11: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	341.84m
Underground Transformers	4
Underground Switchgear	
Poles	2
Overhead Transformer	
Overhead Switch	2

E11673 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: E11673 Midland Distbn Rebu ild/Relocate/VC Ph2 (EJF3 to E5-M27)

Project Number: E11673

Project Year: 2015

Estimated Cost: $95,988

(i) Objective

The objective of this project is to rebuild, with voltage conversion, the old distribution at 1570 Midland Ave.

(ii) Scope of Work

TABLE 12: SCOPE OF WORK DETAILS

District Neighbourhood:	Scarborough Centre
Station(s):	Canadine Midland (4.16kV)
Feeder(s):	SCEJF3

(iii) Justificat ion & Benefits

The distribution at 1570 Midland Ave is currently operating at 4kV and consists of aged assets. This lateral of EJ-F3 was installed in 1968 according to GEAR.

Routine maintenance inspection determined that assets at this location need to be replaced. This project is needed to upgrade the asset to current standard and supply the customer from 27.6kV distribution in order to improve system reliability.

TABLE 13: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	335.9m
Underground Transformers	4
Underground Switchgear	

Assets to be Replaced	
Poles	2
Overhead Transformer	
Overhead Switch	2

E13272 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: E13272 Upgrade UG trunk E51M21 Brimley Rd

Project Number: E13272

Project Year: 2015

Estimated Cost: $228,034

(i) Objective

The objective of this project is to replace the old direct buried 750kcmil cable with 1000kcmil Cu cable in CE duct along Brimley Rd from riser OS59873 (at NW of Brimley-Lawrence) to riser OSL51809 (at P882 Brimley).

(ii) Scope of Work

TABLE 14: SCOPE OF WORK DETAILS

District/Neighbourhood:	Scarborough Centre
Station(s):	Scarborough TS (27.6kV)
Feeder(s):	SCN-AE-51M21

(iii) Justification & Benefits

There is a stretch of undersized cable (as per GEAR record), built direct buried, between riser OS59873 (at NW of Brimley-Lawrence) and riser OSL51809 (at P882 Brimley).

Work will upgrade the current carrying capacity of the cable and refresh aged existing direct buried cable with new cable installed in concrete encased duct. In all, this project will improve the reliability of the feeder and contingency readiness.

TABLE 15: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	212.66m
Underground Transformers	

Assets to be Replaced	
Underground Switchgear	
Poles	2
Overhead Transformer	
Overhead Switch	2

E14136 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: E14136 OH Upgrade R43M24 – Hollis Milne Birchmount (Electrical)

Project Number: E14136

Project Year: 2015

Estimated Cost: $871,476

(i) Objective

The objective is to replace the undersize conductor (by THESL standard 556kcmil conductors) of the NAR43M24 feeder main in sections on Hollis Ave, Milne Ave, part of Mack Ave and Birchmount Rd.

(ii) Scope of Work

TABLE 16: SCOPE OF WORK DETAILS

District Neighbourhood:	Scarborough Southwest
Station(s):	Warden TS (27.6 kV)
Feeder(s):	SCNAR43M24

(iii) Justification & Benefits

There are some sections of undersize conductor on the feeder OH trunk of feeder NAR43M24 and M28. The sections are on Hollis Ave, Milne Ave, part of Mack Ave and Birchmount Rd. During the transfer of load, especially at peak load time, the weak sections are likely to get overloaded and develop sag and/or melt and burn. Toronto Hydro will replace the weak sections of 336 kcmil conductors with standard 556kcmil conductors. This will establish the full capacity feeder main of R43M24 and transfer tie with NAR43M23 and R43M28

TABLE 17: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	
Underground Transformers	2

Assets to be Replaced	
Underground Switchgear	
Poles	37
Overhead Transformer	8
Overhead Switch	3

E15460 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: E15460 Morningside Neilson Install SCADA PMH 47M3 SCNT47M3

Project Number: E15460

Project Year: 2015

Estimated Cost: $689,424

(i) Objective

This project will automate four SF6 PMH-11 switches on the trunk of NT47M3 as recommended by Operations.

(ii) Scope of Work

TABLE 18: SCOPE OF WORK DETAILS

District Neighbourhood:	Scarborough Rouge River
Station(s):	Sheppard TS (27.6kV)
Feeder(s):	SCNT47M3, SCNT47M1

(iii) Justification & Benefits

SCNT47M3 was the worst performing feeder from 2005 to 2012; however, there was a gradual improvement because of the replacement of some failing DB cables. The rebuild continued at a faster pace from 2009 to 2011, which further improved reliability. As of October 2013, it is the second worst performing feeder with a FESI ranking of 12.

Converting four underground switches to SCADA controlled type will improve restoration time under contingency and improve reliability of power.

TABLE 19: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	
Underground Transformers	

Assets to be Replaced	
Underground Switchgear	4
Poles	
Overhead Transformer	
Overhead Switch	

W11147 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: Cable Replacement Bathurst Stn M4, M24, M25

Project Number: W11147

Project Year: 2015

Estimated Cost: $1,181,568

(i) Objective

The objective of this project is to provide adequate capacity in order to maintain the continuity of supply under normal and contingency conditions.

(ii) Scope of Work

TABLE 20: SCOPE OF WORK DETAILS

District Neighbourhood:	York West
Station(s):	Bathurst I TS (27.6 kV), Bathurst II TS (27.6 kV)
Feeder(s):	NY85M4, NY85M24, NY85M25, NY85M31

(iii) Justification & Benefits

An analysis has been done regarding customer's future loads and feeder performance data. It is forecasted that load will rise in 2016 and beyond. New feeders are required to meet growing load.

TABLE 21: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	6881.76 m
Underground Transformers	2
Underground Switchgear	2
Poles	1
Overhead Transformer	
Overhead Switch	1

W11148 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: Cable Replacement Bathurst Station M6, M7, M2, M32

Project Number: W11148

Project Year: 2015

Estimated Cost: $1,911,519 Objective

The objective of this project is to provide adequate capacity in order to maintain the continuity of supply under normal and contingency conditions.

(i) Scope of Work

TABLE 22: SCOPE OF WORK DETAILS

District Neighbourhood:	York West
Station(s):	Bathurst TS (27.6 kV)
Feeder(s):	NY85M6, NY85M7, NY85M2, NY85M32

(ii) Justification & Benefits

An analysis has been done regarding customer's future loads and feeder performance data. It is forecasted that load will rise in 2016 and beyond. New feeders are required to meet growing load.

TABLE 23: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	10015.37 m
Underground Transformers	
Underground Switchgear	
Poles	4
Overhead Transformer	1
Overhead Switch	

W13478 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: P03 SCADA Switch Installation on NY55M5

Project Number: W13478

Project Year: 2015

Estimated Cost: $178,176 Objective

The purpose of this project is to replace two existing manual switches to SCADA switches in order to provide more switching flexibility to feeder 55M5.

(i) Scope of Work

TABLE 24: SCOPE OF WORK DETAILS

District Neighbourhood:	Etobicoke York
Station(s):	Finch TS (27.6 kV)
Feeder(s):	NY55M5

(ii) Justification & Benefits

NY55M5 is a feeder located in North York. The feeder possesses SCADA switches at the tie point but no SCADA sectionalizing points. In discussion with Control Room personnel, it was requested that the switches included in this project be installed in order to make the existing sectionalizing switches more useful, improving the feeder's restoration time.

TABLE 25: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	
Underground Transformers	
Underground Switchgear	
Poles	
Overhead Transformer	

Assets to be Replaced	
Overhead Switch	2

W15228 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: W15228 P01 Canarctic & Wild cat Phase 2 Tie to 55M24 CIVIL NY85M32

Project Number: W15228

Project Year: 2015

Estimated Cost: $427,591

(i) Objective

The primary objective of this scope is the civil portion of providing an adequate tie for 85M32, utilizing 55M24, in the Canarctic and Wildcat area distribution (Phase 2).

(ii) Scope of Work

TABLE 26: SCOPE OF WORK DETAILS

District Neighbourhood:	York West
Station(s):	Bathurst II TS (27.6 kV)
Feeder(s):	NY85M32

(iii) Justificat ion & Benefits

The existing 27.6 kV distribution along Canarctic Dr and Wildcat Rd, near Keele St and Steeles Ave, is supplied from 85M32 and 85M30, and consists of two three-phase loops between PS26636 and PS86071. The area is comprised of commercial customers that are continuing to expand rapidly with emerging loads.

Consumption data using metering suggests that a contingency scenario will result in 201A, which is very close to the continuous rating of the 200K fuse protection scheme. The situation is worsened by the presence of 1/0 STR AL cable, which has a summer emergency ampacity of 180A in a duct bank with three circuits. Through this project, Toronto Hydro will upgrade inadequate assets, which will improve the contingency readiness of the feeder.

W15229 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: W15229 P01 Canarctic & Wildcat Phase 2 Tie to 55M24 ELECTRICAL 85M32

Project Number: W15229

Project Year: 2015

Estimated Cost: $554,460

(i) Objective

The primary objective of this project is to provide an adequate tie for 85M32, utilizing 55M24, in the Canarctic and Wildcat area distribution (Phase 2).

(ii) Scope of Work

TABLE 27: SCOPE OF WORK DETAILS

District Neighbourhood:	York West
Station(s):	
Feeder(s):	85M32

(iii) Justification & Benefits

The existing 27.6 kV distribution along Canarctic Dr and Wildcat Rd, near Keele St and Steeles Ave, is supplied from 85M32 and 85M30, and consists of two three-phase loops between PS26636 and PS86071. The area is comprised of commercial customers that are continuing to expand rapidly with emerging loads.

Consumption data using metering suggests that a contingency scenario will result in 201A, which is very close to the continuous rating of the 200K fuse protection scheme. The situation is worsened by the presence of 1/0 STR AL cable, which has a summer emergency ampacity of 180A in a duct bank with three circuits. Through this project, Toronto Hydro will upgrade inadequate assets, which will improve the contingency readiness of the feeder.

TABLE 28: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	3168.6m
Underground Transformers	
Underground Switchgear	
Poles	
Overhead Transformer	
Overhead Switch	

W15391 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: W15391 Overhead Tie Point at St.Clair and Spadina RD TO35M6 YK35M9

Project Number: W15391

Project Year: 2015

Estimated Cost: $649,885

(i) Objective

To increase restoration capability to feeder 35M9 by creating a tie point between 35M4 and 35M9.

(ii) Scope of Work

TABLE 29: SCOPE OF WORK DETAILS

District Neighbourhood:	
Station(s):	Fairbanks TS
Feeder(s):	35M4, 35M9

(iii) Justification & Benefits

The south-east most portion of 35-M9 (located on the North-West corner of St. Clair and Spadina) has one of the highest load densities in the area. This section of 35-M9 supplies 3500 residents, including 14 large condominium developments, a 400 resident long-term care facility, and St. Michael's College School, accounts for 50% of the total feeder load and has a history of long outage durations largely due to its lack of tie points.

The section is isolated by surrounding 13.8 kV distribution, and currently has no feeder tie locations. This project will establish additional tie point to enable quicker load transfer under feeder contingency conditions.

TABLE 30: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	

Assets to be Replaced	
Underground Transformers	
Underground Switchgear	
Poles	24
Overhead Transformer	
Overhead Switch	

W15394 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: W15394 - Overhead Sectionalizing points on 55M31

Project Number: W15394

Project Year: 2015

Estimated Cost: $137,017

(i) Objective

The purpose of the project is to install SCADA switches to sectionalize feeder 55M31.

(ii) Scope of Work

TABLE 31: SCOPE OF WORK DETAILS

District Neighbourhood:	Etobicoke York
Station(s):	Finch TS
Feeder(s):	55M31

(iii) Justification & Benefits

Having SCADA switches as tie points and at several locations as sectionalizing points will improve the reliability of the system by significantly reducing the restoration time of the majority of segments of the trunk portion of the feeder that are affected by an outage

TABLE 32: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	
Underground Transformers	
Underground Switchgear	1
Poles	
Overhead Transformer	
Overhead Switch	1

W15398 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: W15398 Underground and Overhead ties to 55M30

Project Number: W15398

Project Year: 2015

Estimated Cost: $719,149

(i) Objective

The objective of the scope is to create new tie point between feeder 55M30 and feeder 55M24. In addition to this, the project will replace a manual pad mount switchgear with SCADA to provide operational flexibility to the feeder.

(ii) Scope of Work

TABLE 33: SCOPE OF WORK DETAILS

District Neighbourhood:	York West
Station(s):	Finch TS
Feeder(s):	NY55M30

(iii) Justification & Benefits

Tie points are used to restore power to customers during power outages or planned load transfers. It is important that an adequate number of tie points exist on feeders.

55M30 is a feeder that only had one tie point. Through this project, Toronto Hydro will provide 55M30 with a new tie to 55M24. In addition to this, the project will automate one of the existing Underground ties to provide backup to a section of the feeder.

TABLE 34: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	4829.31m
Underground Transformers	10

Assets to be Replaced	
Underground Switchgear	
Poles	
Overhead Transformer	
Overhead Switch	1

W15402 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: W15402 Underground Tie and Sectionalizer on feeder 55M3

Project Number: W15402

Project Year: 2015

Estimated Cost: $348,713

(i) Objective

The purpose of the project is to install two new SCADA Pad mounted switchgears on feeder 55M3.

(ii) Scope of Work

TABLE 35: SCOPE OF WORK DETAILS

District Neighbourhood:	
Station(s):	Finch TS
Feeder(s):	NY55M3

(iii) Justification & Benefits

Having SCADA switches as tie points and at several locations as sectionalizing points will improve the reliability of the system by significantly reducing the restoration time of the majority of segments of the trunk portion of the feeder that are affected by an outage.

TABLE 36: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	
Underground Transformers	
Underground Switchgear	1
Poles	
Overhead Transformer	
Overhead Switch	

W15450 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: W15450 P1473 The Queensway - Install Scada OH tie between 38M21 and 38M27

Project Number: W15450

Project Year: 2015

Estimated Cost: $105,504Objective

The objective of this scope is to upgrade the tie switch at location OSL11809 to a SCADA enabled tie-point between feeders 38M21 and 38M27.

(i) Scope of Work

TABLE 37: SCOPE OF WORK DETAILS

District Neighbourhood:	
Station(s):	Manby TS
Feeder(s):	

(ii) Justification & Benefits

Customers serviced by the feeders 38M27 and 38M21 have experienced four outages per year between 2010 and 2013. Outage duration on both feeders combined has exceeded 500 minutes per year in the 2010 - 2013 period, with CI of about 300 per year. Given the high frequency of outages, there is a need for tie switching between 38M27 and 38M21 for temporary reconfiguration. Also, the load break switch OSL11809 has become a highly used switch point; however, it takes a long time to perform switching activities because this is a manual switch. Through this project, Toronto Hydro will install a switch that is automated and can be controlled by SCADA remotely from the control room making.

TABLE 38: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	
Underground Transformers	

Assets to be Replaced	
Underground Switchgear	
Poles	1
Overhead Transformer	
Overhead Switch	1

W15459 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: W15459 Sectionalizing / Installi ng Tiepoints on the overhead trunk of 38M29

Project Number: W15459

Project Year: 2015

Estimated Cost: $1,063,446 Objective

The objective of this project is to break the trunk of the 27.6kV feeder 38M29 into manageable segments with SCADA enabled sectionalizing switches and to add a new SCADA enabled tie-point with 38M13 on The Queensway.

(i) Scope of Work

TABLE 39: SCOPE OF WORK DETAILS

District Neighbourhood:	Etobicoke Lakeshore
Station(s):	Manby TS
Feeder(s):	38M29, 38M13

(ii) Justification & Benefits

The 27.6kV Manby TS feeder 38M29 currently does not have any SCADA enabled switch located anywhere along its trunk. The DGO control has therefore been 'blind' to the distribution services on the feeder, especially during contingencies. Until now, the feeder had been able to curtail the length of by localizing faulted segments with the 4kV MS stations in its service area. However, the conversion of all the MS stations has led to a necessary and urgent need to sectionalize the feeder.

Installing SCADA enables switches will allow the control room to reconfigure during contingencies and the new tie switch with 38M13 along The Queensway will improve the control centre's ability to provide quick relief during contingencies.

TABLE 40: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	
Underground Transformers	
Underground Switchgear	
Poles	37
Overhead Transformer	4
Overhead Switch	8

W15517 Project Description

Portfolio: System Service

Program: Contingency Enhancement

Project Title: W15517-P05-SCADA for S ectionalization on 88M46, Richview TS

Project Number: W15517

Project Year: 2015

Estimated Cost: $69,509Objective

The objective of this scope is to install a SCADA switch for better sectionalization of feeder 88M46 and to provide operational flexibility for customers east of Centennial Park Blvd on Eglinton Ave W.

(i) Scope of Work

TABLE 41: SCOPE OF WORK DETAILS

District Neighbourhood:	
Station(s):	Richview TS
Feeder(s):	88M46

(ii) Justification & Benefits

There are many large commercial and industrial customers west of Centennial Park Blvd on Eglinton Ave W. These customers can become stranded during certain outage conditions. In the past there have been a number of customer complaints indicating that that outages are long and affects their day to day operations due to them being connected radially, with no other supply method. To combat this issue, Toronto Hydro plans to further sectionalize the trunk to allow a two way method in order to resupply the corner of Centennial Park and Eglinton Ave W. Performing this action will enable restoration upstream and downstream for these customers and will improve the contingency readiness reliability of the system. Furthermore, this project is needed because the Pan Am games will be operating in the area.

TABLE 42: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1611.99m

Assets to be Replaced	
Underground Transformers	1
Underground Switchgear	3
Poles	47
Overhead Transformer	15
Overhead Switch	23

E7.2 Design Enhancement

BARE CONDUCTOR IN HEAVY VEGETATION

E7.2.1 Summary

Program Description

The Design Enhancement program targets feeder designs that (1) do not possess effective fusing schemes and/or (2) lack resistance to tree contacts in areas with tree canopy intensification in the City of Toronto.

Fusing enhancements are needed to target issues with respect to undersized fuses, fusing miscoordination and redundant trunks. Undersized fuses can operate prematurely during a transient fault, which leads to unnecessary sustained power interruptions. This issue can be mitigated with the instillation of appropriately rated fuse units. The proper alignment of miscoordinated downstream fuses will reduce the impact of outages on an existing lateral by containing the outage at the sub-lateral level. Unprotected redundant trunk segments, which do not provide a path for tie-points and at the same time, supply loads that are below the interrupting capabilities of fuses, expose the entire feeder to a sustained interruption in the event of an outage on that portion of the trunk. This issue is alleviated with the installation of a fuse at the redundant trunk branch.

In addition to making these fusing enhancements, Toronto Hydro plans to install tree proof conductor in areas of heavy forestation that are susceptible to tree contact outages. The installation of tree proof conductor will help make the circuit more resistant to losing power in the event of a tree contact itself.

Table A summarizes the anticipated benefits associated with the Design Enhancement program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Improved service reliability for customers on the targeted feeders; the trunk-related outages that are mitigated can affect up to 7,000 customers ƒ Reduced need to excessively trim trees, thus preserving the aesthetics of existing streetscapes and customer properties
Reliability	ƒ Improved reliability by limiting the frequency and impact of interruptions on the targeted feeders, especially during adverse weather and major storm events. ƒ Installing tree proof conductor can mitigate the frequency of tree contact interruptions, which can cause both momentary and sustained interruptions, especially during adverse weather conditions (e.g. heavy winds).
Safety	ƒ Mitigation of safety risks associated with tree contacts. ƒ Manual switching on trunk portions is minimized and thus, safety risks such as the potential for flashover and injury from breaking parts are managed.
Efficiency	ƒ Prevents complications associated with the restoration of unnecessary trunk outages in terms of switching operations. ƒ Locating faults is made easier. ƒ Prevents the unnecessary replacement of undersized fuses that operate prematurely. ƒ The mitigation of unnecessary load break switch operations extends the life of switches. ƒ The use of tree proof conductor reduces the need for tree trimming cycles.

Program Drivers

At the 27.6 kV primary voltage level, there is a discernable upward trend in the ratio of trunk related outages per year to lateral outages. Similarly, there is an increasing trend of tree related momentary and sustained interruptions on the overhead 27.6 kV system. As trunk related outages impact a much greater number of customers than lateral outages, Toronto Hydro believes it is prudent and necessary to address parts of the system that are vulnerable to trunk related outages by enhancing currently inadequate feeder designs. These types of targeted

investments effectively maximize the customer value derived from existing feeders by minimizing unnecessary failure risk over the life of the assets.

The trigger and secondary drivers for this program are provided in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Reliability	ƒ The Design Enhancement program is needed to address negative reliability trends that have emerged due to load growth and the intensification of tree canopy cover in the City of Toronto. These factors have resulted in inadequate fusing and vulnerability to tree contacts. Forecasted increases in the frequency of adverse weather conditions could exacerbate these issues in the future.
Secondary Drivers	**Reasoning**
System Efficiency	ƒ Premature operation of an undersized fuse requires Toronto Hydro crews to be dispatched for an otherwise unnecessary fuse unit replacement. ƒ Redundant trunk portions can result in unnecessary breaker lockouts, which, from an operational perspective, introduce complications associated with the restoration of trunk outages.

Preferred Alternatives

In establishing the Design Enhancement program, Toronto Hydro considered three alternatives:

(i) Do nothing and accept the increasing reliability risk and operational inefficiencies associated with the design deficiencies.

(ii) Eliminate the susceptibility of overhead assets to tree contacts by rebuilding the distribution system away from trees.

(iii) Introduce fusing enhancements and tree proof conductor to mitigate the risk of reliability degradation.

Option III is the preferred alternative as it is the most cost-effective way of ensuring that feeders are well protected, curtailing sustained trunk outages as well as lateral faults. Installing tree proof conductors in critical areas is expected to reduce tree-related outages and may allow Toronto Hydro to scale back its future tree-trimming cycles.

The difference in the cost of ownership between existing and renewed assets (ΔCOO) for the first year of the program is $5.64 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.2.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $5.23 million, confirming the economic prudence of the investments (see Section E7.2.7).

Timing and Pacing

In terms of program planning and execution, the problem areas will be mapped and grouped together to be addressed in accordance with their respective feeders. Feeders will be prioritized based on the number of sustained interruptions that took place over a five year period and the number of individual locations requiring fusing and bare conductor upgrades.

Toronto Hydro must balance the need to perform feeder enhancements with other necessary renewal work. Accordingly, during the 2015 to 2019 planning period, Toronto Hydro plans to focus on feeders that are in most urgent need and that have the largest impact on the reliability of the system in terms of sustained interruptions. In all, 43 feeders are forecasted for investment in this program.

Table C provides the estimated costs of the program for the 2015-2019 period.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	0.4	1.7	1.7	1.7	1.7

E7.2.2 Program Description

The objective of the Design Enhancement program is to mitigate system reliability concerns by: (1) improving fusing configuration to control the impact of sustained outages and (2) installing tree-proof conductor to reduce the frequency of outages. The investments are primarily focused on the 27.6 kV primary voltage level in the horseshoe area of the grid because the issues are most prevalent in this region.

The total estimated cost of the Design Enhancement program is $7.26 million over the 2015-2019 period.

E7.2.2.1 Fusing Enhancements

Toronto Hydro plans to make targeted fusing enhancements to reduce the frequency and impacts of sustained outages. These investments will help ensure that all existing fuses are adequately sized and that all feeder trunk branches are well-protected.

Fuses in Toronto's Distribution System

The key part of a fuse is the "fusible element", which is designed to melt at a predetermined level of current. Fuses are critical distribution system assets that limit the impact of an outage to a specific location along the feeder and associated downstream customers. Fuses prevent sustained feeder-level outage for all customers on the feeder by not allowing an outage to cascade upstream to a circuit breaker.

A typical feeder is comprised of a main, three-phase "trunk" that initiates from the circuit breaker at a station. The trunk is typically routed through arterial streets and will branch off (without a fuse) in several places for the purpose of providing tie-points with adjacent feeders or to supply three-phase loads. The feeder also has multiple branches called "laterals," which are single, two, or three-phase lines that are protected by fuses, limiting the impact of downstream outages to the branch or a sub-section of the branch.

Toronto Hydro's protection scheme is 'fuse-saving' in that fuses and the relay for the circuit breaker are coordinated such that the breaker will trip before the fuse does. This scheme allows a temporary fault to clear itself, at which point the breaker will reclose. If the fault persists beyond this initial operation, the breaker relay delays sending a trip signal to the breaker, which allows the fuses to operate before the breaker trips. If a fuse does not operate properly, the breaker trips and stays open or "locks out." A breaker lockout usually suggests that the fault is located between

the breaker and a fuse, and is therefore deemed a trunk outage. This scheme is typical on overhead systems, where there is a high likelihood of faults that are temporary in nature, such as when tree limbs or animals contact lines. Fuses are strategically placed on "trunks" to create "laterals" and isolate outages downstream of the fuse to reduce impact to the entire feeder. They are sized in accordance with downstream load. Depending on the number of customers, a lateral may be further partitioned using additional sub-fuses.

Fuses Targeted by the Program

The Design Enhancement program targets undersized fuses, mis-coordinated fuses and redundant trunk sections that lack fusing:

- With undersized fusing , downstream loads surpass peak pre-load conditions (i.e. the constant loading that the fuse can sustain without impairing its ability to perform properly) and results in premature operations during a transient fault. The premature operations result in unnecessary sustained power interruptions. This issue is addressed by replacing the existing SMU-20 fuse with the appropriately rated fuse unit. From an operational efficiency standpoint, the premature operation by an undersized fuse is inefficient because it requires a crew to be physically dispatched to the area to perform a fuse unit replacement that otherwise would not have been required had the proper fusing arrangement been in place.

- Mis-coordinated fuses are laterals with a sub-fuse rating. These fuses operate at a slower pace than an upstream fuse for a particular range of fault currents that originate downstream of their location. As a result, customers located in between a lateral fuse and a sub-fuse are unnecessarily affected by outages downstream of a sub-fuse. As with the previous issue, addressing this problem involves replacing the SMU-20 fuse with the appropriately rated fuse units.

- Redundant feeder trunks are branches that (i) do not provide tie points to other feeders, (ii) feature peak loads that are within the threshold of standard fuse ratings and (iii) are not fused. An outage on these unprotected segments results in unnecessary sustained trunk outages to the entire feeder due to the absence of a fuse. This situation is remedied with the installation of a fuse, which includes the entire SMD-20 cut-out switch and its associated accessories, at the redundant trunk branch. In essence, the "trunk" is converted to a fused "lateral", resulting in quicker restoration times for customers who

experience an outage downstream of the newly installed fuses, as complexities associated sustained trunk outages are avoided.

Toronto Hydro's standards specify the use of SMD-20 cut-out switches with SMU-20 fuse units that are rated at 140 K ("K" denotes the speed of the fuse where, in this case, it represents a "fast" fuse, as per ANSI standard requirements in ANSI C37.42)

Figure 1 below illustrates a typical feeder layout with the three types of fusing deficiencies.

FIGURE 1: TYPICAL FEEDER LAYOUT WITH FUSING DEFICIENCIES

E7.2.2.2 Tree Proof Conductor

Overhead bare conductor in close proximity to mature trees is susceptible to tree related interruptions. Tree related outages are typically induced by adverse weather events such as high winds, wet snow or ice loading, particularly where overhanging branches are in close proximity to overhead distribution lines. This was evidenced during the 2013 Ice Storm.

Tree proof primary aerial conductor is an alternative to conventional bare conductor in overhead construction for heavily treed areas. Tree proof cable consists of compact, extra-hard aluminum conductor (ASC or ACSR) and an extruded covering made up of a conductor shield, inner layer and protective outer layer.

The design of tree proof conductor provides resistance to transient faults resulting from tree contacts that would normally cause momentary outages. In addition, sustained interruptions due to phase-to-phase contacts, animal contacts, or tree contacts are eliminated because of the high dielectric strength of the track resistant, high-density polyethylene outer covering. Figure 2 shows a cross-section of tree proof conductor.

Tree proof conductor Bare conductor

FIGURE 2: CROSS-SECTION OF TREE PROOF CONDUCTOR AND BARE CONDUCTOR

In most areas where bare conductor is currently used, the absence of mature trees at the time of installation meant that tree proof conductor was not required. However, tree canopy growth has necessitated the use of tree proof conductor in certain areas.

As shown in Figure 3, excessive tree trimming to protect bare conductors is often not an aesthetically pleasing solution to tree contact problems and is likely to draw customer complaints. Feeders protected by tree proof conductor do not require the same amount of tree trimming due to less stringent clearance requirements. Toronto Hydro construction standards specify minimum clearance of 450 mm from the nearest 16/27.6 kV tree-proof conductor, while bare conductors require 1270 mm of clearance. All clearances must be relative to the estimated position of maximum sag and swing of the nearest conductor.

FIGURE 3: TYPICAL TREE TRIM

Toronto Hydro currently manages tree trimming based on a set maintenance cycle. Regardless of whether the distribution lines that are routed through trees are bare or tree proof conductor, tree trimming is always required to maintain clearances and to comply with the City of Toronto Urban Forestry cycle pruning guidelines. Historical reliability, in terms of tree related contacts, is one of the determining factors in establishing the tree trim cycles for individual feeders. The use of tree proof conductor could reduce the pace of tree trimming cycles by mitigating tree contact outages.

An ancillary benefit to this program is that load-break switching operations, required as part of the restoration of trunk outages on the affected feeders, will be minimized regardless of whether they are switching is done automatically, remotely, or manually. Frequent use of the loadbreak switch subjects the asset to increased degradation due to parts moving against one another, gradually eroding the material, loosening tolerances, and degrading smooth bearing surfaces from increased friction. This wear can lead to the binding of moving parts and ultimately, failure. Thus, the condition and life expectancy of these assets benefits from less usage. Furthermore, the program will protect Toronto Hydro crew members from safety risks associated with manual switching such as flashover, and from being injured by breaking parts while operating aged and poorly conditioned gang-operated switches on the trunk.

Work on fusing deficiencies and bare conductor in areas of heavy forestation will be coordinated on by feeder.

FIGURE 4 DEPICTS PLANNED WORK FOR YEARS 2015 TO 2019.FIGURE 4: FEEDER EXECUTION YEARS OF DESIGN ENHANCEMENT

The following table is a summary of the estimated quantity of assets that Toronto Hydro plans to address during the 2015 to 2019 period as part of this program.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Fuses (units)	45	21	39	31	29	165
Bare Conductor (m)	0	41,099	37,241	43,941	42,395	164,676

The following table summarizes the anticipated benefits of the Design Enhancement program.

TABLE 2: PROGRAM BENEFITS

Customer Value	ƒ Improved service reliability for customers on the targeted feeders; the trunk-related outages that are mitigated can affect up to 7,000 customers and can cause adverse power quality issues for large industrial facilities on the same station bus. ƒ Reduced need to excessively trim trees, thus preserving the aesthetics of existing streetscapes and customer properties

	ƒ The difference in the cost of ownership between existing and renewed assets (ΔCOO) for the first year of the program is $5.64 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.2.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $5.23 million, confirming the economic prudence of the investments (see Section E7.2.7).
Reliability	ƒ Improved reliability by limiting the frequency and impact of interruptions on the targeted feeders, especially during adverse weather and major storm events. ƒ Installing tree proof conductor can mitigate the frequency of tree contact interruptions, which can cause both momentary and sustained interruptions, especially during adverse weather conditions (e.g. heavy winds).
Safety	ƒ Safety risks associated with tree contacts will be mitigated ƒ Manual switching on trunk portions is minimized and thus, safety risks such as the potential for flashover and injury from breaking parts are controlled.
Efficiency	ƒ Prevents complications associated with the restoration of unnecessary trunk outages in terms of switching operations. ƒ Enhanced fault locating capability. ƒ Prevents the unnecessary replacement of undersized fuses that operate prematurely. ƒ The mitigation of unnecessary load break switch operations extends the life of switches. ƒ The use of tree proof conductor reduces the need for tree trimming cycles.

E7.2.3 Why the Program is Needed

The Design Enhancement program is required to improve system reliability by reducing the frequency and impact of unnecessary service interruptions. At the 27.6 kV primary voltage level, there is a discernable upward trend in the ratio of trunk related outages per year to lateral outages. Similarly, there is an increasing trend of tree related momentary and sustained interruptions on the overhead 27.6 kV system. As trunk related outages impact a much greater number of customers than lateral outages, Toronto Hydro believes it is prudent and necessary to address parts of the system that are vulnerable to trunk related outages by enhancing currently inadequate feeder designs.

E7.2.3.1 Program Drivers

Table 3 presents the trigger and secondary drivers for the Design Enhancement program. The program is a System Service initiative, with a trigger driver of Reliability.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Reliability	ƒ The Design Enhancement program is needed to address negative reliability trends that have emerged due to load growth and the intensification of tree canopy cover in the City of Toronto. These factors have resulted in inadequate fusing and vulnerability to tree contacts. Forecasted increases in the frequency of adverse weather conditions could exacerbate these issues in the future. ƒ As shown in Figure 5, there is an increasing trend of trunk outages, which results in the entire feeder experiencing an outage, and can be mostly attributed to the significant number of redundant trunk locations. ƒ As shown in Figure 6, there has been a steadily increasing trend of tree related outages.
Secondary Drivers	**Reasoning**
System Efficiency	ƒ Premature operation of an undersized fuse requires Toronto Hydro crews to be dispatched for an otherwise unnecessary fuse unit replacement. ƒ Redundant trunk portions can result in unnecessary breaker lockouts, which, from an operational perspective, introduce complications associated with the restoration of trunk outages.

As shown in Figure 5, there is an increasing trend in the ratio of trunk related outages to lateral outages at the 27.6 kV system level. Lateral outages increased by 20% from 2012 to 2013, while trunk outages increased by 53% over the same period.

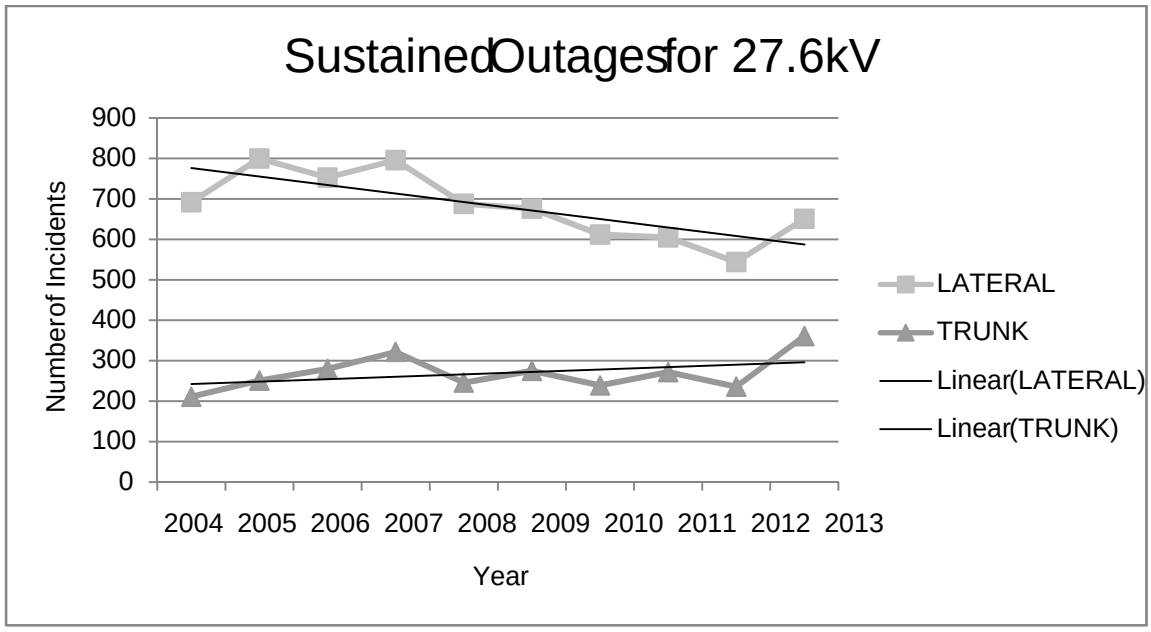


FIGURE 5: HISTORICAL INCIDENTS OF TRUNK AND LATERAL SUSTAINED OUTAGES

Figure 6 shows the five-year historical trend of the outage frequency and impact (in terms of customer interruptions (CI) and customer hours interrupted (CHI)) of tree-related interruptions (including those caused by adverse weather and brush contacts).

FIGURE 6: HISTORICAL TREE-RELATED OUTAGES

The feeders addressed by this program were originally designed and built in accordance with the loading and geographical conditions that existed at the time of construction. As system utilization has increased and vegetation around existing distribution assets has grown, the reliability of some existing feeders has decreased. The following sections discuss these issues in detail.

(i) Fusing and Redundant Trunks

Undersized Fuses

In-service fuses carry an initial load (pre-loading) under normal operating conditions. Excessive pre-loading can inhibit the effective operation of the fuse during an outage and can cause misalignment with the circuit breaker, compromising the "fuse saving" scheme discussed in the Program Description section. Each fuse type/rating can handle a certain amount of emergency peak pre-load without impairing the fuse's ability to properly coordinate and isolate a downstream fault. S&C Electric Company's Data Bulletin 240-195 in Figure 7 tabulates the peak-load capabilities of SMU-20 fuse units. The peak pre-loads represent the maximum loads that each fuse type can sustain (categorized by continuous, daily, or emergency scenarios) before the fuse link is compromised and misaligns with the breaker during fault interruption.

FIGURE 7: S&C ELECTRIC COMPANY'S DATA BULLETIN 240-195 FOR SMU-20 CONTINUOUS, DAILY, AND EMERGENCY PEAK-LOAD CAPABILITY

Misalignment with the breaker can then result in the fuse operating prematurely. The undersized fuses on these laterals expose downstream customers to unnecessary reliability risks. In this scenario, transient faults would cause the undersized fuse to operate faster than the circuit breaker. Contrary to the fuse saving scheme, where the fault would have otherwise been cleared by the upstream circuit breaker, it becomes an unnecessary sustained interruption to customers downstream from the undersized fuse.

There are 17 undersized fuse locations on the 27.6 kV system.

Fuse Mis-coordination

In some areas, fused laterals are further partitioned with sub-lateral fuses to reduce outage impacts on the sub-lateral level. If a sub-lateral fuse is not rated such that it operates and clears prior to an upstream fuse beginning to melt, a fault downstream of the sub-fuse will affect all customers up to the next upstream fuse.

There are 11 mis-coordinated fuse locations on the 27.6 kV system.

Redundant Trunk

In some cases, branches of a feeder trunk do not provide tie points to other feeders, and the loads on these sections happen to be within the threshold of the power interrupting capabilities of Toronto Hydro's highest rated fuse (S&C's SMU-20 140K fuse unit). These redundant branches unnecessarily expose the feeder to breaker lockouts. Installing strategically located fuses at redundant trunk locations can prevent circuit breaker lockouts that lead to sustained trunk outages to the entire feeder.

Redundant trunk portions can result in unnecessary breaker lockouts, which, from an operational perspective, introduce complications associated with the restoration of trunk outages, such as switching operations and longer investigations for the location of the fault. Once a faulted trunk portion is isolated during a circuit breaker lockout (either by means of feeder automation or remote switches), crews must patrol a widespread area on arterial roads or residential streets to identify the source of the outage. In contrast, a blown fuse can typically narrow down the search to a few residential streets.

There are a total of 219 redundant trunk locations on the 27.6 kV system.

Summary

All the above mentioned fusing deficiencies are shown in Figure 1 (in the Program Description section) in a typical feeder layout. These redundant trunk locations can affect up to 7,000 customers on the feeder via a breaker lockout.

Figure 8 displays all undersized fuses, mis-coordinated fuses, and redundant trunk locations at the 27.6 kV primary voltage level. These locations are superimposed with the associated feeders and the average annual sustained outages (based on historical data over the past five years) to illustrate areas that experience the highest number of sustained lateral and trunk outages. As detailed in the Program Description section, undersized fuse locations require fuse upgrades to ensure that unnecessary sustained interruptions are minimized. Mis-coordinated fuse locations also require fuse upgrades for proper coordination and impact reduction. Redundant trunk locations require the installation of a new SMD-20 cut-out switch and fuse link to avoid a sustained trunk outage and minimize the impact to few customers downstream of fuse. Ultimately, investments in these locations will provide reliability improvements in terms of both the frequency and impact of sustained interruptions.

FIGURE 8: LOCATIONS OF FUSING DEFICIENCIES

(ii) Bare Conductor & Tree Contacts

Bare conductors, without elemental barriers, are a common type of overhead wire used to deliver power from supply to consumption points. Toronto Hydro's standard wire gauges for bare overhead conductor operating at 27.6 kV are either 556 kcmil (aluminum stranded conductor) for main trunk lines and #3/0 aluminum conductor steel reinforced for laterals.

System reliability is compromised in areas where bare conductor is currently routed through areas of dense tree canopy. Issues arise because of the bare conductor's susceptibility to tree contacts, which can cause momentary or even sustained interruptions. Tree related outages are typically induced by adverse weather events such as high winds, wet snow or ice loading, particularly where overhanging branches are in close proximity to overhead distribution lines. There has been a steadily increasing trend of sustained and momentary outages due to tree contacts (see section E7.2.5.2 for a detailed discussion of reliability issues).

Figures 9 and 10 show examples of heavy forestation where feeder lines with bare conductor intertwine with mature trees. As was evident during the December 2013 ice storm, one of the most significant contributors to power outages is the weight of ice on tree limbs, which can cause the limbs to fall off or hang and come into contact with power lines in their proximity. This poses an especially severe reliability risk with respect to the trunk portions of feeders, where an outage due to tree contact would affect every customer on that feeder.

FIGURE 9: BARE CONDUCTOR IN HEAVY VEGETATION

FIGURE 10: BARE CONDUCTOR IN HEAVY VEGETATION

Figure 11 shows the location of bare conductors in the horseshoe area (i.e. the former suburbs). The dark red lines and blue lines represent trunk and lateral bare conductors, respectively, in close proximity to mature trees. The lighter green shaded areas indicate tree canopy cover.

FIGURE 11: MAP OF 27.6 KV OH BARE CONDUCTOR

E7.2.4 Timing & Pacing of the Program

As discussed in E7.2.3.1, there are 17 undersized fuses, 11 mis-coordinated fuses, and 219 locations of redundant trunk, and 365,497 m of bare insulated conductor in the proximity of trees. Toronto Hydro must balance the need to perform feeder enhancements with other necessary renewal work, as discussed in Section E2.1. Accordingly, during the 2015 to 2019 planning period, Toronto Hydro plans to focus on feeders that are in most urgent need and that have the largest impact on the reliability of the system in terms of sustained interruptions. In all, 43 feeders will be addressed in this period. More specifically, Toronto Hydro plans to work on a total of 6 undersized fuses, 7 mis-coordinated fuses, 152 redundant trunk locations, and 164,676 m of bare conductor. Feeders that do not require urgent attention will be addressed post-2019.

TABLE 4: HISTORICAL AND FUTURE SPENDING OF DESIGN ENHANCEMENT

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	0.4	1.7	1.7	1.7	1.7

In 2015, Toronto Hydro plans on addressing only the most urgent feeders by making fuse enhancements. Also, a validation study will be conducted in 2015 in order to determine the precise circuit lengths of bare conductors that are prone to contact with trees. The sharp increase in spending from 2015 to 2016 is attributed to the rise in investments associated with the initiation of tree proofing upgrades

E7.2.4.1 Ranking & Prioritization

To achieve planning efficiency, Toronto Hydro plans to execute fusing enhancements and tree proof conductor installations simultaneously, organized by feeder. The relative prioritization of these feeders is determined by assessing the following two criteria.

(1) Historical reliability of the feeder: Toronto Hydro plans to target the worst performing feeders first, based on the number of sustained interruptions over the past five years.

(2) Number of locations to be addressed on the feeder: When determining feeder priority, Toronto Hydro will consider the number of distinct laterals that are undersized, laterals that are mis-coordinated, and redundant trunk branches that require fuses. The number of kilometers of bare conductor requiring upgrade will also be considered. Also, feeders with a substantial amount of redundant trunk portions and trunk bare conductor that requires tree proof conductor will be treated with more urgency due to the severe impact that trunk outages can have on the system. The feeders with the greatest number of the aforementioned locations will be executed first.

E7.2.5 Program Execution

Fusing deficiencies and bare conductor that need to be addressed will be grouped together and worked on according to what feeder they are on. By staging the projects under this program on a feeder basis, multiple issues can be attended to while crews are in a certain geographical area, increasing efficiency and reducing travel times.

The typical scope of work of fusing enhancements includes the installation of new fuses in locations that are identified as having undersized fuses, mis-coordinated fuses, and redundant trunk. The devices are sized and coordinated in accordance with circuit rating, existing loading conditions and upstream fuses and/or station circuit breakers. The replacement of the fuse unit requires the use of S&C's portable loadbreak tool, "Loadbuster", which allows the swap under full feeder load without needing isolation. In situations that require the SMD-20 cut-out switches to be replaced, a temporary disconnect tool can be used that allows customers downstream to be energized while the switch is being replaced. In some cases, a circuit reconfiguration of undersized or mis-coordinated laterals will be needed if downstream loads surpass the standard maximum 140 K fuse type interrupting capabilities. The reconfiguration will split laterals and reroute power for the suitability of a 140 K fuse.

Tree proof conductor initiatives involve restringing bare conductors with tree proof overhead conductor. The tree proof overhead conductor is made of a polyethylene covering and the conductor sizes are #3/0 ACSR or 556.5 kcmil ASC, for laterals and trunks, respectively.

E7.2.5.1 Proposed Work Plan

TABLE 5: 2015-2019 LONG TERM PLAN

Feeder	Station	Year
35M1	FAIRBANKS II TS	2015
35M10	FAIRBANKS II TS	2015
35M11	FAIRBANKS I TS	2015
35M12	FAIRBANKS I TS	2015
35M2	FAIRBANKS II TS	2015
35M3	FAIRBANKS I TS	2015
35M5	FAIRBANKS I TS	2015
35M9	FAIRBANKS II TS	2015
55M28	FINCH II TS	2015
80M10	FAIRCHILD I TS	2016
80M5	FAIRCHILD I TS	2016
85M2	BATHURST I TS	2016
85M25	BATHURST II TS	2016
85M26	BATHURST II TS	2016
85M3	BATHURST I TS	2016
85M6	BATHURST I TS	2016
R29M3	REXDALE TS	2016

Feeder	Station	Year
NAH9M30	ELLESMERE TS	2017
80M1	FAIRCHILD I TS	2017
85M5	BATHURST I TS	2017
NAE5-2M3	SCARBOROUGH WEST TS	2017
34M1	LEASIDE TS	2017
34M7	LEASIDE TS	2017
85M23	BATHURST II TS	2017
NA47M17	SHEPPARD EAST TS	2017
R30M2	HORNER TS	2017
34M2	LEASIDE TS	2018
80M2	FAIRCHILD I TS	2018
NAR43M23	WARDEN TS	2018
NT47M3	SHEPPARD WEST TS	2018
80M30	FAIRCHILD II TS	2018
11M4	RUNNYMEDE TS	2018
55M26	FINCH II TS	2018
NAR43M28	WARDEN TS	2018
NAR43M29	WARDEN TS	2018
55M7	FINCH I TS	2018
80M8	FAIRCHILD I TS	2019
11M8	RUNNYMEDE TS	2019
85M1	BATHURST I TS	2019
NAR43M24	WARDEN TS	2019
35M4	FAIRBANKS II TS	2019
51M21	LESLIE II TS	2019
80M4	FAIRCHILD I TS	2019

E7.2.5.2 Program Risks

A major factor that may inhibit the pace of the Design Enhancement program is the age and condition of assets that are needed to accommodate the new fusing upgrades and tree proof conductors. For undersized and mis-coordinated fuses, Toronto Hydro will replace SMU-20 fuse links that are housed in the SMD-20 cut-out switch. However, before Toronto Hydro can replace certain SMU-20 fuse links, it will have to first replace certain SMD-20 cut-out switches because they have aged, are in poor condition and/or use porcelain insulating material, factors that increase failure risk.

In some locations, Toronto Hydro will need to install new poles and framing for fuse installations or tree proof conductor. Existing poles might have deteriorated to the point that they would compromise the installation of new cut-outs and bolting new framing.

The potential need to perform these additional asset upgrades in order to accommodate the initiatives in this program could inflate the cost of the program and delay construction. Toronto Hydro will study the need for these possible upgrades by conducting field visits to verify the condition of supporting assets (poles, SMD-20 cut-out switch, insulators, etc.) associated with the installation of a fuse or tree-proof conductor.

E7.2.6 Evaluation of Alternatives

E7.2.6.1 Quantification/Evaluation of Options

(i) Status Quo

Maintaining the status quo entails deferring fusing enhancements and tree proof conductor installations past the five year planning horizon of 2015-2019 and maintaining existing configurations. Under this option, capital expenditures would not be made for fusing enhancements and thus, Toronto Hydro would continue to conduct reactive repairs for sustained trunk outages from redundant trunk segments. Complexities involved with restoring sustained trunk outages will persist, contributing to lengthy restoration times. Reactive efforts will also need to be maintained for unnecessary sustained lateral outages due to undersized fuses.

Delaying plans to replace bare overhead conductor with tree proof conductor would result in a continuing pattern of tree related outages. Toronto Hydro currently manages tree trimming based on an aggressive maintenance cycle. However, tree trimming is a temporary solution as it does not permanently remedy the problem of tree related contacts on trunks. As a consequence, tree-related outages will continue to occur

(ii) Fusing Enhancements and Tree proof Conductor

The preferable solution is to install standardized fuses on existing laterals that are undersized, mis-coordinated, or redundant potions of trunk that lack fusing. In some cases, addressing undersized fuses may require reconfiguration work if downstream loading surpasses the standard 140 K fuse threshold. Fusing enhancements and the installation of tree proof conductor would be

expected to provide all of the benefits discussed throughout the narrative, including a reduction in prolonged outages and cost savings with respect to ongoing tree-trimming maintenance.

The cost of ownership (COO) and program net benefit (NPV) associated with the Design Enhancement program is further detailed in Table 6. The cost of ownership is established for both the existing state (COO_E), based on the first year of activities in the program, as well as the new state (COO_N) proposed within the program. The COO of a state reflects the risk of asset failure including both direct and indirect costs, including the costs of customer interruptions, emergency repairs, and asset replacements associated with that design. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NARE) and proposed (NARN) state. Non-asset risks are further explained in Section D3.3. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in COO (ûCOO) is compared to the associated program costs (PC) for the first of activities, the Design Enhancement program produces a NPV value of $5.23 million, as shown in Tables 6 and 7. As this is a positive value, it means that there is a net reduction in explicit and implicit costs to customers by transitioning to strategically located and coordinated fused laterals. It means that the benefits of executing the work outweigh the capital expenditures and thus is economically prudent to carry out the program.

TABLE 6: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	0.18
Non Asset Risk [NAR_E]	5.61
Maintenance Cost [MC_E]	0
Additional Quantifiable Benefits [AQB_E]	0
Cost of Ownership of Existing Assets [COO_E]	5.79

TABLE 7: FUSING ENHANCEMENTS BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 1: Fusing Enhancements (N1)	
Asset Risk [AR_N]	0.15
Non Asset Risk [NAR_N]	0.0017
Maintenance Cost [MC_N]	0
Additional Quantifiable Benefits [AQB_N]	0
Cost of Ownership of New Assets [COO_N]	0.1517
Option 1: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_N)$]	5.64
Program Cost [PC_1]	0.41
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	5.23

E7.2.7 2015 Project Details

Table 8 lists all projects that will be partially or completed executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015.

TABLE 8: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date
X14211	35M10 Fuse Coordination	$130,637	2015
W15493	Overhead Design Enhancement on Fairbanks TS 35M1	$192,105	2015
W15495	Overhead Design Enhancement on Finch TS and Jane MS 55M28	$85,670	2015

E7.2.7.1 X14211 35M10 Fuse Coordination

Program: Design Enhancements

Project Title: 35M10 Fuse Coordination

Project Number: X14211

Project Year: 2015

Estimated Cost: $ 130, 637

(i) Objective

Ensure adequate fusing on 35M10 for better improved reliability

(ii) Scope of Work

Nineteen fuses to be replaced or installed along 35M10 in an effort to co-ordinate fusing on this feeder.

TABLE 9: X14211 SCOPE OF WORK DETAILS

Station(s)	FAIRBANK TS
Feeder(s)	35M10

TABLE 10: E12345 ASSETS REPLACED

Assets (Units)	2015
SMD-20	19

(iii) Justification & Benefits

Fusing Enhancements ensure that unnecessary sustained interruptions and their impacts are minimized, improving overall feeder reliability. The chart below depicts the historical reliability of feeders of 35M10 in terms of trunk and lateral outages. The chart shows illustrates the increasing trend of trunk outages that would be addressed by these fusing enhancements.

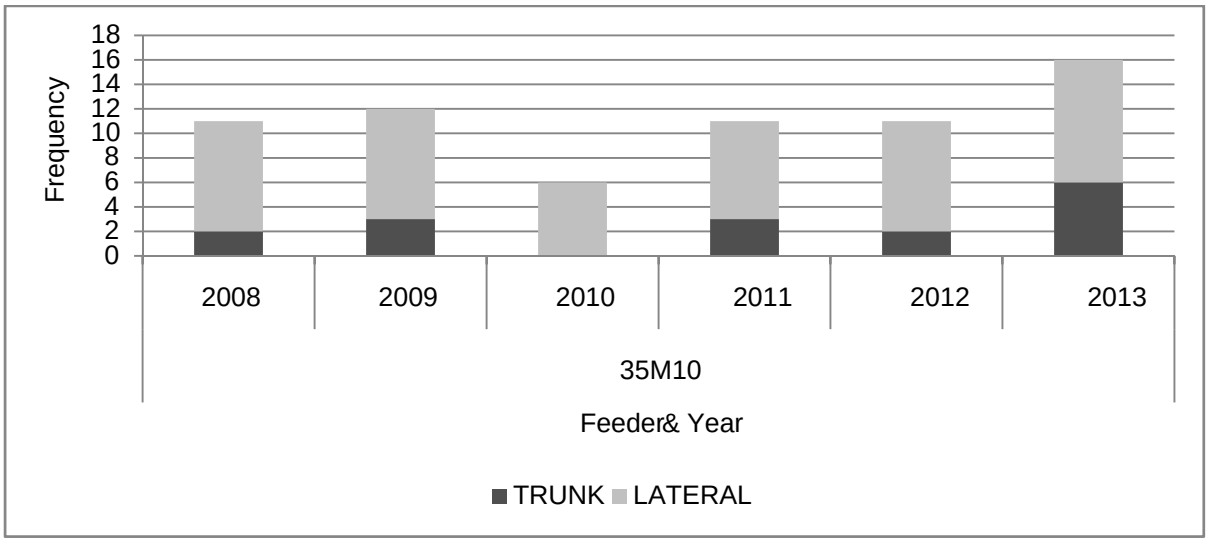


FIGURE 12: HISTORICAL RELIABILITY OF FEEDERS OF 35M10

E7.2.7.2 W15493 Overhead Design Enhancement on Fairbanks TS

Program: Design Enhancements

Project Title: Overhead Design Enhancement on Fairbanks TS

Project Number: W15493

Project Year: 2015

Estimated Cost: $ 192,105

(i) Objective

The objective of this project is to convert portions of the trunk feeder on Fairbanks TS into fused laterals.

(ii) Scope of Work

As part of this project, redundant feeder trunks portions that do not provide tie points and have peak loads that are within the threshold of fuse ratings will be fused. In this case, a new installation of a fuse, which entails the entire SMD-20 cut-out switch and its associated accessories, will be required at the redundant trunk branch. Essentially, the “trunk” is converted to a fused “lateral”.

The following pole locations require the installation of a new fuse (may involve a relocation of an existing asset):

1. Install fuse at pole 28 Trethewey Drive. Also, relocate transformer OT5024 on pole 28 Trethewey Drive to pole 30 on Trethewey Drive
2. Install fuse on Pole 49 Homewood Drive
3. Install fuse on Pole 10 Day Avenue
4. Pole 9 Sellers Avenue. Also, remove OS92387.
5. Pole 38 Holland Park Avenue
6. Pole 192 Glenholme Avenue
7. Pole 35 Stayner Avenue
8. Pole 3 Enid Cres
9. P833 Glencairn Avenue
10. Pole 685 Coldstream Avenue

11. P123 Clenmount Avenue
12. Pole 595 Cranbrooke Avenue and remove OS9482 from pole 563 Cranbrooke Avenue
13. Pole 978 Caledonia Road
14. Pole 14 Hartley Avenue. Also requires the relocations of transformers OT60144 on pole 36 Little Boulevard and install transformer on pole 8 Little Boulevard)
15. Pole 12 Glen Belle Crescent
16. Fuse lateral on Viewmount Avenue
17. Fuse to be installed on Pole 43 Glenmount Avenue
18. Fuse to be installed on Pole 2 Moir Avenue
19. Fuse to be installed on pole 176 Pinewood Avenue. Also, relocate transformer OT61745 from pole 176 at Pinewood Avenue to pole 168 at Pinewood Avenue.

TABLE 11: W15493 SCOPE OF WORK DETAILS

Station(s)	Fairbanks TS
Feeder(s)	35M1, 35M10, 35M11, 35M12, 35M2, 35M3, 35M5, 35M9

TABLE 12: W15493 ASSETS REPLACED

Assets (Units)	2015
SMD-20	19

(iii) Justification & Benefits

An outage on these unprotected segments results in unnecessary sustained trunk outages to the entire feeder due to the lack of a fuse. This project targets improvements to system reliability by will preventing breaker lockouts. In ensuring all redundant trunk portions are fused wherever practical, the number of customers experiencing sustained outages would be limited to customers downstream of the fuse. From an operational perspective, the installation of fuses avoids complications associated with the restoration of trunk outages, such as switching operations and fault locating.

The below chart depicts historical reliability of feeders addressed as part of this job, in terms of trunk and lateral outages.

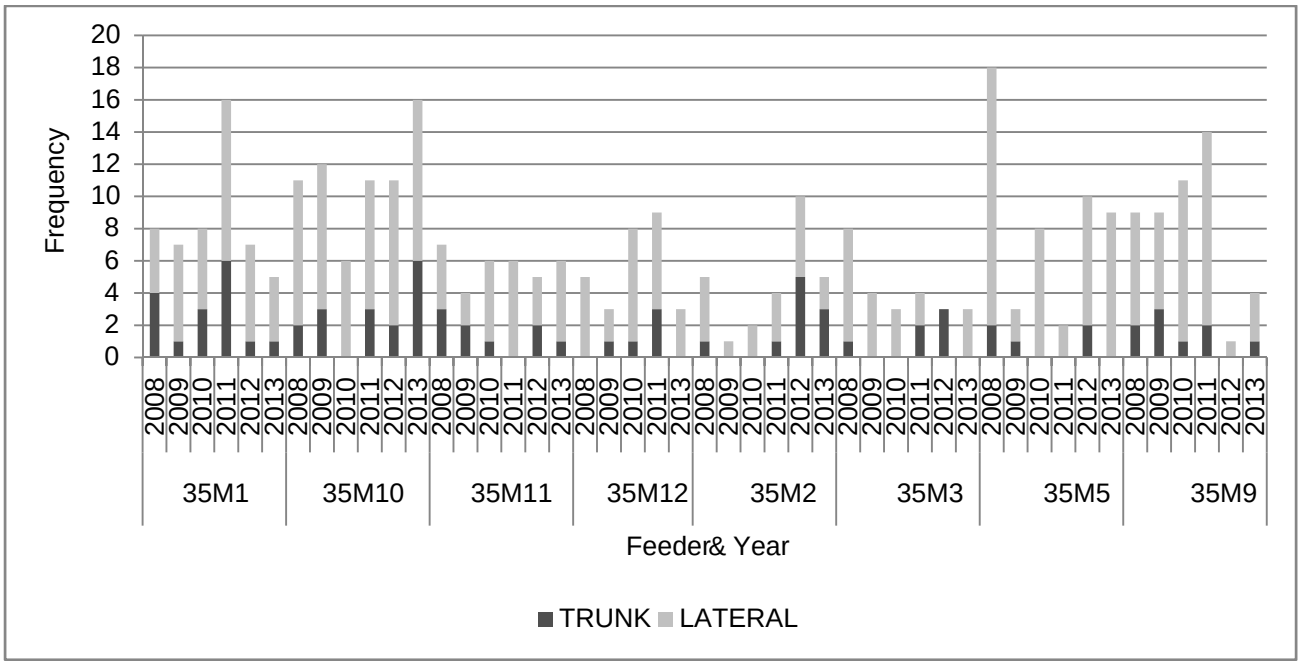


FIGURE 13: HISTORICAL RELIABILITY OF FEEDERS

E7.2.9.2 W15495 Overhead Design Enhancement on Finch TS and Jane MS

Program: Design Enhancements

Project Title: Overhead Design Enhancement on Finch TS and Jane MS

Project Number: W15495

Project Year: 2015

Estimated Cost: $ 85,670

(i) Objective

The objective of this project is to convert portions of the trunk feeder on Fairbanks TS into fused laterals.

(ii) Scope of Work

As part of this project, redundant feeder trunks portions that do not provide tie points and have peak loads that are within the threshold of fuse ratings will be fused. In this case, a new installation of a fuse, which entails the entire SMD-20 cut-out switch and its associated accessories, will be required at the redundant trunk branch. Essentially, the “trunk” is converted to a fused “lateral”.

The following pole locations require the installation of a new fuse (may involve a relocation of an existing asset):

1. Fuse to be installed on pole 22 Gade Drive
2. Fuse to be installed on pole 1 Canton Avenue
3. Fuse to be installed on pole 35 Letchworth Cres
4. Fuse to be installed on pole 36 Deevale Road
5. Fuse to be installed on pole 5 Wheatsheaf Cres
6. Fuse to be installed on pole 5 Checkers Crt
7. Fuse to be installed on pole 89 Laskay Cres

TABLE 13: W15495 SCOPE OF WORK DETAILS

Station(s)	FINCH TS, JANE TS
Feeder(s)	55M28, SS55F3, SS55F4

TABLE 14: W15493 ASSETS REPLACED

Assets (Units)	2015
SMD-20	7

(iii) Justification & Benefits

An outage on these unprotected segments results in unnecessary sustained trunk outages to the entire feeder due to the lack of a fuse. This project targets system reliability improvement by preventing breaker lockouts. In ensuring all redundant trunk portions are fused wherever practical, the number of customers experiencing sustained outages will be limited to customers downstream of the fuse. From an operational perspective, the installation of fuses avoids complications associated with the restoration of trunk outages, such as switching operations and fault locating.

The chart below illustrates the historical reliability of 55M28 in terms of trunk and lateral outages.

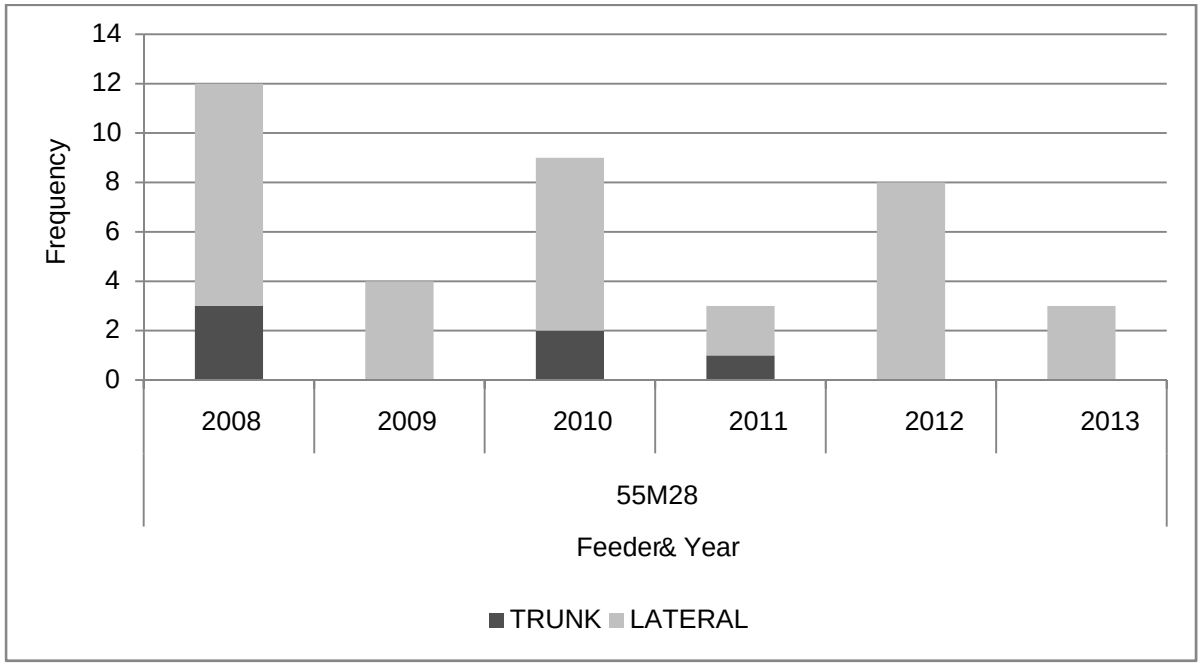


FIGURE 14: HISTORICAL RELIABILITY OF 55M28

E7.3 Feeder Automation

SCADA-MATE SWITCH FOR O/H FEEDER AUTOMATION

E7.3.1 Summary

Program Description

The Feeder Automation program aims to improve system operational efficiency by installing Supervisory Control and Data Acquisition (SCADA) switches that can operate autonomously (i.e. without human intervention). This program focuses on the automation of select feeders in two areas of Toronto Hydro's system: the 27.6 kV open looped system in the "Horseshoe" area and the 13.8 kV underground residential distribution systems in the Downtown area.

In both the Horseshoe and Downtown areas, the switches proposed for automation reside on the main or "trunk" sections of the feeder, which have no protective equipment beyond the station circuit breaker, and which experience outages that generally have the most considerable impacts on customers. The use of automation typically reduces the duration of outages on feeders to under a minute as compared to the typical restoration time of 30 minutes on remote operation SCADA switches and three hours on feeders that require manual switching by crews. These investments are expected to significantly improve SAIDI and SAIFI outcomes, improve

operational efficiency, and help mitigate the impact of certain types of increasingly frequent adverse weather conditions and major storms.

The various other benefits of the Feeder Automation program are further explained in Table A below.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Limits the number of customers affected by a trunk or main loop outage. ƒ Positively impacts power reliability for customers on non-automated feeders as well. Feeder automation decreases the time and effort needed by controllers and switching crews on automated feeders so they can concentrate their attention on non-automated feeders. ƒ Impacts many customers for relatively low cost. While Feeder Automation is not an alternative to asset renewal, the cost of automating a region of the city would typically equal the cost of renewing the asset base of only a section of a targeted feeder. This is further exemplified by the high benefit to cost ratio of the work.
Reliability	ƒ Through automated switching arrangements, restoration following a fault on the feeder trunk occurs in less than a minute. This decreases the number of customers impacted and the outage duration for unaffected customers – resulting in improvements to both SAIDI and SAIFI. ƒ Anticipated benefits of the program include mitigation of impacts from major storms and other adverse weather conditions, which are forecasted to become more frequent as a result of climate change.
Safety	ƒ The new switches have internal grounds, as opposed to the current switches that have external grounds. External grounds are more susceptible to the vault environment and human error during application.
Efficiency	ƒ Feeder automation allows system controllers to make more efficient use of their time. Since switching actions on automated feeders would be able to occur autonomously, crews would be able to focus on other areas requiring restoration. ƒ Enhanced condition monitoring on automated feeders will allow day to day operating decisions and long term asset investment decisions to be made more efficiently and effectively.

Program Drivers

The Feeder Automation program is primarily driven by the system efficiency considerations and is situated in the System Service category. The primary and secondary drivers of the program are detailed in Table B below.

TABLE B: PROGRAM DRIVERS

Primary Driver	Reasoning
System Efficiency	ƒ Significantly improves fault detection, isolation and restoration times during trunk- and/or main loop-related outages. ƒ Potentially mitigates the impact of defective equipment failures on the trunk on reliability, reducing the rate of asset replacements in select cases. ƒ Enables more efficient use of control room and switching crew resources. ƒ By cost-effectively mitigating failure risk costs, Feeder Automation can help maintain a moderate pace of system renewal.
Secondary Driver	**Reasoning**
Reliability	ƒ Decreases the duration of outages on targeted trunk / main loop feeders, facilitating significant reliability improvements for the system and the average customer. ƒ Decreases the number of customers impacted by trunk and main loop-related outages. ƒ Reduces demands on system operators and switching crews during large system outage situations by autonomously restoring power to the unaffected sections of automated feeders, thereby allowing staff to focus on other affected areas.

The lack of automation on trunk portions means that SCADA or manual switching must be used to isolate faults, which increases the duration of outages for customers. In addition, the up to three hour duration for manual switching may be further lengthened if outages occur during times of heavy traffic or in crowded areas. Feeder automation activities, which target the feeder trunk, include the installation or modification of strategically placed SCADA-Mate switches, removing the need for human intervention by automating the switching process to localize the outage in less than one minute.

Preferred Alternative

(1) Toronto Hydro explored three alternatives for mitigating trunk outage failure risk costs:

(2) Maintaining the status quo, foregoing potential improvements.

(3) Install remote operated SCADA-Mate switches: remotely operable SCADA switches bring outage restoration times to approximately 30 minutes during an outage. Lengthy outages

may still result since power controllers may need to manage multiple outages simultaneously.

(4) Install Feeder Automation.

Option 3 is the preferred alternative as it provides significant improvements in system efficiency by automatically isolating faults and thereby improving reliability and restoration efforts, including during major storms. This option effectively reduces the failure risk cost of existing feeder assets, thereby maximizing customer value derived from the existing system. Since the cost of programming SCADA switches and configuring the wireless network for automation is approximately 10% higher than using basic SCADA switch technology, this program is a significantly more cost-effective alternative than Option 2.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $102.74 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.3.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $91.6 million, confirming the economic prudence of the investments (see Section E7.3.7).

Timing and Pacing

Toronto Hydro plans to introduce automation to approximately 130 feeders during the 2015-2019 period. As detailed in Table iii below, this work will cost approximately $54.1 million over this period.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	3.26	0.87	6.24	8.83	0.77	11.1	15.1	9.41	9.99	8.47

The Feeder Automation program will occur alongside Toronto Hydro's proposed renewal work to improve system efficiency and ensure asset replacements are occurring at the most effective time with the most benefit to customers. By implementing automation now, Toronto Hydro has the opportunity to ensure that the cost-effectiveness of the next generation distribution system will be enhanced for current and future ratepayers. The use of modernized equipment and communication infrastructure that supports automation will create a more intelligent grid, one

which provides system operators and planners with high-quality data for future asset management decision making. As such, future asset replacements and planning decisions will be better informed and effective. Toronto Hydro should not postpone these investments beyond 2019, as they are some of the most cost-effective distribution system improvements currently available to Toronto Hydro and its customers.

E7.3.2 Program Description

The Feeder Automation program is designed to improve the process of localizing and isolating faults on the distribution system through the installation and/or refurbishment of SCADA switches with software and sensors that facilitate autonomous operation when faults occur. Automation significantly decreases restoration times for unaffected portions of a feeder that is experiencing a fault. The program's primary objective is to improve the efficiency of the distribution system by reducing the resources and effort required to manage the system during outages. Feeder automation increases the efficiency of the control room by independently locating the fault and performing isolation and power restoration activities that would otherwise have to be performed by a controller.

Automatic restoration occurs when a switch intelligently detects and isolates the fault and restores power to the remainder of the feeder via the station breaker or the tie switches, which connect to other feeders. The use of automatic switches is expected to reduce the duration of outages on automated feeders to under a minute – a drastic reduction as compared to the typical restoration time of 30 minutes on remote operation SCADA switches and three hours on feeders that require a crew to travel to and manually operate switches. The program is also expected to improve operating efficiency in the field by reducing the need for crews to perform manual fault locations and switching activities, freeing up time and resources to focus on the repair of the fault itself. Bypassing the manual fault location and switching activities is expected to reduce the duration of outages on the faulted section(s) of the feeder, since the crews would be able to immediately turn their attention to addressing the outage source. Crew safety would also be enhanced since they would no longer have to manually perform switching on faulted feeders.

The program targets areas of the system that are expected to significantly benefit from expedited fault detection, isolation, and the associated shortened outage restoration times. The program includes plans for the automation of feeders in both the Horseshoe (i.e. the former suburbs) and Downtown areas of Toronto Hydro's system. The automation of these distinct distribution systems requires different technology and equipment, described in more detail in Sections E7.3.2.1 and E7.3.2.2.

Figure 1 shows the areas targeted by the feeder automation program over the 2015 to 2019 period.

FIGURE 1: MAP OF AUTOMATION ZONES AND PLANNED IMPLEMENTATION DATES FOR BOTH HORSESHOE AND DOWNTOWN FEEDER AUTOMATION

The program entails automation of approximately 640 switches located on 130 feeders. The total estimated cost of the program is $54.1 million in the 2015 to 2019 planning period. The following subsections further detail Toronto Hydro's proposal for automating the targeted feeders and explains the distinction between the technical characteristics of feeder automation in the Horseshoe and Downtown systems.

E7.3.2.1 Horseshoe Feeder Automation

Feeder automation in the Horseshoe area targets the 27.6 kV open loop distribution system. Figure 2 provides an example of the typical configuration of an open loop system in this area. Automation of the 27.6 kV system involves the installation of critical tie and sectionalizing switches that can autonomously operate to isolate the problem area and quickly restore power to the unaffected portions of the feeder. Doing so involves the use of software that interprets the data from sensors on SCADA switches to assess the condition of affected feeder segments

during a fault. A switch is then able to determine the state or condition of the feeder segments it connects and operate accordingly.

FIGURE 2: TYPICAL LAYOUT OF 27.6 KV OPEN LOOP SYSTEM. NOTE: THIS DIAGRAM ONLY SHOWS THE FEEDER TRUNK.

An open loop feeder consists of two types of sections, the trunk and the laterals. The trunk is the main portion of the feeder that extends from the station breaker, connects to other nearby trunks and feeds the laterals, which emanate from the trunk to supply side streets. Laterals connect to the trunk by means of fuses and do not connect to any other feeders themselves. When a fault occurs on a lateral, the fuse connecting it to the trunk is blown, isolating the fault area and localizing the outage impact to the customers served by that particular lateral. When a fault occurs on the feeder trunk, all customers connected to the trunk (including those connected via laterals) experience an outage, since the only protective device on the feeder trunk is the station breaker. Accordingly, feeder trunk outages have a significantly larger impact on Toronto Hydro' customers' power reliability than outages on the feeder's laterals. To that end, the proposed

feeder automation program in the Horseshoe area focuses on the feeder trunks. The targeted trunks are typically broken up into segments (this allows them to be resorted in parts) that are connected by automatic switches (referred to as sectionalizing switches) capable of locating and automatically isolating the area experiencing the fault. The automatic switches would also be installed on the ties connecting the targeted feeders with the trunk segments of feeders adjacent to them.

When a fault occurs on the trunk, automation software determines the segment of the trunk it occurred on and proceeds to isolate the faulted section. The software dynamically assesses which adjacent feeders can restore the unaffected sections of the faulted feeder and then carries out the appropriate switching actions to resupply customers. Figure 3 shows the switching actions that would take place in the example system shown in Figure 2. These actions would take place under either manual or autonomous operation; however, they occur more rapidly and without human intervention when automated. When this switching happens autonomously, unaffected customers can be restored within one minute. In addition, automation can localize the fault to a single section of the feeder. If automation is not in place, restoration would require the intervention of the control room to assess where the fault occurred and perform the switching operations remotely via SCADA-Mate switches. In the worst case scenario, a field crew would need to be deployed to locate the fault and manually perform the switching operations. Controllers can typically perform this operation within 30 minutes, while a crew would typically take up to three hours. The timelines of these operations can vary as most Toronto Hydro feeders have a combination of remote switches and manual switches.

FIGURE 3: LAYOUT OF FEEDER OPERATION DURING A FAULT, THESE SAME ACTIONS WOULD OCCUR ON BOTH AN AUTOMATED AND NON-AUTOMATED FEEDER, IT IS TIME IT TAKES THAT IS DEPENDENT ON THE TYPE OF SWITCHES USED. NOTE: THIS DIAGRAM ONLY SHOWS THE FEEDER TRUNK

In the example above, a fault occurred between switches 1 and 2 (S1 and S2) of feeder F1. The feeder automation scheme would detect that a fault occurred between these two switches and open the normally closed switches to isolate the detected fault in that section. Since the remaining sections of the feeder are unaffected by the fault (between S2 to S4) they can be restored through other feeders' supply. In this case, the unaffected portion is resupplied by feeder F3 by closing switch 4 (S4). When outages occur on feeders without automation, this work is done either by system controllers where the switches are remote operable, or via manual switching by field crews where manual switching is required. In either case, automation significantly improves system efficiency by restoring outages multiple times faster than human intervention. This has significant advantages to system reliability for trunk-related outages and can significantly lower outage duration for the benefit of Toronto Hydro's customers. Automation

in the Horseshoe area would reduce total customer interruptions (CI) and customer hours interrupted (CHI) by an anticipated 50%, as shown in Figure 4 below. In all, approximately 75% of the feeder would be able to be restored during trunk related outages following the implementation of automation. The reduction in CI and CHI would also impact the overall SAIDI and SAIFI statistics. In all, the program is expected to significantly improve system reliability in terms of both the frequency and duration of outages. For example, as per the SAIDI graph in Figure 12, over the last five years, the average Toronto Hydro customer experienced an outage lasting over 75 minutes per year (when combining trunk and lateral outage for total system outage). By reducing the number of customers impacted by trunk outages by 75%, the average outage duration would drop to approximately 40 minutes.

FIGURE 4: PROJECTED HORSESHOE RELIABILITY CI AND CHI REDUCTION

Feeder automation in the Horseshoe area requires strategically placed automatic SCADA switches with appropriate communication infrastructure and software. Toronto Hydro positions SCADA switches to optimize the ability of the feeder's trunk to be reconfigured to alternative supply paths during an outage. This design takes into account customer loads and locations and

proximity to, and the loading of, adjacent feeders for each targeted feeder trunk. The SCADA switches utilized in the automation of the Horseshoe area will include overhead and pad-mounted units, depending on whether the segments being tied are overhead or underground. Automation efforts will also include autonomous action of the station breaker in a restoration scenario.

In a number of cases, Toronto Hydro plans to leverage existing overhead SCADA switches, which will only require minor software and communication upgrades to enable desired automation. In cases where existing switches are manually operated, or where the system planners determine that additional new switching nodes are required, new SCADA switches would be installed.

Each SCADA switch requires a remote terminal unit (RTU). RTU's for existing SCADA switches that are currently utilized need to be upgraded so that the switch can operate autonomously. This upgrade consists of a new radio unit, controller faceplate and a software upgrade inside the RTU. The RTUs form an important part of the control and communication infrastructure required for the switches to report remotely and for the automated feeder network to function.

In all, the planned upgrades in the Horseshoe area would improve the operating efficiency of Toronto Hydro's 27.6 kV open loop system and will significantly improve overall system reliability at a low initial investment. Table 1 details the proposed asset installations required for the Horseshoe feeder automation program.

TABLE 1: NEW ASSETS PROPOSED FOR INSTALLATION BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Overhead SCADA Switches	94	63	64	75	63	384
RTU	93	100	64	69	57	383
RTU Upgrade	16	40	34	68	80	238
Radio & Antenna	112	140	98	137	138	625
Underground SCADA Switches	--	31	12	16	12	71

IC

E7.3.2.2 Downtown Feeder Automation

Feeder automation in the Downtown area targets the underground residential distribution (URD) system, which is an underground configuration unique to the former City of Toronto area. The URD is a looped style system with three distinct feeder levels: a main loop, sub-loops and branch circuits (or sub-sub-loops). The main loop does not serve any customers but is equipped with

multiple 600 A switching vaults that allow for the isolation of the sub-loops and branch circuits (which both feed customers) when faults occur. Currently none of these 600 A switches are equipped for remote operation.

Figure 5 is a simplified example of the configuration of a downtown URD feeder.

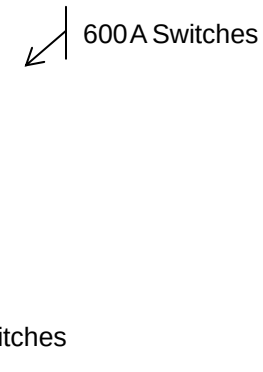


FIGURE 5: TYPICAL LAYOUT OF A DOWNTOWN URD FEEDER; ONLY ONE SUB-LOOP SHOWN FOR SIMPLICITY.

Downtown feeder automation entails replacing existing manual 600 A SF_6 switches in the URD system with new units that can be remotely operated and that are automation-ready. The proposed switches would allow the control room to remotely restore all customers after a fault on the main loop or restore the majority of customers if faults occur on sub-loops or branch circuits. System controllers would be able to remotely operate the new 600 A SCADA switches and gain important fault detection information, improving restoration times. In later years of the program, depending on the success of the original installations, these switches could potentially operate autonomously based on status information available at each switching location. Figure 6 displays the design of the current switch.

FIGURE 6: EXISTING 600 A MANUAL SWITCH INSTALLED IN A SWITCHING VAULT IN THE URD SYSTEM

FIGURE 7: TYPICAL URD FEEDER CONFIGURATION. GREEN DENOTES 600A SWITCH LOCATIONS WHERE NEW SCADA OPERABLE SWITCHES WOULD BE INSTALLED TO ENABLE AUTOMATION OF DOWNTOWN FEEDERS.

As with the Horseshoe feeder automation plan, where automated switches are placed only on the feeder trunk, the Downtown feeder automation plan would only install automated switches on the URD main loop, meaning that fault detection will still be required on the sub-loops. Therefore, the scope of the Downtown area feeder automation work also includes the replacement of existing faulted circuit indicators (FCIs) on the sub and sub-sub loops with new FCIs of a modern design that are capable of communicating with the control room.

An FCI is a device that is installed on a cable segment that can detect whether it has experienced the fault current. The FCIs in the URD system are at the end of their 15-year useful life and often malfunction, leading to interpretation errors by field crews searching for a fault, potentially prolonging the duration of URD system outages. Additional information on the current condition of these assets can be found in section E7.3.3.1. With the proposed automation of the 600 A remote switches and installation of remotely readable FCIs, Toronto Hydro controllers would be able to dispatch crews directly to the location of the fault, thus foregoing the time-consuming fault location procedures, facilitating faster outage restoration timelines on the sub- and sub-sub loops.

FIGURE 8: EXAMPLE OF THE NEW FCIS PROPOSED FOR INSTALLATION, FEATURING A WIRED CONNECTION IN THE VAULT TO COMMUNICATE REMOTELY (NOT PICTURED). DISPLAY COULD BE AS PICTURED OR BE FLASHING OR AUDIBLE FOR ENHANCED MANUAL DETECTION.

Toronto Hydro selected the Harbord Village area (A310CE) as the first feeder to be automated. A discussion of Toronto Hydro's approach and method for selecting and prioritizing which URD feeders will receive automation can be found in Section E7.3.4.1. The A310CE project entails automation of all the 600 A switches and replacement of all the FCIs on the feeder, totaling four switching vaults and approximately 150 FCIs. Each switching vault with a SCADA switch requires an RTU. Fiber optic cable will be used to connect the RTUs in each vault back to an aggregator

at the substation. The FCIs will be connected into the fiber network either by fiber or copper connection, dependent on distance and detailed design.

Toronto Hydro also proposes to automate two additional URD feeders in 2017 in the Little Italy and Palmerstone area (A320CE and A330CE for a total of five 600 A switching vault locations) and two feeders in 2018 in the Rosedale area (A340CS, A360CS for a total of six 600 A switching vault locations). Table 3 details the switching assets and communication infrastructure that will be installed in order to automate the targeted feeders in the Downtown area.

TABLE 2: NEW ASSETS PROPOSED FOR INSTALLATION BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
600A SCADA SF_6 URD Switches	--	4	--	5	6	15
RTU	--	4	--	5	6	15
Fiber Optic Cable (m)	--	3,000	--	3,000	7,000	13,000
Faulted Circuit Indicators (FCI's)	--	150	--	150	150	450

*Length of fiber optic cable necessary is estimated based on the length of primary cable between switching vaults and what fiber would have already been installed. The amount necessary will vary based on detail design.

Toronto Hydro anticipates that the feeder automation program will provide customer value by improving overall system efficiency and reliability by minimizing the duration of outages on targeted feeders. In both the Horseshoe and the Downtown areas, an outage on a feeder's trunk (or main loop) results in a service interruption to all customer on that feeder. By automating the switches on the targeted segments of feeders in the Horseshoe and Downtown areas, a large number of affected customers can be restored swiftly.

Targeted deployment of feeder automation technology is also expected to decrease the overall strain on system controllers during major event days. This can lead to faster restoration times for all customers, including those not located on feeders enabled for automation. In a similar manner, feeder automation is expected to reduce the demand for manual switching from field crews, allowing them to focus on planned switching work or other outages on non-automated feeders. Currently, when field crews need to perform reactive switching, resource limitations result in the postponement of previously scheduled switching work in connection with regularly scheduled maintenance or capital work.

Since feeder automation reduces the magnitude of outages on the feeder's trunk or main loop, it enables Toronto Hydro to postpone planned asset replacement activities scheduled on automated feeders so that other high-priority, critical activities can be completed. In other words,

since the outage impacts and the risk of potential equipment failures on feeder trunks would be diminished through automation, the timing of work on automated feeders can be considered somewhat less rigid. However, feeder automation is not an alternative option nor does it replace the need for asset renewal activities, as it will not prevent faults from occurring and does not deal directly with the growing backlog of end-of-life assets across the distribution system. Feeder automation is intended to improve system efficiency and reliability as Toronto Hydro's critical renewal program continues. The efficiency benefits in particular would be especially valuable to customers over the long-term, as the risks and costs associated with aging assets would be permanently reduced on feeders where feeder automation is installed.

Feeder automation is also expected to improve Toronto Hydro's visibility of system operating conditions, providing the utility with otherwise unobtainable system data. Toronto Hydro can leverage this information to make more informed and efficient asset management decisions in the future. It also will act as a cornerstone for further modernization of the system, since it provides the necessary data acquisition, control, and communication infrastructure (radio network, fiber installations, etc.) necessary for many modernization initiatives (e.g. network vault automation, monitoring of distributed generation, etc).

The following table summarizes the anticipated benefits of the 2015-2019 Feeder Automation program.

TABLE 3: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Limits the number of customers affected by a trunk or main loop outage. ƒ Positively impacts power reliability for customers on non-automated feeders as well. Feeder automation decreases the time and effort needed by controllers and switching crews on automated feeders so they can concentrate their attention on non-automated feeders. ƒ Less streetlights and traffic lights affected by trunk outages, improving public safety and mobility of traffic. ƒ Impacts many customers for relatively low cost. While Feeder Automation is not an alternative to asset renewal, the cost of automating a region of the city would typically equal the cost of renewing the asset base of only a section of a targeted feeder. This is further exemplified by the high benefit to cost ratio of the work. ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $102.74 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.3.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $91.6 million, confirming the economic prudence of the investments (see Section E7.3.7).
Reliability	ƒ Automation has resulted in a reduction of 12,389 CHI and 24,778 CI since its installation in 2010. ƒ Through automated switching arrangements, restoration following a fault on the feeder trunk occurs in less than a minute. This decreases the number of customers impacted and the outage duration for unaffected customers – resulting in improvements to both SAIDI and SAIFI.
Safety	ƒ Manual switching is one of the most inherently risky tasks performed by field crews. The use of SCADA operable switches prevents crews from having to manually perform switching. ƒ The new switches have internal grounds, as opposed to the current switches that have external grounds. External grounds are more susceptible to the vault environment and human error during application.
Efficiency	ƒ Feeder automation allows system controllers to make more efficient use of their time. Since switching actions on automated feeders would be able to occur autonomously, crews would be able to focus on other areas requiring restoration. ƒ Enhanced condition monitoring on automated feeders will allow day to day operating decisions and long term asset investment decisions to be made more efficiently and effectively.

E7.3.3 Why the Program is Needed

The Feeder Automation program is needed to improve the system's ability to efficiently detect, isolate and restore power on the feeder' trunk or main loop. In all, automation is needed to significantly reduce outage durations on poorly performing feeder trunks and main loops in the Horseshoe and Downtown area systems, respectively.

Unlike lateral circuits, when a fault occurs on the trunk or the main loop, it trips the station circuit breaker, causing all customers connected to that feeder to experience an outage. Lateral circuits in the Horseshoe area, or sub-loops in the Downtown, have protective devices such as fuses that localize the outage downstream of the breaker and isolate the fault, leaving the majority of the circuit unaffected. The large number of customers affected and the time required to isolate faults make feeder trunks one of the most vulnerable areas on Toronto Hydro's distribution system with respect to outage impacts. Toronto Hydro's ability to isolate an outage quickly and efficiently plays a significant role in mitigating an outage's impact on customers.

E7.3.3.1 Purpose

Table 4 summarizes the primary and secondary drivers for the Feeder Automation program. This program is a System Service initiative, with a primary driver of system efficiency.

TABLE 4: PROGRAM DRIVERS

Primary Driver	Reasoning
System Efficiency	ƒ Significantly improves fault detection, isolation and restoration times during trunk- and/or main loop-related outages. ƒ Potentially mitigates the impact of defective equipment failures on the trunk on reliability, reducing the rate of asset replacements in select cases. ƒ Enables more efficient use of control room and switching crew resources. ƒ By cost-effectively mitigating failure risk costs, Feeder Automation can help maintain a moderate pace of system renewal.
Secondary Driver	**Reasoning**
Reliability	ƒ Decreases the duration of outages on targeted trunk / main loop feeders, facilitating significant reliability improvements for the system and the average customer. ƒ Decreases the number of customers impacted by trunk and main loop-related outages. ƒ Reduces demands on system operators and switching crews during large system outage situations by autonomously restoring power to the unaffected sections of automated feeders, thereby allowing staff to focus on other affected areas.

Horseshoe System

Toronto Hydro plans to implement feeder automation in the Horseshoe system to improve its operational efficiency and decrease outage impact and restoration times on the targeted feeders. As described in Section E7.3.2.1, Horseshoe area automation targets the open loop 27.6 kV system, where feeders are comprised of two main sections: trunks and laterals (also described in section E7.3.2.1).

Current system design utilizes fuses to isolate faults that occur on lateral segments of the feeder, reducing the impact of outages on laterals to just a few hundred customers. This configuration typically results in feeders with shorter trunk segments that supply numerous long laterals in order to minimize the number of circuit kilometers without upstream fusing. As a result, the total circuit kilometers of laterals is greater than the total circuit kilometers of trunk, meaning that more outage incidents occur on the lateral segments, as seen in Figure 9. However, as illustrated in Figure 10, when comparing the impact of outages on lateral segments to those on the trunk segments, trunk outages affect almost three times as many customers because a fault on the trunk section trips the station breaker, affecting all customers on a feeder. The current system design means that human intervention is needed to localize trunk related outages to a small portion of the feeder (i.e. field crews or operators from the control room need to fault locate and perform switching). Feeder automation activities, which target the feeder trunk, include the installation or modification of strategically placed SCADA-Mate switches, removing the need for human intervention by automating the switching process to localize the outage in under one minute.

FIGURE 9: COMPARISON OF TRUNK VS LATERAL OUTAGES

FIGURE 10: LATERAL VS. TRUNK COMPARISON OF CUSTOMERS INTERRUPTED

Since trunk outages affect more customers and usually involve longer restoration times than lateral outages, they also affect Toronto Hydro's SAIFI and SAIDI statistics. As shown in Figure 11, faults on feeder trunks have approximately three times the SAIFI impact on Toronto Hydro's system as compared to faults on the laterals. Figure 12 illustrates a similar relationship in relation to SAIDI. By expanding feeder automation to more feeders in the system, Toronto Hydro anticipates a material improvement of the average system reliability experienced by all customers. More information on the reliability impact and benefits of feeder automation can be found in Section E7.3.5.2.

FIGURE 11: SAIFI COMPARISON BETWEEN TRUNK AND LATERALS

FIGURE 12: SAIDI COMPARISON BETWEEN TRUNK AND LATERALS

Toronto Hydro currently operates the 27.6 kV feeders in the Horseshoe area through a combination of manual switches and remote operated SCADA switches. The number of switches

on a feeder and their placement varies throughout the feeders in the system and is determined based on a feeder's configuration and loading.

Manual switches require field crews to be deployed to the site to isolate the sections upstream and downstream of the fault site. After physically locating the fault, field crews manually operate the necessary tie switches to adjacent feeders to resupply power to the unaffected portions of the feeder. The manual effort to locate the fault, isolate the faulted section and restore the unaffected customers takes an average of three hours to complete. This timeline can be prolonged when outages occur during rush hour, as heavy traffic and downed traffic lights can delay crews' ability to reach the outage and set up their equipment. In a similar manner, outage restoration timelines can increase during multiple outage events, such as adverse weather days. Not only does this increase the duration of the outage, but it also results in additional expenses in the form of fuel costs.

Unlike manual switches, SCADA switches can be opened and closed remotely. When a fault occurs on a feeder with SCADA switches, the system controller can remotely open the switches upstream and downstream of the fault to isolate. They can then remotely close tie switches that connect to adjacent feeders, resupplying the unaffected sections of the feeder. SCADA switches also have current sensors that allow the controller to quickly assess where the fault occurred. Since this can be done remotely, feeder fault detection, fault isolation, and restoration can be done relatively quickly as compared to the manual process. The typical restoration for a feeder with SCADA switches is under 30 minutes.

By replacing the manual and non-automated SCADA switches with switches designed for feeder automation, Toronto Hydro expects to be able to rely on autonomous detection and isolation of affected portions of the feeders, restoring the majority of customers affected in under a minute. As such, the number of customer outage impacts currently associated with trunk outages is expected to be minimized.

By automating feeders with the worst reliability statistics related to trunk outages (the area of the feeder this technology is protecting), Toronto Hydro can target areas that do not justify capital renewal work due to the condition of equipment on the trunk, but that are still problematic due to the risk of the occasional equipment failure or faults induced by weather or foreign interference. This will provide a protection scheme that will automatically localize the outage to a smaller section of the feeder without human intervention and will reduce the impact to customers system wide.

Downtown (URD) System

Similar to the Horseshoe area, feeder automation in the Downtown area is expected to improve the operating efficiency of the system. The URD system is one of Toronto Hydro's downtown underground service distribution configurations that largely supplies residential loads and smaller commercial loads using a series of feeder loops. Determining the source of an outage in the URD system can be time consuming due to the complexity of the loop system configuration. The design of the URD system features FCIs to aid field crews in the fault locating process in this complicated configuration. Due to the corrosive environment in the switching and transformer vaults, many of which are below grade and poorly ventilated, the location of most FCIs exposes them to higher incidence of mechanical failures, resulting in instances of crews misreading FCI indicators while searching for the location of the fault, prolonging the duration of outages. Figure 13 below shows the corrosion damage on FCI units and the effect it can have on the magnetic core of the unit, which is what allows it to sense the fault currents.

FIGURE 13: CORROSION OF FCI CORE AND MECHANICAL FAILURE

In August 2008 an outage occurred on the URD system due to a failed cable. The fault indicators provided incorrect readings, resulting in crews and system operators attempting to restore the outage based on these incorrect readings. This resulted in a significant prolongation of the outage time; a total CHI of 5,458 and CI of 868. The installation of modern FCIs capable of remote communication would have expedited the fault location and isolation efforts, allowing for a large portion of the feeder to be restored a lot quicker.

The outage in August 2008 is prime example of how the complex configuration of the downtown URD system, combined with the reliability issues of currently deployed FCIs, can cause extended outages on this segment of Toronto Hydro's system. Under current conditions, the URD design requires field crews to perform numerous, time-consuming manual fault location work, which includes travel time to the requisite switching vaults. Figure 14 shows that since 2000, the CHI trend for outages on the URD system has been increasing.

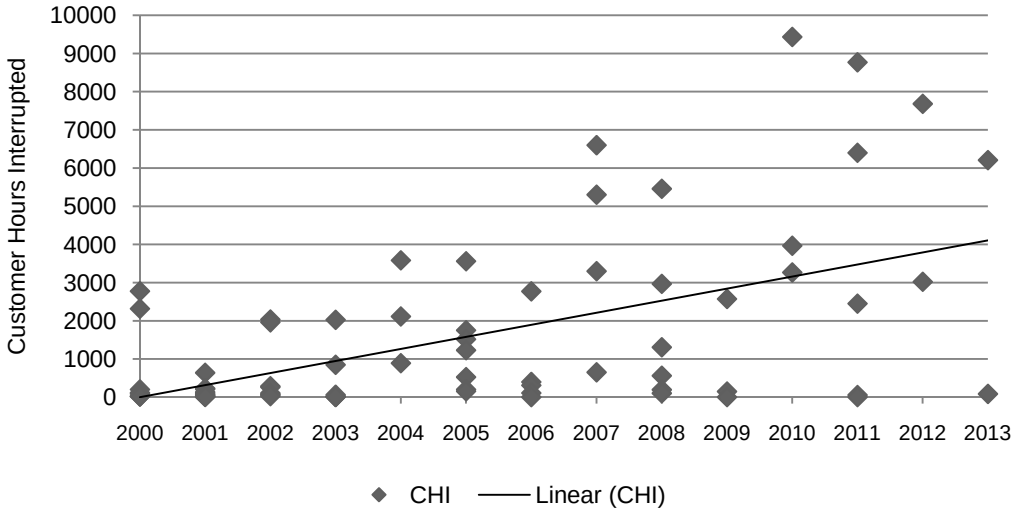


FIGURE 14: CHI OF EACH OUTAGE ON THE URD SYSTEM 2000-2012 (PURE URD FEEDERS ONLY)

The average outage duration on the URD system is historically longer than those on other Toronto Hydro system configurations. This can be seen when examining outage durations for cable faults – the most prevalent fault type on all segments of Toronto Hydro's system. Figure 15 displays the average outage duration for cable faults since 2000 on five different Toronto Hydro systems. The outage duration for cable faults on the URD system has increased on average since 2008. This is consistent with the overall trend of outage time on the URD system, shown in Figure 14.

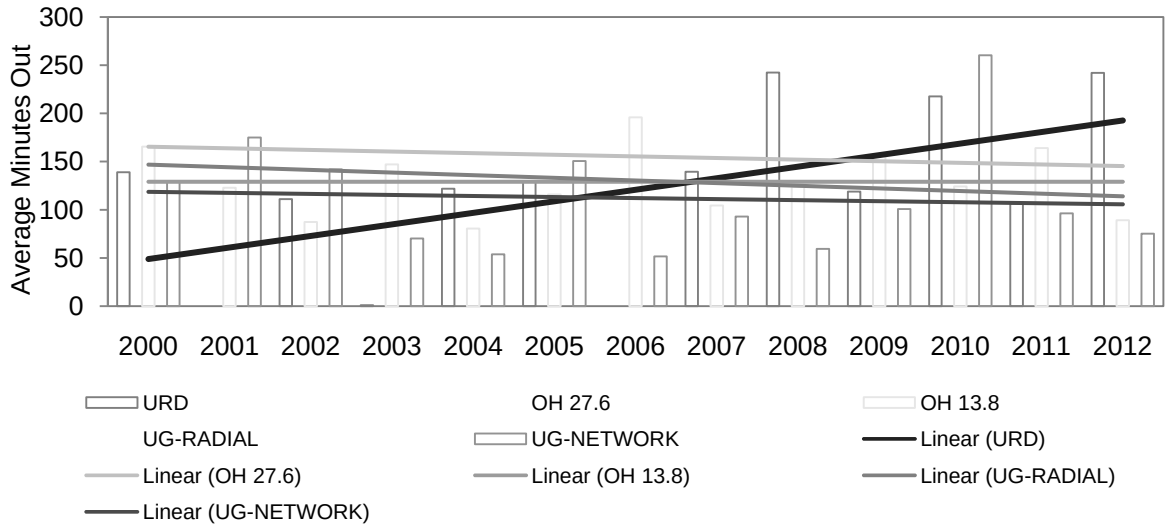


FIGURE 15: YEARLY AVERAGE OUTAGE DURATION FOR UG PRIMARY CABLE FAULTS BY SYSTEM CONFIGURATION TYPE

Table 5 provides the average length of outage durations on each system type from 2000 to 2012 and from 2008 to 2012. The colour of the cell indicates the order of magnitude of the average outage length, with red indicating the longest average outage duration. As with the trend in CHI, it is evident that the URD system has historically experienced the longest outage durations for cable faults, second only to the overhead 27.6 kV system, which is targeted by the Horseshoe automation.

TABLE 5: AVERAGE OUTAGE DURATION FOR DIFFERENT SYSTEM CONFIGURATIONS (FOR OUTAGES CAUSED BY CABLE FAULTS)

	System Average Outage Duration (minutes) 2000-2013	System Average Outage Duration (minutes) 2009-2013 (5yr)
URD	142	142
OH 27.6	165	151
OH 13.8	126	130
UG-RADIAL	123	131
UG-NETWORK	113	125

Figure 15 and Table 6 indicate that URD system warrants improvement when compared to other system types. By installing SCADA operable 600 A switches on the main loop of URD feeders,

Toronto Hydro expects to be able to more quickly restore large portions of customers on the feeder. While SCADA switches are the first step, a further step to make them completely autonomous will further improve restoration times. If the FCIs on the feeder also report remotely, the system operator will be able to dispatch crews to the appropriate switching locations right away, decreasing fault location durations, and subsequently outage durations, dramatically.

E7.3.4 Timing & Pacing of the Program

Toronto Hydro determined the planned pace of feeder automation based on the following considerations:

- Feeder reliability statistics;
- Age of the existing feeder assets;
- Location, and amount, of existing communication infrastructure (e.g. radios, fiber optic cable);
- Staging of work that would allow the company to leverage its existing automated switches and communication infrastructure; and
- Standard testing and acceptance procedures for installation of new equipment.

As per the table below, the total cost of the program over the 2015 to 2019 period is $54.1 million, which includes the automation of approximately 130 feeders. The aggregate yearly budget for the program fluctuate year over year due to the combined effect of the pacing of the Horseshoe and Downtown automation projects.

TABLE 6: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	3.26	0.87	6.24	8.83	0.77	11.1	15.1	9.41	9.99	8.47

The Feeder Automation program will occur alongside Toronto Hydro's proposed renewal work to improve system efficiency and ensure asset replacements are occurring at the most effective time with the most benefit to customers. By implementing automation now, Toronto Hydro has the opportunity to ensure that the cost-effectiveness of the next generation distribution system will be enhanced for current and future ratepayers. The use of modernized equipment and

communication infrastructure that support automation will create a more intelligent grid, one which provides system operators and planners with high-quality data for future asset management decision making. As such, future asset replacements and planning decisions will be better informed and effective. Toronto Hydro should not postpone these investments beyond 2019, as they are some of the most cost-effective distribution system improvements currently available to Toronto Hydro and its customers.

Since the Horseshoe's feeder automation equipment is more mature than Downtown's and has a more established communication infrastructure, the automation work in the Horseshoe area is more front-loaded. Projects in later years make use of some of the assets that will be installed in the earlier years of the program (i.e. adjacent feeder automation zones will be automated sequentially to build off the communication infrastructure of the first zone). As the program progresses, the costs associated with Horseshoe feeder automation will decrease in later years.

Seeing as this is the first time that Toronto Hydro has deployed the type of equipment proposed for installation in the Downtown URD system, Toronto Hydro will follow standard practices for new asset integration. Throughout 2015, the equipment will be tested and impacts of the harsh vault environment (e.g. frequent accumulation of the run-off and ground water) will be assessed. The first URD automation project is planned to take place in 2016 (accounting for a portion of the jump in yearly spend from 2015 to 2016), which is a year after the first installation is made in 2015. Two feeders are planned for automation in 2018 and another two in 2019. The lack of URD automation projects in 2015 and 2017, partially accounts for the year to year variance in program costs.

E7.3.4.1 Ranking & Prioritization

Toronto Hydro assessed whether feeders were suitable for automation based on their reliability history and the utility's knowledge of the location of existing fiber and radio communication infrastructure that could be leveraged to manage overall project costs. Both the Horseshoe and the Downtown feeder automation plans also take into account existing feeder assets, configurations and geography.

Toronto Hydro considered trunk reliability statistics over the past five years in order to prioritize planned work for the Horseshoe area. The frequency of historical outages on candidate feeders provided a good benchmark for how helpful feeder automation would have been and how useful it would be going forward. Higher prioritization was given to feeders that would have most benefitted from automation. Toronto Hydro applied a similar approach for the Downtown feeders,

with particular focus being placed on outages on both the main and sub-loops. For the Downtown feeders, the planners also consulted control room staff to assist in determining which Downtown feeders would benefit most from the automation of the 600A switches.

As mentioned earlier, feeder prioritization also accounted for the feeders' geographic locations. By targeting adjacent feeders, Toronto Hydro can establish a network of automated feeders that will be able to resupply one another in the event of an outage. Automating adjacent feeders provides the basis for project zones, as displayed in Figure 1. Work planned for these zones expands on the existing adjacent network of automated feeders and their switch and communication (radio or fiber) infrastructure. This process of planning automation in zones of geographically proximate feeders heavily impacts the order and prioritization of projects under the Feeder automation program.

E7.3.5 Program Execution

The proposed Feeder Automation program is scoped at a feeder level. The work will be executed based on "automation zones", which each zone being comprised of multiple feeders in proximity to one another. See Figure 1 showing a map of the planned automation zones.

When a zone is planned for automation, all of the switches on the affected feeders are identified (current switch and RTU type). Additionally, the load of existing segments of the feeder will be examined to determine if additional tie points are needed. The switches will be added or replaced one-by-one, coordinated with any other work in the area to ensure minimal switching. Once all switch assets are installed, the switch manufacturer will conduct a radio survey to ensure that the site selected is appropriate given the required communication. Following the completion of switch installation for a given zone, site acceptance testing will be performed to confirm that the automation software installed in each switch controller is functioning properly.

E7.3.5.1 Proposed Work Plan

As mentioned earlier, the work will be executed based on "automation zones", which each zone being comprised of multiple feeders in proximity to one another. Using this approach, adjacent feeders that are connected to one another through tie switches can be automated in the same project year. The installation of the switches themselves will be executed on a feeder basis. Table 7 outlines the feeders planned for automation, their proposed year of execution and the station area they service. The plan presented covers the 2015 to 2019 work period, though feeder automation work is expected to continue beyond 2019.

TABLE 7: 2015-2019 LONG TERM PLAN

Year	Feeder	Station	Area
2015	80M1	Fairchild TS	Horseshoe
2015	80M4	Fairchild TS	Horseshoe
2015	80M8	Fairchild TS	Horseshoe
2015	80M21	Fairchild TS	Horseshoe
2015	38M8	Manby TS	Horseshoe
2015	38M5	Manby TS	Horseshoe
2015	38M4	Manby TS	Horseshoe
2015	30M9	Horner TS	Horseshoe
2015	5M2	Scarborough TS	Horseshoe
2015	5M4	Scarborough TS	Horseshoe
2015	5M6	Scarborough TS	Horseshoe
2015	5M8	Scarborough TS	Horseshoe
2015	5M10	Scarborough TS	Horseshoe
2015	5M21	Scarborough TS	Horseshoe
2015	5M22	Scarborough TS	Horseshoe
2015	5M23	Scarborough TS	Horseshoe
2015	5M24	Scarborough TS	Horseshoe
2015	5M25	Scarborough TS	Horseshoe
2015	5M26	Scarborough TS	Horseshoe
2015	5M27	Scarborough TS	Horseshoe
2015	5M29	Scarborough TS	Horseshoe
2015	5M30	Scarborough TS	Horseshoe
2016	A310CE	Cecil TS	Downtown
2016	502M21	Cavanagh TS	Horseshoe
2016	502M28	Cavanagh TS	Horseshoe
2016	63M3	Agincourt TS	Horseshoe
2016	26M21	Malvern TS	Horseshoe
2016	26M31	Malvern TS	Horseshoe
2016	26M32	Malvern TS	Horseshoe
2016	26M34	Malvern TS	Horseshoe
2016	26M36	Malvern TS	Horseshoe
2016	H9M23	Ellesmere TS	Horseshoe
2016	H9M25	Ellesmere TS	Horseshoe
2016	H9M26	Ellesmere TS	Horseshoe
2016	Zone 5a	Finch TS	Horseshoe
2017	Zone 6a	Manby TS	Horseshoe
2017	Zone 6b	Bermondsey TS	Horseshoe
2017	Zone 6c	Fairchild TS	Horseshoe

Year	Feeder	Station	Area
2018	Zone 7a	Richview TS	Horseshoe
2018	Zone 7b	Leslie TS	Horseshoe
2018	Zone 7c	Warden TS	Horseshoe
2018	A320CE	Cecil TS	Downtown
2018	A330CE	Cecil TS	Downtown
2019	A340CS	Charles TS	Downtown
2019	A360CS	Charles TS	Downtown
2019	Zone 8a	Rexdale TS	Horseshoe
2019	Zone 8b	Runnymede TS	Horseshoe
2019	Zone 8c	Sheppard/Ellesmere TS	Horseshoe

E7.3.5.2 Program Risks

(i) New Large Customer Loads

The proposed automatic switch locations are determined based on the current optimal feeder configuration, which takes into account the feeder loading levels. Additional loads of new large customers, such as a data centre, industrial facility or a group of new high-rise buildings, could cause some sections of the feeder to be overloaded during power restoration activities, potentially leading to additional outages. As such, Toronto Hydro may be required to reconfigure its automation plans later in the program. Toronto Hydro mitigates this risk by monitoring load forecasts and anticipated developments on an ongoing basis.

Integrity of the Communication Infrastructure

Horseshoe automation requires the installation of a peer-to-peer mesh network that will enable the switching nodes to communicate with one another in the field. The network's functionality is dependent on the sequence of the nodes being built, since nodes need to be able to communicate with one another. As such, a communication design needs to be established between switches and the control room. The sequence of work has been determined by a radio frequency (RF) design to ensure that the integrity of the communication system is maintained. In essence, a delay in the conversion of a single feeder segment can slow down the implementation of a project in a particular zone. Toronto Hydro plans to mitigate this risk by ensuring that the radio design is capable of allowing multiple feeders to have automation infrastructure constructed at the same time, allowing multiple crews to work on different feeders simultaneously.

Premature Asset Failure

In Downtown area automation, approximately 80% of the switches targeted for replacement with new 600 A switches are nearing or are at their end of useful lives. As such, these switches may require reactive replacement before the planned work can be executed due to failure or deteriorating conditions such as low gas levels. In this scenario, Toronto Hydro would have to amend its work schedule. To address this risk, SCADA-ready switches will be installed if reactive replacements are required and the RTUs will then be installed at a later date through the Feeder Automation program.

E7.3.5.3 External Constraints

An external constraint of the Feeder Automation program is the need for Toronto Hydro to coordinate activities with Hydro One Networks Inc. (HONI) so that station breakers, which are owned by HONI, will be updated. While feeder automation can be undertaken without autonomous station breakers (since a system controller could close the breaker as necessary or the automation can seek restoration from tied feeders), a truly automated feeder requires that the breaker also be automated as it is the easiest source to restore power from. Coordination with HONI can delay the complete automation of feeders in the Horseshoe where HONI owns the station breakers. In the Downtown area, breakers are owned by Toronto Hydro and as such, this external constraint does not apply. Toronto Hydro is currently working with HONI to automate station breakers and expects that future automation work will include the update of station breakers. Initially, the update of station breakers may only occur in the year following Toronto Hydro's automation.

Another external consideration is the fact that the installation of the new communications framework required for feeder automation can affect the overall radio performance on the open loop system. Since the feeder automation scheme uses a different communication system, peer-to-peer mesh network as opposed to the traditional point-to-point network, it requires a custom design to ensure that there are enough communication nodes from the switches radio. Where there are shortfalls in coverage, additional repeater radios will have to be installed to act as communication stepping stones to ensure adequate coverage. At the present time, Toronto Hydro relies on an external contractor to perform some of these activities and the timeline or design can be affected if communication cannot be achieved in a cost-effective manner. As the system expands, this issue will become less salient as additional radios are placed in the field, which will provide sufficient coverage.

E7.3.5.4 Standard & Regulation Adherence

The communication system required to enable feeder automation is encrypted and all communication radios (i.e. radios that communicate back to the control room) are located on Toronto Hydro properties or approved private properties. Furthermore, the configuration of the communication network has been designed to ensure that each location has at least one redundant path in the event a radio malfunctions or is put offline.

All switching procedures for automation are in accordance to the Electrical Utility Safety Regulations to ensure that automation does not occur while crew members are within the vicinity of the feeder. Measures have been introduced to ensure that automation times out after an allocated time frame and that feeders with disabled automation cannot be used in the automation process.

E7.3.6 Evaluation of Alternatives

E7.3.6.1 Quantification/Evaluation of Options

(i) Status Quo: Leave the System as is

By maintaining the status quo, Toronto Hydro would not address the prolonged restoration times, which can range from 20 minutes to three hours depending on the mix of manual and SCADA switches on a given feeder. While some Horseshoe feeders use SCADA switches, manual switches in both the Horseshoe and Downtown areas would continue to be used. In all, the considerable issues with respect to system efficiency, reliability and safety will not be addressed.

The continued cost of ownership associated with the Status Quo option (COO_E) is highlighted in Table 10.

(ii) Option 2: Install Remote Operated SCADA-Mate Switches

By installing remote-operated SCADA switches, Toronto Hydro would improve the system by adding data acquisition and control points. This would allow the controller to assess the condition of a feeder using the sensors of the SCADA switch and then remotely operate the switches to isolate the faulted section. A controller can typically restore a Horseshoe area feeder within thirty minutes using remote operable switches.

This option entails an increased investment in the form of installing additional SCADA switches in the Horseshoe and Downtown areas. Under this option, Toronto Hydro controllers would utilize manual intervention of the controller (instead of automated intelligence) to assess the fault and determine the optimal means of restoring it through adjacent feeders. Lengthy outages would likely persist since controllers could potentially be required to manage multiple outages concurrently, as is the case during adverse weather events, and the many substantial benefits of rapid isolation and restoration associated with full automation would not be realized.

The cost of ownership (COO_{N1}) and program net benefit (NPV_1) associated with installation of remote operable switches is further detailed in Table 9.

(ii) Option 3: Install Feeder Automation

Toronto Hydro's preferred option is the Feeder Automation program. With this option, Toronto Hydro would strategically install SCADA switches to either sectionalize a feeder or tie two feeders together for the purpose of restoration. In the Horseshoe area, this would be accomplished by utilizing existing SCADA switches and installing new switches in areas that require them. In the Downtown area, feeder automation would entail the replacement of 600A main-loop switches with SCADA switches. By undertaking the Feeder Automation program, Toronto Hydro would improve the efficiency and reliability of the system while also eliminating safety risks.

The cost of programming SCADA switches and configuring the wireless network for automation is approximately 10% higher than using basic SCADA switch technology. The modest cost increase for automation over a basic remote-operated system is warranted because the investment is expected to significantly improve system reliability for the average customer and improves Toronto Hydro's operational efficiency with respect to trunk outage restoration efforts. Automation modernizes the grid by mitigating the risk of large-impact outages on the most vulnerable part of feeder, the trunk or main-loop. It also provides real-time information to the controller with respect to feeder operation. The software can manage the initial work that would otherwise be required to be undertaken by an operator, freeing the operator and crew to manage the faulted area more quickly.

The COO_{N2} and NPV_2 associated with the Feeder Automation program is further detailed in Table 10. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_{N2}) based on the first year of activities in this program. The COO_{N2} of a state reflects the risk of asset failure including both direct and indirect costs; these costs include customer interruptions, emergency repairs, and asset replacements associated with that design. In

addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NAR_E) and proposed (NAR_{N2}) state. Non-asset risks are further explained in Section D3.3. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership ($\hat{u}COO_2$) is compared to the associated program costs (PC_2) for the first of activities, the Feeder Automation program produces a net benefit (NPV_2) value of $91.60 million, as shown in Tables 8 and 9.

TABLE 8: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	99.75
Non Asset Risk [NAR_E]	512.64
Maintenance Cost [MC_E]	
Additional Quantifiable Benefits [AQB_E]	
Cost of Ownership of Existing Assets [COO_E]	612.40

TABLE 9: SCADA-MATE SWITCHES BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 2: SCADA-Mate Switches (N1)	
Asset Risk [AR_{N1}]	103.53
Non Asset Risk [NAR_{N1}]	420.18
Maintenance Cost [MC_{N1}]	
Additional Quantifiable Benefits [AQB_{N1}]	
Cost of Ownership of New Assets [COO_{N1}]	523.71
Option 2: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_{N1})$]	47.05
Program Cost [PC_1]	11.14
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	35.91

TABLE 10: FEEDER AUTOMATION – BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 3: Feeder Automation (N2)	
Asset Risk [AR_{N2}]	93.48
Non Asset Risk [NAR_{N2}]	416.17
Maintenance Cost [MC_{N2}]	
Additional Quantifiable Benefits [AQB_{N2}]	
Cost of Ownership of New Assets [COO_{N2}]	509.65
Option 3: Program Net Benefit (NPV_{2})	
Difference in Cost of Ownership [$\hat{u}COO_2 = (COO_E - COO_{N2})$]	102.74
Program Cost [PC_2]	11.14
Program Net Benefit [$NPV_{2} = (\hat{u}COO_2 - PC_2)$]	91.60

E7.3.7 2015 Project Details

Table 11 lists all projects that are planned for partial or complete execution as part of the 2015 work program. Note that the table shows total costs for each program. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015.

TABLE 11: 2015 PROJECTS

Scope Number	Project Name	Total Project Cost ($ Millions)	Start Date
E12596	Feeder Automation Site Acceptance Tests Cavanagh & Agincourt TS	0.21	2015
E12679	Repeater Radio Installation for Scarborough East	0.27	2015
E14387	Feeder Automation Scarborough TS - 5M2	0.69	2015
E14388	Feeder Automation Scarborough TS - 5M4	0.64	2015
E14389	Feeder Automation Scarborough TS - 5M6	0.59	2015
E14390	Feeder Automation Scarborough TS - 5M8	0.44	2015
E14391	Feeder Automation Scarborough TS - 5M10	0.53	2015
E14392	Feeder Automation Scarborough TS - 5M21	0.56	2015
E14393	Feeder Automation Scarborough TS - 5M22	0.38	2015
E14394	Feeder Automation Scarborough TS - 5M23	0.33	2015
E14395	Feeder Automation Scarborough TS - 5M24	0.44	2015
E14396	Feeder Automation Scarborough TS - 5M25	0.38	2015

Scope Number	Project Name	Total Project Cost ($ Millions)	Start Date
E14397	Feeder Automation Scarborough TS - 5M26	0.58	2015
E14398	Feeder Automation Scarborough TS - 5M27	0.63	2015
E14399	Feeder Automation Scarborough TS - 5M29	0.43	2015
E14400	Feeder Automation Scarborough TS - 5M30	0.38	2015
E14401	Feeder Automation Site Acceptance Test Elec Scarborough TS	0.21	2015
W12632	Feeder Automation - Site Acceptance Test Bathurst II TS	0.20	2015
W13366	Feeder Automation Fairchild TS - 80M1	0.45	2015
W13368	Feeder Automation Fairchild TS - 80M04	0.32	2015
W13370	Feeder Automation Fairchild TS - 80M08	0.18	2015
W13373	Feeder Automation Fairchild TS - 80M21	0.25	2015
W13379	Feeder Automation Horner TS - 30M09	0.46	2015
W13381	Feeder Automation Manby TS - 38M08	0.28	2015
W13383	Feeder Automation Manby TS - 38M05	0.16	2015
W13384	Feeder Automation Manby TS - 38M04	0.27	2015
W13483	Feeder Automation Etobicoke RR IFRS compliant	0.18	2015

Scope Number	Project Name	Total Project Cost ($ Millions)	Start Date
W13484	Feeder Automation Fairchild Survey/Repeater Radio Installation	0.18	2015
W13485	Feeder Automation Etobicoke Site Acceptance Test	0.15	2015
W13486	Feeder Automation Fairchild TS - Site Acceptance Test	0.15	2015
W13499	Feeder Automation Bathurst TS Site Acceptance Test	0.21	2015

The following subsections provide additional details for all 2015 projects.

E7.3.7.1 Feeder Automation Scarborough TS Project Description

Investment Category: System Service

Program: Feeder Automation

Project Title: Feeder Automation Scarborough TS

Project Number: E12679, E14387, E14388, E14389, E14390, E14391, E14392, E14393, E14394, E14395, E14396, E14397, E14398, E14399, E14400, E14401

Project Year: 2015

Estimated Cost: $7.48 million

(i) Objective

The objective of this project is to automate the selected feeders being supplied from Scarborough East TS and expand the network that has been established from Cavangh and Agincourt TS.

(ii) Scope of Work

TABLE 12: SCOPE OF WORK DETAILS

District Neighborhood	SCARBOROUGH
Station(s)	SCARBOROUGH EAST TS
Feeder(s)	5M2, 5M6,5M8,5M10,5M21,5M22,5M23,5M24,5M25,5M26,5M27,5M29,5M30

TABLE 13: ASSETS REPLACED

Assets (Units)	2015
SCADArMate Switches	62
RTU	63
RTU Upgrade	7
Radio & Antenna	71

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(iii) Justification & Benefits

Automating this area of the system is expected to mitigate trunk related outages that have occurred in the past.

This project will expand the automated network that will first be established at Cavanagh and Agincourt TS, just north of this area. After automating this area, Toronto Hydro will be able to further expand automation to the east, west and south of this location.

E7.3.7.2 Feeder Automation Fairchild TS Project Description

Investment Category: System Service

Program: Feeder Automation

Project Title: Feeder Automation Fairchild TS

Project Number: W13366, W13368, W13370, W13373, W13484, W13499

Project Year: 2015

Estimated Cost: $1.59 million

(i) Objective

The objective of this project is to automate the selected feeders being supplied from Fairchild TS and expand the network that has been established from Bathurst TS.

(ii) Scope of Work

TABLE 14: SCOPE OF WORK DETAILS

District Neighborhood	NEWTONBROOK & WILLOWDALE
Station(s)	FAIRCHILD TS
Feeder(s)	80M1, 80M4, 80M8, 80M21

TABLE 15: ASSETS REPLACED

Assets (Units)	2015
SCADA-Mate Switch	14
RTU	14
RTU Upgrade	9
Radio & Antenna	23

(iii) Justification & Benefits

Automating this area of the system is expected to mitigate trunk related outages that have occurred in the past.

This project commenced several years ago and is half complete; however, work was halted because of the 2012 IRM decision. The remaining work needs to be completed in order to achieve full automation.

This project will expand the automated network that will first be established at Bathurst TS, just west of this area. After automating this area, Toronto Hydro will be able to further expand automation to east if this location.

E7.3.7.3 Feeder Automation Etobicoke Project Description

Investment Category: System Service

Program: Feeder Automation

Project Title: Feeder Automation Etobicoke

Project Number: W13379, W13381, W13383, W13384, W13483, W13485

Project Year: 2015

Estimated Cost: $1.51 million

(i) Objective

The objective of this scope is to automate the selected feeders being supplied from Manby and Horner TS and establish a new network in Etobicoke.

(ii) Scope of Work

TABLE 16: SCOPE OF WORK DETAILS

District Neighborhood	SOUTH ETOBICOKE
Station(s)	MANBY AND HORNER TS
Feeder(s)	30M9, 38M8, 38M5, 38M4

TABLE 17: ASSETS REPLACED

Assets (Units)	2015
SCADArMate Switches	18
RTU	16
RTU Upgrade	0
Radio & Antenna	18

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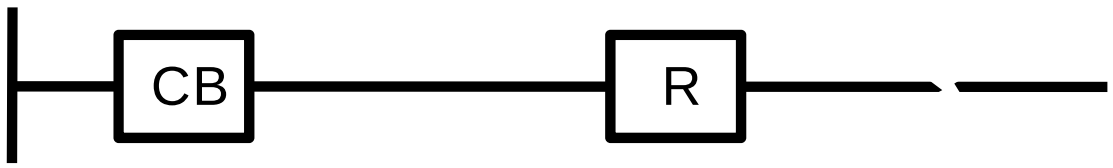
(iii) Justification & Benefits

Automating this area of the system is expected to mitigate trunk related outages that have occurred in the past.

This project commenced several years ago and is half complete; however, work was halted because of the 2012 IRM decision. The remaining work must be completed in order to achieve full automation.

After automating this area, Toronto Hydro will be able to further expand automation in the Etobicoke area.

E7.4 Overhead Momentary Reduction



TYPICAL RECLOSER CONFIGURATION

E7.4.1 Summary

Program Description

The Overhead Momentary Reduction program involves the installation of reclosers, primarily on the feeder trunk, to address feeders that are experiencing numerous momentary and sustained interruptions. Reclosers are small pole-mounted breakers which would allow Toronto Hydro to better isolate a feeder during a momentary or sustained interruption, thereby limiting the number of customers impacted by an outage.

For a comprehensive explanation of recloser technology and how Toronto Hydro plans to use it, please refer to section E7.4.2 below.

A summary of anticipated benefits from this program is provided in the following table.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Limits service outages to the smallest possible segment of the system. ƒ Protect customers' sensitive equipment.
Reliability	ƒ Reduces the impact of temporary and sustained interruptions. • ƒ Reduces the time to locate and clear faults.

Safety	ƒ Eliminates safety hazards due to faults as fast as possible, for example: if energized lines were to fall on a road or highway, the section of the feeder would be isolated. ƒ Crews can safely operate the reclosers from their vehicles using Wi-Fi communication link to a laptop computer. ƒ Reduce the manual switching required for crews; this is considered a high risk task which will translate in positive impact on workers safety.
Efficiency	ƒ Coordination of reclosers, breakers, fuses and sectionalizers is performed to protect the distribution system against all kinds of faults and ensure minimum service interruption to customers. ƒ Benefits Toronto Hydro personnel with respect to patrolling faulted sections of the feeder. Crews will not have to patrol the entire feeder, only the faulted section.

Program Drivers

The trigger and secondary drivers of this program are detailed in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Reliability	ƒ Momentary interruptions account for 54% of all outages on the Toronto Hydro distribution system ƒ Momentary interruptions can have a substantial negative impact on customers that rely on continuity of service for sensitive equipment. ƒ Certain faults can cause the breaker to open without operating a lateral fuse and with the fault clearing shortly thereafter. Reclosers can limit the impacts of this type of interruption to a smaller section of the feeder.
Secondary Driver	**Reasoning**
System Efficiency	ƒ In the absence of reclosers, breaker-level faults require crews to patrol the entire feeder to locate the fault. Reclosers can reduce the amount of time and resources required to locate a fault.
Safety	ƒ Reclosers are expected to reduce the manual switching required for crews to sectionalize a circuit. Crews can safely operate the reclosers from their vehicles using Wi-Fi communication link to a laptop computer. ƒ Reclosers are expected to provide protection from injury and damage during unforeseen operating events, especially from failures of equipment or faults caused by damaged or objects foreign to the system

Preferred Alternative

Toronto Hydro considered two alternatives for addressing momentary interruptions:

(1) Do nothing beyond existing maintenance (e.g., tree trimming and insulator washing) where momentary interruptions occur frequently. This option would not sufficiently address the reliability concerns posed by momentary interruptions on feeders with especially poor momentary interruption statistics.

(2) Installation of Reclosers to mitigate the high number of momentary interruptions which occur despite the presence of comprehensive maintenance programs

Option 2 is preferred alternative, as it allows Toronto Hydro to put in place a solution designed to effectively limit the impact of momentary interruptions on the system, thereby limiting both the inconvenience and possible damage to sensitive equipment caused by this type of fault.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $6.40 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.4.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $5.76 million, confirming the economic prudence of the investments (see Section E7.4.7).

Timing and Pacing

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	0	0	$0.64	$0.64	$0.64

Reclosers are a new technology for Toronto Hydro and the pacing of the program reflects this point. In the first two years of the program, 2015 and 2016, Toronto Hydro will carefully examine how to best integrate reclosers into the system, with consideration given to the coordination of reclosers with other assets. This coordination will involve Hydro One Networks Inc. (HONI) and multiple internal stakeholders. The pacing of the program will, in part, depend on outcomes from these consultations. Studies and planning exercises will provide Toronto Hydro with valuable and detailed information with respect to how to introduce the new technology into the current system and to ensure it is compatible with Toronto Hydro's business processes.

Toronto Hydro plans to install reclosers at a pace of approximately eight units per year over the 2017 to 2019 period. The installation of reclosers follows from Toronto Hydro's general outlook for grid modernization and represents proactive, necessary and timely efforts to reduce the impact of momentary interruptions in the system. The program will continue beyond 2019, targeting stations that are experiencing a high number of momentary interruptions.

E7.4.2 Program Description

The Overhead Momentary Reduction program involves the installation of reclosers on feeders that have experienced a high number of momentary and sustained interruptions. The objective of the program is to help minimize the number of customers affected by these interruptions across the system.

A momentary interruption is a single operation of an interrupting device that results in a voltage of zero that lasts less than one minute. A sustained interruption is any interruption not classified as a momentary interruption, that is, any interruption that lasts more than one minute.

Reclosers are small circuit breakers located at the top of distribution poles and are typically used on very long distribution feeders. Reclosers isolate a section of the feeder during momentary and sustained interruptions or overload conditions, thereby minimizing the number of customers experiencing service loss. Since reclosers act as small circuit breakers, they have the capability to restore power automatically in temporary or permanent fault situations, hence the name "recloser". See Figure 1 for an image of a recloser.

FIGURE 1: RECLOSER INSTALLED ON A POLE

Reclosers are set to trip at a lower fault current than the breaker at the station so that the fault can be isolated downstream. In other words, a single event on the feeder will only cut off power to the section handled by a recloser, long before the feeder breaker at the station would notice a problem. This is beneficial to customers, especially those that are particularly sensitive to momentary interruptions such as manufacturers, where a momentary outage can shut down production.

The benefits of reclosers can be understood by comparing the current Toronto Hydro distribution system without reclosers to one in which reclosers are installed. In the current distribution system, feeders are protected with circuit breakers at each station. In the event of a fault, the circuit breaker at the station activates and opens to turn-off power, which prevents damage from occurring to station and feeder assets. As a result, all customers on the circuit experience a momentary interruption. Afterwards, the circuit breaker closes to restore power to the entire

feeder. If the fault persists on the feeder, the circuit breaker will activate once again, creating a permanent fault on the feeder.

Reclosers function in a nearly identical fashion to the station breakers described in the previous scenario. However, instead of being positioned at the station and protecting the entire feeder at once, reclosers are strategically placed along the feeder downstream from the breaker in order to reduce the number of customers affected by momentary and sustained interruptions. In a Toronto Hydro distribution system with reclosers, the circuit breaker, reclosers and downstream fuses would be coordinated. If a temporary fault occurred downstream of the recloser, the recloser would activate before the circuit breaker, leaving the breaker uninterrupted and limiting the momentary loss of power to the circuit downstream of the recloser instead of the entire feeder. In the case of sustained interruptions on the feeder, the recloser time delay curve allows the fuse to clear (in the same manner that a station breaker allows the downstream fuses to clear), resulting in an interruption only to the lateral on which the fault occurred.

Figure 2 illustrates a basic feeder arrangement with the circuit breaker (labeled as “CB”) functioning as station-level/trunk-level protection and a downstream lateral protected by a fuse that is coordinated with the breaker. Approximately 3,000 customers can be affected in the event of a momentary or forced interruption that affects the entire trunk portion of a feeder. Figure 3 demonstrates how reclosers improve reliability indices by mitigating both momentary and sustained interruptions.

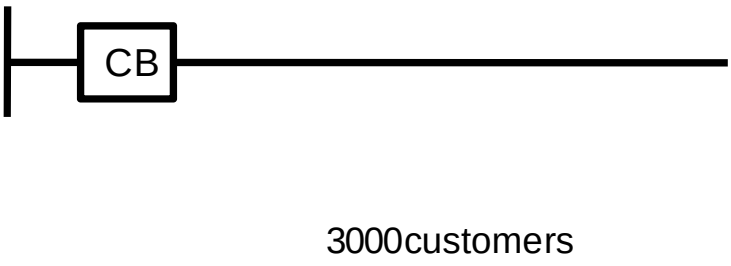


FIGURE 2: BASIC FEEDER ARRANGEMENT WITH A CIRCUIT BREAKER AND DOWNSTREAM FUSE

Figure 3 shows a feeder with a circuit breaker and a recloser. The recloser (labeled as “R”) is strategically placed on the feeder to minimize the impact of a fault to customers. In the event of a momentary or forced interruption on section B (which includes all load downstream of the recloser), the recloser senses the fault and opens, isolating section B of the feeder. As a result,

customers on section A (which includes all load between the breaker and recloser) will not be impacted by the fault or experience an interruption. If the fault were to happen on section A, momentary or sustained, the entire feeder would experience an outage.

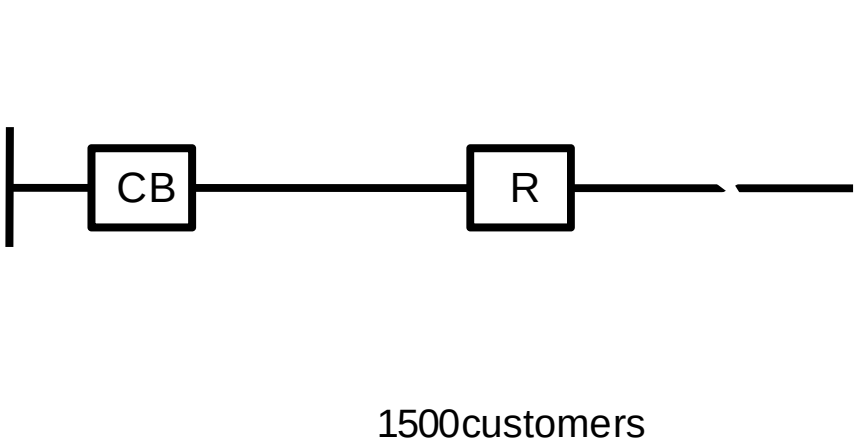


FIGURE 3: FEEDER WITH CIRCUIT BREAKER AND LINE RECLOSER

To address its reliability challenges, discussed in section E.7.4.3, Toronto Hydro plans on installing reclosers on overhead feeders (13.8 kV and 27.6 kV). The installation will take place at the feeder trunk, which will help minimize the effects of a fault on the main feeder and help divide the feeder into smaller sections. Reclosers will not be installed on the downtown core area, which is supplied by the secondary network system.[1] The 4.16 kV systems will also not be part of the program since the infrastructures is reaching end-of-life and the assets will be replaced using a higher voltage level like 27.6 kV.

By adding a midpoint recloser and providing trip coordination with the circuit breaker, temporary faults downstream of the recloser will no longer be expected to affect customers upstream. This technology is relatively low cost and will benefit all customer classes on feeders that experience a high number of momentary interruptions. In particular, reclosers have the potential to deliver significant value to critical customers in commercial or industrial areas or who otherwise rely on sensitive electronics to generate revenue or to maintain operational continuity.

Preventive maintenance measures such as tree trimming, animal guard installation and lightning arrestor replacement do not fully prevent momentary interruptions to distribution feeders, and certain feeders tend to experience a disproportionate number of momentary interruptions that

[1] The network system is designed in such a way that customers do not experience momentary outages if one feeder, and associated network units, are taken out of service.

they experience. Using reclosers, in combination with Toronto Hydro's maintenance programs, will help: (a) reduce the impact of outages on the feeders; (b) reduce the average amount of time required to restore service to customers located on the faulted section of the feeder; (c) minimize the required time (and therefore cost) to find and remove faults, and (d) reduce the need to perform manual switching.

The implementation of reclosers will also have a positive impact on worker safety. Without reclosers, Toronto Hydro crews are required to manually operate switches along the trunk in order to sectionalize the feeder. Manual switching is considered a high risk task for field crews. The installation of reclosers would entail a reduction in manual switching activities that would be required to restore power.

Table 1 shows the number of assets that Toronto Hydro plans to install during the 2015 to 2019 period. In 2015 and 2016, Toronto Hydro will examine and evaluate the integration of reclosers with existing feeder technology and protection schemes. Coordination with other protection devices is important to ensure that, when a fault occurs, the smallest section of the circuit is disconnected to minimize disruption of power to customers. Without this coordination, the recloser would not provide intended benefits; instead, they would act as a regular switch and would not reduce the impact of both momentary and sustained interruptions experienced by a feeder.

TABLE 1: ASSETS TO BE INSTALLED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Reclosers	0	0	8	8	8	24
Poles	0	0	8	8	8	24

Toronto Hydro plans to spend an estimated $1.92 million on the Overhead Momentary Reduction program during the 2015 to 2019 period.

Table 2 summarizes the anticipated benefits of the Overhead Momentary Reduction program. The program is a grid modernization initiative that is expected to provide greater system reliability and outage management, increase operational efficiencies, improve levels of service and reduce economic losses caused by outages to sensitive customers.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Helps limit service outages to the smallest possible segment of the system. ƒ Facilitates protection of customer-owned sensitive equipment. ƒ The difference in the cost of ownership between existing and renewed assets (ΔCOO_1) for the first year of the program is $6.40 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.4.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV_1 of $5.76 million, confirming the economic prudence of the investments (see Section E7.4.7).
Reliability	ƒ Reduces the impact of temporary and sustained interruptions. • ƒ Reduces the time to locate and clear faults.
Safety	ƒ Addresses safety hazards due to faults as fast as possible, for example: if energized lines were to fall on a road or highway, the section of the feeder will be isolated. ƒ Crews can safely operate the reclosers from their vehicles using Wi-Fi communication link to a laptop computer. ƒ Reduces the manual switching required for crews, which is considered a high risk task. Addressing this issue is expected to have positive impact on worker safety.
Efficiency	ƒ Coordination of reclosers, breakers, fuses and sectionalizers is performed to protect the distribution system against all kinds of faults and ensure minimum service interruption to customers. ƒ Benefits Toronto Hydro personnel with respect to patrolling faulted sections of the feeder. Crews will not have to patrol the entire feeder, only the faulted section.

E7.4.3 Why the Program is Needed

E7.4.3.1 Program Drivers

Table 3 presents the trigger and secondary drivers for the Overhead Momentary Reduction program. The trigger driver of reliability situates this program in the System Service investment category.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Reliability	ƒ Momentary interruptions account for 54% of all outages on the Toronto Hydro distribution system (Figure 4). ƒ Momentary interruptions can have a substantial negative impact on customers that rely on continuity of service for sensitive equipment. ƒ Certain faults can cause the breaker to open without operating a lateral fuse and with the fault clearing shortly thereafter.
Secondary Drivers	**Reasoning**
System Efficiency	ƒ In the absence of reclosers, breaker-level faults will require crews to patrol the entire feeder to locate the fault. Reclosers can reduce the amount of time and resources required to locate a fault.
Safety	ƒ Reclosers will reduce the manual switching required for crews to sectionalize a circuit. Crews can safely operate the reclosers from their vehicles using Wi-Fi communication link to a laptop computer. ƒ Reclosers will provide protection from injury and damage during unforeseen operating events, especially from failures of equipment or faults caused by damaged or objects foreign to the system

Momentary interruptions account for 54% of the interruptions affecting Toronto Hydro's distribution system, as shown in Figure 4. These interruptions are of particular concern for customers that rely on continuous uninterrupted service for their sensitive equipment, such as high-precision manufacturing equipment, computers, digital clocks, and others. Power interruptions can result in customer inconveniences such as having to reset clocks and reprogram the equipment. The impacts can be most severe for businesses, manufactures and other organizations using computers, digital controls and automatic systems. For these customers, momentary interruptions can result in the crashing of electronic devices and lost production, retail sales, and inventory.

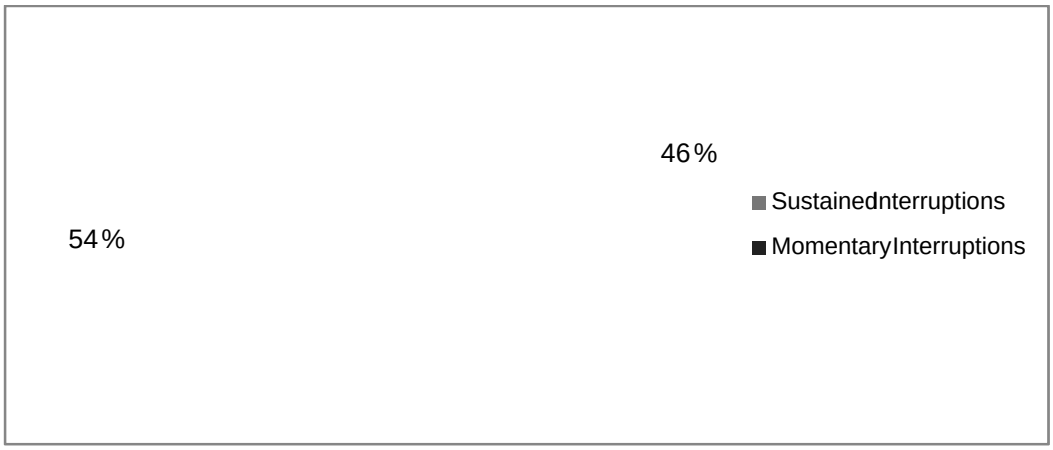


FIGURE 4: PERCENTAGE OF MOMENTARY INTERRUPTIONS BASED ON THE TOTAL NUMBER OF OUTAGES FROM 2009-2013

Figure 5 highlights the areas of the system that experience a high frequency of momentary interruptions. This map relates to Figure 6, which shows the stations with highest number of momentary interruptions. For the 2017-2019 timeframe, Toronto expects to target the following stations: Richview Station, Warden Station, Leslie Station and Dufferin Station. Some of the areas highlighted in red are not targeted in the 2015-2019 planning horizon because they currently fall under the implementation of the Feeder Automation program (refer to Section E7.3). In the future, Toronto Hydro expects to eventually integrate recloser technology with existing Feeder Automation technology in order to provide a fully optimized protection scheme on feeder trunks throughout the system.

FIGURE 5: MOMENTARY FREQUENCY BREAKDOWN BY FEEDER FROM 2011-2013

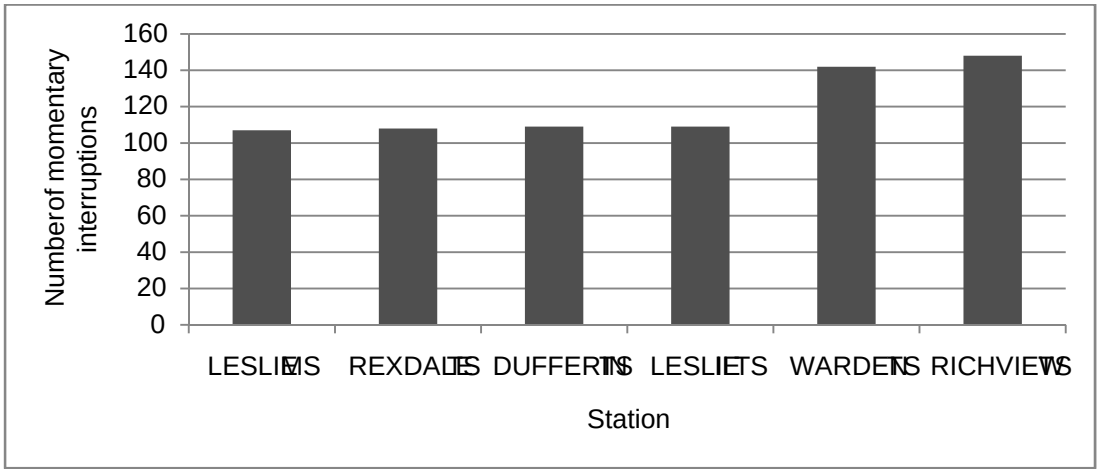


FIGURE 6: TOTAL NUMBER OF MOMENTARY INTERRUPTIONS BY STATION

E7.4.4 Timing & Pacing of the Program

Table 4 provides the estimated costs for the program and the timing of spending.

TABLE 4: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	0	0	$0.64	$0.64	$0.64

Reclosers are a new technology for Toronto Hydro and the pacing of the program reflects this point. In the first two years of the program, 2015 and 2016, Toronto Hydro will carefully examine how to best integrate reclosers into the system, with consideration given to the coordination of reclosers with other assets. This coordination will involve Hydro One Networks Inc. (HONI) and multiple internal stakeholders from Toronto Hydro. The pacing of the program will, in part, depend on outcomes from these consultations. Studies and planning exercises will provide Toronto Hydro with valuable and detailed information with respect to how to introduce the new technology into the current system and to ensure it is compatible with Toronto Hydro's business processes. Specific issues and initiatives that will be considered include the development of safety, control and operating practices, as well as a determination as to what is the optimal design, location, specifications and controls for the integration of reclosers.

Toronto Hydro plans to install reclosers at a pace of approximately eight units per year over the 2017 to 2019 period. The installation of reclosers follows from Toronto Hydro's general outlook for grid modernization and represents proactive, necessary and timely efforts to reduce the impact of momentary interruptions in the system. The program will continue beyond 2019, targeting stations that are experiencing a high number of momentary interruptions.

Figure 7 provides a map of the areas of the city that are the proposed focus of this program over the 2017 to 2019 period; these areas were selected because of the high frequency of momentary outages experienced on these feeders.

FIGURE 7: RECLOSER INVESTMENT FOR 2017-2019

E7.4.4.1 Ranking & Prioritization

The prioritization of work in the Overhead Momentary Reduction program will take into account both the historic performance of feeders and results of the study that will be performed in 2015 and 2016. The study will determine the capability of existing stations circuit breakers to be coordinated and work together with reclosers. It is Toronto Hydro's intention to target feeders with the highest number of momentary interruptions in the past three years in order to minimize outages.

Assuming a successful completion of the technology study, Toronto Hydro will eventually introduce recloser technology across the entire distribution system, but will first target feeders that experience the highest number of momentary interruptions over the 2015 to 2019 period.

E7.4.5 Program Execution

The installation of reclosers will include the replacement of poles onto which reclosers will be installed. The installation of new poles may require pole framing and conductor replacement. As

well, the coordination of reclosers with both upstream and downstream equipment will have to be performed.

Protection coordination is crucial for the proper operation of the reclosers within the time-current curves of the breaker and downstream fuses. Coordination with other protection devices is important in order to ensure that the faults are localized into small sections to minimize disruptions of supply to customers. Without this coordination, a recloser will operate as a regular switch instead of the using its full capabilities, thereby failing to reduce the number of momentary and sustained interruptions.

E7.4.5.1 Proposed Work Plan

Table 5 represents the 2017-2019 Long Term Plan investment on the Toronto Hydro Stations.

TABLE 5: 2015-2019 LONG TERM PLAN

Year	Station
2017	Richview TS
2017	Warden TS
2018	Warden TS
2018	Leslie TS
2019	Leslie TS
2019	Dufferin TS

E7.4.5.2 Program Risks

The following are risks to program completion that Toronto Hydro considers when planning and executing the installation of reclosers.

One potential risk is stakeholder coordination. Timely communication and coordination with HONI will be crucial for the completion of the recloser installation. Toronto Hydro owns 61% of the circuit breakers within the City of Toronto. The remaining 38% are owned by HONI. To establish communication between breaker and reclosers, the settings at the station breaker must be adjusted, and Toronto Hydro will rely on HONI's cooperation to establish coordination with their breakers. This risk will be mitigated by engaging HONI early in the process, specifically while the study is performed.

E7.4.6 Evaluation of Alternatives

E7.4.6.1 Quantification/Evaluation of Options

(i) Status Quo

By maintaining the status quo, Toronto Hydro would continue to monitor and evaluate feeders that experience many momentary interruptions and will perform maintenance work to help mitigate the number of outages. This work includes tree trimming, insulator washing, the installation of animal guards, infrared scans and other activities. While maintenance activities can help prevent some momentary interruptions, Toronto Hydro anticipates that interruptions will continue to be a significant reliability concern.

(ii) Installation of Reclosers

Introducing reclosers into the feeder circuit will give Toronto Hydro the flexibility to sectionalize and isolate permanent faults to drastically minimize the effect of interruptions. This option is recommended because it is the only course of action that provides the benefits discussed throughout the narrative and addresses the serious issues facing customers with respect to momentary and sustained interruptions.

The cost of ownership (COO) and program net benefit (NPV) associated with the Overhead Momentary Reduction program is further detailed in Table 6. The cost of ownership is established for both the existing state (COO_E), and the proposed new state (COO_N) based on the first year of activities within this program. The cost of ownership (COO) of a state reflects the risk of asset failure including both direct and indirect costs. These costs including customer interruptions, emergency repairs, and asset replacements associated with that design. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NAR_E) and proposed (NAR_N) state. Non-asset risks are further explained in Section D3.3. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership (ΔCOO_1) is compared to the associated program costs (PC_1) for the first of activities, the Overhead Momentary Reduction program produces a net benefit (NPV_1) value of $5.76 million, as shown in Table 6 and Table 7.

TABLE 6: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E]	63.54
Non Asset Risk [NAR_E]	375.69
Maintenance Cost [MC_E]	
Additional Quantifiable Benefits [AQB_E]	
Cost of Ownership of Existing Assets [COO_E]	439.23

TABLE 7: OVERHEAD MOMENTARY REDUCTION BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 1: Overhead Momentary Reduction (N)	
Asset Risk [AR_N]	60.90
Non Asset Risk [NAR_N]	371.93
Maintenance Cost [MC_N]	
Additional Quantifiable Benefits [AQB_N]	
Cost of Ownership of New Assets [COO_N]	432.83
Option 1: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_N)$]	6.40
Program Cost [PC_1]	0.64
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	5.76

E7.5 Handwell Upgrades

E7.5.1 Summary

Program Description

The Handwell Upgrades program completes the activities previously described in the Ontario Energy Board (OEB) approved Handwell Replacement segment as part of Toronto Hydro's 2012-2014 rate filing. Toronto Hydro's Handwell Upgrades program replaces (i) existing legacy handwells made of conductive material (i.e., a concrete body and metal cover) with new non-conductive handwells, and (ii) secondary conductors between handwells. Using these new composite handwells removes the risk of handwells becoming energized due to defective conductor connections within. Replacing secondary conductor between handwells and reconnecting conductors with water tight connectors renews the old conductors that are operating beyond their useful lives. It also helps protect the connection point from roadside contaminants

Table A summarizes the benefits associated with the Handwell Upgrades program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Reliability	ƒ The non-conductive handwell, together with new secondary conductor and water tight connections, will mitigate the risk of interruptions to the street lighting secondary supply source caused by contact voltage or corroded/loose connections.

Efficiency	ƒ Toronto Hydro will able to reduce the frequency of scheduled contact voltage scans across the city.
Safety	ƒ Minimizes the risk of contact voltage harming individuals, pets and wildlife.

Program Drivers

The Handwell Upgrades program is primarily driven by the safety issues associated with the risk of contact voltage. As established in previous rate filings, Toronto Hydro considers handwells to be a critical safety issue, and as such, this program has been positioned within the System Service category. The trigger and secondary drivers for this program are provided in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Safety	x Contact voltage on handwells, poles, street fixtures and sidewalk surfaces poses a safety risk to the public. In the City of Toronto, on both November 20, 2008 and January 13, 2009, pet fatalities occurred because the animals came into contact with energized assets. Toronto Hydro also received reports of children and pets receiving contact voltage shocks in early 2009.
Secondary Driver	**Reasoning**
Functional Obsolescence	x Older legacy handwells that are made of conductive material are not able to safely house secondary conductors. x The handwell body is conductive and wire connections inside were made using connectors that, due to corrosion and water damage over time, may become exposed and come into contact with the handwell lid or body. This results in contact voltage on the handwell, pole, street fixtures or the sidewalk surface.

Preferred Alternative

The Handwell Upgrades program analyzed and evaluated the following options:

(i) Do nothing and accept the safety risks associated with metallic, conductive handwells

(ii) Proactive Replacement of metallic handwells with new non-conductive ones

Option II is the preferred alternative as it mitigates the existing public safety hazard.

Timing and Pacing

The number of units replaced and project costs have varied over the years because, in some locations, Toronto Hydro needed to undertake civil construction in order to address collapsed ducts or the fact that some existing conductors are direct-buried (i.e., they were not installed in ducts); these activities delay completion times and introduce additional expenses.

In terms of project execution, secondary conductors between handwells are replaced at the same time as the handwells themselves, unless additional civil construction is required to install or rebuild conduits. Where additional civil construction is needed, the conductors are replaced after the civil work is completed. Table C provides the estimated costs of the program for the 2015-2019 period.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	21.1	32.9	12.6	11.7	16.2	4.98	-	-	-	-

E7.5.2 Program Description

Handwells are used to supply 120 V power to street lights, bus shelters and signs, etc. Toronto Hydro began replacing all existing handwells following the Level III emergency in 2009, after children and pets received shocks from contact voltage originating from faulty handwells. At the start of the handwell replacement program in 2010, Toronto Hydro estimated that there were approximately 11,700 handwells in the field. However, during program execution, Toronto Hydro determined that, as of the end of 2013, there are more than 13,000 handwells. These additional locations were found by crews while performing handwell replacement work.

The replacement work that began in 2010 continued as part of the Incremental Capital Module (ICM) within Toronto Hydro's 2012-2014 IRM Filing. This work was subsequently approved by the Ontario Energy Board (OEB). Toronto Hydro forecasts to have replaced all but 723 existing handwells with new, non-conducting composite handwells by the end of 2014. Toronto Hydro iplans to complete replacement of those remaining 723 existing handwells not addressed in prior years.

Most of the remaining 723 locations are in the downtown area. Work will involve replacing existing handwells with new handwells made of non-conducting composite material. Any existing handwells that are found to be empty are physically removed and the vacated space filled.

FIGURE 1: NON-CONDUCTIVE HANDWELL

Existing secondary conductors between handwells will be replaced if possible. If the site condition does not allow for the replacement of conductors during the handwell replacement work

(due to a collapsed conduit or existing direct buried conductor), the location will be marked for follow-up work where civil construction will likely be needed to install new conduit between handwells. All new electrical connections in the handwell will be made using a water tight connector as shown in Figure 2.

FIGURE 2: NEW HANDWELL WATER TIGHT CONNECTOR

The following table summarizes the expected benefits of this program.

TABLE 1: SUMMARY OF PROGRAM BENEFITS

Reliability	ƒ The non-conductive handwell, together with new conductor and water tight connections, reduces interruptions due to contact voltage or corroded/loose connections.
Efficiency	ƒ Removes need for Toronto Hydro to allocate significant amount of resources for contact voltage mitigation after the program is completed. ƒ Allows for adjustment to the frequency of scheduled contact voltage scans across the city, which potentially reduces maintenance costs.
Safety	ƒ Minimize the risk of contact voltage on city property from handwells

E7.5.3 Why the Program is Needed

Handwells made of conductive materials, including concrete bodies and metallic lids, have been shown to be a potential a source of contact voltage. Compromised electrical connections inside a handwell can energize the handwell and surrounding area through either direct contact with the handwell or through salt water accumulated in the handwell, which acts as a conducting medium. During the contact voltage emergency, all handwells were inspected for damage and wiring connections in handwells and hand holes in street lighting poles were re-connected where possible using new water tight connections to mitigate the immediate risk.

Contact voltage may appear on the following locations on the street:

- Sidewalk surface
- Metallic or concrete poles installed on energized sidewalk
- Signs mounted on energized sidewalk
- Handwells made of a concrete body or with a metallic cover

Following the Level III emergency, Toronto Hydro launched a citywide program to replace all existing handwells with non-conductive material as well as replacing conductors between handwells to ensure long term risk from contact voltage due to existing obsolete hardware is removed. To further enhance the integrity of the electrical connection from water seepage into the live conductor, all new electrical connections in handwells are made using water tight connectors as shown in Error! Reference source not found. The lug with wires connected is fully inserted into a gel filled pouch to ensure full blockage of any water contact with the live conductors.

E7.5.3.1 Program Drivers

Table 2 presents the trigger and secondary drivers for Secondary Upgrades program. This program is primarily driven by the safety issues associated with the risk of contact voltage. A secondary driver is functionally obsolete due to the design of these assets. As established in previous rate filings, handwells are a critical issue to Toronto Hydro, and as such, this program has been positioned within the System Service category.

TABLE 2: PROGRAM DRIVERS

Tigger Driver	Reasoning
Safety	Potential Public Safety Risk: ƒ Contact voltage on handwells, poles, street fixtures and sidewalk surfaces is a safety risk to the public. In Toronto, there were pet fatalities caused by contact voltage on November 20, 2008 and January 13, 2009. Toronto Hydro also received reports of children and pets receiving contact voltage shocks in early 2009. ƒ There has been a reported case of human fatality as a result of contact voltage in the city of New York.
Secondary Driver	**Reasoning**
Functional Obsolescence	ƒ Older legacy type handwells that are made of conductive material such as metal lid or concrete body are not able to safely house secondary conductors. ƒ The handwell body is conductive and wire connections inside were made using connectors that, over time, due to corrosion and water damage, may become exposed and come in contact with the handwell lid or body. ƒ This results in contact voltage on the handwell, pole, street fixtures or the sidewalk surface.

Saltwater enters handwells during the winter season where salt is spread on the sidewalks to melt the snow.

Between 2008 and 2009, two dogs were fatally shocked and incidents of risk to children by contact voltage in the City of Toronto. In response, Toronto Hydro declared a level III emergency in early 2009 to study and mitigate the safety risks associated with contact voltage across the city. During the contact voltage emergency, all handwells were inspected for damage, and wiring connections in handwells and hand holes in street lighting poles were re-connected where possible using new water tight connections to mitigate the immediate risk.

Contact voltage may occur at the following locations on the street:

- ƒ sidewalk surface,
- ƒ metallic or concrete poles installed on energized sidewalk,
- ƒ signs mounted on energized sidewalk, and
- ƒ handwells made of a concrete body or with a metallic cover.

Following the Level III emergency, Toronto Hydro launched a city-wide program to replace all handwells with ones made of non-conductive material and to also replace conductors between handwells in order to eliminate the long-term safety risks associated with the obsolete hardware. To further protect the electrical connection from water seepage into the live conductor, all new electrical connections in handwells are made using water tight connectors as shown in Figure 2.

(i) Safety

Handwells installed on city sidewalks are used as junction boxes to safely contain electrical connections that supply power to street lights or road fixtures such as crosswalk signs, bus shelters and advertising signs. Historically, electrical connections in handwells were made using a split bolt wrapped in layers of polyvinyl chloride tape and self-amalgamating plastic in order to protect the connections from coming into contact with the handwell body or the metal lid, which could produce contact voltage on the surface.

Toronto Hydro discovered that over time, seasonal freezing and thawing cycles of water in the handwells can damage the tape and loosen the electrical connection inside, eventually exposing the live conductor (as shown in Figure 3 below). As previously mentioned, the live conductor can energize the handwell. The energized handwell may in turn, energize the pavement and fixtures in the area, creating a serious safety hazard.

FIGURE 3: EXPOSED CONDUCTOR

(ii) Functional Obsolescence

Toronto Hydro determined that existing handwells with concrete bodies and/or metal lids were functionally obsolete because these assets are unable to reliably and safely house sidewalk secondary connections. The typical useful life for concrete handwells is approximately 50 years. These assets degrade thorough exposure to road contaminants such as water, dirt and salt, which leads to corrosion of reinforcing steel, spalling of concrete and rusting of covers. Independent of whether an existing handwell has exceeded this life expectancy, as previously described, Toronto Hydro has determined that all existing handwells composed of a concrete body and metal lid present a safety concern and are functionally obsolete.

Secondary conductors installed underground are constantly exposed to water and soil contaminants that degrade their insulation strength. Over time, insulation jackets can break down and result in short-circuit and failure of the conductor. The normal useful life of these secondary conductors is 20 to 25 years. Toronto Hydro plans on renewing secondary conductors at the same time as it replaces remaining handwells.

E7.5.4 Timing & Pacing of the Program

As noted previously, Toronto Hydro has been replacing legacy handwells with new non-conductive handwells since 2009. By the end of 2014, Toronto Hydro expects to replace almost all of the existing handwells with the new design. The remaining 723 handwells are scheduled to be replaced by the end of 2015.

TABLE 3: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	21.1	32.9	12.6	11.7	16.2	4.98	-	-	-	-
Number of handwells replaced	3,127	2,476	2,127	1,828	2,500	723	-	-	-	-
Number of handwells removed	534	637	319	126	0	0	-	-	-	-

The number of units replaced and project costs have varied over the years because in some locations, Toronto Hydro needed to undertake civil construction in order to address collapsed ducts or the fact that some existing conductors are direct-buried (i.e., they were not installed in ducts); these activities delay completion times and introduce additional expenses. The cost for 2010 and 2011 are higher because after the cessation of Level III emergency, Toronto Hydro started to replace existing metallic handwell covers with Tiercon plastic lids as an immediate measure to remove the risk of contact voltage hazard to the public. In addition there was followup repair work that needed to be performed on defects that were identified during the Level III emergency. Some of these items involved: Installation of street lighting fuse; repair faulted underground cable; and replacement of defective street lighting poles.

The forecasted number of handwell removals (as opposed to replacements) for 2014 and 2015 is currently zero, as Toronto Hydro is unable to determine whether a handwell has been abandoned until crews physically open the unit in the field. Therefore, Toronto Hydro assumes that all remaining handwells will require replacement.

E7.5.4.1 Ranking & Prioritization

Toronto Hydro expects to replace all remaining legacy handwells by the end of 2015.

E7.5.6 Program Execution

Toronto Hydro will organize the work to be conducted through this program by location. In each location, Toronto Hydro will need to excavate a small portion of the sidewalk in order to remove the existing handwell before the new handwell is installed. Conductors between handwells are also expected to be replaced at the same time if they can be easily removed. In cases where the conductor between handwells is directly buried in-ground or the conduit between handwells has collapsed, the conductor replacement will occur after the necessary civil construction work is completed.

Where follow-up civil construction is required to install new conduits between handwells, design work and city approval will be required before the construction takes place. Any handwell found to be abandoned and empty will be physically removed from the sidewalk and the vacated space will be filled.

As these conductors primarily supply power to street lights, bus shelters or street banner signs, interruption of power during construction will not have a significant impact on the public.

E7.5.6.1 Program Risks

The timing and costs of replacements will be impacted by the amount of civil work that is required. Follow-up civil work will require additional design and approval time, and may also be impacted by City moratoriums.

E7.5.7 Evaluation of Alternatives

E7.5.7.1 Evaluation of Options

Toronto Hydro considered two alternatives, maintain the status quo or proactively replace handwells.

(i) Option 1: Status Quo

By maintaining the status quo, Toronto would take a reactive approach to handwell replacements. More specifically, it would respond to contact voltage incidents as they occur and would only replace units following a reported incident of contact voltage. Toronto Hydro does not recommend using this reactive approach because it introduces potential public safety risks.

(ii) Option 2: Proactive Replacement

Under this option, Toronto Hydro would proactively replace metal handwells with non-conductive handwells, and would replace the conductors between handwells and connections with water tight connectors. Proactive replacement of handwells is the preferred option as this approach will mitigate existing potential public safety hazards.

APPENDIX A: Execution CHALLENGES

As previously discussed in Section B of this schedule, when executing its capital program Toronto Hydro must be prepared to respond to circumstances "on the ground" in order to make the most efficient use of resources and ultimately deliver the best value for its customers. From a planning point of view, this means that the utility must be able to substitute, defer and add projects in the annual work program in any given year to accommodate the operational realities that it experiences in the course of its work program.

This appendix describes aspects of Toronto Hydro's services territory that add complexity to the execution of large capital projects.

1. Weather and the natural environment

A number of unpredictable work execution challenges arise due to severe weather and conditions that exist in the natural environment. These challenges are difficult to assess in advance of undertaking projects and planned work.

Weather

Unpredictable weather events have the potential to impact work execution in two ways. One is that extreme weather (e.g. very cold or very hot temperatures) over a prolonged period can cause projects to be delayed. Second, severe weather such as extreme wind, ice, and rain events can cause wide-spread damage to Toronto Hydro's distribution system and necessitate the redirection of crews from planned work to emergency storm restoration activities.

An example of a prolonged weather pattern that impacted Toronto Hydro's ability to execute planned work was the cold experienced during the 2013-2014 winter. Due to frost, snow, and ice, utilities are generally challenged to conduct civil and pole installation work during winter months. To manage this reality, Toronto Hydro conducts significant amounts of civil work in the lead up to winter and then does not schedule much civil work until winter conditions subside. Given that the 2013-2014 winter was particularly long and cold, resulting in frost settling deep into the ground, civil work was substantially delayed in 2014. The long winter not only impacted capital projects but also maintenance programs such as insulator washing that cannot be conducted in cold temperatures.

Examples of severe weather events causing damage to Toronto Hydro's distribution system occurred on October 29, 2013 (i.e. Hurricane Sandy) and December 21, 2014 (i.e. the 2013 Ice

Storm). In response to the damage caused by these severe weather events, Toronto Hydro redirected all available crews, including crews working on planned projects and programs, to emergency storm restoration activities. In any given year, the amount of time and delay caused by severe weather can vary but can equate to weeks of construction time across all projects as evidenced in 2013, where planned work was delayed due to flooding in July, strong winds in August and October, and the ice storm in December. Some of the delays were overcome by working overtime at an increased cost to individual projects.

The Natural Environment

The natural environment can create challenges due to issues that may involve soil conditions, ground water, and vegetation. Prior to work execution, Toronto Hydro attempts to plan for the natural environment and mitigate associated risks. However, it is not uncommon for even the most prudently planned projects to be delayed due to challenges associated with the natural environment.

One set of challenges that are encountered are related to the soil conditions found on sites where planned projects are being conducted. For example, it is not uncommon for Toronto Hydro to encounter shale while installing poles. When identified, shale must be removed using a jackhammer causing delays and increased costs. Toronto Hydro tries to mitigate the risk of unexpected shale using test pits prior to commencing work. These test pits require additional site visits and are costly. As a result, it is prudent for Toronto Hydro to only undertake such costs if there is a reason to believe that soil conditions are abnormal.

Another risk related to soil conditions is soil contamination. The removal and disposal of contaminated soil can be particularly costly and can delay projects if identified during work execution. An example of a where this did occur is the Strachan TS Civil Egress project. This project was required to construct cable chambers and underground conduits from Hydro One's Strachan TS to Manitoba Drive. When construction commenced, contaminated soil was discovered and the additional cost for soil testing, removal, and disposal was $400,000.

A second set of challenges associated with the natural environment is excessive ground water. Although de-watering needs are anticipated for many projects including those that are undertaken close to Lake Ontario, these needs can significantly exceed estimates and contingencies. In some cases, de-watering specialists need to be called in during work execution as excessive and unanticipated water levels delay the project and increase costs. Further complications can arise if soil is contaminated and de-watering is required. Finally, Toronto Hydro may need to obtain a

permit from the City of Toronto to pump water out and to release it in the City's sewer system. An example of excessive de-watering needs occurred during the civil construction work associated with the Copeland TS project. Some of the conduits and cable chambers being built as part of this project resulted in an additional $375,000 for excessive de-watering.

Beyond the de-watering challenges described above, complications can also arise with de-watering that is required following heavy rains. For example, the heavy rain on July 9, 2013 and the flooding that ensued caused work at a number of Toronto Hydro's construction sites across the City to stop until de-watering could be completed. Project schedules as a result were generally delayed for approximately four days each.

A third set of challenges associated with the natural environment is related to vegetation, specifically trees. Many of Toronto Hydro's overhead and underground construction projects have the potential to negatively impact trees and as part of the design and estimating process, Toronto Hydro takes into consideration precautions to protect trees. These precautions are often conditions of obtaining permits and approvals from the City of Toronto. These conditions are enforced by City inspectors that may visit sites during construction. In many cases, precautions must be expanded upon or altered during work execution based on conditions that are identified at the time. For example, Toronto Hydro may need to dig deeper, alter trench routes, or construct unplanned tree tunnels during work execution to avoid damaging a tree. These requirements can and do result in delays and additional costs.

2. External Stakeholders

Work execution challenges often arise as a result of external stakeholder needs, preferences, requests, and actions. External stakeholders include the City of Toronto, Toronto Hydro's customers, Hydro One, and a wide variety of other organizations and individuals that have an interest in the work that Toronto Hydro undertakes. Challenges that are related to external stakeholders can greatly impact project and program schedules and costs as illustrated by the examples that follow.

The City of Toronto

A significant stakeholder in all work that Toronto Hydro undertakes is the City of Toronto. The vast majority of Toronto Hydro's assets are located on City road allowances and co-exist with City (e.g. water and sewer systems, roads, sidewalks) and other utility (e.g. telecommunications, gas lines) and non-utility (e.g. TTC) infrastructure. To enable the efficient management of road

allowances, the City has implemented a number of co-ordination, permitting, and approval processes that have the potential to influence work execution, schedules, and budgets.

An example of how the City's processes can impact work execution is road moratoria that are implemented following City road improvement projects. (Moratoria are implemented pursuant to the City's Municipal Consent Requirements for the Installation of Plant Within City of Toronto Streets.) Depending on the type of road (e.g. road, curb, sidewalk) improvement that the City undertakes, utilities such as Toronto Hydro will not be granted permits to conduct subsequent construction work for a period of three to 10 years.

In situations where the City advances or provides short notice for road improvements, Toronto Hydro must re-prioritize work to ensure that projects that are planned in the short and medium terms are completed before a moratorium goes into place. A specific example of this is work that Toronto Hydro planned in the Hogg's Hollow area of Toronto. Plans were to initially execute the work in five sequential phases. When the City announced that it was moving forward with road improvement work, Toronto Hydro brought forward the execution of the fifth phase to avoid a road moratorium after 2013. Re-prioritizing projects in this manner can force the deferral of another project and has the potential to increase costs depending on whether the project must be undertaken by a different contractor or resource group.

Another example is work that Toronto Hydro had to conduct as a result of a series of City projects (e.g. granite sidewalk retrofit; water main replacement) in the vicinity of Bay and Bloor Streets. During one project, Toronto Hydro was given only three months to complete its work and during another project, Toronto Hydro had to rebuild an overhead pole line during the Christmas season. Typically, work in this area is constrained as restrictions to only work certain hours of the day, to only occupy a certain length of street at a time, to minimize disruption to local business, and to eliminate work during rush hour are in place. Given the tight timelines imposed, Toronto Hydro had to obtain noise exemptions from City and crews had to work overtime resulting in costs that would not otherwise have been required. Another project on Asquith Avenue in the same vicinity needed to be delayed entirely and was only completed in 2014 as a result of City work in the area.

On many occasions, challenges that arise as a result of City requests do not result in delays or additional costs, but instead result in a need to advance costs from one year to the preceding year. One example is a voltage conversion project south of Bloor Street. Initially, Toronto Hydro had planned to finish the project by May 1, 2014 when the City asked for the project to be

completed by March 31, 2014 due to a planned water main and sewer replacement project. To accommodate the City's request, Toronto Hydro started construction in the last quarter of 2013 and advanced more than $200,000 of expenditures into 2013. Another example is a project to replace direct buried cable on Starview Lane and Rockbank Crescent in the Weston Road and Sheppard Avenue area. To avoid a scheduling conflict with other City's water main and sewer work, Toronto Hydro advanced an additional $250,000 into 2013.

Customers

A second set of stakeholders that can introduce unexpected challenges during work execution are customers and members of the public. Although Toronto Hydro undertakes significant customer engagement activities (e.g. informational letters, town hall meetings, responses to requests for accommodation) before and during planned work, and although the vast majority of Toronto Hydro's customers are supportive and very reasonable when work is being undertaken in proximity to their homes and businesses, incidents and challenges do arise.

One example is the aforementioned set of projects at Bay and Bloor Streets in downtown Toronto. During one project, pedestrian control in the area became so challenging that Toronto Hydro had to increase the budgeted number of paid duty police officers from one to two. In addition, one of the buildings along the project route started renovations at the same time that Toronto Hydro's project was to be executed. The building's contractors installed scaffolds outside the building for two months and this prevented Toronto Hydro from commencing its project during this time.

Hydro One Networks

Toronto Hydro is supplied by Hydro One Networks and owns equipment at 34 transformer station sites that are owned by Hydro One Networks. The equipment at station sites is tightly integrated and the two companies must closely coordinate planned work. At times, even the best efforts and plans cannot fully mitigate the risk that challenges will arise and delays will occur.

3. Operating Environment

Work execution challenges that are brought on by the Operating Environment relate to issues that arise as a result of working within congested underground utility corridors that are shared with other service providers such as the City of Toronto's Water Division, natural gas and telecom companies. This includes past tenants or users of the space that now makes up the corridors.

These challenges, as illustrated below, can greatly influence Toronto Hydro's ability to execute work on schedule and on budget.

Ageing Infrastructure

Challenges often arise due to the need to work around ageing infrastructure that is often owned by third parties (or Toronto Hydro). One example of this is water and sewage lines. Around these lines, Toronto Hydro utilizes specialized excavation techniques such as vac-truck digging to mitigate the risk of damage. However, ageing lines have at times broken open despite the use of these techniques and have caused water or sewage spills that delay projects and increase costs.

A particular example of the unexpected failure of water and sewage lines during the execution of a Toronto Hydro project occurred on Laird Drive in East York. As illustrated in Figure 1, a sewer line was uncovered and during the project, the line began to leak as a result of a defective fitting. The fitting needed to be replaced and the line needed to be supported during the construction of the duct bank.

FIGURE 1: SEWAGE LINE UNCOVERED DURING DUCT BANK CONSTRUCTION

As part of the same project, a water line was also uncovered while constructing a new cable chamber. This water line began to leak and water migrated into the chamber as shown in Figure

2. These two issues caused weeks of delays in the construction schedule of the Laird Drive project.

FIGURE 2: WATER LINE LEAK FLOODING CABLE CHAMBER DURING CONSTRUCTION

Another particular example occurred where Toronto Hydro needed to construct a duct structure well below an old existing water main. This main can be seen at the bottom of the trench in Figure 3. During excavation, the water main broke. (Water can be seen running in the trench in Figure 3.) The main had to be repaired and supported by chains, which caused delays and additional costs in the project.

FIGURE 3: WATER MAIN LEAK AT THE BOTTOM OF A TRENCH

Beyond ageing water and sewer infrastructure, challenges also arise during work execution in the vicinity of telecommunication infrastructure and even Toronto Hydro's own infrastructure. For example, older telecom cables were buried directly into the ground without concrete encasings as found during a recent project on Toresdale Avenue in North York. Precautions to mitigate the risk of damage to in-service cables during the Toresdale Avenue project added to costs and if damage had occurred, would have resulted in delays. Precautions must also be taken with Toronto Hydro's own infrastructure, which often must be supported and maintained in functional condition throughout a project. The following figures illustrate live cables being supported during construction projects.

FIGURE 4: IN-SERVICE CABLE BEING SUPPORTED AS A LARGE CABLE CHAMBER WAS RE-CONSTRUCTED IN THE AFOREMENTIONED LAIRD DRIVE PROJECT.

FIGURE 5: IN-SERVICE CABLES BEING SUPPORTED DURING A VAULT RE-BUILD AT WELLINGTON AND EMILY STREETS IN DOWNTOWN TORONTO.

FIGURE 6: IN-SERVICE CABLES BEING SUPPORTED DURING A VAULT RE-BUILD AT 390 BAY STREET IN DOWNTOWN TORONTO.

The complexity of some of these work sites and the necessity to support at times ageing and deteriorated assets can lead to issues arising, delays in work schedules, and increased costs.

Undocumented Sites and Infrastructure

During work execution, it is not uncommon for Toronto Hydro to encounter sites and infrastructure that are not documented or difficult to anticipate. Some of these discoveries can be accommodated within the scope of a project. However, some are particularly unique and result in unavoidable delays and costs. Discoveries often cause projects to be placed on hold as they necessitate investigations, project redesigns, and new permits.

One example of a unique discovery during work execution is an unregistered archaeological site that was found on Scenic Hill Court in Scarborough. The discovery was made during an underground civil construction project and resulted in a four-month delay in the project.

A second example of a unique discovery is an old undocumented gas pipe that was found during a system expansion project to supply new customer load. The project was replacing an overhead single circuit steel pole line with a new double circuit wood pole line. When an old cast iron pipe was discovered, pole installation was halted and a subsequent investigation revealed that the pipe was an abandoned gas main. Enbridge was contacted and approval to break out the

abandoned gas main at the proposed new wood pole locations was obtained. The impact of the abandoned pipe, which included breaking out the pipe at 28 pole locations, resulted in an addition $120,000 expenditures and approximately three weeks of delay.

FIGURE 7: ABANDONED GAS MAIN FOUND DURING POLE PLACEMENT

FIGURE 8: POLE PLACED IN VICINITY OF ABANDONED GAS MAIN

E7.6 Polymer SMD-20 Switch Renewal

FAILED SMD-20 SWITCH

E7.6.1 Summary

Program Description

The Polymer SMD-20 Switch Renewal program completes the SMD-20 replacement program that was created as part of the incremental capital module (ICM) and approved under the 2012-2014 IRM filing submission.

Polymer SMD-20 switches are used to mount SMU-20 fuse units onto distribution poles. SMU-20 fuse units protect the upstream circuit and equipment from faults that occur on the circuit downstream of the fuse units. SMD-20 switches must be manually operated by Toronto Hydro with a loadbreak tool, which necessitates the use of a significant amount of manual force. In 2011, there were two incidents of SMD-20 switches breaking while being operated by Toronto Hydro crew members. These incidents prompted Toronto Hydro to conduct a comprehensive failure analysis study. Based on the results of this study and the manufacturer's own analysis, it was determined that a defect in the switch weakens the insulator, which leads to failure of the asset. Consequently, Toronto Hydro concluded that its SMD-20 switches installed from 2006 to 2011 are defective and require immediate replacement.

Table A summarizes the anticipated benefits associated with the Polymer SMD-20 Switch Renewal program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Improves restoration times ƒ Reduces the potential for property damage from broken switches
Reliability	ƒ Reduces the need to install a switch when a fault occurs, reducing outages by two hours per switch **ƒ** Potential mitigation of 33,564 CHI
Safety	ƒ Reduces the risk of injury to field crew due to falling broken pieces ƒ Reduces the risk of arcing and flashover **ƒ** Reduces the risk of injury to the public and property from falling pieces
Efficiency	ƒ Can open and close on load without the need to de-energize ƒ Field crews can focus on refusing and fault location without the added task of replacing the SMD-20 switch

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Program Drivers

Polymer SMD-20 switches manufactured between 2006 and 2011 are defective and require replacement for safety and reliability reasons. The trigger and secondary drivers for this program are provided in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Safety	**ƒ** The high probability of SMD-20's failing poses safety hazards for Toronto Hydro crews. **ƒ** When switches break, pieces of the unit can fall on Toronto Hydro crews operating the loadbreak tool underneath. As well, Toronto Hydro crews are exposed to flashover. **ƒ** The safety issues listed above can also extend to the public, as the fracture of the switch can occur without direct contact if there is a substantial load applied to it. Similarly, pieces can fall and injure the public and property that are in close proximity.
Secondary Drivers	**Reasoning**
Substandard Performance	**ƒ** The asset has been identified by the manufacturer, S&C Electric Ltd., as being inherently defective. ƒ The switch has a high probability of breaking apart under normal operating conditions and within its own technical specifications.
Reliability	**ƒ** When an outage occurs causing the fuse to blow on a defective SMD-20, the entire unit must be replaced instead of just the fuse, prolonging the outage to affected customers by two hours for single phase switches and by 3.5 hours for three phase switches.

Preferred Alternative

The Polymer SMD-20 Switch Renewal program analyzed and evaluated the following options:

(i) Replace the Defective SMD-20 Switches Reactively

(ii) Replace the Defective SMD-20 Switches Proactively

Option II is the preferred alternative as it will eliminate all safety and operational risks that are associated with defective SMD-20 switches and improve reliability seen to customers.

Timing and Pacing

All necessary replacements will be made in 2015. The aggressive replacement schedule is necessary so that Toronto Hydro can alleviate the safety and reliability risks that the system is currently exposed to in a timely manner. Without immediate action, operational difficulties will continue because switches will continue to fail. Table C provides the estimated costs of the program for the 2015-2019 period.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	**0**	**0**	**0**	**0.84**	**2.85**	**4.84**	**0**	**0**	**0**	**0**

/C

E7.6.2 Program Description

The Polymer SMD-20 Switch Renewal program will continue the replacement activities that were initiated as part of the Ontario Energy Board (OEB) approved Polymer SMD-20 Switches segment of Toronto Hydro's 2012-2014 ICM application. The projects to be undertaken under this program are identical in nature to the jobs included in the 2012-2014 filing. Toronto Hydro plans to complete the replacement of defective SMD-20 switches by the end of 2015 at a total cost of $4.84million. The program will first target switches on feeders with the worst reliability and will then replace the remaining switches. Table 1 shows the number of assets to be replaced by asset class.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Asset (Units)	2015	2016	2017	2018	2019	Total
1-Phase Units	407	-	-	-	-	407
3-Phase Units	751	-	-	-	-	751

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The 1,158 defective switch locations that remain in Toronto Hydro's distribution system are made up of 407 single phase locations and 751 three phase locations (which consist of three switches clustered together). As such, a total of 2,660 discreet SMD-20 switching units is targeted for replacement as part of this program.

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The locations of switches that are scheduled to be replaced are illustrated in Figure 1 below.

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FIGURE 1: MAP OF THE REMAINING DEFECTIVE SMD-20 SWITCH LOCATIONS IN THE SYSTEM

As illustrated in Figure 2, Polymer SMD-20 switches are used to mount SMU-20 fuse units on overhead distribution poles. The SMU-20 fuse is designed to interrupt fault current caused by equipment downstream of the fuse on the distribution system, and is necessary to protect assets from the impacts of fault current, overloading, and to isolate faulted equipment from the feeder. The SMD-20 switches are used as isolation and restoration devices to the lateral section of the circuit by opening and closing the switch. In order to operate these switches for isolation, restoration or to access or replace a fuse on the switches, Toronto Hydro crews must manually operate the switches using an eight foot loadbreak tool. The SMD-20 switch is comprised of an insulator, latch and hinge assembly and the SMU-20 fuse unit. The insulator isolates the live components of the circuit from the pole. The latch and hinge assembly holds the SMU-20 fuse unit and is designed to allow the fuse to swing open if blown. The SMU-20 fuse unit houses the fuse and allows it to interface with the SMD-20 switch by the latch and hinge assembly.

FIGURE 2: SMD-20 SWITCH

In 2011, there were two incidents of SMD-20 switches breaking apart while being operated by field crews. An investigation concluded that the switches had a manufacturing defect, causing them to fail by breaking apart under the stress applied during normal operation. It was determined that switches manufactured from 2006 to 2011 were defective and require replacement (section E7.6.3.1 provides further details on the switching defects and investigation).

A proactive replacement program was approved by the OEB as part of the incremental capital module (ICM) within the 2012-2014 rate filing to replace the defective SMD-20 switches with newly designed SMD-20 switches that utilize a fiberglass core with five times the breaking strength of the old design (Figure 3). These switches can endure the physical load that is placed on them when operated. Installation of the new switches mitigates the functional, safety and reliability issues posed by the defective switches.

FIGURE 3: COMPARISON OF NEW DESIGN AND OLD DESIGN

Program Benefits

Replacing defective SMD-20 switches provides value to Toronto Hydro customers by improving reliability and mitigating safety risks with respect to individuals and property. As well, by proactively replacing these switches, Toronto Hydro is able to mitigate the risk of extended customer outages associated with the reactive replacement of defective switches. Failure risks associated with SMD-20 switches are further detailed in section E7.6.3.1.

The installation of the new generation SMD-20 switches provides several efficiency advantages for fuse coordination and isolation and restoration. The switch was designed to open and close while the circuit is loaded; it can safely break an energized circuit using the loadbreak tool and can close back onto load using a hotstick tool. A properly operating switch can be operated immediately after a fault is repaired while the defective switch requires removal and replacement with a new switch. The opening and closing of a switch is shown in Figures 4 and 5.

FIGURE 4: LOADBREAK TOOL OPENING AN SMD-20 SWITCH

FIGURE 5: HOTSTICK CLOSING SMD-20 SWITCH

Crews are able to quickly isolate and restore the circuit downstream of the SMD-20 switch whereas other technologies might require another method of isolation. Also, the SMD-20 switch makes fuse replacement simple, since a crew on the ground can unhook it from the switch using the loadbreak tool, as opposed to other fuse designs where crews must physically uninstall the entire switch via a bucket truck. A properly operating SMD-20 switch also automatically opens when the fuse is blown. This not only provides additional protection to clear a fault, but also

provides a visual cue to Toronto Hydro crews when patrolling to assist in determining fault location. Crews are able to limit their fault search to downstream of the fuse location. Finally, the newly designed SMD-20 switch features alternating diameter sheds that helps prevent bridging in wet and polluted environments. The watersheds help prevent contamination from building up which can cause a flashover.

A summary of benefits is provided below in Table 2. A number of these benefits are discussed in further detail in Section E7.6.3.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ	Improves restoration times
	ƒ	Reduces the potential for property damage
	ƒ	The difference in the cost of ownership between existing and renewed assets ($\hat{u}COO_1$) for the first year of the program is $11.5 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.6.7).
	ƒ	Accounting for capital program costs, the first year's activities deliver a positive NPV_1 of $6.7 million, confirming the economic prudence of the investments (see Section E7.6.7).
Reliability	ƒ	Reduces the need to install a switch when a fault occurs, reducing outages by two hours per switch
	ƒ	Potential mitigation of 33,564 CHI
Safety	ƒ	Reduces the risk of injury to field crew due to falling broken pieces
	ƒ	Reduces the risk of arcing and flashover
	ƒ	Reduces the risk of injury to the public and property from falling pieces
Efficiency	ƒ	Can open and close on load without the need to de-energize
	ƒ	Field crews can focus on refusing and fault location without the added task of replacing the SMD-20 switch

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/C

/C

E7.6.3 Why the Program is Needed

Polymer SMD-20 switches manufactured between 2006 and 2011 are defective and require replacement for safety and reliability reasons.

E7.6.3.1 Program Drivers

Table 3 summarizes the trigger and secondary drivers for the Polymer-SMD-20 Switch Renewal program. This program is a System Service initiative with a trigger driver is safety.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Safety	ƒ The high probability of SMD-20s failing poses safety hazards for Toronto Hydro crews. ƒ When switches break, pieces of the unit can fall on Toronto Hydro crews operating the loadbreak tool underneath. As well, Toronto Hydro crews are exposed to flashover. ƒ The safety issues listed above can also extend to the public, as the fracture of the switch can occur without direct contact if there is a substantial load applied to it. Similarly, pieces can fall pose a risk to the public.
Secondary Drivers	**Reasoning**
Substandard Performance	ƒ The asset has been identified by the manufacturer, S&C Electric Ltd., as being inherently defective. ƒ The switch has a high probability of breaking apart under normal operating conditions and within its own technical specifications.
Reliability	ƒ When an outage occurs causing the fuse to blow on a defective SMD-20, the entire unit must be replaced instead of just the fuse, prolonging the outage to affected customers by two hours for single phase switches and by 3.5 hours for three phase switches.

In order to open the SMD-20 switch safely under load, a loadbreak tool that attaches to the switch and is manually pulled open by a field crew is required. The SMD-20 switch can be closed using a standard hotstick. Its design guides the switch closed within several inches and the switch is finally closed with a purposeful thrust. The force of the operation, in combination with the defect inherent in SMD-20s manufactured between 2006 and 2011, has caused a high probability of failure when these switches are used.

A failed switch can be seen in Figure 6. After the two failure incidents occurred in 2011, a failure analysis was initiated to investigate the cause. Fourteen SMD-20 switches were randomly selected from the Toronto Hydro warehouse for testing. Out of the 14 random switches selected, 13 failed in less than 10 operations. Details of the study can be found in Phase 1 of Toronto Hydro's 2012-2014 rate filing[1]. The manufacturer, S&C Electric Ltd., also conducted a study on their own, reaching the same conclusions as Toronto Hydro, that the SMD-20 switches are defective.

[1] EB-2012-0064, Application and Evidence (May 10, 2012), at Tab 4, Schedule B7, Page 7.

FIGURE 6: FAILED SMD-20 SWITCH

Figure 7 shows a failed switch prior to and after operation. The root cause of the SMD-20 failures was determined to be a small crack located internally in the polymer core material. This crack creates a weak point in the insulator core, causing it to break when force is applied, such as when the loadbreak tool is used. The crack was determined to be due to a manufacturing defect and could have resulted from improper mold temperature, mold fill speed or improper core handling prior to silicon over-molding during the manufacturing process.

FIGURE 7: BEFORE AND AFTER SWITCH OPERATION DURING TESTING

The crack in the polymer core is covered by the outer silicon housing, which prevents the defect from being detected in the field. Figure 8 shows the outer silicone housing over the core where a potential crack could be covered.

FIGURE 8: FAILED SMD-20 SWITCH

Since the first incident in September 2011, awareness of the issue has grown among utilities within the province. Bulletins have been published by the distributor of the switches (November

28, 2011), Toronto Hydro (November 9, 2011), Electrical Safety Authority (December 9, 2011) and the manufacturer (November 30, 2011) (See Appendix A). The insulator of the SMD-20 is bolted onto the pole and serves to isolate the live circuit from the pole and to maintain the switch's structure so that it can be operated safely. The nature of the defect causes the insulator to shear while the operating force is applied the switch, meaning that if when switch breaks, pieces of the switch could fall below onto a crew member or could be projected onto property nearby, such as parked cars.

Defective SMD-20s may also arc as the switch breaks apart, potentially causing a flashover – a safety hazard that could subject Toronto Hydro crews to risk of injury. These hazards also extend to any members of the public in the area. As well, the failure of a switch extends outage restoration time as the entire switch must be replaced in order to correct the problem instead of simply replacing the fuse.

As of 2015, Toronto Hydro expects that there will be 2,660 defective switches remaining in the distribution system at 1,158 locations. These defective switches can potentially cause interruptions for up to 26,455 customers, resulting in up to 40,809 CHI as shown in Table 4. On average, each location has the potential to interrupt 23 customers, contributing to 35 CHI. An SMD-20 on a single phase lateral can add an additional two hours of outage time to a lateral fault, while an SMD-20 on a three-phase lateral can add an additional three-and-a-half hours. ***IC***

TABLE 4: TOTAL ACCUMULATED RELIABILITY

Switch Type	Accumulated CI	Accumulated CHI
1-Phase	25,704	38,556
3-Phase	751	2,253
Total	**26,455**	**40,809**

IC

E7.6.4 Timing & Pacing of the Program

As per the table below, this program is expected to cost $4.84 million in 2015.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	0	0	0	0.84	2.85	4.84	0	0	0	0

Toronto Hydro has been proactively removing defective SMD-20 switches since 2013, targeting feeders that have historically experienced a large number of outages since they are more likely to experience faults going forward. This program continues replacement of the SMD-20 switches through the final year of the three year program, such that, by the end of 2015, Toronto Hydro expects all defective SMD-20 switches will be replaced. The aggressive replacement schedule is necessary so that Toronto Hydro can alleviate the safety and reliability risks that the system is currently exposed to in a timely manner. Without immediate action, operational difficulties will continue because switches will continue to fail.

E7.6.4.1 Ranking & Prioritization

Toronto Hydro continues to prioritize the replacement of defective SMD-20 switches by giving weight to the number of outages that had occurred historically on the relevant feeders in order to minimize the risk that a defective switch would need to be operated or replaced reactively.

E7.6.5 Program Execution

The switches that need to be replaced have been grouped by geographical location in order to make replacement efforts more efficient and easier to coordinate. This form of grouping allows the control room to more effectively manage the replacement work as opposed to having to manage multiple locations scattered throughout the distribution system. Addressing defective switches in clustered locations improves the cost-efficiency of the program by allowing crews to spend more time on actual replacement rather than travel time.

In order to replace the defective switches, a field crew will disassemble the defective switches using the load disconnect tool, which allows the crews to bypass the SMD-20 switch being replaced. Using this approach, crews can install a new switch and transfer over the customer load without requiring an outage to connected customers.

E7.6.5.1 Program Risks

This program will address 1,103 switch locations system-wide. In some locations, it may be difficult to obtain permits if other work is being done by other city utilities at the same time. In addition the Pan Am Games set to take place in 2015 have introduced certain restrictions with respect to working on areas that are being used as a route for the games. These issues could delay the scheduling of certain portions of this program. Toronto Hydro will take these issues into account when scheduling the replacements.

Another program risk is that some poles may be in worse condition than indicated in Toronto Hydro's records and may require replacement – including re-installation of all attached equipment – while changing out the SMD-20 switch. Replacing the poles would increase costs and further strain resources that are needed to complete this program; however, Toronto Hydro does not anticipate that this would prevent the successful completion of the program.

E7.6.5.2 Standard & Regulation Adherence

The manufacturer has developed a new polymer insulator design that incorporates a fiberglass core that provides greater flexibility and has an ultimate bend strength that is five times greater than the old SMD-20 switch design. The manufacturer also improved their production testing and quality assurance policies and procedures. Toronto Hydro has also initiated a quality assurance and vendor management program for this product by increasing the audit count, introducing vigorous test report reviews and revising construction standards, specifications, and quality procedures. These measures will significantly reduce the probability of future defective switches being installed into the system.

The testing criteria of the Institute of Electrical and Electronics Engineers (IEEE) C37.41, which is the standard for design testing on disconnecting cut-out type switches, is to operate the switch 67 times at the manufacturing stage to ensure quality of operation. Ten of the newly designed SMD-20 switches were randomly selected and each one successfully operated 70 times without failure, indicating that they are not defective.

E7.6.6 Evaluation of Alternatives

E7.6.6.1 Quantification/Evaluation of Options

(i) Option 1: Replace the Defective SMD-20 Switches Reactively

Under this option, the defective SMD-20 switches would be replaced reactively after they fail in the field. This alternative involves lower capital expenditures in the short-term as compared to proactively replacing all of the switches. However, this course of action would delay the replacement of all defective SMD-20 switches currently in the field, subjecting Toronto Hydro crews and the public to safety risks associated with this equipment. Furthermore, customers will continue to experience prolonged outages when a defective switch fails and requires replacing.

(ii) Option 2: Replace the Defective SMD-20 Switches Proactively

Under this option, Toronto Hydro would continue the previously approved program to proactively replace all defective switches. This recommended course of action will eliminate all of the safety and operational risks that are associated with defective SMD-20 switches.

The cost of ownership (COO) and program net benefit (NPV) associated with the Polymer SMD-20 Switch Renewal program is further detailed in Table 6. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities within this program. The cost of ownership (COO) of a state reflects the risk of asset failure including both direct and indirect costs. These costs include customer interruptions, emergency repairs, and asset replacements associated with a given design. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NAR_E) and proposed (NAR_N) state. Non-asset risks are further explained in Section D3.3. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3.

TABLE 6 : COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

When the difference in cost of ownership ($\hat{u}COO_1$) is compared to the associated program costs (PC_1) for the first of activities, the Polymer SMD-20 Switch Renewal program produces a net benefit (NPV_1) value of $6.7 million, as shown in Table 7. /C

TABLE 7: POLYMER SMD-20 SWITCH RENEWAL BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (Millions)	
Difference in Asset Risk **[$\hat{u}AR = AR_E - AR_N$]**	$9.2	/C
Difference in Non Asset Risk **[$\hat{N}AR = NAR_E - NAR_N$]**	$2.3	/C
Difference in Cost of Ownership **[$\hat{C}OO_1 = (COO_E – COO_N) = \hat{u}AR + \hat{N}AR$]**	$11.5	/C
Program Cost [PC_1]	$4.8	/C
Program Net Benefit [$NPV_1 = (\hat{C}OO_1 – PC_1)$]	**$6.7**	/C

E7.6.7 2015 Projects

Table 8 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

- previously filed projects that appeared as jobs in the OEB approved Polymer SMD-20 Switches segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and
- projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 8: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Projects	CIR Projects
1.56	3.28

/C

Table 9 lists all projects that will be partially or completely executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 9: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
E14635	E14635-P10 SMD-20 Replacement NY North York part 1	$0.63	2015	ICM
E14643	E14643-P10 SMD-20 Replacement NY North York part 2	$0.28	2015	ICM
W13509	W13509-P10-SMD-20 Replacement PH6-Runnymede, Fairbanks, Finch	$0.34	2015	ICM
W13510	W13510-P10-SMD-20 Replacement PH7-Bathurst TS, Fairchild TS	$0.31	2015	ICM
E15430	E15430 Scarborough East SMD-20 Replacement -Sheppard TS SCNT47M3	$0.03	2015	CIR
E15431	E15431 Scarborough East SMD-20 Replacement -Ellesmere TS SCNAH9M21	$0.04	2015	CIR
E15451	E15451 Leaside TS SMD switch replacement 34M5,34M6 Leaside TS	$0.03	2015	CIR

/C

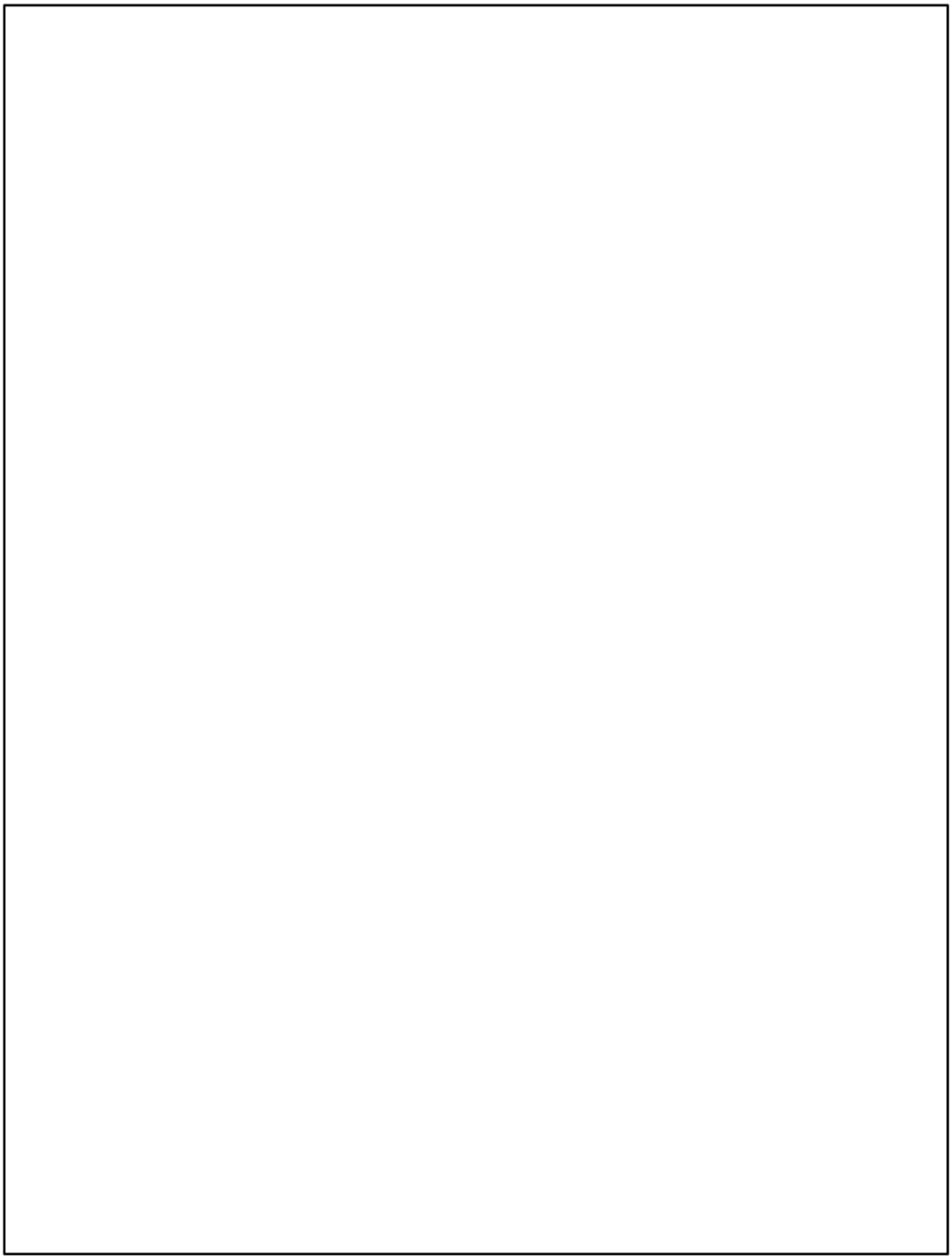
Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
E15452	E15452 Leslie MS SMD switch replacement SS68 Leslie MS	$0.01	2015	CIR
E15432	E15432 Scarborough East SMD-20 Replacement Malvern Ts SCNAR26M22	$0.02	2015	CIR
E15444	E15444 SMD20 Switch Replacement Bermondsey II TS	$0.15	2015	CIR
E15443	E15443 SMD20 Switch Replacement Scarborough TS	$0.14	2015	CIR
W15413	W15413 P10-SMD20 Replacements 2015 PH2 Manby TS and 38M1	$0.55	2015	CIR
W15416	W15416 P10-SMD20 2015 PH4 - Fairbanks TS, Bathurst TS	$0.24	2015	CIR
W15409	W15409-P10 SMD20 Replacement 2015 PH1 - Runnymede TS, Fairbanks TS	$0.19	2015	CIR
W15414	W15414 - P10 SMD20 Replacements 2015 PH3 - Finch TS 55M1	$0.35	2015	CIR
W15417	W15417 P10 - SMD20 Replacements 2015 PH5 - Richview TS 88M1	$0.63	2015	CIR
W15418	W15418 P10-SMD20 Replacements 2015 PH6 Rexdale TS R29M1	$0.27	2015	CIR
W15420	W15420 P10-SMD20 Replacements 2015 PH7 - Horner TS R30M3	$0.31	2015	CIR
W15421	W15421 P10 -SMD20 Replacements 2015 PH8 PJF1	$0.19	2015	CIR
W15441	W15441 P10 - SMD20 Replacements 2015 - Centre A-202-BN	$0.14	2015	CIR

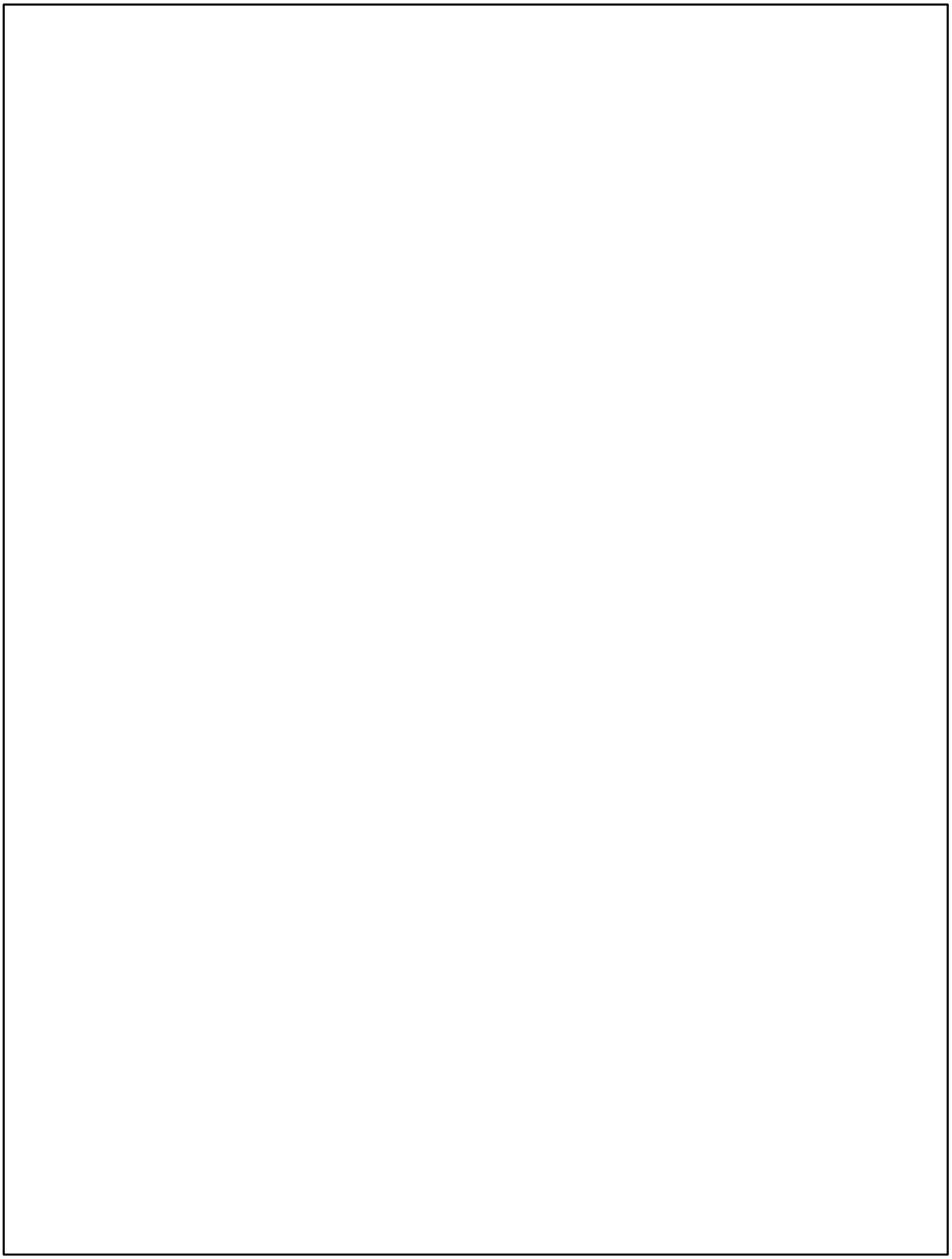
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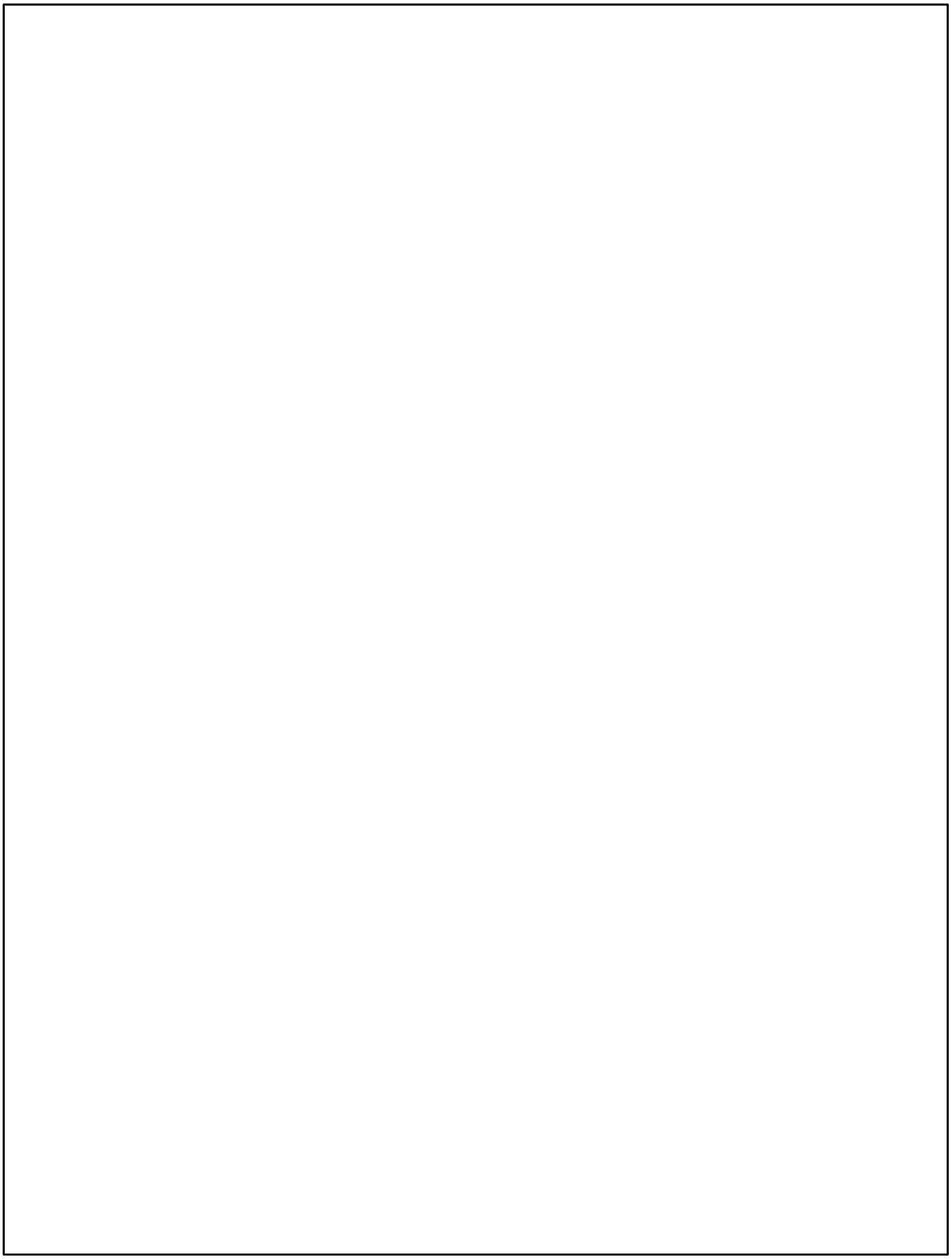
Appendix A

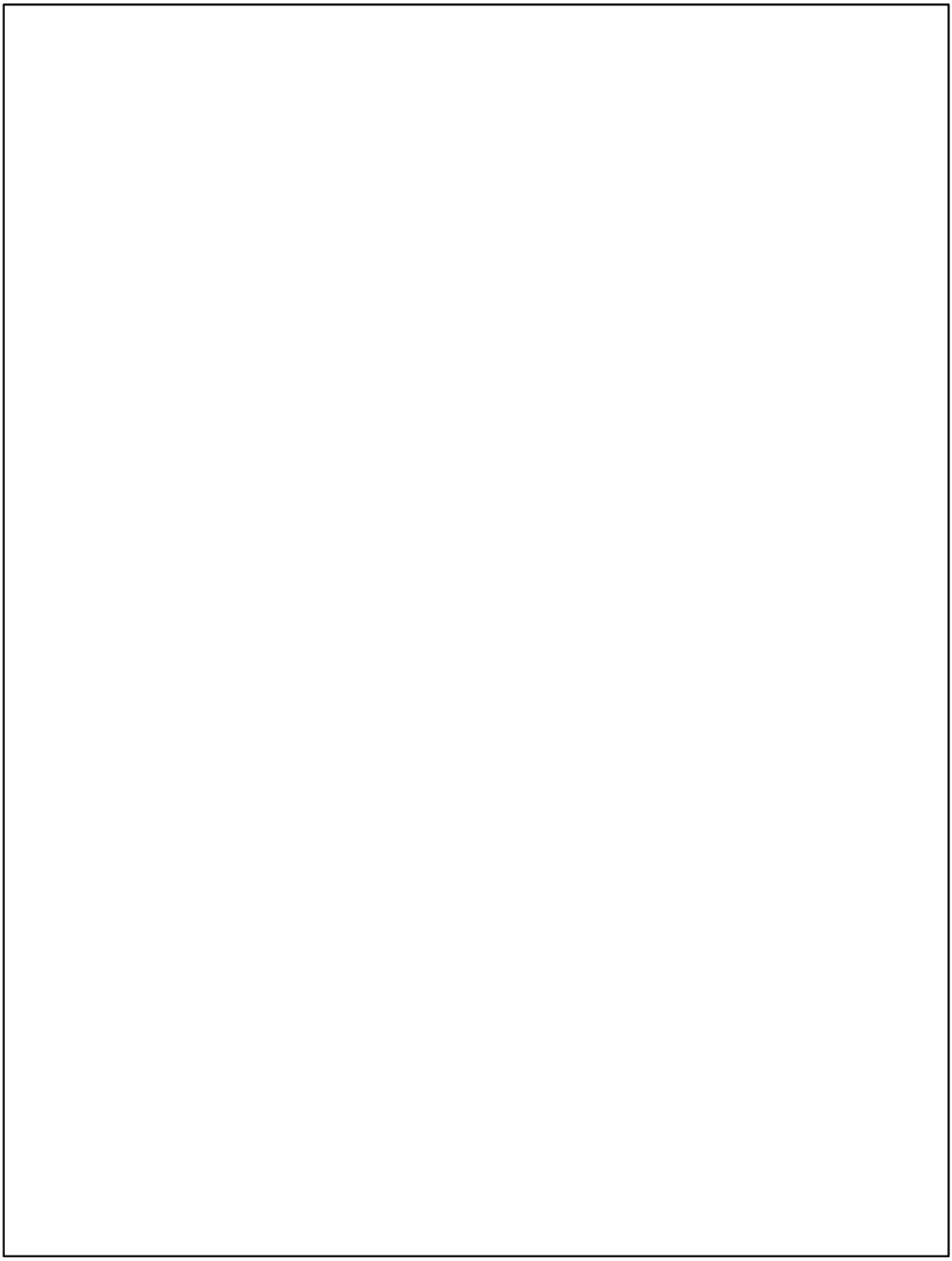
POLYMER SMD-20 SWITCH RENEWAL TEST RESULTS & BULLETINS

A1 Test Results Document from S&C Electric Canada Ltd. December 2011

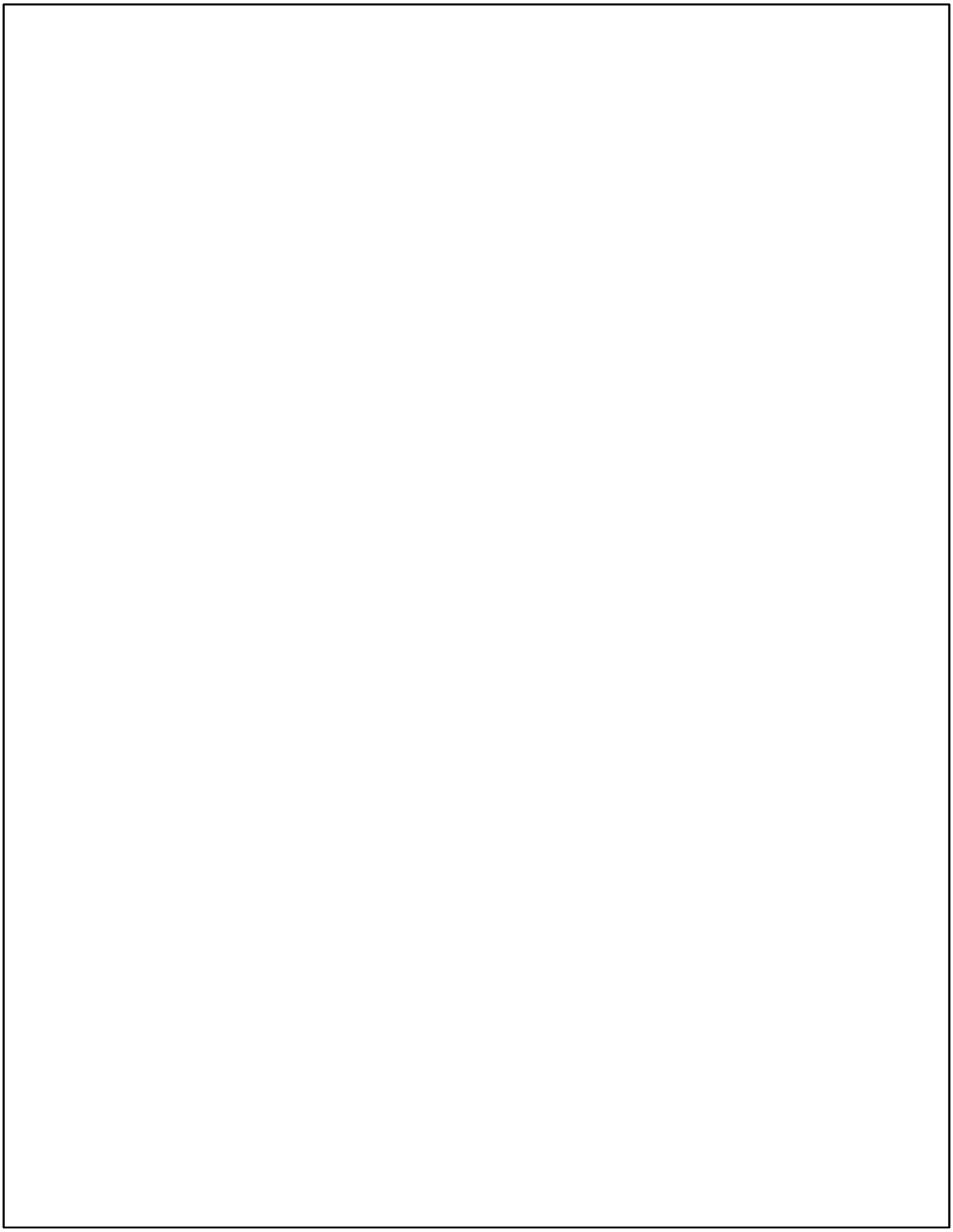


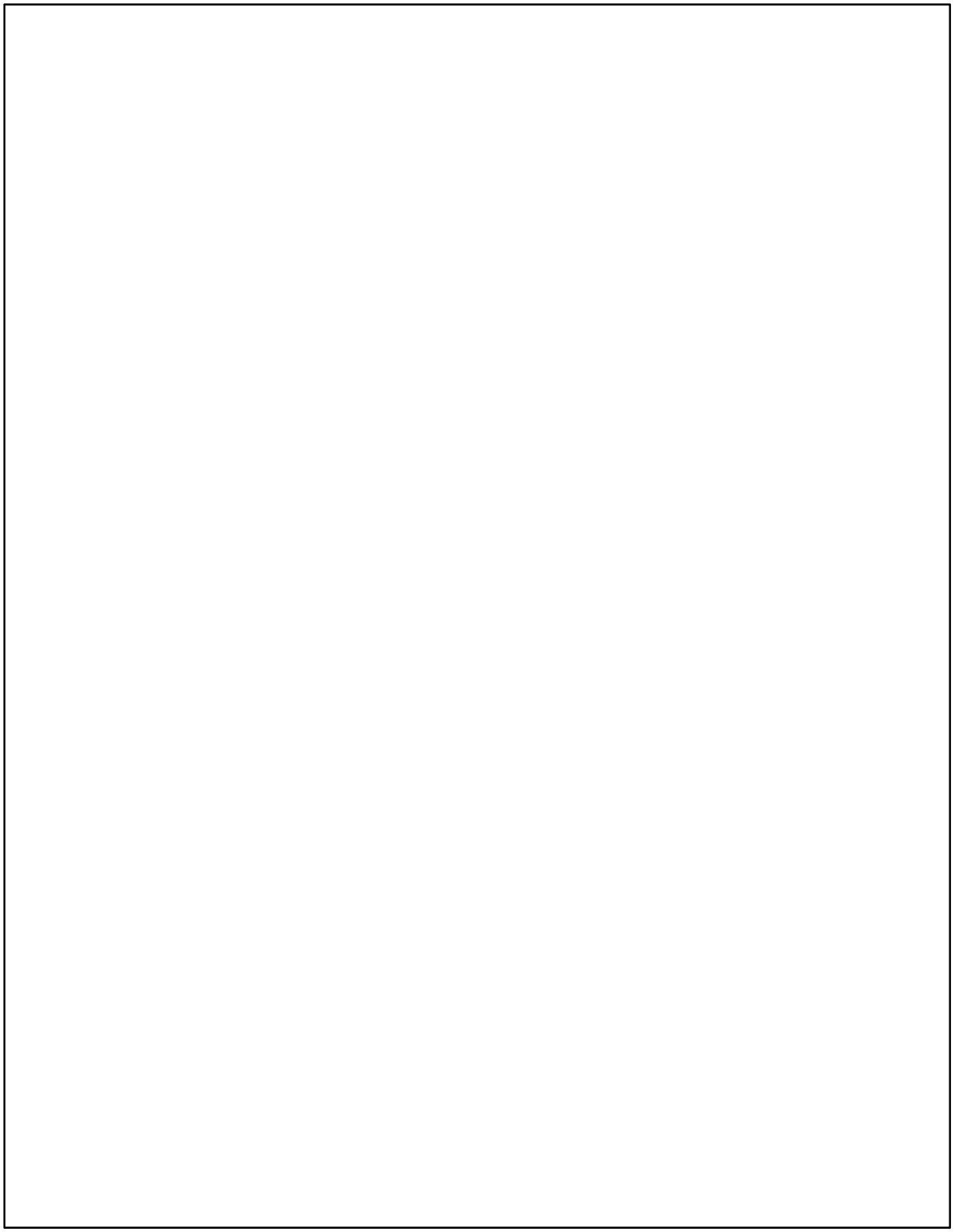




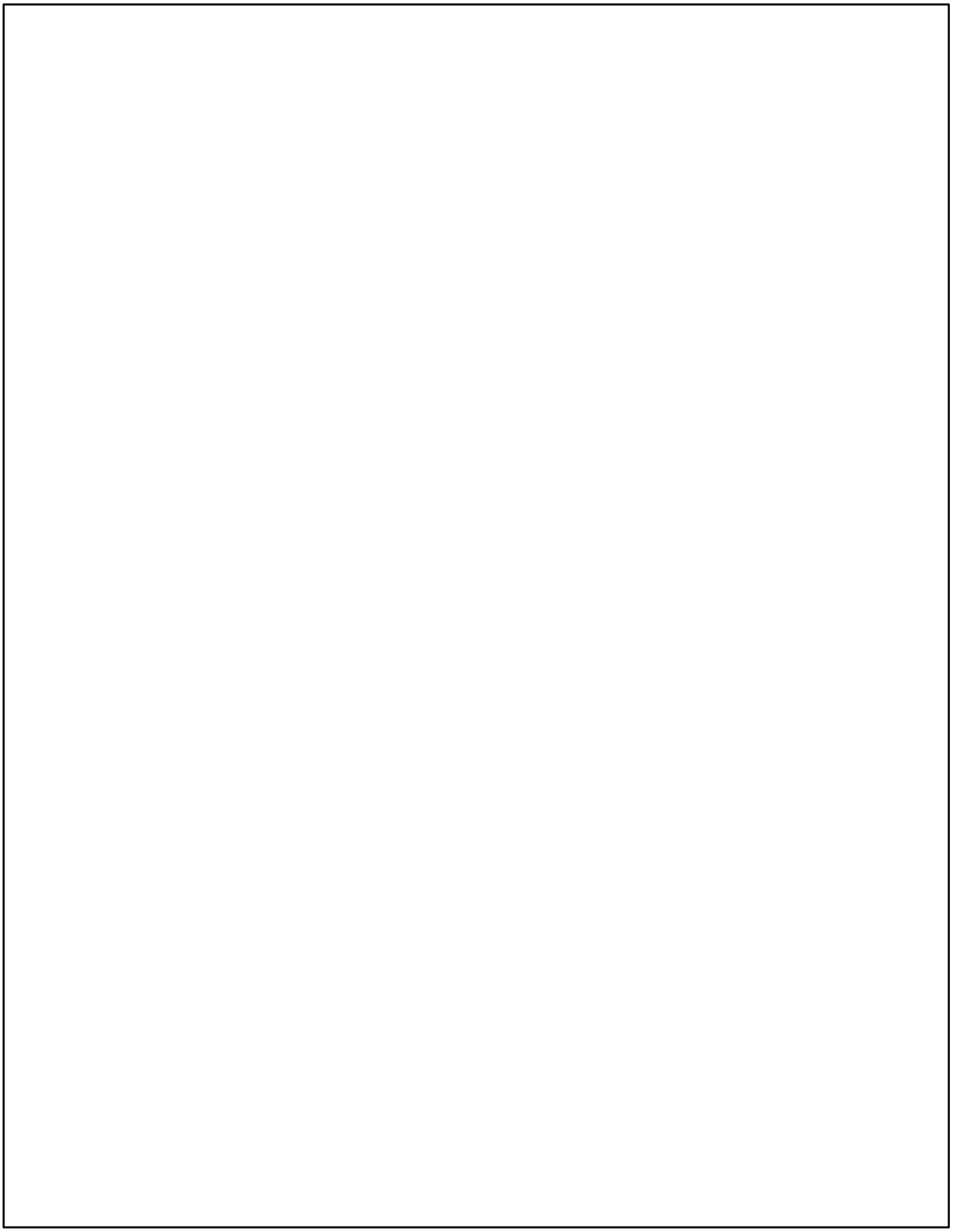


A2 SMD-20 Switch Load Disconnect Tool and Process



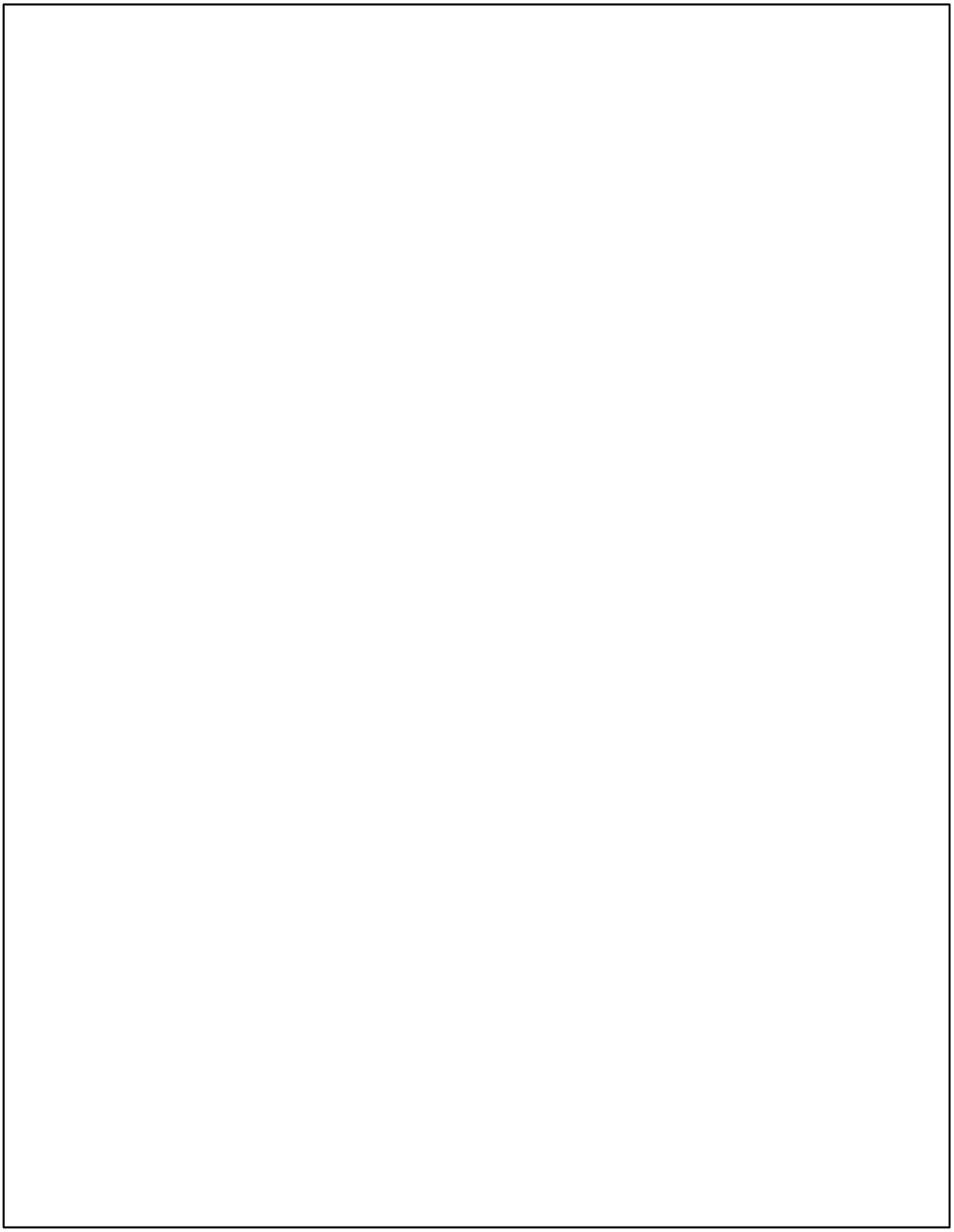


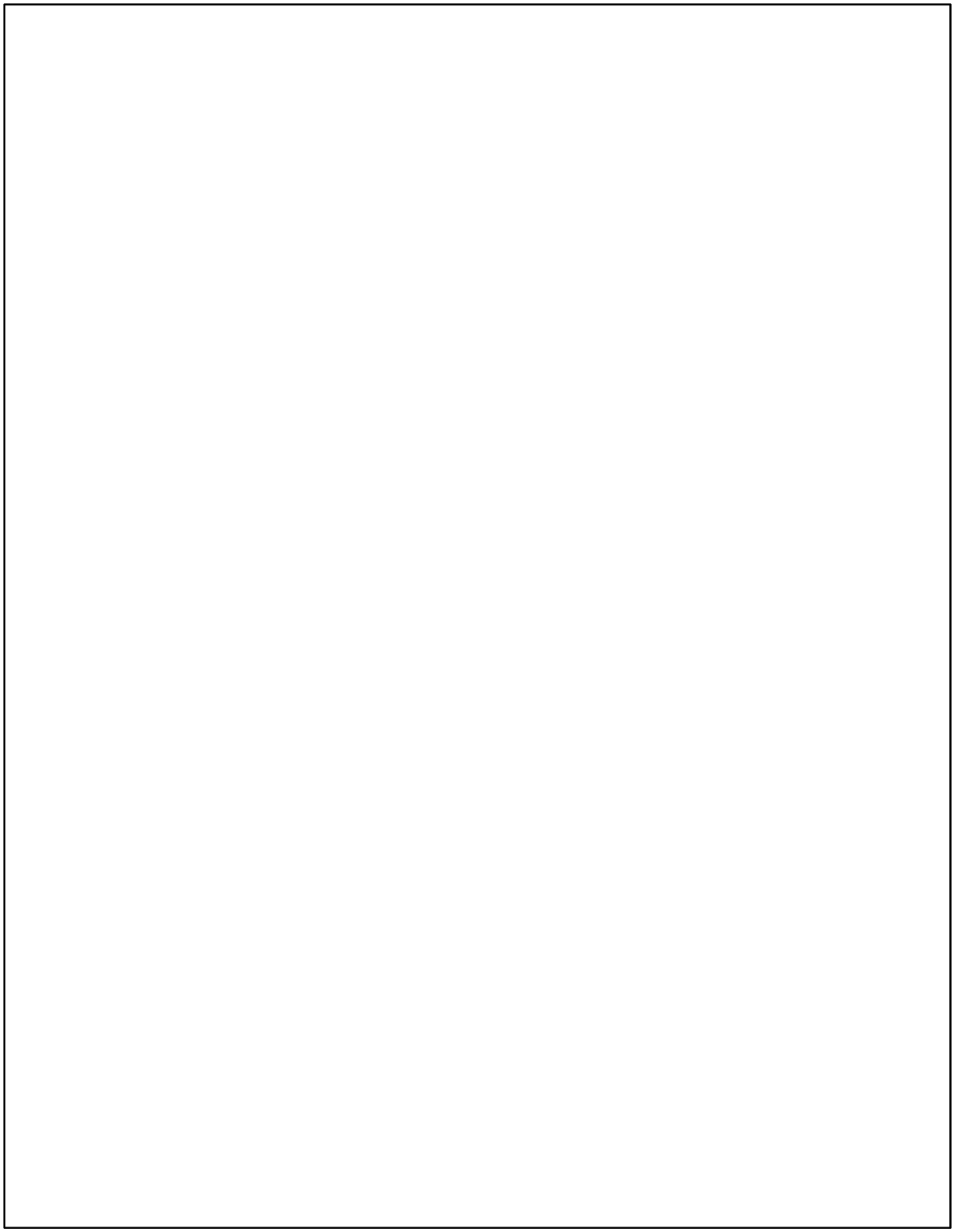
A3 Environment Safety and Health Bulletin Nov 2011

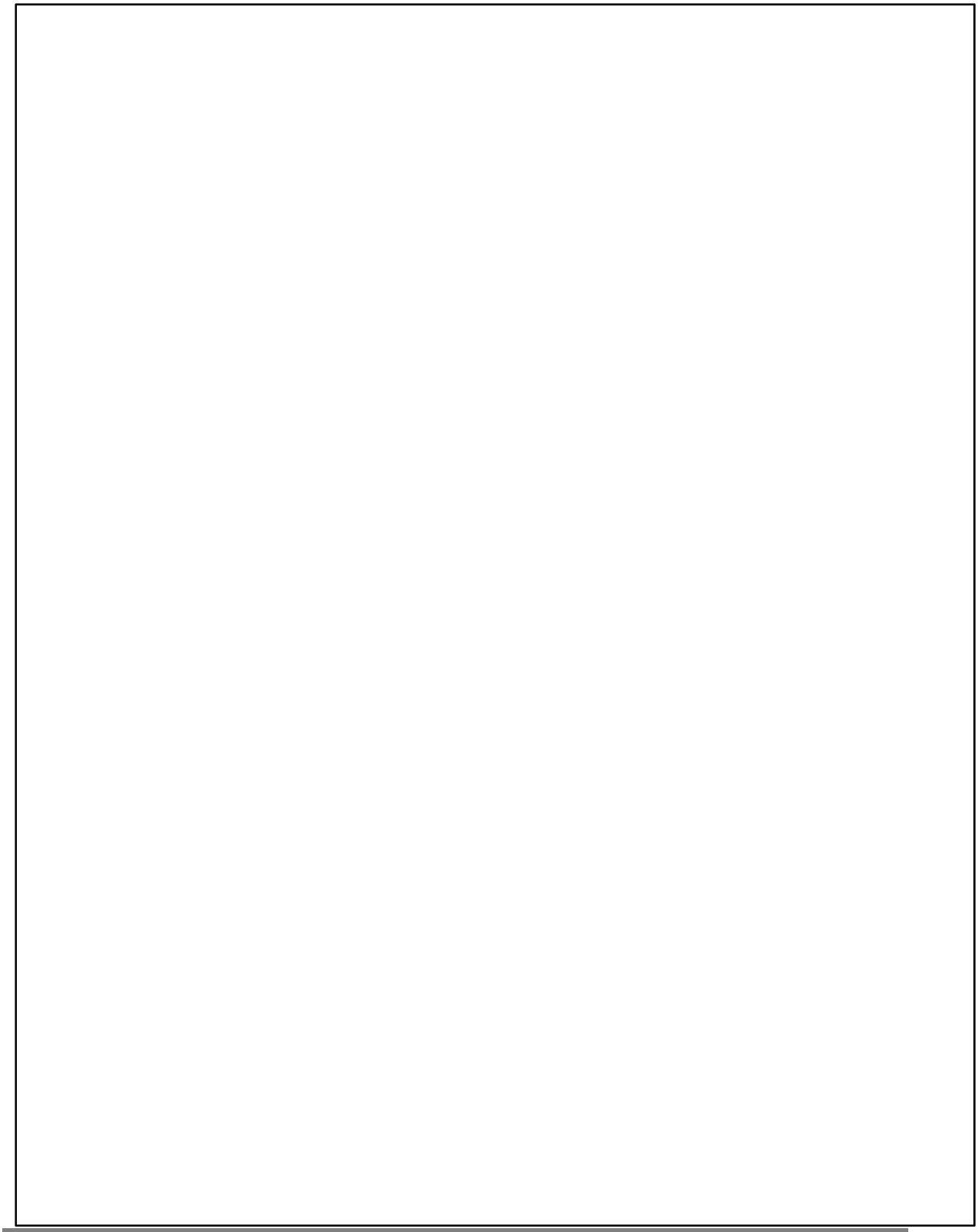


A4 ESA Safety Bulletin Dec 2011

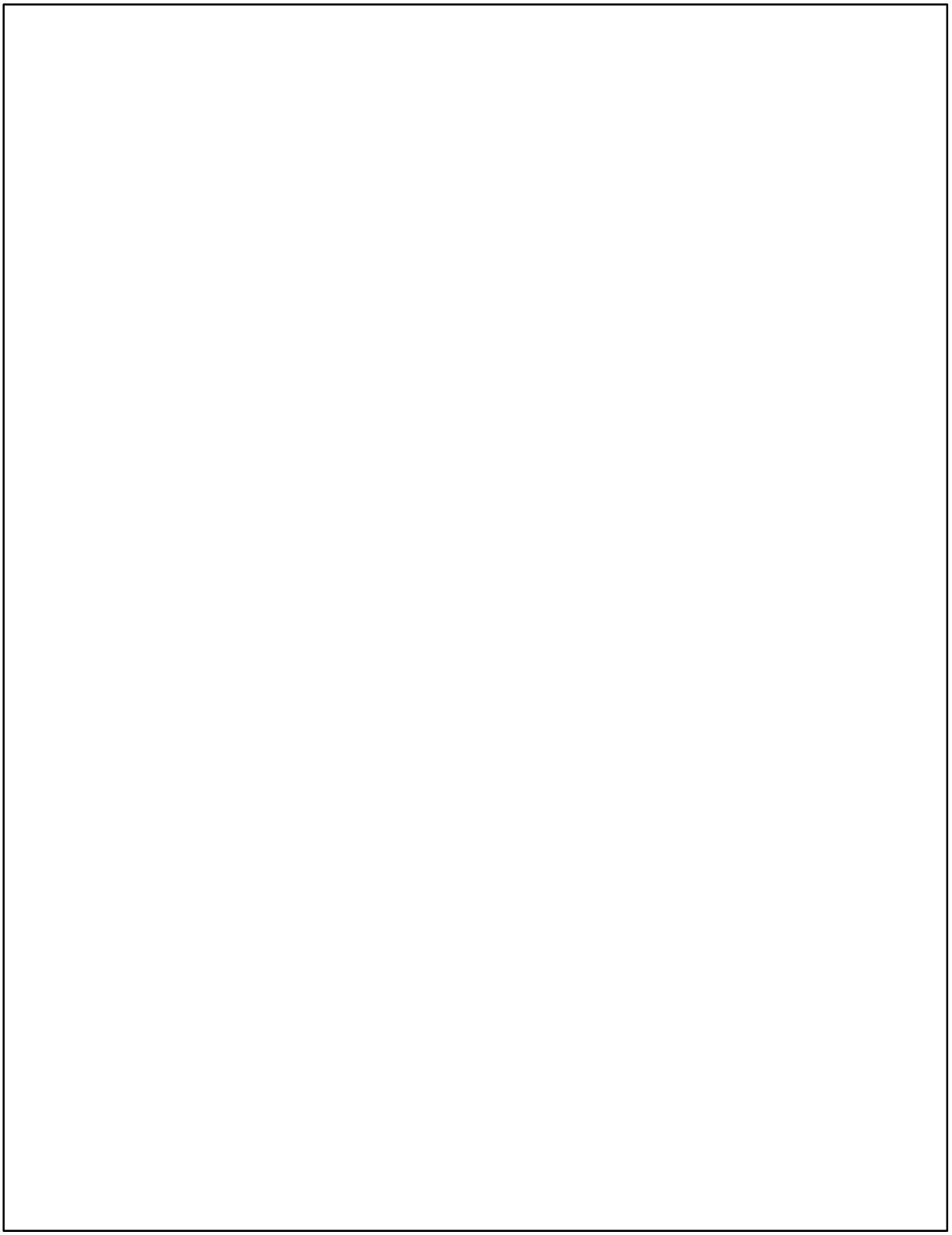
ESA SAFETY BULLETIN, DECEMBER 2011



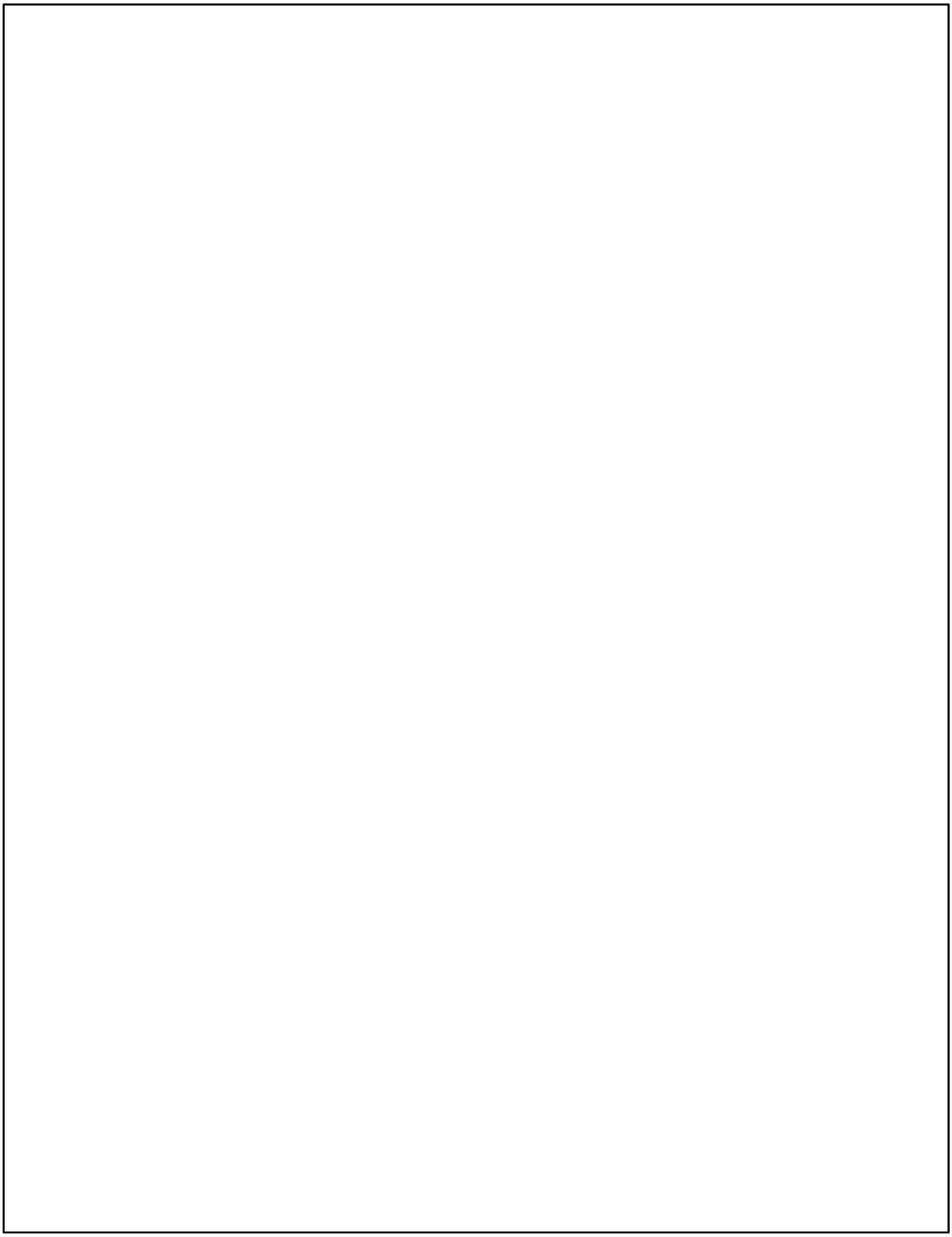


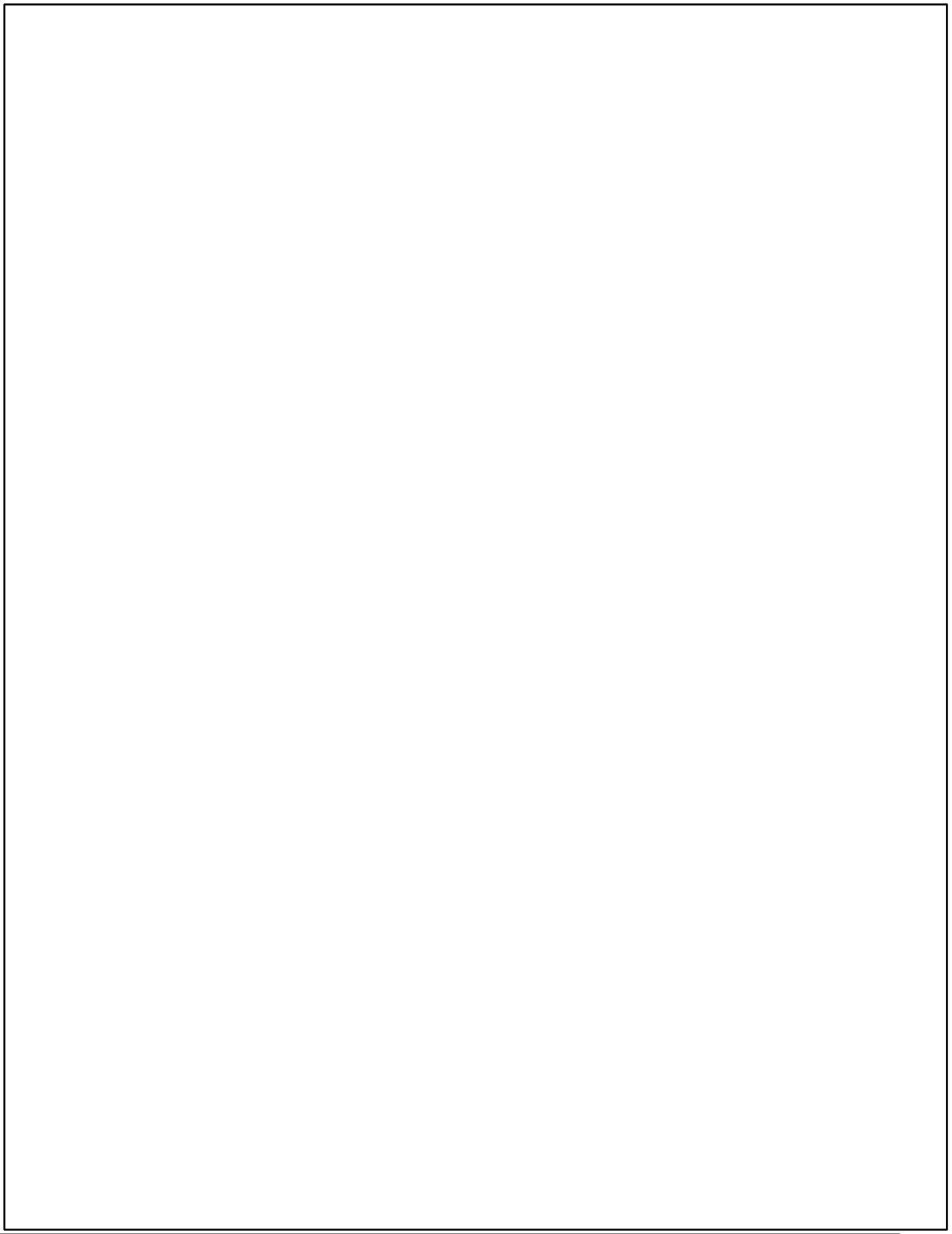


LETTER FROM HD SUPPLY – UTILITIES, NOVEMBER 2011



1 LETTER S&C ELECTRIC CANADA LTD., NOVEMBER 2011





E7.7 Downtown Contingency



FEEDER TIES

E7.7.1 Summary

Program Description

The objective of the Downtown Contingency program is to provide load transfer capability between stations in the downtown area. There are currently 15 stations and 557 13.8 kV feeders spread out throughout the downtown area, and only 15 of these feeders, or about 3%, have inter-station feeder ties. The lack of inter-station feeder ties in Toronto's downtown area means that there is currently a significant and unmitigated risk that a large number of customers could experience long duration outages due to station loss of supply, which can be caused by events such as station flooding and catastrophic equipment failure, as well as loss of supply from the transmitter. Mitigation of this risk will effectively enhance the customer value derived from existing assets by minimizing failure risks of the existing downtown dual-radial configuration.

Toronto Hydro plans to establish inter-station feeder ties for all 557 13.8 kV feeders in the Toronto downtown area. This is accomplished by tying feeders from one station to adjacent feeders from another station.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Improved outage restoration times ƒ Reduces likelihood of business customer monetary losses due to loss of supply ƒ Reduces likelihood of business closure due to loss of supply

Reliability	ƒ Provides alternate power supply to customers where none presently exists.
Safety	ƒ Provides alternate power supply to customers that depend on it for their health and safety, such as those relying on life-support equipment.
Efficiency	ƒ Ability to remotely transfer the load from one station to another.

Program Drivers

Between August 2003 and July 2013, there were 17 major station outage events in the downtown area, with an average interruption time of 8.2 hours per event. These outages resulted in an average annual customer interruption cost (CIC) of $12.4 million. If inter-station feeder ties had been installed and available to pick-up these customer loads, the number customer hours interrupted (CHI) would have been reduced by 86%.

The trigger and secondary drivers for this program are provided in Table B.

TABLE B: PROGRAM DRIVER

Trigger Driver	Reasoning
Reliability	ƒ Significant and unmitigated risk of customers experiencing long outages due to station loss of supply.
Secondary Drivers	Reasoning
Operational Constraints	ƒ During station outage conditions, Toronto Hydro is unable to efficiently and quickly restore power to customers. ƒ Inability to transfer load between adjacent stations on temporary or permanent basis.
Safety	ƒ The loss of power supply can put certain customers at risk, such as those that rely on life-support equipment. ƒ The loss of power supply during extreme weather events can put customers at risk.

Preferred Alternative

Toronto Hydro considered the following alternatives for addressing the contingency risks associated with feeders lacking inter-station feeder ties downtown.

(i) Maintaining the status quo: Toronto Hydro would not resolve issues which are imminent and therefore leave customers with excess risk and potentially reduced reliability.

(ii) Purchase mobile equipment: An alternative to the status quo includes the use of mobile generators/switchgears or inter-feeder ties. The use of mobile equipment is not feasible due to its high capital and maintenance costs as well as unsuitability for fully resolving contingency issues.

(iii) Downtown Contingency program: install inter-station feeder ties across the downtown area where they are currently lacking.

The use of inter-station feeder ties is recommended because it is the only option that will provide Toronto Hydro with the capability to restore supply to most of its downtown customers under outage conditions, thereby fully mitigating loss-of-supply risk to the extent feasible.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $3.07 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.7.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $2.33 million, confirming the economic prudence of the investments (see Section E7.7.7).

Timing and Pacing

The timing of the Downtown Contingency program was established to ensure continuing progress on this long-term program while balancing resource usage with other system investment priorities during the 2015 to 2019 period.

The proposed program would allow transfer of customer loads on feeders between:

- Dufferin TS & Cecil TS
- Dufferin TS & Strachan TS
- Dufferin TS & Wiltshire TS
- Basin TS & Carlaw TS

Investments begin in 2016 to allow for necessary HONI transformer replacements.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	1.09	4.66	0.05	1.09	1.04	0	0.74	0.74	1.00	0.88

E7.7.2 Program Description

The Downtown Contingency program involves the installation of inter-station feeder ties between distribution feeders located in various stations in the downtown area of Toronto. At the present time, there are 15 stations and 557 13.8 kV feeders spread out throughout the downtown area. Only 15 of these feeders, or about 3%, currently have inter-station feeder ties. Table 1 lists the six inter-station feeder-ties that will be established through the Downtown Contingency program during the 2015 to 2019 planning period.

TABLE 1: SIX INTER-STATION FEEDER-TIES

Feeder	Station
A204BN & A250E feeders	Basin & Carlaw stations
A273DN & A57W feeders	Dufferin & Wilshire stations
A256DN & A34W feeders	Dufferin & Wilshire stations
A257DN & A230T feeders	Dufferin & Strachan stations
A530DN & A390CE feeders	Dufferin & Cecil stations
A254DN & A390CE feeders	Dufferin & Cecil stations

Typically, the downtown area is setup so that 500 kVA to 10 MVA load customers are supplied by two 13.8 kV radial feeders from the same transformer station (TS) switchgear. One feeder acts as the primary feeder while the other operates on a stand-by basis. During an outage to a normal feeder, the stand-by feeder supplies power to the affected customers. Figure 1 illustrates the downtown dual radial distribution feeder design. As the figure shows, each TS supplies its customers independently, and none of the station feeders have ties with the adjacent station's feeders. As a result, under some contingency conditions, such as complete or partial station outages, this configuration leads to lengthy customer outages while Toronto Hydro repairs the station.

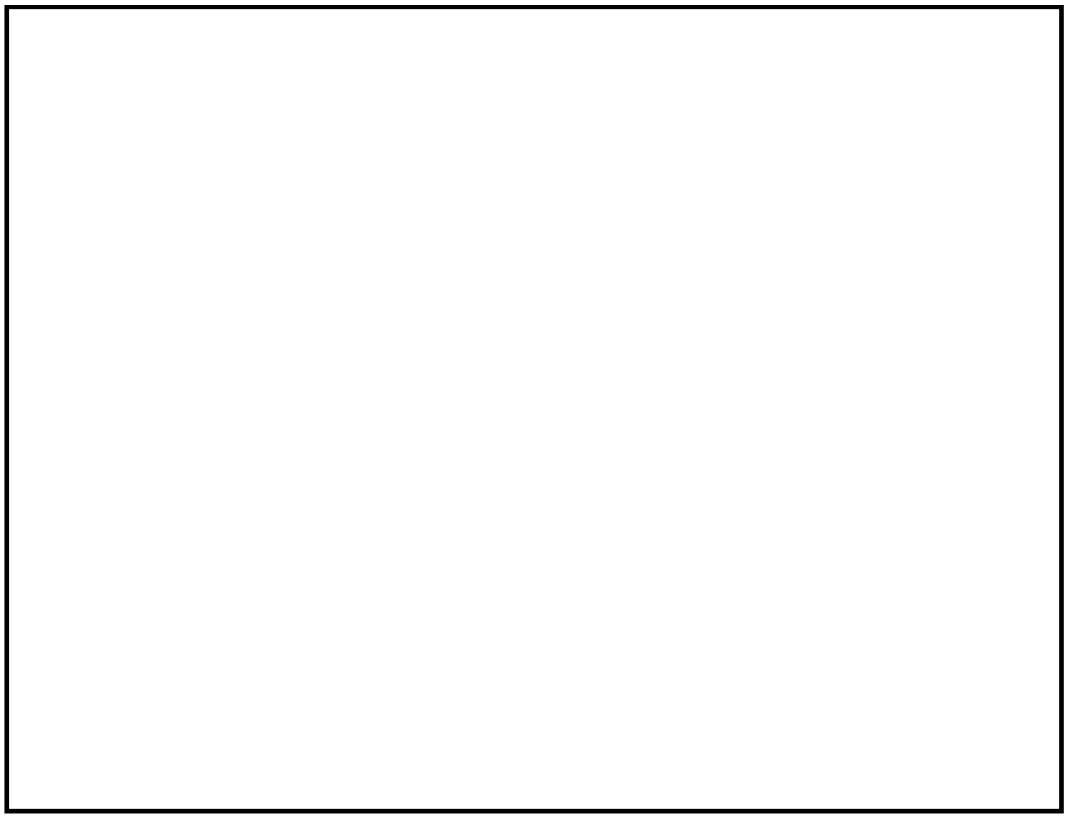


FIGURE 1: DUAL RADIAL DISTRIBUTION DESIGN UTILIZED IN TORONTO DOWNTOWN AREA

In contrast, outside of the downtown Toronto, the distribution system is configured as an open loop design. An open loop system incorporates many ties between feeders; in particular, it includes ties between feeders housed in different stations. As a result, contingency situations do not typically lead to lengthy outages because most areas can be quickly re-supplied by an alternative station when necessary. Figure 2 illustrates how the downtown Toronto example can be modified to gain the benefits of the design used outside of the downtown core.

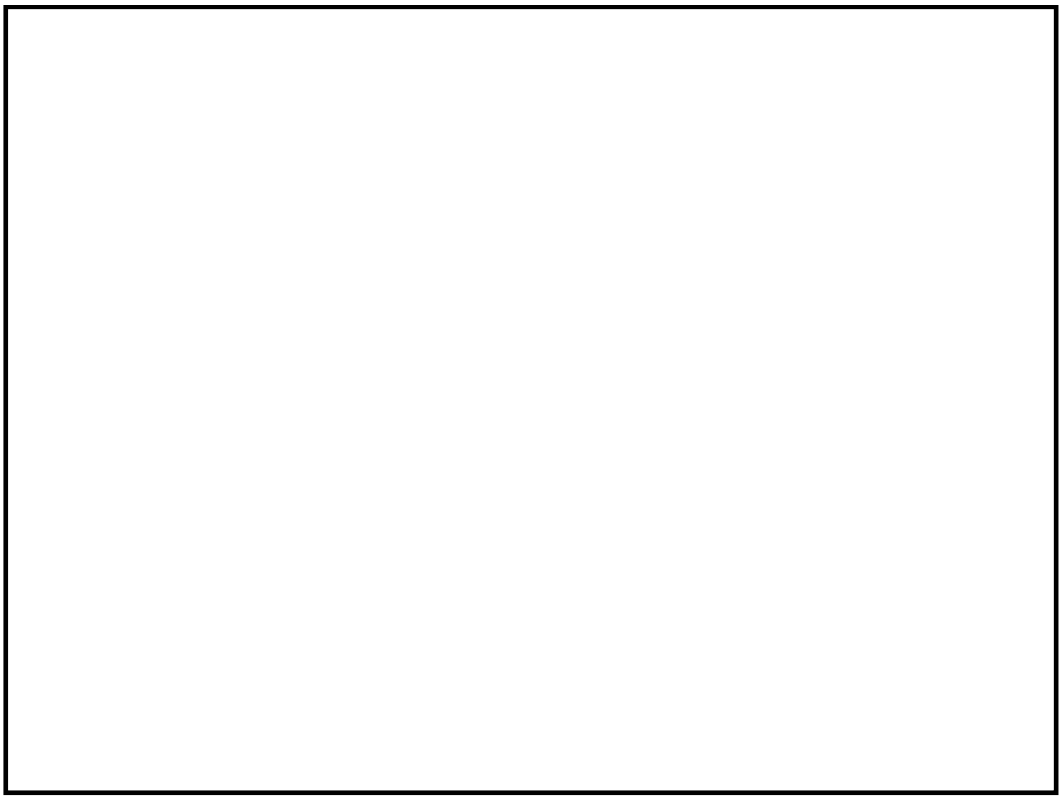


FIGURE 2: DOWNTOWN AREA INTER-STATION FEEDER –TIES DESIGN WITH REMOTE CONTROLLED SWITCHES

Toronto Hydro plans to execute six discrete Downtown Contingency projects between 2015 and 2019, similar in nature to the example above, between the following transformer stations (TS) and municipal stations (MS):

- Basin TS and George & Duke MS (one project)
- Dufferin TS and Cecil TS (two projects)
- Dufferin TS and Strachan TS (one project)
- Dufferin TS and Wiltshire TS (two projects)

Toronto Hydro plans to spend an estimated $3.36 million on the Downtown Contingency program between 2015 and 2019. Figure 3 shows the locations of the six proposed feeder tie projects.

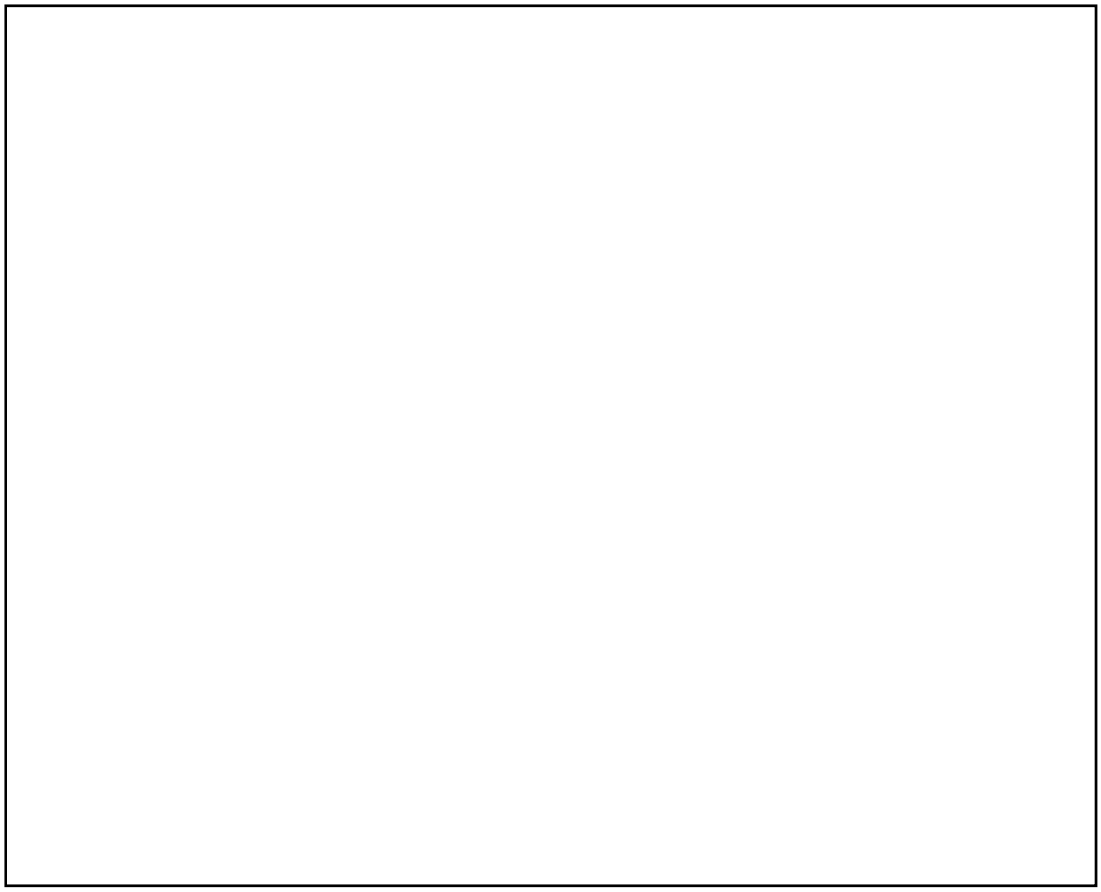


FIGURE 3: INTER-STATION FEEDER-TIE PROJECTS

This program involves the use of new assets and/or the replacement of existing assets in order to provide load transfer capabilities between the adjacent stations. The major assets of the program are tabulated in Table 2 below and include underground (UG) and overhead (OH) switches as well as UG cable and OH conductor.

TABLE 2: ASSETS ADDED / REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
UG Switch	0	0	0	1	0	1
OH Switch	0	4	2	2	2	10
UG Cable (km)	0	0.1	0.6	1.3	3.0	5
OH Conductor (km)	0	0.35	0.2	1.3	0.02	1.87

The Downtown–Contingency program is expected to improve overall system efficiency through optimized distribution system management. With the installation and commissioning of inter-station feeder ties, power system controllers will have the ability to remotely transfer the load from one station to another in the downtown area of Toronto, optimizing management of the distribution system during planned work and unplanned emergency situations. Through this program, inter-station feeder ties will be provided remote operable switches that are under the control of the power system controllers. Using this configuration, the expected service restoration time would drop from an average of 8.2 hours to approximately one hour, providing a significant benefit to affected customers.

A summary of the program's benefits is provided below.

TABLE 3: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Improved outage restoration times for downtown customers ƒ Reduces likelihood of inventory losses due to loss of supply (eg: frozen good, perishables). ƒ Reduces likelihood of business closure due to loss of supply. ƒ The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $3.07 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.7.7). ƒ Accounting for capital program costs, the first year's activities deliver a positive NPV of $2.33 million, confirming the economic prudence of the investments (see Section E7.7.7).
Reliability	ƒ Provides alternate power supply to customers where none presently exists. ƒ Provides the ability to address virtually any station loss of supply incident, including flooding, equipment failure, HONI loss of supply, damage caused by third parties and environmental impairment.
Efficiency	ƒ Improves overall system efficiency through optimized distribution system management. Ability to remotely transfer the load from one station to another.
Safety	ƒ Provides alternate power supply to customers that depend on it for their health and safety, such as those relying on life-support equipment.

E7.7.3 Why the Program is Needed

The Downtown Contingency program is needed to mitigate the loss of supply risks related to partial or complete station outages in the downtown area of Toronto. Toronto Hydro plans to mitigate these risks by executing inter-station feeder-tie projects that will provide sufficient distribution load transfer capability during partial or complete station outages.

E7.7.3.1 Program Drivers

Table 4 provides the trigger and secondary drivers of the Downtown Contingency program, with the trigger driver being the need to mitigate critical risks to system reliability.

TABLE 4: PROGRAM DRIVERS

Trigger Driver	Reasoning
Reliability	ƒ There is significant, unmitigated risk of customers experiencing long outages due to station loss of supply incidents.
Secondary Drivers	**Reasoning**
Operational Constraints	ƒ During partial or complete station outage conditions, Toronto Hydro is unable to efficiently and quickly restore power to customers. ƒ Toronto Hydro is currently unable to transfer load between adjacent stations on temporary or permanent basis.
Safety	ƒ The loss of power supply for an extended time can put certain customers at risk, such as those that rely on life-support equipment. ƒ The loss of power supply during extreme weather events can put customers at risk.

(i) Reliability

The primary objective of the Downtown Contingency program is to address the risk of customers in the downtown area facing lengthy service disruptions caused by low probability, high impact events such as partial or complete station failure. All six inter-station feeder tie projects in the 2015 to 2019 program are expected to allow Toronto Hydro to remotely transfer loads to adjacent station feeders within one hour, resulting in reliability improvements for customers on these feeders.

While major downtown contingency incidents are infrequent, the occurrence of one would have a significant impact on system reliability if feeder ties are not out into place. In the past decade, seventeen partial and complete station outages have occurred in the downtown area, which have resulted in a total CHI of 1,369,668 (see Table 5). These represent a significant portion of all of the major loss of supply incidents that have ever occurred in downtown Toronto.

For example, in January of 2009, Dufferin TS was completely shut down because HONI's fire suppression system flooded the station; this incident was responsible for 626,692 CHI that year (62% of all downtown CHI) and 34,308 CI. Some customers were left without electricity for up to

24 hours. In all, this outage incident ranks as the worst loss of supply incident in the last ten years.

The most recent downtown contingency incident took place in July of 2013. Flooding at Richview station triggered an outage in Manby station, which in turn caused HONI supply failures at Strachan, Wiltshire, and Windsor stations. The incident resulted in a total of 33,875 CI and 50,777 CHI.

TABLE 5: DOWNTOWN CONTINGENCY OUTAGES AUGUST 2003 THROUGH JULY 2013

DATE	CMO (Customer Minutes Out)	CHI (Customer Hours of Interruption)	CI (Customers Interrupted)	OUTAGE DURATION (Minutes)	STATION NAME	OUTAGE CAUSE
14-Aug-03	22,272,720	371,212	9,010	2,472	Dufferin TS	Loss of supply -TS flooding
01-Dec-03	1,573,297	26,222	10,021	157	Main TS	Loss of supply - Raccoon on Main TS Transformer - T3
27-Jan-04	313,774	5,230	3,555	90	Terauley TS	Loss of supply - Snow
21-Aug-04	159,011	2,650	1,700	270	Strachan TS	Station Equipment Failure
29-Aug-04	74,460	1,241	1,020	73	Windsor TS	Loss of supply - TS Equipment failure
04-Dec-04	9,960	166	60	243	Windsor TS	Loss of supply - TS Equipment failure
23-Jan-05	2,304,288	38,405	3,556	632	Terauley TS	Flooding of T S basement - City water main broken
26-Jul-05	4,603,904	76,732	24,005	1,850	George & Duke MS	Loss of supply - TS Equipment failure
23-Aug-07	1,625,517	27,092	4,971	327	Glengrove TS	Defective Station Equipment
27-Nov-07	1,023,984	17,066	6,564	156	George & Duke MS	Loss of supply - Outage on HONI J1-J2 Ring bus @ Esplande TS
15-Jan-09	37,601,491	626,692	34,308	1,418	Dufferin TS	Adverse Environment
09-May-09	2,443,452	40,724	18,511	132	Dufferin TS	Loss of supply - Raccoon contact with T2 transformer

DATE	CMO (Customer Minutes Out)	CHI (Customer Hours of Interruption)	CI (Customers Interrupted)	OUTAGE DURATION (Minutes)	STATION NAME	OUTAGE CAUSE
09-May-09	1,104,831	18,414	8,307	133	Dufferin TS	Loss of supply - Raccoon contact with T2 transformer
05-Jul-10	4,022,761	67,046	36,984	138	Strachan TS	Loss of supply - Explosion @ Manby TS
08-Jul-13	1,083,808	18,063	15,271	76	Strachan TS	Loss of Supply - Manby & Richview TSs flooding
08-Jul-13	1,721,744	28,696	14,851	134	Wiltshire TS	Loss of Supply - Manby & Richview TSs flooding
08-Jul-13	241,052	4,018	3,753	68	Windsor TS	Loss of Supply - Manby & Richview TSs flooding
Total	82,180,054	1, 369,668	196,447	8,369		

In the incidents above, if inter-station feeder ties were available to transfer loads within one hour, the CHI would have been reduced from 1,369,668 to 196,447, an 86% improvement as illustrated in Figure 4 below.

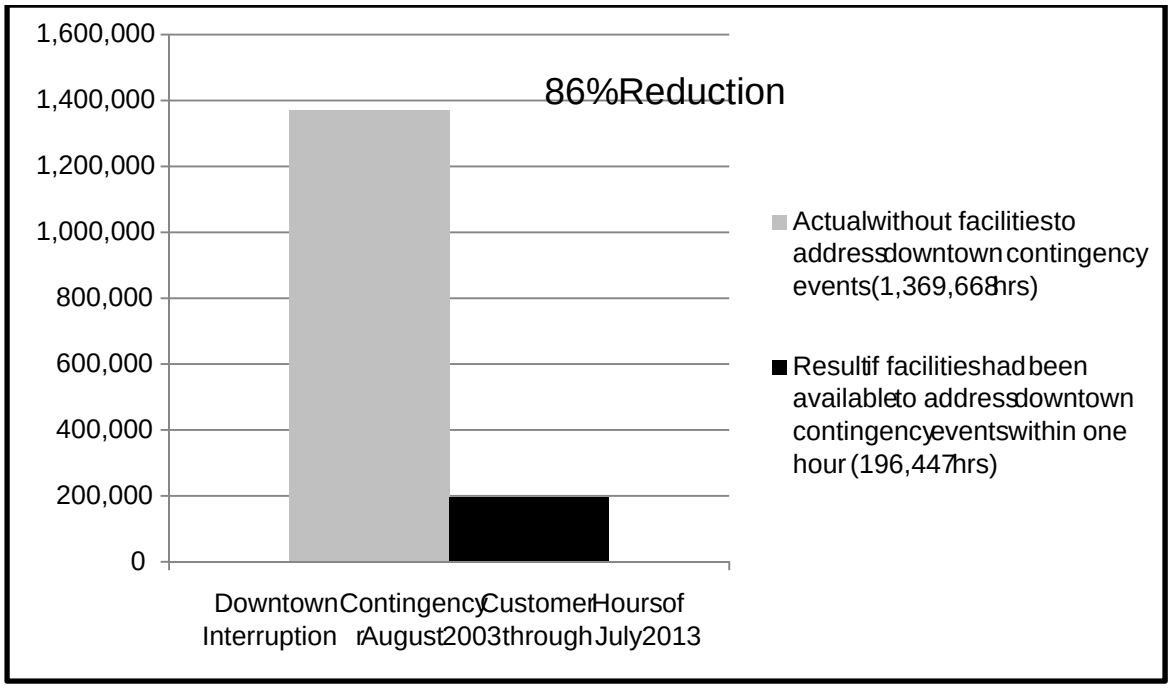


FIGURE 4: RELIABILITY IMPACT OF DOWNTOWN STATION LOAD TRANSFER IMPLEMENTATION

The fact that virtually all of the major loss of supply incidents have occurred in the last decade indicates that conditions in and around the 15 downtown stations are worsening as time progresses. Most of these incidents are due to flooding incidents, which are largely random and unpredictable, but can have considerable impacts. Historically, most flooding incidents were due to failure of man-made water systems. However, the three flooding incidents that occurred in 2013 were all due to extreme weather events. Climate change models for the Toronto area suggest that extreme weather conditions are likely to occur more frequently in future years, increasing the urgency to mitigate this risk. The only method of ensuring that such failures in the downtown area do not affect downtown customers is to introduce back-up supply through inter-station feeder ties.

(ii) Operational Constraints

The provision of inter-station feeder ties will provide new operational capabilities in the downtown area of Toronto, similar to what already exists in other parts of Toronto Hydro's system. Improvements to system operational efficiency and power restoration time will be enabled through the use of remote operable switches under the control of power system controllers, and

field crews will not need to be dispatched to perform switching operations for contingencies. Service restoration times are forecast to improve from a historic average of 8.2 hours interruption following a loss of supply event, to approximately one hour.

The Downtown Contingency program is also expected to enable Toronto Hydro to respond to both station and feeder capacity constraints that are not associated with loss of supply incidents. An example is urgent reactive maintenance work that must be performed on station equipment. Such work typically requires a portion of station equipment to be taken out of service, and may result in overloading the remaining equipment or feeders. Downtown Contingency inter-station feeder ties provide the ability to offload station equipment under such conditions.

(iii) Safety

The Downtown Contingency program is expected to improve the overall safety of the distribution system. In the event of a feeder fault, controllers would have the ability to remotely isolate and transfer a feeder load to another station and quickly re-supply customers with power. This will mitigate the consequence of long term outages to customers. Over the last ten years, Toronto Hydro's longest station outage was over 41 hours.

The customers most at risk from long term service interruptions are those electronic medical support equipment. Such equipment generally has battery back-up that can sustain service for several hours following a service interruption. A lengthy outage would almost certainly result in the failure of such equipment and could potentially put customers' health at risk.

The utility keeps track of life-support customers in a master list and, during service interruption situations, takes special actions to ensure their continued wellbeing, such as providing emergency generators. However, as enrollment in this program is voluntary, Toronto Hydro may not be aware of all affected customers.

Similarly, hospitals have many patients that could be put at risk in the event of lengthy power outages. Although hospitals have back-up generators, they typically have no more than one day's supply of fuel on hand. Finally, the loss of power during the winter and summer months can potentially pose safety risks to customers, as they depend on heating and cooling systems to moderate the temperate. In particular, seniors, infants, the disabled and people who are ill may face heightened risk.

Downtown Contingency inter-station feeder ties provide is expected to enable Toronto Hydro to restore service in about one hour during contingency situation. This outage duration is generally short enough to mitigate the majority of the above noted safety risks.

E7.7.4 Timing & Pacing of the Program

As per the table below, the total cost of the program over the 2015-2019 period is $3.36 million.

TABLE 6: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	1.09	4.66	0.05	1.09	1.04	0	0.74	0.74	1.00	0.88

Over the last five years, work has been conducted between several feeders of Dufferin TS and adjacent stations to provide inter-station feeder tie capabilities. This has resulted in the ability to transfer customer loads between adjacent stations in the downtown Toronto area. The timing of the Downtown Contingency program was established to ensure continuing progress on this long-term program while balancing resource usage against other system investment priorities during the 2015 to 2019 period.

The proposed program will allow remote, rapid transfer of customer loads on feeders between:

- Dufferin TS & Cecil TS
- Dufferin TS & Strachan TS
- Dufferin TS & Wiltshire TS
- Basin TS & Carlaw TS

The load transfer capabilities that would become available represents roughly 6% of Basin TS loading, 4% of Carlaw TS loading, 2% of Cecil TS loading, 20% of Dufferin TS loading, 6% of Strachan TS loading, and 6% of Wiltshire TS loading. In all, this program is expected to improve reliability issues at six of the 15 downtown stations, and provides backup supply to approximately 9,000 customers, or 53 MVA of load.

Originally seven Downtown Contingency projects were planned for the 2015 to 2019 period. However, two projects that were originally planned for 2015 have been rescheduled. One was advanced to 2014 because the critical path for this project permitted this change. The second

requires the prior installation of new A10-11E switchgear at Carlaw station and has been rescheduled for 2016. Replacement of this switchgear has been delayed to accommodate HONI transformer replacement constraints associated with the Pan Am Games. It is impractical to advance the other 2016 project to 2015, and, as a result, the two projects will be undertaken in 2016 and none in 2015.

E7.7.4.1 Ranking & Prioritization

The ranking and prioritization of the work within this program is predominantly based on the following factors:

- Historical Outages Data : Historical station outage data for the 15 downtown area stations has been assessed to determine the priority for inter-station feeder ties. Only supply related outages were considered (e.g. transmission system loss of supply, station equipment failure, external infrastructure failure, extreme weather events, etc.). Stations with a higher outage history received higher priority.

- Execution Complexities: Projects within the program that are easier to implement because they are associated with fewer technical and implementation difficulties will be completed first; OH feeders have fewer technical challenges as compared to UG feeders. For example, Toronto Hydro will have to ensure that downtown stations with underground feeders have sufficient space for feeder tie switches in UG vaults near stations and along the feeder tie locations. In addition, Toronto Hydro will have to undertake substantial civil work to upgrade UG vaults and cable chambers before underground inter-station feeder ties can be installed.

Based on these factors, six overhead feeder tie projects are planned for 2015 through 2019. Five out of the six inter-station feeder ties involve Dufferin station feeders.

E7.7.5 Program Execution

The projects to be completed under the Downtown Contingency inter-station feeder tie program are not associated with high program execution risks. For instance, Toronto Hydro is afforded flexibility as to where it places switching and tie locations, resulting in more design and construction options than is typically available for downtown program projects.

As shown in Figure 2, inter-station feeder tie projects involve the installation of new switches near each station and at feeder tie locations, and feeder extensions to the proposed feeder tie

locations. Depending on the complexity of project, it is expected to take 10 to 15 months to complete one inter-station feeder tie.

Typically, the following steps are considered in the planning and execution of an inter-station feeder tie project:

- Review the station outages history to find out which stations experience the most loss of supply outages;
- Review the adjacent stations buses to identify compatible bus configurations (e.g. low / high impedance or three-wire / four-wire bus);
- Review adjacent station feeder types (e.g. overhead / underground or normal / stand-by), routes, locations and loadings;
- Begin technical planning and design;
- Use the typical project planning scope process for developing and executing the inter-station feeder ties project.

Inter-station feeder tie operation is based on the "break then make" principal. With reference to Figure 2, this means that before tying a station (TS1) feeder to an adjacent station (TS2) feeder, the remote controlled load break switch on the tying station's (TS1) feeder must be opened first. Then, the remote controlled load break switch of the adjacent station's (TS2) feeder may be closed. This is required to avoid paralleling of two different stations.

While the 2015 to 2019 program mostly addresses the overhead (OH) distribution system, one underground switch will be installed to tie an OH feeder to an underground residential distribution (URD) feeder. Figure 5 is a photo of a SF_6 load break switch, which is used for underground residential distribution (URD) feeder. Figure 6 is a pole-mounted SCADA mate switch, which is used for overhead feeders.

FIGURE 5: 600A SF6 LOAD BREAK SWITCH

FIGURE 6: SCADA MATE – POLE MOUNTED SWITCH

E7.7.5.1 Proposed Work Plan

Under the Downtown Contingency program, six inter-station overhead feeder tie projects are proposed to be completed from 2015 to 2019. Five of the six inter-station projects involve Dufferin Station. Table 7 lists the proposed projects.

TABLE 7: 2015-2019 LONG TERM PLAN

Year	Feeder	Station
2015	-	-
2016	A204BN & A250E feeders-	Basin & Carlaw stations
2016	A273DN & A57W feeders	Dufferin & Wilshire stations
2017	A256DN & A34W feeders	Dufferin & Wilshire stations
2018	A257DN & A230T feeders	Dufferin & Strachan stations
2018	A530DN & A390CE feeders	Dufferin & Cecil stations
2019	A254DN & A390CE feeders	Dufferin & Cecil stations

E7.7.5.2 Program Risks

The following are program risks that Toronto Hydro plans on mitigating:

- The City of Toronto is expected to perform work in the next few years along some major and minor corridors in the downtown area. Road construction moratoriums and the difficulty of obtaining city permits for civil work will potentially create issues for the downtown contingency program. Toronto Hydro will coordinate its work with the city in line with its requirements and schedule work accordingly to mitigate these risks.

- Toronto Hydro is required to co-ordinate with HONI with respect to the addition or replacement of station switchgear (buses) and the replacement of high impedance neutral reactors of power transformer with low-impedance reactors. Toronto Hydro cannot use the bus until HONI completes their work, which puts the program schedule at risk. Toronto Hydro will mitigate this issue by coordinating with HONI to create a jointly planned schedule with work that be completed in phases.

E7.7.5.3 External Constraints

External third parties may affect the Downtown Contingency Program. Some of the program's projects depend on equipment and plant that is not owned by Toronto Hydro. In such cases, work will need to be coordinated with the applicable third party, and may need to be postponed or re-designed. Examples of third party infrastructure include HONI equipment, wired and wireless telecommunications infrastructure, wired and wireless television services, and Toronto Hydro infrastructure located on private property.

E7.7.6 Evaluation of Alternatives

E7.7.6.1 Quantification/Evaluation of Options

Three alternatives were considered for this program:

- Maintain the status quo,
- Use mobile generators and switchgears, and
- Introduce inter-station feeder ties.

(i) Status Quo

By maintaining the status quo, Toronto Hydro would not introduce load transfer capability by tying feeders from one station to an adjacent feeder. This option is not recommended because customers would continue to be exposed to the risk of prolonged outages under partial or complete station outage conditions.

(ii) Mobile Generators and Switchgear

Mobile Generator units can be used during the construction and maintenance of the distribution system, or to supply emergency loads during a feeder failure. Figure 7 below is a mobile generator.

FIGURE 7: MOBILE GENERATOR

Mobile generators

Mobile generators are not suitable for low probability, high-impact station outage scenarios (e.g. HONI loss of supply, station equipment failure, external infrastructure failure, extreme weather events, etc.) due to the high initial capital and high maintenance costs.

Typically no more than twelve 2 MVA generators are available within a 24 hour notice period to pick up customer loads following a major station incident. Three to five generators would be

required per feeder for peak loading, with an average of about 35 feeders per station. This represents less than 10% of a typical downtown station's maximum capacity and therefore the use of this equipment can only be considered a partial, inadequate solution.

Mobile switchgear

Mobile switchgear is not suitable for low probability, high-impact station outage scenarios (e.g. HONI loss of supply, etc.)

If HONI supply is operating normally, but Toronto Hydro's 13.8kV station switchgear fails and is not repairable, then the feeders connected to this switchgear will be unable to provide power to downstream customers. Under such conditions supply to the downstream customers can be maintained by:

- Transporting and installing a mobile switchgear near the affected station,
- Connecting mobile switchgear to the 13.8kV secondary of the HONI existing 115/13.8kV, power transformer at the station, and
- Re-cabling and connecting feeders from the affected station switchgear's to the mobile switchgear,

Under such scenarios, following a switchgear failure, customers can expect to experience a day to week long service interruption depending on which station is affected. Toronto Hydro has no history of such types of station failures occurring in the downtown area that have resulted in the permanent loss of station switchgear.

(iii) Inter-Station Feeder ties

The use of inter-station feeder ties is recommended because it is the only option that will provide Toronto Hydro with the capability to restore supply to most of its downtown customers during partial or complete station outages conditions and any loss of supply incident.

The cost of ownership (COO) and program net benefit (NPV) associated with Downtown Contingency is further detailed in Tables 8 and 9. The cost of ownership is established for both the existing state (COO_E), and the proposed new state (COO_N) based on the first year of planned activities in this program. The cost of ownership (COO) of a state reflects the risk of asset failure, including both direct and indirect costs; these costs include customer interruptions, emergency repairs, and asset replacements associated with that design. Costs in maintenance activities are

also included for both states. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first of activities, the Downtown Contingency produces a net benefit (NPV) value of $2.33 million as shown in Tables 8 and 9.

TABLE 8: COST OF OWNERSHIP OF EXISTING ASSETS/STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk [AR_E] customer outage cost	$4.48
Non Asset Risk [NAR_E]	$0
Maintenance Cost [MC_E]	$0
Additional Quantifiable Benefits [AQB_E]	$0
Cost of Ownership of Existing Assets [COO_E]	$4.48

TABLE 9: STATION-TO-STATION FEEDER TIES BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 1: Station-to-Station Feeder Ties	
Asset Risk [AR_N] customer outage cost	$1.38
Non Asset Risk [NAR_N]	$0
Maintenance Cost [MC_N]	$0.03
Additional Quantifiable Benefits [AQB_N]	$0
Cost of Ownership of New Assets [COO_N]	$1.41
Option 1: Program Net Benefit (NPV_1)	
Difference in Cost of Ownership [$ûCOO_1 = (COO_E - COO_N)$]	$3.07
Program Cost [PC_1]	$0.74
Program Net Benefit [$NPV_1 = (ûCOO_1 - PC_1)$]	$2.33

E7.8 Customer-Owned Substation Protection

AGING CUSTOMER-OWNED SUBSTATION EQUIPMENT

E7.8.1 Summary

Program Description

The Customer-Owned Substation Protection (COSP) program is designed to address customer-owned substations which may have an effect on the larger grid. These are defined as customer-owned civil structures that accommodate customer-owned electrical equipment and that connect to Toronto Hydro's distribution system. There are currently 2,110 customer-owned substations in the Toronto Hydro network; 1,417 substations are located in the Horseshoe area (i.e. the former suburbs) and 693 are in the vicinity of downtown Toronto.

The customer-owned protection devices associated with these substations do not alone offer sufficient protection. It is important that utility-owned protection devices be installed upstream from the customer-owned substations, except in situations where the customer-owned device is located in Toronto Hydro's underground network in the downtown area of Toronto. There are several instances in which the current configuration is non-compliant with Toronto Hydro standards, either because: (1) Toronto Hydro-owned protection devices are absent altogether or need to be replaced; or (2) customer-owned protection devices do not meet required standards. Proper coordination between the protection devices and the station breaker is necessary to localize the negative impact of a fault at the customer-owned substation. Therefore, non-

compliance can lead to a lack of adequate protection, which, historically, has resulted in service disruptions.

To remedy this situation, Toronto Hydro proposes to install or replace Toronto Hydro-owned high voltage protective devices and will coordinate them with station breaker relays and the customer-owned protection devices.

The COSP program is made up of two phases. In the "Audit Phase", Toronto Hydro plans to audit all of the customer-owned and Toronto Hydro-owned protection devices to assess their coordination, condition and operability, including their ability to provide protection. This phase will begin in early 2015 and is scheduled to be completed by the end of 2018.

The second phase of the program, the "Implementation Phase", will commence on a rolling basis once audit results become available. As such, Toronto Hydro expects the Implementation Phase to commence by the third quarter of 2015. It will involve a mix of equipment upgrades to be completed by customers and the installation by Toronto Hydro of high-voltage protection devices upstream from customer-owned substations. During this phase, Toronto Hydro plans to also address previously identified issues associated with poorly maintained assets.

The anticipated benefits of this program are summarized in the following table.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Helps prevent customers from experiencing power outages. ƒ Increases the quality of power, providing customers with a better service and experience.
Reliability	ƒ Reduces the impact of interruptions (CI and CHI) by isolating outages. ƒ Anticipated reduction in interruptions would reduce stress to equipment on the grid.
Safety	ƒ Improves the safety of distribution system for both the general public and Toronto Hydro employees.
Efficiency	ƒ Information obtained regarding customer-owned substations through this program could also be used to verify and update the data captured in the GIS. ƒ Verifying and updating data regarding customer-owned equipment would also add flexibility for existing or future programs and avoid the additional work needed for other teams to collect this data. ƒ Controllable costs could be reduced because the high voltage protection devices will be coordinated with circuit breakers and act accordingly to prevent wide-spread outages

Program Drivers

The trigger and secondary drivers for this program are outlined in Table B.

TABLE B: PROGRAM DRIVERS

Primary Driver	Reasoning
Reliability	ƒ The failure of customer-owned equipment resulted in approximately 17 interruptions per year. ƒ If customer-owned protective devices fail to clear the fault at the customer-owned substations and the Toronto Hydro-owned protection devices are not in place or coordinate properly, there is likelihood of a larger outage affected a broad base of customers. In absence of the proper upstream high voltage protective devices, station breakers will operate, interrupting all customers on the feeder. ƒ Aged and/or unmaintained customer-owned protection devices pose significant reliability issues because of their risk of failure.
Secondary Driver	**Reasoning**
Safety	Currently, 22% of the visited customer-owned substations in Horseshoe area were identified as being poorly maintained or past their useful life. These substations can create safety hazards for both the general public and Toronto Hydro employees: ƒ Heavily rusted electrical equipment within the substation can be a fire hazard. ƒ Poorly maintained transformers and glass-made lightning arresters could fail and cause damage to their surroundings. ƒ Poorly maintained civil structures within the customer-owned substation (e.g., heavily rusted substation tower, pole and fence/door) can collapse.

Preferred Alternative

Toronto Hydro considered the following options for addressing the potential impact of poorly maintained customer-owned stations and inadequate protection equipment.

(i) Status Quo – Continue to perform repairs reactively, after equipment has failed and/or following an outage event. Reliability challenges and safety risks are expected to continue to worsen over time.

(ii) Proposed Program – Execution of this program, whereby inspections are performed and protection is enabled at customer-owned substations over the next five-year period wherever necessary.

The proposed program is preferred as it mitigates the safety, reliability and operational flexibility issues related to deteriorating and poorly coordinated customer-owned equipment.

Timing and Pacing

The total estimated cost for the COSP program over the 2015 to 2019 period is forecasted to be approximately $4.04 million. This estimation is based on costs of inspection, analysis, design and construction of Toronto-Hydro-owned protective devices for an estimated 210 customer-owned substations. There is no historical spending for the COSP program as there has not been a systemic program-based approach to this issue to date.

The installation of utility-owned protection devices is expected to occur at a rate of 50 substations a year, completing 200 substations from 2016 to 2019. Toronto Hydro plans to address the remaining 10 substations during the 3rd and 4th quarters of 2015. The estimated costs of the COSP program for the 2015-2019 period are provided in Table C below.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Annual Spend ($M)	0	0	0	0	0	$0.59	$1.03	$1.03	$0.78	$0.61

E7.8.2 Program Description

The Customer-Owned Stations Program (COSP) is designed to address customer-owned substations which may have an effect on the larger grid. These are defined by Toronto Hydro's Conditions of Service as customer-owned civil structures that accommodate customer-owned electrical equipment and that connect to Toronto Hydro's distribution system. Figure 1 shows the locations of the 2,110 customer-owned substations in the Toronto Hydro network; 1,417 substations are located in the Horseshoe area (i.e. the former suburbs) and 693 are in the vicinity of downtown Toronto.

FIGURE 1: MAP OF ALL CUSTOMER-OWNED SUBSTATIONS IN THE TORONTO HYDRO NETWORK

Customer-owned substations are used by commercial and industrial customers who tend to have significant power usage. Customer-owned substations include both civil assets (e.g. substation overhead steel structures) and electrical assets (e.g. high voltage transformers, high voltage protective devices, and primary switchgear). Figure 2 shows the typical structures of both open and enclosed high voltage customer-owned substations.

FIGURE 2: EXAMPLES OF OPEN AND ENCLOSED CUSTOMER-OWNED SUBSTATIONS

Customer-owned protection devices do not alone offer sufficient protection. It is important that utility-owned protection devices be installed upstream from the customer-owned substations, except in situations where the customer-owned device is located in Toronto Hydro's underground network in the downtown area of Toronto. The redundancy in protection and coordination is necessary to ensure the failure of a customer-owned protection device to clear a fault does not trigger the station breaker and interrupt other customers on the same feeder.

There are several instances in which the current configuration is non-compliant with Toronto Hydro standards, either because: (1) Toronto Hydro-owned protection devices are absent altogether or need to be replaced; or (2) customer-owned protection devices do not meet required standards. Proper coordination between the protection devices and the station breaker is necessary to localize the negative impact of a fault at the customer-owned substation. Therefore, non-compliance can lead to a lack of adequate protection, which, historically, has resulted in several service disruptions. For example, in July 2010, the failure of a customer-owned arrester within the substation at 40 Titan Road caused a power outage. Feeder 38-M3's circuit breaker auto-reclosed and immediately tripped, resulting in 1,090 Customers Interrupted (CI) and 281 Customer Hours Interrupted (CHI). The lack of an upstream Toronto Hydro-owned protection device is partly responsible for this outage (please refer to Section E7.8.3.1 for additional details regarding reliability issues).

In addition to the reliability issues in connection with non-compliance with standards, customer-owned substations also pose several safety risks to the general public and to Toronto Hydro crew members working in close proximity to the equipment. Safety risks include fire hazards (if electrical components are unmaintained and heavily rusted), environmental hazards (if equipment is leaking oil), and other types of damage (please refer to Section E7.8.3.1 for additional details regarding reliability issues).

Toronto Hydro crews are required to operate and be in proximity to customer-owned equipment to off-load customers under the following circumstances:

(1) A fire at the customer's premises;

(2) To control backfeed caused by damaged Toronto Hydro-owned conductors;

(3) To disconnect customer-owned equipment when there is customer related issues (e.g., damaged customer-owned conductors); and

(4) When the customer-owned equipment or vegetation has an impact on the reliability of Toronto Hydro's distribution system.

If customer-owned equipment and upstream Toronto Hydro-owned protection devices are not coordinated with each other and with the applicable station breaker, there is a risk that in the event of a fault, all customers on the applicable feeder would experience a power interruption because the station breaker would operate before the protection devices do. As well, in some cases, Toronto Hydro-owned protective devices may not be in place because legacy standards did not require them at the time of construction. Finally, in other situations, current customer-owned protection devices may be absent or inadequate, details of which is discussed in section E7.8.3.1. To remedy these issues and ensure that faults at customer-owned substations are isolated, Toronto Hydro proposes to install or replace Toronto Hydro-owned high voltage protective devices and will coordinate them with station breaker relays and the customer-owned protection devices.

The COSP program is made up of two phases. In the "Audit Phase", Toronto Hydro plans to audit all of the customer-owned and Toronto Hydro-owned protection devices to assess their coordination, condition and operability, including their ability to provide protection. This phase will begin in early 2015 and is scheduled to be completed by the end of 2018.

The second phase of the program, the "Implementation Phase", will commence on a rolling basis once audit results become available. As such, Toronto Hydro expects the Implementation Phase to commence by the third quarter of 2015. It will involve a mix of equipment upgrades to be completed by customers and the installation by Toronto Hydro of high-voltage protection devices upstream from customer-owned substations. During this phase, Toronto Hydro plans to also address previously identified issues associated with poorly maintained assets.

One of the following two options will be implemented to address any problems identified through the engineering analysis of customer-owned substation equipment and associated protection devices:

(1) If Toronto Hydro-owned protective devices are no longer adequate because of changes to the customer-owned equipment, or such devices are not in place where needed, Toronto Hydro would install or replace its protection devices.

(2) If the condition of customer-owned equipment is an issue, Toronto Hydro would advise the customer to upgrade their equipment to ensure compliance with the utility's standards, as determined by equipment's physical conditions and protection settings (please refer to section E7.8.5.2 for details).

The COSP program will first address sites on Toronto Hydro's overhead distribution system, as they are simpler to access and address. With respect to the underground system, Toronto Hydro will primarily focus on reviewing existing customer protection and coordination schemes and will undertake construction only where necessary, as identified by thorough analysis (please refer to section E7.8.3.1 for guidelines for customer-owned substation protection and connections to distribution system). This planning decision was made in light of the unique structures and connections of customer-owned substations on the underground distribution system, and the relative complexity of the system itself.

Toronto Hydro plans to invest an estimated $4.04 million in the COSP program during the 2015 to 2019 period. This investment involves the construction of an estimated 630 Toronto Hydro-owned single-phase protection devices at 210 customer-owned substations, as shown in Table 1. Toronto Hydro expects to install protection devices at these substations because they are currently missing upstream, Toronto Hydro-owned protection devices, as determined by Toronto Hydro's GIS platform (refer to section E7.8.3.1, subsection: Program Asset Demographic). If more substations are identified through the completion of the GIS review and the actual site inspections and analysis, Toronto Hydro plans to address these locations beyond the 2015-2019

timeline. Toronto Hydro will notify the customer if deficiencies are identified at the customer-owned substation. The repairs or upgrade of the customer-owned equipment shall be carried out by the customer at their expense (refer to section E7.8.5.2 Standard & Regulation Adherence).

TABLE 1: ASSETS TO BE INSTALLED

Assets (Units)	2015	2016	2017	2018	2019	Total
High-voltage protection device (single-phase)	30	150	150	150	150	630

The costs for this program were calculated based on the cost of installing in-line fuse products as required by Toronto Hydro standards (10-1300C fused disconnect in-line switches for primary voltage of 13.8 and 27.6 kV). In addition, Toronto Hydro added 25% for contingency cost purposes (15% standard project contingency and 10% risk contingency), as the utility may need to remove or replace other assets or perform other activities to complete the construction and installation of a protection device. In all, the average unit cost is forecasted to be approximately $6,410 per high voltage protection device (single-phase). A detailed list of estimated project spending for 2015 can be found in Table 7, "2015 Projects", in section E7.8.7.

A summary of anticipated program benefits is provided in the table below.

TABLE 2: PROGRAM BENEFITS

Customer Value	ƒ Helps prevent customers from experiencing power outages, which could otherwise lead to monetary losses (e.g., potential revenue loss from retail sales). ƒ Helps improve the quality of power, which would provide customers with a better service and experience.
Reliability	ƒ Power reliability would be enhanced through the upgrade and maintenance of customer-owned equipment. ƒ Reduces the impact of interruptions (CI and CHI) by isolating outages. ƒ A reduction in interruptions will reduce stress to equipment on the grid.
Safety	ƒ Improves the safety of distribution system for both the general public and Toronto Hydro employees.
Efficiency	ƒ Information obtained regarding customer-owned substations through this program could also be used to verify and update the data captured in the GIS. ƒ Verifying and updating data regarding customer-owned equipment would also add flexibility for existing or future programs and avoid the additional work needed for other teams

	to collect this data. ƒ Controllable costs could be reduced because the high voltage protection devices will be coordinated with circuit breakers and act accordingly to prevent wide-spread outages

E7.8.3 Why the Program is Needed

The COSP program is needed so that Toronto Hydro can ensure that customer-owned protection devices are properly maintained and that appropriate safeguards are in place, including Toronto Hydro-owned protection devices. In doing so, Toronto Hydro expects to minimize existing reliability issues (refer to section E7.8.3.1) and enhance the protection of other customers from interruptions that would otherwise be caused by the failure of customer-owned equipment at a specific substation. In addition, this program will enhance the safety of the system.

E7.8.3.1 Purpose

Table 3 presents the trigger and secondary drivers for the COSP program. This program's primary driver is reliability.

TABLE 3: CUSTOMER-OWNED SUBSTATI ON PROTECTION PROGRAM DRIVERS

Trigger Drivers	Reasoning
Reliability	ƒ The failure of customer-owned equipment has resulted in approximately 17 interruptions per year. ƒ If customer-owned protective devices fail to clear the fault at the customer-owned substations and the Toronto Hydro-owned protection devices are not in place or coordinate properly, there is likely to be a larger outage affected a broad base of customers. In absence of the proper upstream high voltage protective devices, station breakers will operate, interrupting all customers on the feeder. ƒ Aged and/or unmaintained customer-owned protection devices pose significant reliability issues because of their risk of failure.
Secondary Drivers	**Reasoning**
Safety	Currently, 22% of the visited customer-owned substations in the Horseshoe area were identified as being in need of maintenance or past their useful life. These substations can create safety hazards for both the general public and Toronto Hydro employees: ƒ Heavily rusted electrical equipment within the substation can be a fire hazard. ƒ Poorly maintained transformers and glass-made lightning arresters could fail and cause damage to their surroundings. ƒ Poorly maintained civil structures within the customer-owned substation (e.g., heavily rusted substation tower, pole and fence/door) can

	collapse.

The trigger driver for this program is reliability. During a fault, an uncoordinated upstream protection device is a device that fails to act after the customer-owned protection device operates, but before the station breaker comes into action. If the Toronto Hydro-owned protection devices are improperly set, or if they are absent altogether, the inability for a customer-owned protection device to isolate a fault will lead to the station breakers triggering, which would interrupt the entire feeder.

While Toronto Hydro has protection devices in most places in the Horseshoe area, in some instances, these devices are inadequate or absent altogether. There are several explanations as to why this issue might exist:

(1) At the time of original construction, the impact that a customer's load could have on the system may have been negligible. However, over time, a customer's load may have risen considerably. Given the increase in customers and associate loads, these substations can now have a significant impact on the reliability of power supply and can no longer be neglected.

(2) Some customers could be large enough for the substations to not have its upstream protection setup at the time of original construction (e.g., substation is too large to have upstream fuses). Today, the gang-operated load-break SCADA switches could be used to connect this type of large substation to the feeder trunk as specified in Toronto Hydro's current standards.

(3) At the time of construction, the manufacturers might not have had the preferred protection devices available (e.g., fuse sizes were limited) for the specific customer-owned substations and loading requirements. As technology evolved, more options are now available (e.g., fuses at higher rating), which would provide better protection to the system.

As discussed above, in addition to issues with respect to customer-owned protection devices, Toronto Hydro must also address its own assets. Toronto Hydro plans to further investigate and minimize the existing and potential impacts associated with its upstream protective devices. More specifically, Toronto Hydro must ensure that such devices are in-line with the utility's most recent standards.

The previously discussed situation that took place at 40 Titan Road in July 2010 illustrates the issues that can arise when utility-owned protection devices are not in place. The current standards require the in-line fused switches to be put in as a second line of defense. Regardless of the physical condition of the customer-owned equipment at this location, redundancy in protection and coordination of equipment was necessary to prevent outages to other customers on the same feeder in the event the customer-owned protection device failed to clear the fault.

As specified in Toronto Hydro Requirements for The Design and Construction of Customer-Owned High Voltage Substations Toronto Hydro requires its protection devices to be in place, upstream from the high-voltage customer-owned substations. This is consistent with the industry standards and good utility practice. It is designed to prevent interruptions to other customers when customer protection device fails to clear the fault at one substation. The following summarizes the current three main options and provides further guidelines for customer-owned substation protection and connections to the distribution system.

1. Lateral fuses are used:
    1.1. Lateral feeder with aggregate transformer MVA under 11 MVA (27.6 kV network).
    1.2. Maximum single transformer or aggregate MVA of 5 MVA at the customer-owned substation. (27.6 kV network).
    1.3. Lateral feeder with aggregate transformer MVA under 5 MVA (13.8 kV overhead network only).
    1.4. Maximum single transformer or aggregate MVA of 1.5 MVA at the customer-owned substation. (13.8 kV overhead network only).
2. A three-phase, gang-operated load-break SCADA switch may be used to connect the customer to the feeder trunk for customers with a maximum load of up to 10 MVA (27.6 kV network)
3. Connect directly to the main underground feeder (13.8 kV underground network).

Absent or uncoordinated protection devices continue to cause sustained interruptions at the feeder level. According to Toronto Hydro's Interruption Tracking Information System (ITIS), there have been 83 interruptions that were caused by the failure of customer-owned equipment from 2009 to 2013. Figure 3 shows the outage distribution across the City of Toronto. Approximately

53% of the interruptions occurred in Toronto Hydro's overhead distribution system while 47% were in the underground network.

FIGURE 3: HISTORICAL RELIABILITY EVENTS 2009-2013

In 73 of the events mentioned above, the customer-owned and upstream utility-owned protective equipment failed to minimize the faults, which impacted many upstream customers. In all, these events led to 58,382 CI and 24,665 CHI. On average, if the impacts were limited to the faulted customer, each interruption would have only cause two CHI and one CI. Instead, each outage produced an average of 800 CI and 338 CHI. These figures illustrate the importance of verifying that customer-owned protection devices are in compliance with Toronto Hydro's current standards, and that Toronto Hydro-owned protection devices are installed and properly functioning upstream.

It should be noted that the outage figures mentioned above do not take into account 10 of the 83 outages in which the fault was successfully isolated at the customer's location. These faults produced a total CHI and CI of 20 and 10 respectively.

Figure 4 illustrates the number of interruptions that have occurred since 2009 as a result of faults on customer-owned substations, which impacted upstream customers. The restoration of service following each interruption can take anywhere from a few minutes to hours, which can ultimately result in thousands of hours in total CHI.

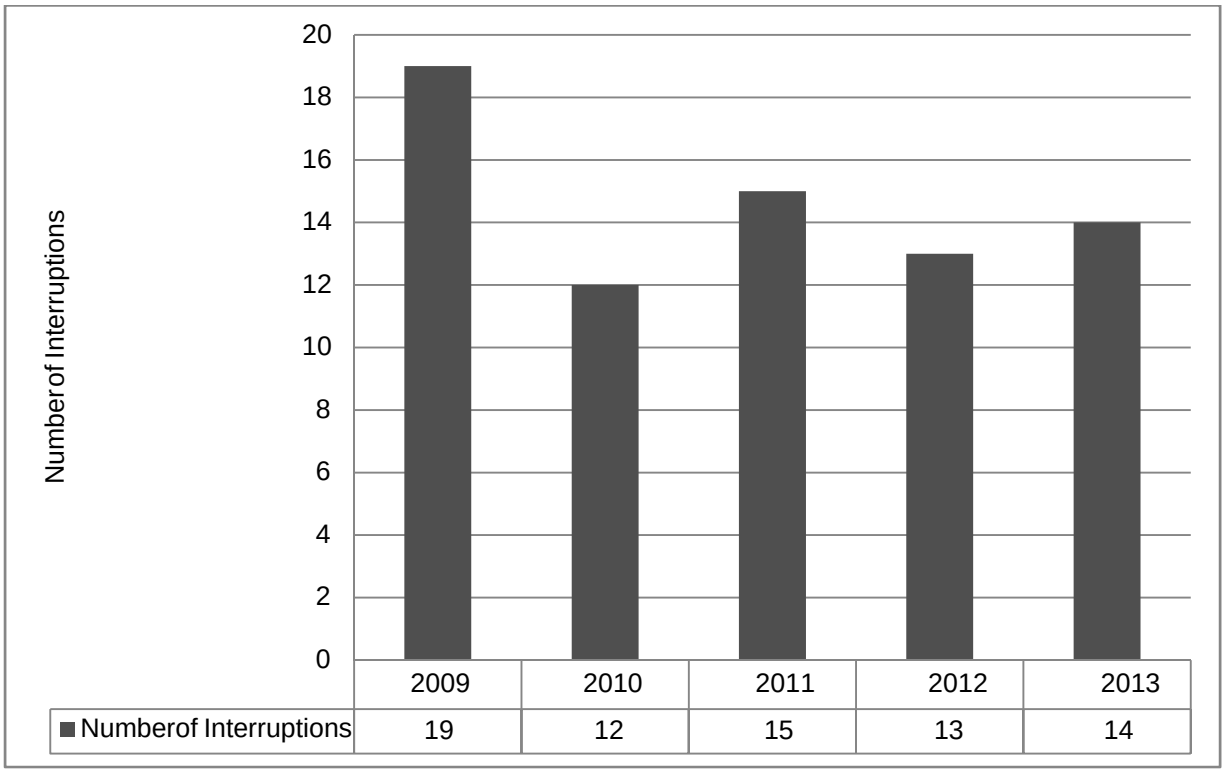


FIGURE 4: INTERRUPTIONS DUE TO FAILURE OF CUSTOMER-OWNED ASSETS

In addition to the issues caused by absent or inadequate utility-owned protection devices, poorly maintained customer-owned substations also cause reliability and safety issues. Customer-owned assets have a much higher chance of failure due to age or improper maintenance. In particular, electrical equipment can cause short circuits and fire hazards if it is heavily rusted. As well, faults can occur if the customer fails to remove vegetation located inside of a substation or close to the overhead incoming feeder. In addition, aged or unmaintained civil structures are at risk of failing and collapsing, which can damage the surrounding area and create faults.

Figure 5 shows customer-owned assets that have been poorly maintained. Severe rust is visible on all the electrical equipment. This equipment is extremely dangerous and can cause injury. For

example, an overloaded transformer with poorly maintained dielectric fluid is more likely to fail and can lead to an electrical fire.

FIGURE 5: EXAMPLES OF AGED AND POORLY MAINTAINED EQUIPMENT

Without proper isolation and protections in place, customer-owned asset failures will cause reliability issues for the grid, interrupting many upstream customers and putting stress on Toronto Hydro's assets. As well, these issues create safety issues for the general public and Toronto Hydro crew members. Accordingly, through the proposed program, Toronto Hydro plans to identify the poorly maintained substations and will advise the asset owner that equipment upgrade, repair or replacement is necessary (refer to section E7.8.5.2).

Based on data collected from the site inspection of 256 substations (185 are in the Horseshoe area and 71 are in the Downtown area), Toronto Hydro determined that 21 of 185 customer-owned substations visited in the Horseshoe area (which is primarily overhead) were identified as

having power transformers past their useful lives. Table 4 provides the useful lives of equipment that is typically found in customer-owned substations.

TABLE 4: USEFUL LIFE FOR CUSTOMER-OWNED SUBSTATION

Assets (Units)	Asset Size	Useful Life (years)
Power Transformer	5 MVA, 27.6 kV	44
Station Steel Structures and Overhead Bus Work	Bus Structure for 27.6 kV	67
Outdoor Station Disconnect Switch	600 A, 27.6 kV	40

The following example illustrates the issues associated with inadequate or missing Toronto Hydro-owned protection devices and non-functioning customer-owned protection devices. In August 2012, the customer-owned load break switches on both A72WR and A73WR feeders flashed over and faulted. As a result, the circuit breakers of feeders A72WR, A73WR, A26WR and A43WR automatically operated to open the circuit. The outage lasted six hours and affected four of Toronto Hydro's large customers: 18 York Office Tower, Famous Players, Ice Condo Temp and Maple Leaf Square. Proper upstream Toronto Hydro-owned protection devices would have isolated the fault to the substation at 16 York Street and minimized the impact to other customers.

Program Asset Demographics

Toronto Hydro is currently in the process of reviewing the Geographic Information System (GIS) for missing utility-owned protection devices for customer-owned substations in the overhead distribution system. This exercise is the first step in identifying the customer-owned substations in Toronto Hydro's distribution system that should be targeted by this program. Up to May 31, 2014, 210 customer-owned substations without upstream utility-owned protection devices had been identified within the overhead distribution network. Toronto Hydro expects this total to grow upon the completion of the review process in GIS. The accuracy of the above data will be improved through physical inspections of customer-owned substations.

In some instances, the proper utility-owned protective devices may not be installed upstream either due to the legacy standards that existed at the time of construction (as was the case in the 40 Titan Road example in the Program Description) or because customers upgraded or replaced their equipment and failed to communicate these changes to Toronto Hydro. In the latter case, the existing protection settings may not be effective or in alignment with the upgraded/replaced equipment.

A sample including 214 customer-owned substations (approximately 10% of the total population) was initially planned for preliminary inspection and analysis. Analysis of the remaining substations will be carried out upon completion of the sample population. As of May 31, 2014, Toronto Hydro has visited 256 customer-owned substations (214 sample locations and an additional 42 substations). Of those 256 customer-owned substations, 185 are in Horseshoe and 71 are in Downtown. The analysis of the visited substations is in progress, which includes asset assessment of the substation as well as protection and coordination.

During the sample substations inspections in the Horseshoe area, 64 of the 185 visited substations were found to be missing upstream utility-owned protection devices. All 64 of these substations are amongst the substations first identified in the GIS. All 71 substations visited in the downtown Toronto area are located in Toronto Hydro's underground network. All of these substations are missing upstream Toronto Hydro-owned protection devices located in between customer-owned protection devices and the station breakers.

The site visits are conducted by way of visual inspections. 40 out of 185 (22%) customer-owned substations that were visited in the Horseshoe area have been identified as either aged or poorly maintained, while three out of 71 substations (5%) in the downtown area of Toronto were deemed aged or poorly maintained. However, Toronto Hydro expects the number for downtown area of Toronto to be higher due to the missing manufacture date of the customer-owned equipment in most of the inspected substations. If the current ratios hold for the entire population, about 312 of the 1,417 substations in Horseshoe area and 35 of the 693 substations in the downtown area of Toronto will have similar issues. Based on the current findings, through the COSP program, Toronto Hydro plans to first inspect and analyze the remaining customer-owned substations in the Horseshoe area (mainly overhead network) and the substations in the downtown area of Toronto (underground network).

TABLE 5: STATUS OF CUSTOMER-OWNED SUBSTATION INSPECTIONS

	Number of Customer-owned Substations	Number of Sample Substations (Initially Planned for Inspection)	Number of Inspected Substations as of May 30, 2014 (Actual)	Number of Substations without utility-owned protection devices	Number of Substations that identified as aged or poorly maintained
Horseshoe	1,417	144	185	64	40
Downtown	693	70	71	71	3
Total	2,110	214	256	135	43

As discussed earlier in the Program Asset Demographic section, Table 6 illustrates the findings of the sample substations inspection. Please note that the sampling and the GIS review are two separate processes and the candidates were all randomly chosen. The inspection work of the 214 sample substations was completed in May 2014, at which point an additional 42 substations were inspected to increase the available dataset.

E7.8.4 Timing & Pacing of the Program

As per the table below, the total estimated cost for the COSP program over the 2015 to 2019 period is $4.04 million. Program spending was derived based on the costs of the inspection, analysis, design and construction of Toronto-Hydro-owned protective devices upstream for the estimated 210 customer-owned substations.

TABLE 6: HISTORICAL & FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	$0.59	$1.03	$1.03	$0.78	$0.61

The Implementation Phase will commence on a rolling basis once audit results become available. As such, Toronto Hydro expects the Implementation Phase to commence by the third quarter of 2015. That phase will involve a mix of equipment upgrades to be completed by customers and the installation by Toronto Hydro of high-voltage protection devices upstream from customer-

owned substations. During this phase, Toronto Hydro will also address previously identified issues associated with poorly maintained assets.

Toronto Hydro plans to install 150 Toronto Hydro-owned protection devices at 50 customer-owned substations per year through 2016-2019, for a total of 200 substations. The remaining 10 customer-owned substations will be addressed with the use of 30 Toronto Hydro-owned protective devices (single-phase) in the 3rd and 4th quarters of 2015. This timeline will allow Toronto Hydro to complete the construction work for all 210 substations within the 2015-2019 period.

E7.8.4.1 Ranking & Prioritization

As discussed earlier, inspection and analysis work is currently in progress to determine the condition of assets and the current protection scheme. The 10 customer-owned substations that have been identified as missing upstream utility-owned protection devices have already been inspected are scheduled to be addressed in 2015. Three out of the 10 substations have been identified as being aged and/or poorly maintained. As discussed earlier in the narrative, customer-owned substations in the overhead distribution system will be targeted first followed by the ones within the underground system. Specific substations will be determined to have a higher prioritization in the program execution phase based on the physical condition of the inspected assets and absence of utility-owned protection devices. With that in mind, sequencing of work with the COSP program is based on the following four factors:

(1) Customer-owned substations that are in Toronto Hydro's overhead distribution system will be analyzed first. Overhead connections are more susceptible to reliability issues such as faults caused by trees and animals, as the electrical components are exposed to the elements. An estimated 210 substations on the overhead system are currently missing Toronto Hydro-owned protection devices.

(2) The number of interruptions caused by a fault at the customer-owned equipment. According to ITIS data for 2009-2013, the Horseshoe region has experienced the greatest number (45 out of 83) of interruptions that were caused by a fault at customer-owned equipment. This area is given higher priority.

(3) Condition of the equipment - Customer-owned equipment that has aged and/or is poorly maintained will be given higher priority because it represents the greatest safety risks.

(4) Protection and Coordination - Changes/modifications may have been made to customer-owned equipment that was never communicated to Toronto Hydro. As a result, improper coordination between the customer-owned equipment and that of Toronto Hydro may be in place. In addition, there may be an absence of necessary Toronto Hydro-owned protection devices. Priority will be given to both the aforementioned situations because they present significant reliability risks to the system.

Additional factors may affect the pace of implementation for the program. One such factor is the time required to gather customer data, which may vary significantly for reasons such as multiple site visits required to collect the data. In addition, Toronto Hydro cannot control the pace at which its customers respond to requests for additional information.

E7.8.5 Program Execution

Through the COSP program, Toronto Hydro plans to first assess the physical condition of customer-owned high voltage substations, as well as the current protection and coordination scheme, which includes both customer high-voltage protection devices and associated Toronto Hydro-owned upstream protection at all 2,110 customer-owned substations. Six to nine months into this assessment phase, Toronto Hydro plans to begin implementing solutions to the issues discovered during the assessment.

The proposed work for the years 2015-2019 will involve analysis of the assessment data to determine if Toronto Hydro owned protection devices are missing or if their settings are appropriate. Assessment of equipment for safety and maintenance purposes will be performed on the transformer, switches, fuses and other electrical equipment and civil structures at the customer-owned substation. Based on the outcome of the technical analysis for each individual customer-owned substation, the implementation phase will be conducted. This phase may require that the customer perform equipment upgrades, and/or the installation of Toronto Hydro upstream high voltage protection devices.

The execution of the proposed program for each customer-owned substation location may involve the following four stages, described in detail below, following the list:

(i) Customer-Owned Substation Inspection

Site inspections will be performed to verify the existence of utility-owned protection devices, evaluate the physical condition of the substation, and to gather information on customer-owned equipment (e.g., customer-owned electrical and civil assets within the substation). In the previous

example at 40 Titan Road, the substation would have been identified as missing upstream Toronto Hydro protection devices.

(ii) Customer-Owned Substation Analysis & Report

Asset assessment, protection and coordination analysis needs to be performed to determine the best solution and protection settings for each substation. If customer-owned equipment is identified as non-compliant with Toronto Hydro's standards, then the customer will be advised to upgrade and apply appropriate changes (refer to section E7.8.5.2). In the example, the current customer-owned substation is outdoors with a 750 kVA transformer and overhead connection. According to Toronto Hydro's latest construction standards, disconnect in-line fused switches should be put in place to isolate the fault at the customer-owned substation. In instances where existing protection is adequate, Toronto Hydro plans to take no action.

(iii) Design for Construction of Toronto Hydro High-Voltage Protection Devices

Design for construction will be conducted by Toronto Hydro's designers. They will prepare drawings and further specify the exact equipment and associated work required to install the required protection devices for each substation. In addition, the design process will indicate the additional work that must be done prior to the completion of the construction (i.e. if a pole needs to be replaced and/or if tree trimming required for the construction work).

(iv) Construction of High-Voltage Protection Devices

Once the previous processes are completed, the final task of asset construction would commerce on each individual substation. Asset construction work may involve coordinating switching arrangement with the customer and Toronto Hydro, installing or replacing the necessary equipment and other support services. At the current stage, due to the reactive/dynamic nature of the proposed work and lack of data and analysis regarding customer-owned substations, detailed project-by-project information cannot be produced until further investigations are completed.

E7.8.5.1 Program Risks

One of the chief risks of the COSP program is related to the reactive/dynamic characteristic of the implementation phase. The total number of stations that require new or replacement protective devices has yet to be determined. As well, the costs associated with the installation of new or replacement protective devices will differ depending on the results of the assessment. For

example, some locations may already have a switch in place but may be missing a fuse. In this case, as long as the condition of the currently installed equipment is adequate, Toronto Hydro will only be required to install a fuse. In the same vein, if Toronto Hydro determined that a pole is too low or corrupted, it may have to install a new poll. Since it is impossible to predetermine all of these costs, Toronto Hydro has built in a 25% contingency (15% standard project contingency and 10% risk contingency) budget to the cost of this program.

Acquiring all necessary data and documentation is another risk of the program. Some equipment data is not readily available to Toronto Hydro because it is associated with customer-owned substations (e.g., primary protective devices or damaged transformer nameplate). In these instances, Toronto Hydro will need to contact the asset owner to obtain the required information. Since Toronto Hydro has no control over the customer's response time, this process may result in delays. However, Toronto Hydro will follow-up with the customer periodically for the requested information to try to keep this program risk at minimal.

E7.8.5.2 Standard & Regulation Adherence

As specified in Toronto Hydro Requirements for The Design and Construction of Customer-Owned High Voltage Substations, customers shall satisfy the required standards to coordinate with Toronto Hydro upstream protective devices. Based on the primary voltage and rating of the transformer, customer-owned protection and utility-owned protective devices shall be as per Toronto Hydro guidelines. System studies will be performed to confirm coordination with the feeder's circuit breaker at the terminal station. In short, these documents contain detailed information regarding the responsibilities of owners and the latest standards for customer-owned substations.

As specified in Conditions Of Service (revision 13), Section 1.7.5 – Customer-Owned Equipment, Infrastructure and Property, where Toronto Hydro indentifies, through an inspection or other activity, deficiencies relating to the equipment, infrastructure, or property owned by the customer, such as deficiencies to walls, ceilings, floors, doors, vents, drains, electrical devices or other elements, Toronto Hydro may:

- Notify the customer of the deficiencies
- Provide a reasonable time for the customer to correct the deficiencies; and
- If circumstances merit, request that the customer to correct the deficiency in a manner that brings the equipment, infrastructure, or property up to current standards even if the

equipment, infrastructure, or property was designed, installed, or constructed to an older standard. Examples of circumstances that may merit the application of a current standard include, but are not limited to, the existence of health or safety hazards, legal or regulatory requirements, and conditions that may impact the integrity, reliability, or operability of the distribution system or any equipment that supplies the customer.

If notified of deficiencies, or requested to correct deficiencies in a particular manner, the customer shall correct the deficiencies and comply with any requests. If the customer does not correct the deficiencies within the reasonable time, or if the corrections are not considered adequate by Toronto Hydro or an inspection authority, Toronto Hydro may disconnect the supply of electricity to the customer or may correct the deficiencies at the customer's expense, and Toronto Hydro shall not be liable to the customer for any damage arising as a result of or in the course of disconnecting supply or correcting the deficiencies other than physical damage to facilities arising directly from entry on the customer's property.

E7.8.6 Evaluation of Alternatives

E7.8.6.1 Quantification/Evaluation of Options

(i) Status Quo

The status quo would have Toronto Hydro continue to perform repairs reactively, after equipment has failed and/or following an outage. The considerable reliability challenges and safety risks currently posed by the status quo would continue and potentially worsen. The inspection of sample substations has indicated that over 22% of customer-owned substations in the Horseshoe area are either aged or poorly maintained. With regular maintenance of the customer-owned substations often being neglected, this equipment is increasingly likely to fail and cause reliability (e.g., outages to upstream customers) and safety (e.g., vault fire) problems on or near Toronto Hydro's distribution system. The failure of customer-owned equipment has already resulted in approximately 17 interruptions per year during the 2009-2013 period. This number is likely to increase in the near future if the proposed program is not implemented. For these reasons, Toronto Hydro does not recommend this option.

(ii) Proposed Plan

By undertaking the COSP program (i.e. the preferred option), Toronto Hydro expects to improve the safety, reliability and operational flexibility of its system. More specifically with respect to reliability, the program will enable Toronto Hydro to isolate faults at customer-owned substations, which will minimize the likelihood that an entire feeder would be affected by a fault at a customer-owned substation; thus, reducing the number of customers that will experience power outages.

E7.8.7 2015 Projects

Toronto Hydro must first inspect and analyze the specific circumstances surrounding each problem area before designing and constructing a solution that addresses all deficiencies. To gather the necessary data and analysis regarding customer-owned substations, further research and additional site visits are required.

Table 7 lists projects that are planned for completion in 2015.

TABLE 7: 2015 PROJECTS

Estimate Number	Quantity	Task	Cost	Year
E30476	522	Customer-owned Substation inspections	$248,000	2015
E30476	428	Customer-owned Substation analysis & report	$174,000	2015
E30476	20	Design for construction of Toronto Hydro owned high voltage protection devices (3 phase)	$87,000	2015
E30476	30	Construction of Toronto Hydro owned high voltage protection devices (per phase)	$87,000	2015

E7.9 Station Expansion

13.8 KV METAL CLAD SWITCHGEAR IN THE CENTRAL TORONTO AREA.

E7.9.1 Summary

Program Description

The Stations Expansion program involves upgrades to station infrastructure located at Toronto Hydro supply points where Toronto Hydro receives power from Hydro One Networks Inc. (HONI). The upgrades aim to address ongoing trends in customer connection requirements and loading by addressing system limitations imposed by existing stations equipment. The system limitations fall into one of three categories: capacity shortfalls, short circuit current limitations and support for a large new customer connection.

In order to address the issues described herein, Toronto Hydro plans to pursue the following projects in the 2015-2019 period:

- Expansion of Copeland TS, which will provide an additional 144 MVA of capacity to the area as well as a significant number of new feeder positions. This expansion is referred to as “Phase 2” of Copeland TS. The scope of Phase 2 is incremental to what has previously been presented to the OEB, and includes installation of two additional 72 MVA busses, three gas insulated power transformers and installation of a transfer bus to allow

for utilization of the spare transformer to back up Copeland TS and/or other stations through the installation of ties.

- Construction of a new Toronto Hydro owned transformer station in the Manby TS area, as well as an expansion of Runnymede TS to include one additional bus. This work will provide sufficient capacity to the area to allow for rebalancing of loads and facilitate development in the area.

- Incremental upgrade of HONI's T12 at Strachan TS from 75 MVA to 100 MVA to leverage HONI's asset renewal program.

- Installation of a four position, outdoor, open air bus structure at Basin TS rated for up to 750 MVA of short circuit current. Additionally, the installation of two new circuit breakers at Bathurst TS to enable construction of a dedicated feeder to a large customer will be required. As HONI owns the bus at this location, both parties will be required to collaborate.

Table A summarizes the anticipated benefits associated with the Station Expansion program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	- Ensure Toronto Hydro continues to meet its obligations to current and future customers with respect to providing a reliable supply of electricity. - Ensure that capacity and feeder positions are available to connect new customers to the most technically appropriate station based on location, reducing connection costs to individual customers. - Facilitate redevelopment of potential high growth areas of the city of Toronto (waterfront, south Etobicoke, Portlands, etc.). - Facilitate the connection of renewable resources by upgrading short circuit limitations of existing infrastructure.
Reliability	- Enable Toronto Hydro to maintain the basic design principles upon which the distribution system was constructed (i.e. N-1 design). - Facilitate renewal of aging 13.8 kV switchgear, which are critical links in the distribution of electricity to customers. - Installation of additional capacity near load centers will enable reduced feeder lengths, which generally results in a more reliable system.
Safety	- Overloading equipment reduces the remaining equipment life, thereby increasing failure risk. Depending on the equipment and the failure mode, a failure could result in an explosion, fire or other potential safety hazard. This program reduces the likelihood of overloading equipment, which reduces equipment failure risk.
Efficiency	- Increased capacity will allow for more flexibility in scheduling planned

	outages for maintenance at the effected stations. Currently, Toronto Hydro and Hydro One maintenance may be deferred because of system loading. ƒ New customers who are located within the impacted areas are more likely to be serviced from the station that is geographically closest, reducing connection costs. ƒ Completion of the Strachan TS transformer upgrade would prevent Toronto Hydro from having to pay the full cost to replace the transformer again when additional capacity is required. It would also reduce the overall future cost to fully utilize the 72 MVA rating of the A1-2T or A9-10T busses.
Other	**ƒ** Supports the continued economic development in Toronto by ensuring that electrical capacity is sufficient to support ongoing growth. ƒ Supports other important Toronto Hydro programs such as transformer station switchgear renewal and station-to-station ties.

Program Drivers

The Stations Expansion program is primarily driven by capacity constraints, due to the fact that several stations within Toronto Hydro's service territory will exceed rated peak capacity in the near term (i.e., next five to ten years). The trigger and secondary drivers for this program are provided in Table B.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Capacity Constraints	**ƒ** Several stations within Toronto Hydro service territory are forecasted to exceed rated peak capacity in five to ten years. ƒ Several stations are running low on spare station bus feeder positions, which are required to connect large new customers (including large office towers, condos or data centres). ƒ Some stations are at risk of being unable to accommodate DG connections ƒ With station load exceeding capacity, Toronto Hydro would need to operate the system outside of design parameters, leading to: o reduced reliability, o costly short-term load transfer projects, o suboptimal connection points for new customers, o reduced flexibility to schedule outages for maintenance, and o compromised ability to restore power under contingencies.
Secondary Drivers	**Reasoning**
Reliability	**ƒ** System capacity under an N-1 contingency (where any single system

	component is out of service) is defined based on the element with the lowest rating. ƒ Additional capacity will support planned switchgear renewal, where space limitations prevent direct load transfers from old to new equipment. ƒ Lack of spare capacity limits Toronto Hydro's ability to complete maintenance (which in turn increases failure risk) and increases the likelihood of customer outages in the event of an equipment failure.

Preferred Alternative

Toronto Hydro has identified alternative options to address several issues and evaluated the options based on current and future needs of the system. As an alternative to undertaking capital work, the potential for Conservation and Demand Management (CDM) was evaluated. However, the potential peak reduction achieved through CDM is not sufficient to materially defer or eliminate the need for the capital projects included in this program. Toronto Hydro does plan to undertake a demand reduction program to address future capacity needs at Cecil TS. The details of this program are provided in E7.10 Local Demand Response.

Timing and Pacing

Station Expansion projects generally require material capital investment, involve significant coordination with HONI and are extremely complex to execute. For these reasons, detailed project execution scheduling and feasibility is difficult to estimate until the project is underway.

The timing for projects is driven by system need (i.e., when the forecasted capacity shortfall is expected to materialize) and anticipated project lead times. Delay of the program could result in rotating blackouts, voltage reductions, inability to execute planned work (maintenance or capital) and reduced reliability (due to long feeder lengths that would be required for load transfers).

Table C provides the estimated costs of the program for the 2015-2019 period.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	**6.9**	**32.5**	**18.6**	**61.2**	**79.5**	**43.8**	**41.6**	**36.5**	**22.0**	**44.0**

/C

E7.9.2 Program Description

The objective of the Station Expansions program is to address limitations and constraints placed on the distribution system by existing transformer station infrastructure. These constraints fall into one of three categories:

(1) Forecasted thermal capacity shortfalls due to increasing electricity demand,

(2) Short circuit current limitation/shortfalls due to forecasted distributed generation (DG) connections, and

(3) Requirements for additional feeder positions to connect very large customers.

In each case, Toronto Hydro has identified specific projects to mitigate these issues and ensure that the utility can continue fulfilling all of its obligations under the Distribution System Code (DSC). Each issue is described in further detail in the sections below. A summary of the projects included as part of the Stations Expansion program is provided in Table 1.

TABLE 1: SUMMARY OF STATIONS EXPANSION PROJECTS

Description	Station(s) Impacted	Need	Anticipated Project Start	Anticipated Project Finish	Cost ($M)
Copeland TS – Phase 1 (carry over)	Copeland TS	Capacity	2013	2016	192.9
New Transformer Station in Manby TS area	Horner TS, Manby TS	Capacity	2016	2019	72
Expansion of Runnymede TS	Runnymede TS, Fairbank TS	Capacity	2016	2017	33
Copeland TS - Phase 2	Windsor TS, Esplanade TS (George and Duke MS), Copeland TS	Capacity	2019	2020	46
HONI T12 replacement and upgrade	Strachan TS	Capacity	2018	2018	0.5
Basin TS short circuit upgrades	Basin TS	Short Circuit	2015	2015	2
Bathurst – New Feeder Positions	Bathurst TS	Feeder Positions	2018	2018	1.5

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A summary of the anticipated benefits associated with completion of the Station Expansion program are provided in Table 2.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Ensure Toronto Hydro continues to meet its obligations to current and future customers with respect to providing a reliable supply of electricity. ƒ Toronto Hydro will be able to continue to serve customers under first contingency, without the need for rolling blackouts or voltage reduction. ƒ Enable completion of maintenance and planned capital work without requiring significant customer outages. ƒ Ensure that capacity and feeder positions are available to connect new customers to the most technically appropriate station based on location, reducing connection costs to individual customers. ƒ Facilitate redevelopment of potential high growth areas of the city of Toronto (waterfront, south Etobicoke, Portlands, etc.). ƒ Facilitate the connection of renewable resources by upgrading short circuit limitations of existing infrastructure.
Reliability	ƒ Enable Toronto Hydro to maintain the basic design principles upon which the distribution system was constructed (i.e. N-1 design). ƒ Facilitate renewal of aging 13.8 kV switchgear, which are critical links in the distribution of electricity to customers. ƒ Enable Toronto Hydro's long term vision to install station-to-station ties for back up and contingency support purposes. Sufficient capacity would be required to make effective use of these ties. ƒ Installation of additional capacity near load centers is expected to enable reduced feeder lengths, which generally results in a more reliable system.
Safety	ƒ Overloading equipment reduces the remaining equipment life, thereby increasing failure risk. Depending on the equipment and the failure mode, a failure could result in an explosion, fire or other potential safety hazard. This program reduces the likelihood of overloading equipment, which reduces equipment failure risk.
Efficiency	ƒ Increased capacity would allow more flexibility in scheduling planned outages for maintenance at the effected stations. Currently, Toronto Hydro and HONI maintenance may be deferred because of system loading. ƒ New customers located within the impacted areas are more likely to be serviced from the station that is geographically closest, reducing connection costs. ƒ Additional capacity would enable system reconfiguration to optimize the supply to customers who are currently supplied in a sub-optimal manner (i.e. from station other than the one that is closes to them). This may occur when there is not sufficient capacity to connect a customer to the closest station. This will serve to reduce line losses and improve reliability.

	ƒ Completion of the Strachan TS transformer upgrade would prevent Toronto Hydro from having to pay the full cost to replace the transformer again when additional capacity is required. It will also reduce the overall future cost to fully utilize the 72 MVA rating of the A1-2T or A9-10T busses.
Other	ƒ Overloading equipment reduces the remaining equipment life, thereby increasing failure risk. Depending on the equipment and the failure mode, a failure could result in an oil spill, fire or other potential environmental hazard. This program reduces the likelihood of overloading equipment and associated failure risk, which reduces the associated potential environmental risks. ƒ Supports the continued economic development in Toronto by ensuring that electrical capacity is sufficient to support ongoing growth. ƒ Supports other important Toronto Hydro programs such as transformer station switchgear renewal and station-to-station ties.

E7.9.2.1 Capacity Shortfalls

Toronto Hydro completes a ten-year station bus load forecast on an annual basis. The purpose of this forecast is to identify long term station and station bus capacity adequacy to meet existing and future peak load demand. The outputs of this forecast trigger the proactive investigation of investment options for mitigating potential station-level system constraints. The goal is ultimately to inform short-term investment decision making such that it aligns with long-term system needs. This is a critical part of Toronto Hydro's planning process. The exhaustion of all available capacity would have an enormous impact on overall system performance, and the lead times associated with some of the potential solutions are much longer than the average distribution system investment project.

Toronto Hydro is also an active participant in the OPA-led Central Toronto Integrated Regional Resource Planning (IRRP) process. As a contributing member of the IRRP Working Group, along with the OPA, HONI and the IESO, Toronto Hydro has supported the IRRP Working Group efforts to assess the adequacy of the transmission system in serving current and future needs. Through the assessment phase, the IRRP Working Group has identified certain near-term needs that require action on the part of Toronto Hydro (along with HONI coordination), needs that are addressed by projects within the Stations Expansion program. More specifically, the needs include an additional step-down relief in the Windsor / Esplanade / George and Duke / Copeland and the Manby / Horner / Runnymede / Fairbank areas. The OPA has requested that Toronto Hydro pursue development of options to address these needs. In general, these options include

station or bus expansion, permanent station-to-station load transfers and/or improving system capability for inter-station load transfers.

Based on Toronto Hydro's 2014 load forecast (and other considerations described throughout this document), there are three areas for which it is prudent and necessary for Toronto Hydro to undertake projects to add capacity within the 2015 to 2019 period:

(1) South-west Toronto (service territory of Horner TS, Manby TS, Fairbank TS and Runnymede TS), shown in Figure 1.

FIGURE 1: SERVICE AREA OF SOUTH-WEST TORONTO AREA (HORNER TS, MANBY TS, RUNNYMEDE TS AND FAIRBANK TS)

(2) Downtown core (service territory of Windsor TS, Esplanade TS, George and Duke MS and, once in service, Copeland TS), shown in Figure 2.

FIGURE 2: SERVICE TERRITORY OF DOWNTOWN CORE TRANSFORMER STATIONS

(3) Service territory of Strachan TS, shown in Figure 3.

FIGURE 3: SERVICE TERRITORY OF STRACHAN TRANSFORMER STATION

In each case, Toronto Hydro has identified and evaluated the practical options for satisfying the short term and/or long term needs of the system. Planned projects are expected to enable the utility to continue providing reliable service – specified as N-1 design (refer to section E7.9.3.1) – to current and future customers in a cost-efficient manner. It should be noted that some of the projects in this program, in particular those involving addition of entirely new infrastructure, require extensive collaboration and coordination with third parties to validate project costs, feasibility and overall prudence in the context of the overall electricity system serving the Greater Toronto Area. This collaboration is ongoing as part of the OPA-led Regional Planning Process. Toronto Hydro expects to continue to work with its partners at the OPA, HONI and the IESO to

develop the complete scope of such projects, in particular any upstream transmission level work required to enable the project benefits, and move forward towards implementation.

South-West Toronto

For the south-west Toronto area, Toronto Hydro plans to pursue implementation of two independent solutions. The first solution involves the installation of an additional 27.6 kV load serving bus at Runnymede TS. As this station is owned by HONI, Toronto Hydro has submitted a connection application to HONI to formally identify the need for additional capacity and to request a study to determine feasibility, requisite transmission upgrades and detailed project costs. This request is expected to be addressed once the first phase of the Toronto Regional Plan exercise is complete. The preferred option is the Runnymede TS expansion option as it is expected to provide relief to both Runnymede TS and Fairbank TS load, which is isolated from adjacent stations by the Humber River, Highway 401 and 13.8 kV distribution areas. In parallel, Toronto Hydro also plans to pursue an entirely new transformer station in the existing Manby TS service territory. This transformer station is expected to provide direct capacity relief to Manby TS and Horner TS. Both areas continue to experience the redevelopment of previously vacant land with large condo projects and energy intensive data centres. This new transformer station would be supplied from the 230 kV transmission system, which would reduce the load on the 115 kV lines currently supplying Runnymede TS, Fairbank TS and much of the 13.8 kV distribution system in central Toronto.

Downtown Core

For the downtown core area encompassing the current (and planned) service territories of Windsor TS, Esplanade TS, George and Duke MS (which is supplied from Esplanade TS) and Copeland TS, Toronto Hydro plans to introduce additional bus and feeder capacity, additional feeder positions and enhanced reliability through Phase 2 of the Copeland TS project. Phase 1, which includes construction of the station facility, installation of the high voltage transmission connections, two power transformers and two busses, is expected to be completed in 2016. Towards the end of the 2015 to 2019 time period, Toronto Hydro anticipates needing Phase 2 to address emerging and future capacity and feeder position shortages anticipated as a result of current growth and planned intensification of currently vacant lands in the area. Toronto Hydro proposes that Phase 2 involve the installation of three power transformers (two load serving, one back up), a transfer bus to enable station to station ties and utilization of the backup transformer, ***/C***

and two load serving busses. This project will enable full utilization of the station site and transmission system connection work that is being completed under Phase 1.

Strachan TS

HONI has informed Toronto Hydro that they will be replacing their existing 75 MVA T12 transformer at Strachan TS due to end-of-life. This transformer is one of a pair of 115 kV to 13.8 kV transformers supplying Toronto Hydro's A5-6T and A7-8T busses. As this is a HONI asset, HONI is obligated to pay the entire replacement cost to maintain the current capacity of the system. Instead of a like-for-like replacement, Toronto Hydro has requested that HONI replace the existing unit with a standard 100 MVA transformer. Under these circumstances, Toronto Hydro is obligated to make a capital contribution to HONI equal to the incremental cost associated with installing a 100 MVA unit rather than a 75 MVA unit as is installed today. Once both existing transformers have been replaced with 100 MVA transformers, the capacity available to Toronto Hydro will be increased by a total of 64 MVA. This is desirable, as the capacity of this station is forecasted to reach 96% by 2023. Alternatively, Toronto Hydro can allow HONI to replace T12 with a 75 MVA unit, and then request that both transformers be replaced (again) and upgraded to 100 MVA in 5 to 10 years when required due to loading. Under these circumstances, where HONI upgrades their assets solely at the request of Toronto Hydro, Toronto Hydro is obligated to make a capital contribution equal to 100% of HONI replacement cost. Therefore, upgrading the transformer at this time is a more cost effective alternative.

E7.9.2.2 Short Circuit Limitations

In order to facilitate connection of DG projects to the distribution system, Toronto Hydro must ensure that there is sufficient short-circuit capacity available at the connection point. Short-circuit capacity refers to the ability of equipment to withstand the maximum short-circuit current that could arise in the event of a phase-to-phase or phase-to-ground fault. In particular, circuit breakers have a maximum current that they are designed to interrupt and the system must be designed so that this maximum current value is not exceeded. The available short-circuit current is determined by the impedance of the upstream transformers, the short-circuit contribution of any connected rotating loads (i.e., synchronous or induction motors, which release energy back out to the grid under fault conditions) and the short-circuit contribution of any connected generation.

When Toronto Hydro receives a DG connection request, it completes a connection impact assessment. As a result of these connection impact assessment processes, Toronto Hydro has identified that Basin TS is at its short-circuit capacity of 470 MVA (18 kA at 15 kV). There is

currently a 5-MW DG source connected to this station, which is forced to operate under constraints due to short circuit considerations. Also, Toronto Hydro is currently developing a generation project (to be connected to the distribution system at Basin TS) that would be prevented from connecting because it would result in the short-circuit rating being exceeded. Toronto Hydro is proposing to eliminate these short-circuit constraints. Discussions with HONI are ongoing, and the proposed solution is to implement changes to the normal operating state of the existing transformers and protection circuits supplying the A7-8BN bus. Implementation of these modifications will require collaboration and agreement with HONI as their upstream equipment (circuit breakers, transformers and protection) would likely require modification as well.

E7.9.2.3 Additional Feeder Position Requirements

Toronto Hydro has received notice from a large customer currently being supplied from Bathurst TS indicating that they plan to expand their operation significantly over the next several years, from 11.5 MW to 14.5MW in 2018, with an ultimate long term load of 22 MW at a yet to be determined date. Given the amount of load required by this customer, Toronto Hydro anticipates that a dedicated feeder will be required. To address this need, Toronto Hydro will make a formal request to HONI to install of a new pair of feeder breakers on the HONI-owned bus. The design of Bathurst TS requires two circuit breakers to be installed at the same time to provide backup for each other while under contingency. Since HONI owns the bus at this station, the requisite work would be shared between HONI and Toronto Hydro; Toronto Hydro would purchase and install the circuit breakers and HONI would be asked to complete the necessary work to connect the new circuit breakers to their bus. Toronto Hydro would be obligated to make a capital contribution to HONI to complete this work pursuant to the requirements of the Transmission System Code (TSC). As well, the customer would be required to make a capital contribution to Toronto Hydro to cover the distribution costs (as required by the DSC); however the station upgrade costs covered under this project are not recoverable from the customer.

Table 3 provides some illustration of assets that will be impacted through the execution of this program.

TABLE 3: EXAMPLES OF STATION ASSETS

Picture	Description
	13.8 kV metal clad switchgear in the central Toronto area. Owned by Toronto Hydro and contains the bus and circuit breakers.
	HONI-owned power transformer.

Picture	Description
	A Toronto Hydro-owned outdoor 27.6 kV oil circuit breaker used in the Horseshoe area.
	Outdoor open air 27.6 kV bus and associated oil circuit breakers. The bus (located behind the screening) is owned by HONI and the circuit breakers are primarily owned by Toronto Hydro.

E7.9.3 Why the Program is Needed

The projects comprising the Stations Expansion program stem from Toronto Hydro's need to mitigate forecasted system constraints as set out in Section E7.9.3.1. As described throughout this narrative, Toronto Hydro has experienced a significant amount of load growth in recent years. This growth is concentrated in specific areas of the city where there is a large amount of densification and redevelopment – a trend which is expected to continue in the future. Toronto Hydro continues to receive connection requests that require incremental distribution system capacity. The direct effect of this trend is that the existing system is approaching capacity at several locations, making necessary to ensure that Toronto Hydro is able to manage the distribution system in an efficient and responsible manner. As a result, Toronto Hydro has developed this program to address forecasted system constraints (capacity, feeder positions, short circuit capacity, etc). The projects that Toronto Hydro has planned are expected to mitigate the short-term and long-term forecasted capacity shortfalls, support future system needs (such as load transfers to enable switchgear renewal work in the downtown core), and enable the introduction of backup capabilities (station-to-station ties). It will also proactively facilitate connection of new load and generation customers.

E7.9.3.1 Program Drivers

The Stations Expansion program is primarily driven by capacity constraints, due to the fact that several stations within Toronto Hydro's service territory are expected to exceed rated peak capacity in the near term (i.e., next five to ten years), as further explained in Table 4. Due to the critical system capacity issues that this program is intended to address, this program is positioned as part of the System Service category.

TABLE 4: PROGRAM DRIVERS

Trigger Driver	Reasoning
Capacity Constraints	***f*** Several stations within Toronto Hydro service territory are forecasted to exceed rated peak capacity in five to ten years. *f* Several stations are running low on spare station bus feeder positions, which are required to connect large new customers (including large office towers, condos or data centres). *f* Some stations are at risk of being unable to accommodate DG connections *f* With station load exceeding capacity, Toronto Hydro would need to operate the system outside of design parameters, leading to: o reduced reliability, o costly short-term load transfer projects,

	o suboptimal connection points for new customers, o reduced flexibility to schedule outages for maintenance, and o compromised ability to restore power under contingencies.
Secondary Driver	**Reasoning**
Reliability	***f*** System capacity under an N-1 contingency (where any single system component is out of service) is defined based on the element with the lowest rating. *f* Additional capacity will support planned switchgear renewal, where space limitations prevent direct load transfers from old to new equipment. *f* Lack of spare capacity limits Toronto Hydro's ability to complete maintenance (which in turn increases failure risk) and increases the likelihood of customer outages in the event of an equipment failure.

Toronto Hydro receives power from the IESO-controlled grid at 35 individual TS located throughout the City of Toronto. At each station, the voltage is converted from either 230 kV or 115 kV to 27.6 kV or 13.8 kV. From these delivery points, Toronto Hydro distributes power to its end-use customers.

Each station in the system has a specific maximum capacity that it is capable of delivering. This limit is derived from the ten-day limited time rating of the lowest rated element at the station, allowing the system to operate with any specific element out of service for up to ten days without permanently compromising the life of the remaining equipment. This is a long-standing industry practice and is typically referred to as "N-1" design. In addition to providing redundancy in the event of unplanned outages, it also enables Toronto Hydro to undertake planned outages for equipment upgrades or repairs. In order to maintain this redundancy (and ensure that the system is being operated within its design parameters), the peak load supplied from a station must be equal to or less than this capacity rating. "N-1" design is a distribution industry best practice that is employed throughout Ontario. Without a backup supply for first contingency situations, any equipment failure is likely to result in a prolonged outage to customers (essentially until replacement equipment could be located, delivered to site and installed). Given the lead time associated with procuring major stations equipment (typically eight to 24 months), the risk of equipment failure and prolonged outages is not tolerable to Toronto Hydro and its customers.

Every year Toronto Hydro completes a ten-year station bus load forecast, based on the following methodology:

(1) Toronto Hydro identifies the summer and winter peak loads for each bus supplying Toronto Hydro feeders (regardless of which utility owns the actual bus).

(2) Peak loads are normalized to the average historical temperature at which the peak has occurred.

(3) Five-year historical growth rates are calculated. Different growth rates are calculated for the six distinct areas of the system. These areas are defined by shared distribution system characteristics, demographics, historical growth and potential for future growth.

(4) Customer connection requests are added based on the desired in service date of the customer and the amount of load requested.

(5) An adjustment factor of 70% is applied to the load requested by customers to reflect past experience of load being overstated at the application phase.

(6) For larger customers, new customer load is added to future years according to either the load build up profile provided by the customer, or in absence of that information, in accordance with a standard build up profile of 60% in year one, 20% in year two and the remaining 20% in year three. Historically, Toronto Hydro has observed that it takes several years for a large customer's full load to materialize.

The historical growth rates (as calculated in part 3) are applied to forecast load for years four to 10.

FIGURE 4: TEN-YEAR STATION BUS LOAD FORECAST PROCESS

The purpose of this forecast is to provide distribution system planners with an outlook of spare capacity available at each station bus and to inform planning decisions such that they are aligned with long-term system needs. As Toronto Hydro receives new connection requests following the issuance of the annual forecast, Toronto Hydro assesses and monitors their potential impact on bus capacity. These connection requests are formally included in the following year's load forecast.

DG and CDM initiatives are not explicitly addressed by the station bus load forecast, as they could serve to mask incipient capacity shortages and their impact on peak demand is often difficult to predict. Rather, the historical impacts on peak load of these initiatives are accounted for in the growth rate calculation. In order to ensure delivery of electricity in a reliable manner, Toronto Hydro must design its system to serve the peak demand, and thus any generation, load shifting or demand response initiative that is not guaranteed to be in operation at the system peak must be disregarded for capacity planning purposes. If not, the utility could be in position where rotating blackouts or load shedding are necessary. That said, DG that is known with certainty to be available at system peak, or CDM initiatives which are certain to reduce peak demand, can both be considered practical alternatives to adding capacity. The relative merits of these generic alternatives depend on the specific circumstances being assessed.

When Toronto Hydro identifies that the load on a station bus is forecasted to exceed capacity, planners identify and assess the available options. This assessment considers the magnitude of the problem, the timeframe, and the long-term needs of the area. A summary of typical solutions is provided in Table 5.

TABLE 5: TYPICAL CAPACITY RELIEF OPTIONS

Option	Prerequisites	Comments
Transfer load to a different bus within the station	Requires an existing bus at the same station with sufficient capacity and feeder positions to accept the new load.	*f* Generally the most cost effective option when available. *f* Some technical restrictions (3-wire vs. 4-wire busses, ability to segment existing load, etc).
Transfer load to a bus at a different station	Requires an existing bus at a nearby station with sufficient capacity and feeder positions to accept the new load. Must be feasible to construct the necessary distribution infrastructure to permanently transfer the load (for example,	*f* Can require significant amount of new infrastructure. *f* Can be very expensive. *f* Technical limits on feeder length must be respected in order to maintain system within design parameters.

Option	Prerequisites	Comments
	there must be spare civil infrastructure between the new station and the load to be transferred).	*f* Investment does not actually result in an increase in capacity – rather, it simply means available capacity is being utilized sooner than it would have been otherwise.
Permanent peak reduction through conservation, demand management or distributed generation initiatives	Potential for peak reduction must be sufficient to mitigate shortfall. Must be persistent. There must be a guaranteed funding mechanism (i.e. the load or generation customer has signed an agreement and paid the requisite deposit to connect to the system).	*f* Reductions must be realized before forecasted overload of bus. *f* Only impact on peak demand is relevant. Impact on energy consumed is irrelevant.
Replace and upgrade limiting component at station	Typically requires coordination with HONI. There must be a specific component or set of components that is exclusively limiting capacity (i.e. a cable section, a transformer, etc).	*f* Some elements can be replaced at relatively low cost and result in incremental capacity. *f* Some Toronto Hydro switchgear replacement projects will result in additional capacity. *f* Toronto Hydro often requests that HONI upgrade transformer ratings to provide additional capacity when they renew their assets.
Expand an existing station by installing a new bus and/or new transformation and/or new transmission infrastructure	Requires sufficient physical space at the station to facilitate expansion. Requires sufficient upstream (transmission) capacity.	*f* Can be very costly. *f* Requires coordination with HONI. *f* Existing ownership of these assets (HONI vs. Toronto Hydro) varies throughout the city. *f* Costs highly dependent on requisite transmission upgrades.
Build a new station	Requires a suitable site located sufficiently close to serve the new load of offload the existing station.	*f* Can be very costly. *f* Requires coordination with HONI. *f* Costs highly dependent on requisite transmission upgrades. *f* Generally lengthy approvals and lead times.

Toronto Hydro's 2014 station bus load forecast identified two general areas of the city where station infrastructure is approaching rated capacity. Each area is discussed in detail below.

(i) Windsor TS / Esplanade TS (George and Duke MS) / Copeland TS

For planning purposes, Toronto Hydro reviews station loading across groups of stations that serve areas with similar demographics. Loading at four stations located in the downtown core of the City of Toronto are of particular concern. These stations encompass a total of 11 busses. Toronto Hydro forecasts that five of these busses will be at or above 95% capacity by 2020 and six of these busses will be above 95% capacity by 2023. To date Toronto Hydro has been able to accommodate the load growth by utilizing existing spare capacity and through the construction of a new transformer station (Copeland TS, which is included in the analysis). From 2008 to 2013, the peak load weather-independent growth rate for the downtown transformer stations identified here is approximately 1.3%. This is less than the weather dependant growth rate quoted in past rate filings (2%, which applied to the entire 13.8 kV system), as starting with the 2014 load forecast Toronto Hydro has normalized historical peaks to correct for weather effects prior to calculating growth rate. This approach is conservative in that it results in a lower growth rate, but it does not account for potential peak demand growth that might result from climate change. Using raw 2008 to 2013 peak data to calculate historical growth rates results in a growth rate of 2.0%, which is consistent with past findings. This indicates that recent weather trends – ostensibly peak summer temperatures – have resulted in an increase in peak electricity demand. If peak temperatures continue to increase, as is predicted by many climate change studies, it can be expected that this will provide upward pressure on peak demand. Toronto Hydro's 2014 summer load forecast for this area is provided in Table 6.

TABLE 6: 2014 LOAD FORECAST FOR COPELAND TS, ESPLANADE TS AND WINDSOR TS AREAS

STATION / BUS	FIRM CAPACITY(MVA)		YEAR										
	100%	95%	2013*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
COPELAND (115KV/13.8KV) TS													
A1r2CL	72	68			60	60	60	60	61	62	63	64	64
A3r4CL	72	68			9	61	63	63	64	65	66	67	
Total of all Buses	144	136			69	121	123	123	125	127	129	131	132
Surplus MVA					75	23	21	21	19	17	15	13	12
% Loading (Load/Future Firm Cap)					48	84	85	85	87	88	90	91	92
ESPLANADE (115KV/13.8KV) TS													
A1r2GD	69	66			62	63	64	65					
A3r4GD (Formerly A5r6GD)	69	66	57	57	61	63	65						
A1r2X	69	66	56	61	63	49	50	50	51	52	52	53	54
Total of all Buses	207	198	179	185	186	175	179	181	184	187	187	190	193
Surplus MVA			28	22	21	32	28	26	23	20	20	17	14
% Loading (Load/2013 Firm Cap)			86	89	90	85	86	87	89	90	90	92	93
WINDSOR (115KV/13.8KV) TS													
A11r12	69	66	51	48	48	51	57	58	59	0	0	24	24
A13r14	41	39	34	38	33	34	34	35	35	36	36	37	37
A15r16	69	66				60	56	57	57	58	59	36	36
A17r18	49	47	43	44	0	44	45	46	46				
A3r4	59	56	51	54		54	55	0	0				
A5r6	59	56			46	0	0	55					
Total of all Buses	337	321	301	320	256	243	247	251	253	258	260	265	268
Surplus MVA **			36	17	32	35	31	27	25	19	17	72	69
% Loading (Load/2013 Firm Cap) **			89	95	89	87	89	90	91	93	94	79	80
Total of all Stations													
Bus Total	688	655	480	505	511	539	549	555	562	572	576	586	593
Surplus MVA **			64	39	128	90	80	74	67	56	52	102	95
% Loading (Load/2013 Firm Cap) **			88	93	80	86	87	88	89	91	92	85	86

For planning purposes, Toronto Hydro considers a bus at a 13.8 kV station in the former City of Toronto area to be overloaded when it reaches 95% of the rated capacity. This is to account for the lead time required to offload a bus and implement a permanent solution, as well as the fact that the utility must keep sufficient spare capacity on each bus to accommodate any new customer connection requests. Typically, customers request connection anywhere from one to three years in advance, whereas a load relief solution can take anywhere from one to four years to implement, depending on the nature of the existing configuration. It is possible for a customer to request more load than is available on a bus in a shorter timeframe than Toronto Hydro can respond. As shown in the load forecast, within ten years, six of the busses supplied from Windsor TS, Copeland TS and Esplanade TS are forecasted to require capacity relief.

An important indicator of load growth is the number of new connection requests that are received from customers. These requests are submitted by existing and potential customers seeking to

increase their load and/or requiring entirely new connection points. The number of new connections requested for the past several years is shown in Table 7.

TABLE 7: NUMBER OF NEW CUSTOMER CONNECTION REQUESTS BY STATION BY REQUESTED IN SERVICE YEAR

Year	2006	2007	2008	2009	2010	2011	2012	2013
Esplanade TS	1	3	1	2	3	1	6	0
George and Duke MS	4	8	8	9	5	7	12	2
Windsor TS	7	18	10	14	13	13	16	14
Area Total	**12**	**29**	**19**	**25**	**21**	**21**	**34**	**16**

The total number of new connections requested for this specific area is shown in Figure 5.

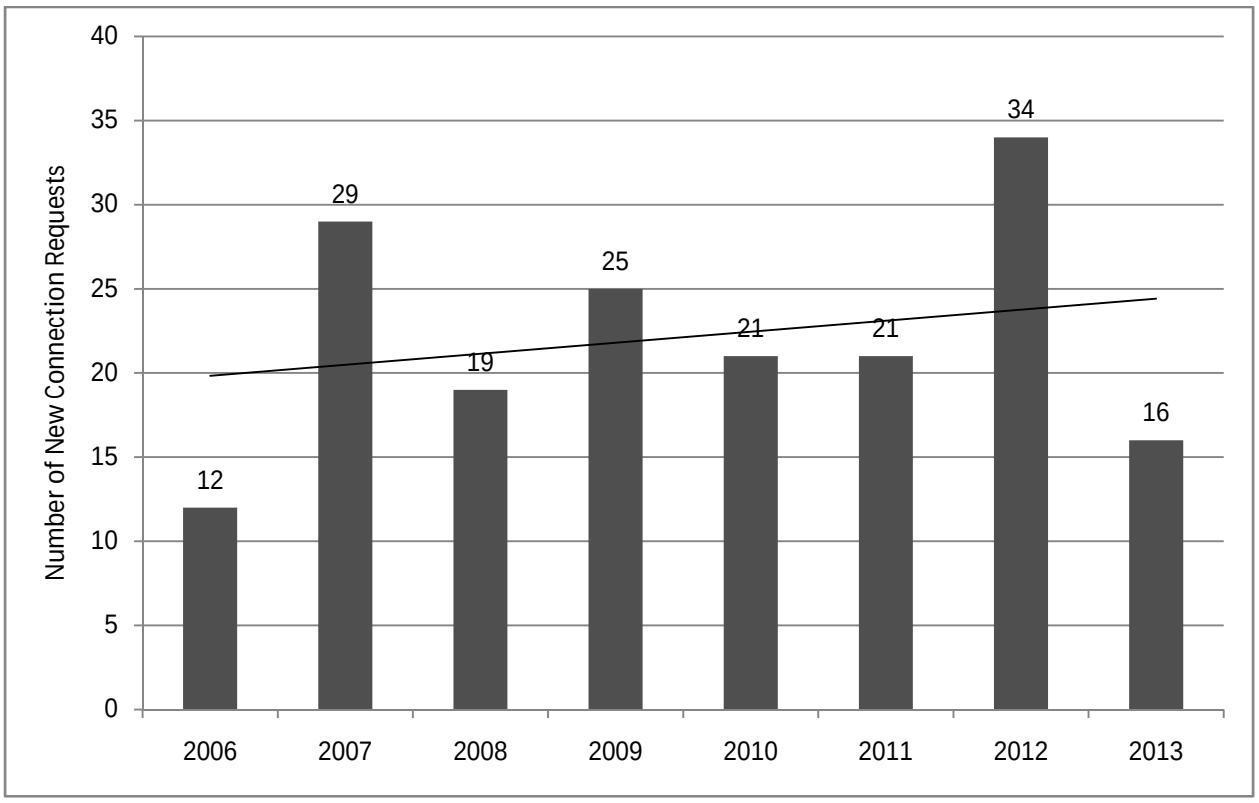


FIGURE 5: TREND OF TOTAL NUMBER OF NEW CUSTOMER CONNECTION REQUESTS FOR ALL AREAS BY REQUESTED IN SERVICE YEAR (WINDSOR / ESPLANADE / GEORGE & DUKE / COPELAND AREAS)

As depicted in the graph, for several years the Windsor, Esplanade, George and Duke and Copeland areas have shown a generally increasing trend in the number of connection requests in

a given year. While a stable trend would indicate that load can be expected to continue to grow at the current rate, an increasing trend strongly suggests that load growth may accelerate in the future.

The impact of various CDM initiatives has been considered as well. For each station, Toronto Hydro's CDM team has forecasted peak load reductions that are achievable over five and ten years based on 2014 OPA targets, energy efficiency initiatives, demand response initiatives and codes and standards changes. For the purposes of this assessment, these station level estimates have been averaged across the number of busses at each station to provide an indication of how much capacity relief can be expected as a result of CDM initiatives. This information is shown in Table 8.

TABLE 8: FORECASTED PEAK REDUCTION THROUGH CDM INITIATIVES

Station	Number of Busses	Cumulative Peak Reduction in MW (2014-2019)	Cumulative Peak Reduction in MW (2019-2024)	Average Cumulative Peak Reduction per Bus in MW (2014-2019)	Average Cumulative Peak Reduction per Bus in MW (2019-2024)
Copeland TS / Windsor TS	8	7.7	8.5	1.0	1.1
Esplanade TS / George and Duke MS	3	3.7	4.0	1.2	1.3

Comparing the forecasted peak load reduction through CDM at the bus level to the forecasted capacity shortfalls shows that CDM initiatives would be insufficient to defer or offset the need for additional capacity. Furthermore, the peak reduction achievable through CDM initiatives is likely to be overstated here as Toronto Hydro's load forecasting methodology intrinsically assumes that CDM, demand response and DG impact on peak demand growth rates will persist for the entire forecast period, and therefore the forecast is offset based on the assumption that peak reductions will continue to be realized at the same rate as past years.

As discussed in Section E7.9.3.1, the first option for relieving bus capacity is generally to transfer load to an adjacent bus at the same station, or even a nearby station. For the downtown core, where these stations are located, this is often more technically complex and costly. The distribution system in downtown Toronto operates at a primary voltage of 13.8 kV and is operationally unique compared to the utility's service territory served by the 27.6 kV system, known as the "Horseshoe" area. The 13.8 kV area – the oldest part of Toronto Hydro's system –

is comprised of feeders radiating from 17 (soon to be 18 with Copeland TS) central Toronto stations that supply customers located in their geographic service areas. There are very few interconnections between different stations, meaning that load transfers between stations typically require construction of new civil and electrical infrastructure. These load transfers can be extremely costly and challenging to implement given the space limitations and the congested nature of the existing utility infrastructure in the area. Load transfers also require available spare feeder positions on the bus receiving the load transfer. Spare feeder positions are increasingly scarce at certain stations as Toronto Hydro continues connecting new customers.

A typical 13.8 kV station arrangement is shown in Figure E7.96 below. The numbers along the bottom of the figure indicate the feeder number or connected station equipment (such as a station service transformer or potential transformers for voltage measurement). “SP” designates a spare feeder position. The bus in Figure 6 depicts a bus with only two remaining feeder positions; once these positions are assigned, the ability of this bus to accept load transfers or supply additional large customers is severely restricted.

FIGURE 6: TYPICAL DOUBLE BUS SINGLE BREAKER STATION CONFIGURATION

Another limitation to load transfers is imposed by the distribution system design. 13.8 kV feeders can be either 3-wire or 4-wire, referring to the electrical configuration of the transformer secondary windings supplying the bus and the resulting number of wires running from the station. A 3-wire system generally supplies three phase load, and connections are made between phases. There is no neutral wire. A 4-wire system has three wires plus a fourth for the neutral connection and supplies both single phase (line to neutral) and three phase (line to line to line) load. At the station, a bus is designed to support either 3-wire load or 4-wire load. A 4-wire bus can supply 3-wire load; however, a 3-wire bus cannot supply 4-wire load unless the switchgear and neutral grounding system at the station is upgraded/replaced. Unlike the Horseshoe area, the downtown system is not designed with the capability to transfer load through switching operations. Lastly, the nature of the load itself affects whether or not it can be transferred to a

different bus or station. In the downtown core, the majority of customers are made up of either large commercial or residential buildings or secondary networks. In these cases, the load is actually comprised of discrete, indivisible "chunks". Even if there is spare capacity on a nearby bus, there may not be enough capacity to transfer an entire customer, thus preventing utilization of the remaining bus capacity. For example, if Bus A is overloaded and Bus B has 10 MVA in spare capacity, and the smallest discrete chunk of load on Bus A is >10 MVA, Bus B cannot be utilized to off load Bus A. A summary of some of the characteristics impacting load transfer feasibility for Esplanade TS, Windsor TS, George and Duke MS and Copeland TS is provided in Table 9.

TABLE 9: BUS CHARACTERISTICS

Station	Bus	Spare Feeder Positions (2016)[1]	Bus Type	Amount of Large Discrete Customer Load	Amount of Network Load
Copeland TS	A1-2CL	4	4-wire	High	Low
Copeland TS	A3-4CL	2	4-wire	High	Low
Windsor TS	A3-4WR	4	3-wire	High	High
Windsor TS	A5-6WR	0[2]	3-wire	High	High
Windsor TS	A11-12WR	0	3-wire	High	Minimal
Windsor TS	A13-14WR	4	3-wire	High	Minimal
Windsor TS	A15-16WR	0	3-wire	High	Low
Windsor TS	A17-18WR	12	3-wire	High	Low
Esplanade TS	A1-2X	6	3-wire	High	Medium
George and Duke MS	A1-2GD	2	4-wire	High	Low
George and Duke MS	A3-4GD	0	3-wire	High	High

1. 2016 forecasted spare feeder positions is shown to reflect benefits of completion of Copeland TS Phase 1.
2. A5-6WR will be out of service for replacement in 2016.

Some additional considerations outlining the need for additional capacity in this area are summarized in Table 10.

/C

TABLE 10: ADDITIONAL STATION-BY-STATION CONSIDERATIONS

Station	Considerations
Esplanade TS and George and Duke MS	ƒ George and Duke MS is supplied by medium voltage express feeders from Esplanade TS. ƒ GD supplies some network load – limits ability to install feeders back to back and thus limits overall availability of feeder positions. ƒ Prime location for new condo or office developments. ƒ Significant potential for redevelopment and load growth – the City of Toronto has developed long term "Precinct Plans" for area near Esplanade TS (West Don Lands, East Bayfront). ƒ Space is available for station expansion. ƒ A1-2GD is a four wire busses approaching 95%, which requires capacity relief in the near future. A1-2X at Esplanade TS is a 3- wire bus and therefore cannot be used to provide relief (although it is nearing 95% capacity as well).
Strachan TS	ƒ Prime location for new condo developments (King West, Liberty Village, etc.). ƒ Potential for generation connections (Exhibition Place, Island MS). ƒ Significant potential for redevelopment and load growth (Exhibition Place). ƒ Replacements of Strachan A5-6T planned, A7-8T in progress. ƒ Space is available for station expansion. ƒ A5-6T and A7-8T are 3-wire busses and cannot accommodate 4-wire load.
Windsor TS	ƒ Current plan is to replace all six switchgear one after another o 2015: A5-6 : 2017: A3-4 : 2019: A11-12. o This will reduce overall capacity at the station by 39 to 65 MVA for the foreseeable future. ƒ Station is effectively at capacity due to switchgear replacements, additional loads likely to be connected to Copeland. ƒ Prime location for new condo or office developments. ƒ Capacity on A3-4WR and A5-6WR revised downward by HONI (from 68 to 59 MVA) as a result of an analysis of LTR rating of series reactors. ƒ No space is available for station expansion. ƒ Currently only three of six busses can accommodate new feeder positions.
Copeland TS (Phase 1, 144MVA)	ƒ Will provide support for Windsor TS switchgear replacements. ƒ Energization date of 2016. ƒ Station built with provisions for expansion to 244 MVA. ƒ Transmission connection work completed with Phase 1. ƒ Will primarily service load currently supplied by Windsor TS and new customers (some load will be transferred from Esplanade TS and Terauley TS as well).

/C

As new load and customers materialize, Toronto Hydro anticipates having to undertake a number of load transfer projects to maintain all 11 busses located in the Windsor / Esplanade / Copeland area that are below 95% of their rated capacity. Based on the load forecast and the system limitations described throughout this section, Toronto Hydro anticipates that after 2023, there will be no feasible options to supply future load/customers. Therefore, additional capacity must be installed and available in the area no later than the end of 2023. Should peak demand growth

outpace the historical rate in this area over the next several years, this need will be accelerated. Thus, it is crucial that Toronto Hydro begin implementing a solution towards the end of the 2015-19 filing period.

Toronto Hydro's objectives for this program are to ensure that the utility is able to continue to fulfill its obligations under the DSC to connect new customers in its service territory, to enable replacement of aging infrastructure (i.e. switchgear replacements where no space currently exists to stage the construction without transferring load to an adjacent station), and to do so in such a way that maximizes value to ratepayers. In order to provide sufficient system capacity to meet these objectives Toronto Hydro is proposing to expand Copeland TS to its full design capacity. Project details are as follows:

Installation of three power transformers (two directly supplying busses, one backup on potential), installation of two load serving busses rated at 72 MVA each and installation of a transfer bus to facilitate station-to-station and intra-station load transfers for contingency purposes.

This would add capacity to the downtown core which would be utilized to provide additional capacity support for adjacent stations and additional feeder positions to support Windsor TS.

Toronto Hydro's total high level estimated incremental cost is $46 million, a small portion of which is expected to be a capital contribution to HONI. $24 million of these costs are anticipated to occur in 2019, with the remaining project costs carried over to 2020.

Toronto Hydro estimates that this project will require two years to complete, plus at a minimum one to two additional years to transfer load to the new infrastructure. Based on the above-mentioned critical "need" date of 2023, the project is scheduled to commence in 2019 for completion of the station work in 2020. Load transfers and system reconfiguration would take place between 2021 and 2022, in time to address the 2023 need date. Note that this timeline may need to be accelerated depending on the actual peak demand growth rate observed in the near future.

Toronto Hydro plans to pursue this project with its partners at the OPA, HONI and the IESO as part of the Regional Planning process. Any decision to proceed would be undertaken only after consultation with these stakeholders.

(ii) Strachan TS

Strachan TS, located at Strachan Avenue and Fleet Street, supplies much of the south-west portion of central Toronto, including Exhibition Place, BMO Field and Ontario Place. The station is comprised of four load service busses, each supplied from two windings from two of four different HONI transformers located on site (designed as T12, T13, T14 and T16). HONI has indicated to Toronto Hydro that they plan to replace the 75 MVA T12 transformer because it has reached its end-of-life. This transformer supplies Toronto Hydro's A5-6T and A7-8T busses. Toronto Hydro is proposing to request that HONI upgrade the size of the replacement transformer from 75 MVA to 100 MVA. Under these circumstances, Toronto Hydro would be responsible for paying the incremental difference in cost relative to a like-for-like replacement. This will provide additional capacity and flexibility to the area at a fraction of the cost should such an upgrade be completed solely at Toronto Hydro's request. Currently, the A1-2T and the A9-10 busses are rated for 72 MVA; however their actual capacity is limited to 56 MVA by the transformer size. Once both transformers supplying a bus are upgrade to standard 100 MVA units, the full rating of the bus can be utilized.

The 2014 load forecast for the Strachan TS area is shown in Table 11.

TABLE 11: 2014 SUMMER LOAD FORECAST FOR STRACHAN TS

STATION / BUS	FIRM CAPACITY(MVA)		YEAR										
	100%	95%	2013*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
STRACHAN (115KV/13.8KV) TS													
A1r2	56	53	46	50	52								
A9r10 (Formerly A3r4)	50	48	37	41	42	43	43	44	44	45	46	46	47
A5r6	40	38	23	25	29	31	32	33	33	34	34	34	35
A7r8	40	38	36	37	33	34	35	35	36	36	36	37	37
Total of all Buses	192	182	142	153	156	162	164	167	169	172	173	175	178
Surplus MVA			50	39	36	30	28	25	23	20	19	17	14
% Loading (Load/2013 Firm Cap)			74	80	81	84	85	87	88	90	90	91	93

By 2023, the station is forecasted to reach 93% loading overall. At that point in time, Toronto Hydro will have the option to request replacement of the other transformer(s) supplying the A1-2T or the A9-10T, which will result in a capacity increase to 72 MVA. This represents an opportunity to leverage HONI's planned asset renewal program to benefit Toronto Hydro ratepayers. Toronto Hydro estimates that its cost to complete this work will be $0.5M.

(iii) South-West Toronto (Horner TS, Manby TS, Runnymede TS, Fairbank TS areas)

There are currently four stations in the south-west part of Toronto Hydro's service territory that are forecasted to be at capacity in the near future. These stations are Horner TS, Manby TS, Runnymede TS and Fairbank TS.

FIGURE 7: MANBY TS

FIGURE 8: HORNER TS

FIGURE 9: RUNNYMEDE TS

FIGURE 10: FAIRBANK TS

This location in the Horseshoe area distributes electricity at a primary voltage of 27.6 kV. There is generally some dynamic load transfer capability built in to move load between stations through

operational switching, although it is limited by technical considerations such as voltage drop and reliability, as longer feeders, such as those connecting these stations, generally have a negative impact on reliability. At these stations, the demarcation point between HONI and Toronto Hydro is the feeder breaker. HONI owns everything up to and including the secondary side of the feeder breaker, while Toronto Hydro owns everything electrically downstream from that point. The 2014 load forecast for these stations is provided in Table 12.

TABLE 11: 2014 SUMMER LOAD FORECAST (SOUTH-WEST TORONTO)

STATION / BUS	FIRM CAPACITY(MVA)		YEAR										
	100%	95%	2013*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
FAIRBANK (115KV/27.6KV) TS													
B & Q	95	90	92										
Y & Z	97	92	82	81	82	82	83	84	85	86	87	88	89
Total of all Buses	192	182	174	180	184	187	189	191	186	188	190	192	195
Surplus MVA			18	12	8	5	3	1	6	4	2	0	r3
% Loading (Load/2013 Firm Cap)			91	94	96	97	98	99	97	98	99		
HORNER (230KV/27.6KV) TS													
B & Y	192	182	153	167	173	181	186	190					
Total of all Buses	192	182	153	167	173	181	186	190	195	199	204	208	213
Surplus MVA			39	25	19	11	6	2	r3	r7	r12	r16	r21
% Loading (Load/2013 Firm Cap)			80	87	90	94	97	99					
MANBY (230KV/27.6KV) TS													
B & Y	63	60		60									
Q & Z (see note 2)	63	60			52	54	55	56	57	59	60	61	
V & F	112	106	93	91	93	95	97	100	102	104	107	109	111
Total of all Buses	238	226	232	219	213	219	224	229	234	240	245	250	256
Surplus MVA			6	19	25	19	14	9	4	r2	r7	r12	r18
% Loading (Load/2013 Firm Cap)			97	92	89	92	94	96	98				
RUNNYMEDE (115KV/27.6KV) TS													
B & Y	117	111	108	107	109	105	108	110	111	112	113	115	116
Total of all Buses	117	111	108	107	109	105	108	110	111	112	113	115	116
Surplus MVA			9	10	8	12	9	7	6	5	4	2	1
% Loading (Load/2013 Firm Cap)			92	91	93	90	92	94	95	96	97	98	99
Total of all Stations													
Bus Total	739	701	667	673	679	692	707	720	726	739	752	765	780
Surplus MVA			72	66	60	47	32	19	13	0	r13	r26	r41
% Loading (Load/2013 Firm Cap)			90	91	92	94	96	97	98				

As can be seen in Table 13 above, Toronto Hydro is forecasting that the total capacity for the entire area will be exhausted by 2020. The load forecast utilizes a growth rate of 1.1% for Runnymede TS and Fairbank TS, and a growth rate of 2.3% for Manby TS and Horner TS. These growth rates were determined based on weather corrected historical peak loads. Actual peak load can vary significantly on a year-over-year basis if there is an abnormally large (or small) volume

of customer connection requests, and based on the size of said requests. Generally, Toronto Hydro tries to balance loading between area station busses through load transfers. However, this is becoming increasingly difficult in this area of the system given that all four stations are reaching capacity. Over the past few years, Toronto Hydro has seen an increasing number of requests for connection in the areas served by these stations. This is illustrated in Table 13 and Figure 12, respectively.

TABLE 12: NUMBER OF CONNECTION REQUESTS BY STATION

Year	2006	2007	2008	2009	2010	2011	2012	2013
Fairbank TS	2	4	3	2	4	5	6	8
Horner TS	11	7	3	8	5	4	12	7
Manby TS	8	3	4	5	3	4	8	6
Runnymede TS	1	3	0	4	1	0	7	0
Area Total	**16**	**17**	**18**	**10**	**19**	**16**	**30**	**29**

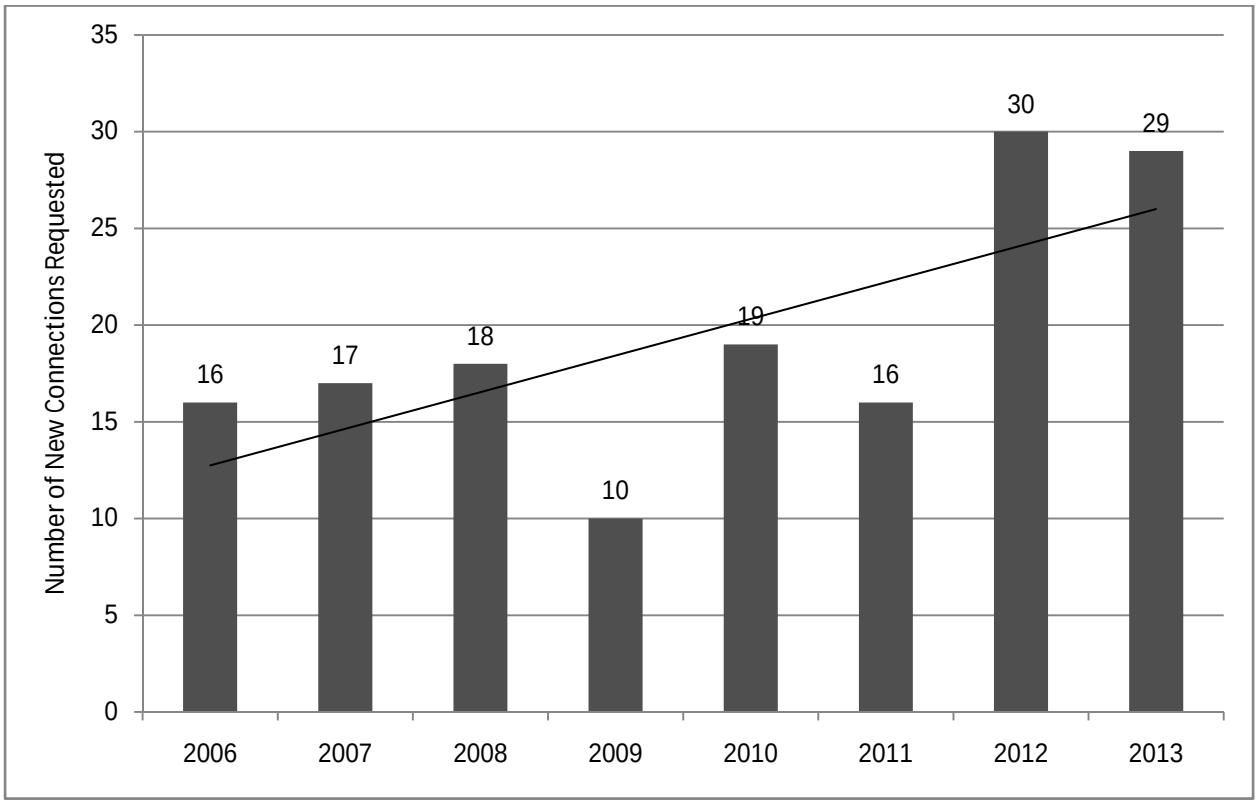


FIGURE 11: TOTAL AREA CONNECTION REQUESTS (HORNER / MANBY / FAIRBANK / RUNNYMEDE AREAS)

The increasing trend in connection requests received across the area strongly implies that peak demand is expected to continue growing at historical levels. Toronto Hydro has also observed a corresponding increase in the aggregate amount of new load to connect. This is illustrated in Table 14 and Figure 12, respectively.

TABLE 13: TOTAL LOAD OF CUSTOMER CONNECTION REQUESTS (MVA)

Year	2006	2007	2008	2009	2010	2011	2012	2013
Fairbank TS	1.3	0.6	0.9	0.1	0.3	1.7	9.7	3.5
Horner TS	9.3	7.4	7.9	14.8	5.2	7.3	9.7	24.6
Manby TS	7.1	1.4	3.0	9.2	3.7	5.6	5.5	3.4
Runnymede TS	0.7	1.9	0.0	1.0	0.0	0.0	23.6	0.0
Area Total	**18.4**	**11.3**	**11.9**	**25.1**	**9.2**	**14.5**	**48.5**	**31.6**

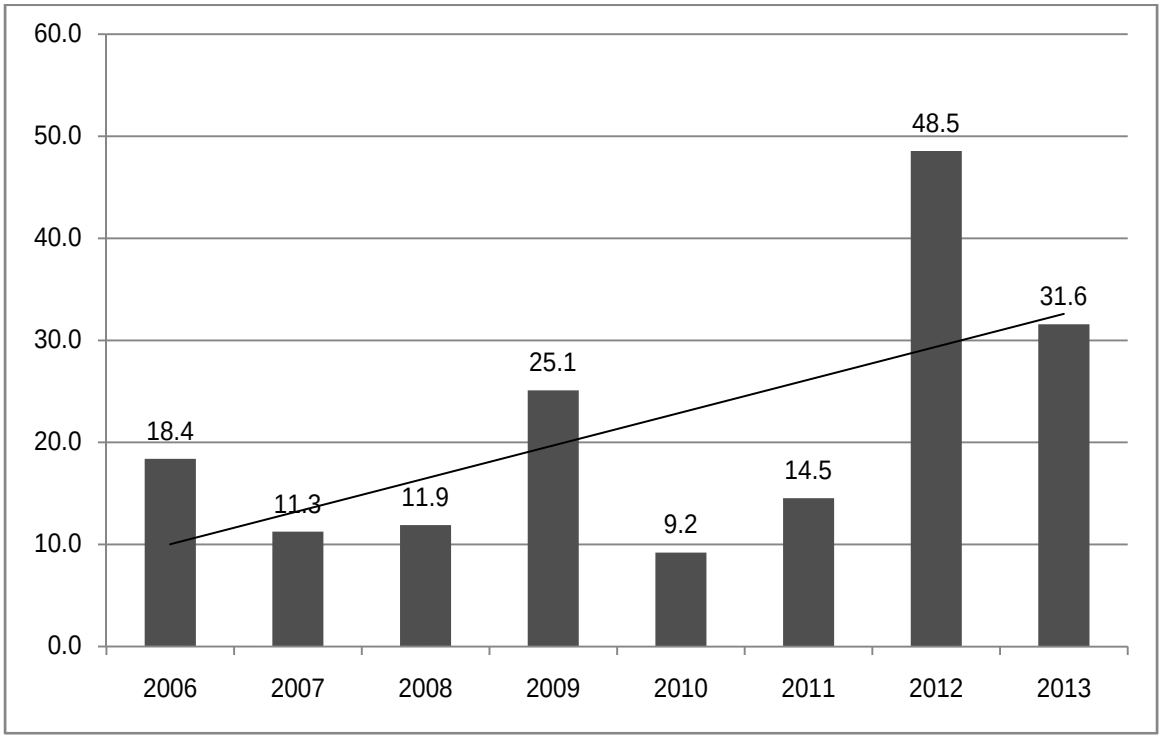


FIGURE 12: TOTAL LOAD (MVA) OF AREA CONNECTION REQUESTS (HORNER / MANBY / FAIRBANK / RUNNYMEDE AREAS)

The connection data presented in these figures is incorporated in to the 2014 load forecast. While not all the load will materialize, this data serves as a useful indicator of the level of customer connection activity Toronto Hydro is facing.

An additional consideration for Runnymede TS and Fairbank TS is the Eglinton Crosstown LRT project currently being undertaken by Metrolinx.

FIGURE 13: EGLINTON CROSSTOWN LRT (SOURCE: WWW.THECROSSTOWN.CA)

The proposed transit stations from Bathurst Station West to Mt. Dennis are located in the Fairbank TS or Runnymede TS service territory. Toronto Hydro is involved with ongoing discussions with Metrolinx regarding their power requirements, and preliminary information indicates that up to 33 MVA of permanent power will be required for this segment of the line, adding to the overall load demand in this area. Long term, it stands to reason that development (and thus electricity demand) will intensify along the Eglinton corridor once the new LRT line is in full service.

As was the case with for Windsor TS, Copeland TS and Esplanade, Toronto Hydro has also assessed the impact of various CDM initiatives. Toronto Hydro's CDM team has forecasted peak

load reductions that are achievable over five and ten years based on 2014 OPA targets, energy efficiency initiatives, demand response initiatives and codes and standards changes. For the purposes of this assessment, these station level estimates have been averaged across the number of busses at each station to provide an indication of how much capacity relief can be expected as a result of CDM initiatives. This information is shown in Table 15. This level of reduction is insufficient to address the need for additional capacity in these areas.

TABLE 14: FORECASTED PEAK REDUCTION THROUGH CDM

Station	# of Bus Pairs	Cumulative Peak Reduction in MW (2014-2019)	Cumulative Peak Reduction in MW (2019-2024)	Average Cumulative Peak Reduction per Bus Pair in MW (2014-2019)	Average Cumulative Peak Reduction per Bus Pair in MW (2019-2024)
Horner TS	1	5.2	5.6	5.2	5.6
Manby TS	3	7.3	7.8	2.4	2.6
Runnymede TS	1	4.2	4.8	4.2	4.8
Fairbank TS	2	8.1	9.4	4.0	4.7

Some additional considerations pertaining to system need in this are summarized in Table 16.

TABLE 15: LIST OF STATION-BY-STATION CONSIDERATIONS

Station	Considerations
Horner TS	***f*** Station is surrounded by physical barriers (Lake Ontario, Enersource service territory, the Gardiner Expressway and the Humber River), which make load transfers more challenging and expensive. *f* In addition to the information contained in the load forecast, and the connection requests not included in the forecast, Toronto Hydro received an inquiry in early 2013 from a customer claiming to require up to 60 MVA by 2019. While no official request has been received, Toronto Hydro will be challenged significantly to supply this customer should they formally indicate their intention to proceed. *f* Toronto Hydro has submitted a connection application to HONI to confirm a cost, schedule and feasibility for installation of a new bus and the requisite transmission capacity.
Manby TS	***f*** Station is adjacent to Richview TS (which has spare capacity). Toronto Hydro has reviewed load transfer options in detail; however, the cost is significant and the load relief would only be temporary. These stations are separated by Highway 401, which presents a challenge to transferring load between stations. *f* Toronto Hydro understands that there is no physical space on the HONI-owned site for a new bus.

Station	Considerations
Runnymede TS	ƒ Toronto Hydro has submitted a connection application to HONI to confirm a cost, schedule and feasibility for installation of a new bus and the requisite transmission capacity. ƒ This station is supplied from the 115kV lines originating at Manby TS. HONI has indicated that installation of new capacity at this station would have a negative impact on the overall supply capacity of those lines (in excess of the amount of capacity added). ƒ This station is separated from Richview TS and Manby TS by the Humber River, making load transfers complicated and costly. It also borders the 13.8kV system (no load transfers possible between different voltage classes) and Fairbank TS, which is also overloaded. ƒ Toronto Hydro's CDM team is targeting this area for future demand response programs. Once the impact of this program is defined, Toronto Hydro will review its impact on capacity expansion plans.
Fairbank TS	ƒ Toronto Hydro understands that there is no physical space on the HONI owned site for a new bus. ƒ Toronto Hydro's CDM team is targeting this are for future demand response programs. Once the impact of this program is defined, Toronto Hydro will review its impact on capacity expansion plans.

As is the case with the previously discussed downtown station expansion program, Toronto Hydro's objective for the South West Toronto portion of the program is to ensure that it is able to continue fulfilling its obligations under the DSC by connecting new customers in its service territory in a manner that maximizes ratepayer value. To accomplish this objective, Toronto Hydro is currently proposing to undertake two projects:

(1) Installation of a new HONI owned bus at Runnymede TS (minimum 60 MVA).

This project would involve the installation of two power transformers with a minimum 60 MVA LTR rating and a bus pair. It is assumed that no transmission upgrades are required.

This would add capacity to the area east of the Humber River and south of highway 401 which would provide support to Fairbank TS and Runnymede TS without requiring any river or highway crossings.

A formal Connection Application has been submitted to HONI. HONI is required to respond with a cost and schedule to address the forecasted shortfall.

Toronto Hydro's high level estimated cost is $33 million, which would be a capital contribution to HONI.

Toronto Hydro's estimated project schedule is to commence construction in 2016 for completion in 2017.

(2) Construction of a new Toronto Hydro-owned station in the Manby TS area (minimum 100 MVA).

This project would involve the purchase and preparation of a suitable site, high voltage connection work, installation of two power transformers and a bus pair and construction of the necessary civil egress infrastructure.

This would add capacity support to the Horner TS and Manby TS areas.

Toronto Hydro is currently working to identify potential areas to site a new transformer station, preferably within two kms from the existing 230 kV transmission system (which would simplify project execution).

Would ideally be supplied from the 230kV system and provide direct relief to Manby TS, Runnymede TS and the 115 kV transmission system supplying the western portion of central Toronto.

Toronto Hydro's high level estimate is $72M, part of which would likely be a capital contribution to HONI.

Toronto Hydro's estimated project schedule is to commence construction in 2016 for completion in 2019.

Toronto Hydro plans to pursue these options with its partners at the OPA, HONI and the IESO as part of the next phase of the Regional Planning process. Any decision to proceed will be made upon agreement that these projects are prudent and appropriate solutions from a transmission system planning perspective in addition to a distribution system planning perspective.

(iv) Basin TS Short Circuit Upgrades

Basin TS is located in the "Portlands" area of Toronto, south-east of the downtown core. The station is comprised of two dual winding HONI owned power transformers (designated T3 and T5) and two Toronto Hydro owned busses (designate A5-6BN and A7-8BN). One characteristic of power distribution systems that limit connection of DG resources is the "short circuit level". Essentially, this refers to the system's ability to withstand the current generated by a short circuit on the system. Large currents generate significant amounts of heat, induce strong magnetic fields

and are more difficult to interrupt compared to normal operating currents. As a result, power system equipment has a maximum rated amount of short circuit current that it can withstand. This is particularly important for circuit breakers as they are the devices whose purpose it is to interrupt said current and isolate faults. The amount of short circuit current available at a given point in the system is calculated based on the impedances of the power lines and equipment (high impedance serves to limit fault current), the size and location of rotating loads (large industrial motors, which in the event of a fault release energy out into the distribution system) and the amount and location of connected DG resources (which will also supply energy in to a fault).

As part of the connection process for generation projects, Toronto Hydro regularly assesses the short circuit capacity available at the station. In the case of Basin TS, Toronto Hydro has identified that short circuit levels are presently at the station capacity of 470 MVA. Toronto Hydro is currently developing a generation project at the Ashbridges Bay Wastewater Treatment Plant which will add an additional 60 MVA of short circuit current. This connection cannot currently be made. As a solution, Toronto Hydro is proposing to take action and work with HONI to upgrade the short circuit rating of the station by modifying the configuration of the bus supply. This will likely also involve installation of some additional equipment (circuit breakers and short current limiting devices) at Basin TS, the need for which will be established upon completion of a detailed technical analysis in conjunction with HONI. This job will also require upgrades to protection settings and may involve reconfiguration of the existing transformer connections. A high level estimate of the total cost for this work is $2 million, of which $0.5 million is anticipated to be a capital contribution to HONI. Any solution pursued by Toronto Hydro will require extensive cooperation and collaboration with HONI.

(v) Bathurst TS – New Feeder Positions

Bathurst TS is a HONI owned station located in the Bathurst Street and Finch Avenue area. The ownership arrangement is such that Toronto Hydro owns the feeder circuit breakers and HONI owns the bus and all assets upstream from that point. Toronto Hydro has received notice from a large customer that it anticipates the need for a dedicated feeder in the coming years to support expansion plans. In order to respond to this need, Toronto Hydro will be required to request a pair of bus positions at Bathurst TS to install two new feeder circuit breakers to support this request. Based on the standard design of the station, two circuit breakers would be required for reliability purpose as they are designed to back each other up in contingency situations.

TABLE 17: SPENDING BY PROJECT

Project	2015	2016	2017	2018	2019	Future
Copeland Phase 1	$41.8M	$13.1M	-	-	-	-
New Transformer Station in Manby TS area	-	$12.0M	$20.0M	$20.0M	$20.0M	-
Expansion of Runnymede TS	-	$16.5M	$16.5M	-	-	-
Copeland TS - Phase 2	-	-	-	-	$24.0M	$22.0M
HONI T12 replacement and upgrade	-	-	-	$0.5M	-	-
Basin TS short circuit upgrades	$2.0M	-	-	-	-	-
Bathurst – New Feeder Positions	-	-	-	$1.5M	-	-

/C

Construction on Copeland Transformer Station (TS) began in 2013 and is expected to be completed in 2016. Copeland TS is a uniquely challenging project located in the dense urban core of the city. The station design places most of the equipment underground and includes a tunnel connection to HONI's Front Street tunnel. Excavation of the main site began in 2013 and was completed before the end of that year. Presently, civil construction is under way on the project. Cable tunnel mining is complete and concrete placement is ongoing. Major equipment orders were placed in 2013. Manufacturing, factory acceptance testing and delivery of most of the major equipment occurred in 2014 and it is now in secure storage awaiting station readiness for installation.

/C

Initially, Toronto Hydro estimated the Copeland TS (Phase 1) project would be completed by the end of 2014. However, due to several unforeseen events and factors, Toronto Hydro now expects the construction to be completed in the second quarter of 2016. The project's overall cost is expected to remain within the OEB-approved amount; however, the timing of certain portions of those expenditures will shift given the delay to the construction completion date (i.e. some of the 2014 forecast spend is now deferred to 2015 and 2016). The delay is attributable to a variety of factors, including the effect of unusually adverse weather events, a generally harsh winter in 2014, challenging site conditions and contractor performance. Other causes of delay include unforeseen obstructions found on site (not known at time of the RFP or identified in engineering reviews of site records), and delays in securing appropriate permits for certain on-site activities (i.e. lane closure permit for tunnel boring subcontractor).



/C

In addition to Copeland Phase 1, the majority of the remaining historical spending over the 2010 to 2014 time period on Station Expansion type work can be attributed to the Leaside-Birch transmission reinforcement project, which involved upgrades to the 115 kV transmission lines between Leaside TS and Wiltshire TS, and installation of additional feeder breakers at various 27.6 kV stations to support load growth due to new customer connections. It should also be noted

that the 2010 and 2011 historical spending includes capital contributions made to HONI for transformer station switchgear replacement projects. While these costs would normally be categorized under the Station Switchgear Renewal program, for these years Toronto Hydro is unable to delineate between contributions made for renewal projects and contributions made for expansion projects.

E7.9.4.1 Ranking & Prioritization

Toronto Hydro prioritized the projects comprising this program based on the following criteria:

- Forecasted year of capacity shortfall,
- Magnitude of forecasted capacity shortfall, and
- Lead time required to complete each individual project and degree of complexity

A complete list of projects that Toronto Hydro plans to undertake, including their timing and prioritization is provided in Table 19.

TABLE 18: PROJECT TIMING

Project	In Service Year	Timing and Prioritization
Basin TS Short Circuit Upgrades	2015	*f* Timing based on forecasted short circuit capacity shortage and planned in service year of Ashbridges Bay generation project.
Copeland Phase 2	2020	*f* Toronto Hydro forecasts that through a combination of small scale load transfers, the need for additional capacity in the Copeland/Windsor/Esplanade area can be deferred to 2023 at the absolute latest. *f* Upon completion of this project, Toronto Hydro will require one to two years to transfer load to the new busses and rebalance load in the area.
Strachan TS Transformer Upgrade	2018	*f* Timing is contingent on HONIs asset renew programs.
Runnymede TS Expansion	2017	*f* Based on the 2014 summer load forecast, Toronto Hydro requires immediate capacity relief as one bus at Fairbank TS is already overloaded. Short term measures (small load transfers) can be implemented to buy time but additional capacity is required as soon as possible. *f* In service year of 2017 for additional capacity reflects anticipated project lead time.
New Transformer	2019	*f* Toronto Hydro is in need of immediate capacity relief at Manby TS as the station has already exceeded capacity in

Project	In Service Year	Timing and Prioritization
Station in south Etobicoke		the summer of 2013. ƒ Horner TS is forecasted to be at 102% capacity by the end of 2019. ƒ In service year of 2017 for additional capacity reflects anticipated project lead time.
Bathurst – New Feeder Positions	2018	ƒ In service date of 2018 reflects customer's proposed in service date.

E7.9.6 Program Execution

A generalized overview of the steps and prerequisites required to implement each type of job contained in this program is provided in the table below. This summary is intended to provide a high level overview of the key steps involved with each job. It does not represent the exact scope of work for each project.

TABLE 19: TYPICAL STATION CAPACITY RELIEF OPTIONS

Job Type	Steps	Execution Risks	External Coordination
Load transfer	1. Distribution Planner assesses feasibility and issues scope to construct new infrastructure. 2. Station planner issues scope to prepare new feeder position on receiving bus (if required). 3. Scopes are issued to designers. 4. Scopes are issued for construction.	x Given the complex nature of these projects, there are inherent planning challenges/risks that can impact overall project cost and feasibility. x Road moratoriums can cause permitting complications.	x Standard Toronto Hydro customer engagement for construction projects in their area.
Upgrading of HONI equipment (i.e. a transformer)	1. Toronto Hydro submits connection application to HONI requesting additional capacity through equipment upgrade. 2. HONI reviews request and if acceptable, provides cost and schedule. 3. Toronto Hydro and HONI	x If a HONI owned asset is being replaced and it is not at the end of its life useful, Toronto Hydro is required to compensate HONI. x Schedule depends	x Formal agreement with HONI required for study and completion of work.

Job Type	Steps	Execution Risks	External Coordination
	sign Connection Cost Recovery Agreement (CCRA). 4. HONI completes work.	on HONI's ability to execute the work. x Overall project cost highly dependent on HONI estimates.	
Expansion of a Toronto Hydro-owned station	1. Toronto Hydro station planner identifies need. 2. Toronto Hydro submits connection application to HONI to assess feasibility, cost and schedule for requisite transmission connection work. 3. Scope issued to Toronto Hydro execution groups. 4. HONI reviews request and if acceptable, provides cost and schedule. 5. Toronto Hydro and HONI sign CCRA. 6. Toronto Hydro executes its work. 7. New infrastructure energized upon completion of HONI and Toronto Hydro work.	x Schedule depends on HONI's ability to execute the work. x Overall project cost highly dependent on HONI estimates. x Requires significant coordination with distribution planners to ensure load transfers occur in an optimized manner.	x Standard Toronto Hydro customer engagement for construction projects in their area. x Additional communication with the community is necessary if expansion is observable during or after construction. x Formal agreement with HONI required for study and completion of work.
Expansion of a HONI-owned station	1. Toronto Hydro station planner identifies need. 2. Toronto Hydro submits connection application to HONI to assess feasibility, cost and schedule for requisite transmission connection work. 3. HONI reviews request and if acceptable, provides cost and schedule. 4. Toronto Hydro and HONI sign CCRA.	x Schedule depends on HONI's ability to execute the work. x Overall project cost highly dependent on HONI estimates. x Requires significant coordination with distribution planners to ensure load transfers	x Toronto Hydro would support HONI with community engagement as required.

Job Type	Steps	Execution Risks	External Coordination
	5. New infrastructure energized upon completion of HONI work.	occur in an optimized manner.	
Construction of a new Toronto Hydro-owned station	1. Toronto Hydro station planner identifies need. 2. Toronto Hydro submits connection application to HONI to assess feasibility, cost and schedule for requisite transmission connection work. 3. Scope issued to Toronto Hydro execution groups. 4. HONI reviews request and if acceptable, provides cost and schedule. 5. Toronto Hydro and HONI sign CCRA. 6. Toronto Hydro executes its work. 7. New infrastructure energized upon completion of HONI and Toronto Hydro work.	x Schedule depends on HONI's ability to execute the work. x Overall project cost highly dependent on HONI estimates. x Requires significant coordination with distribution planners to ensure load transfers occur in an optimized manner.	x Toronto Hydro will support HONI with community engagement as required.

E7.9.7 Evaluation of Alternatives

E7.9.7.1 Quantification / Evaluation of Options

Toronto Hydro has identified alternative options to address several issues and evaluated the options based on current and future needs of the system. The impact of forecasted peak reductions through CDM has been included in the plan.

(i) Windsor / Esplanade / George & Duke / Copeland

Issue: As described in detail in Section E7.9.3, Toronto Hydro requires additional capacity in the area served by Windsor, Esplanade, George and Duke and Copeland stations to serve both near and long term system needs. In summary:

- By 2019 Toronto Hydro forecasts that two busses will be overloaded at George and Duke MS and two busses overloaded at Windsor TS.
- By 2025 Toronto Hydro forecasts that one bus will be overloaded at Copeland TS, two busses overloaded at George and Duke MS and three busses overloaded at Windsor TS.
- Currently at Windsor TS, four out of six busses have no spare feeder positions to connect new customers. One bus has a single spare feeder position and one bus has two spare feeder positions.
- Currently at George and Duke MS, one bus has no spare feeder positions and one bus has six spare feeder positions.
- Currently at Esplanade TS, the sole bus has only three spare feeder positions.
- Once in service, Copeland TS is forecasted to have six and three spare positions on each its two busses, respectively.

Toronto Hydro anticipates that at the current pace of development in these areas, both bus and feeder position will be at or near capacity within five to ten years. In identifying solutions to these issues, Toronto Hydro considered the following options.

Chosen Option: Expansion of Copeland TS

- Completion of Copeland TS Phase 2, which includes the purchase and installation of three power transformers (two on load, one on potential spare), two distribution 72 MVA busses and one transfer bus to facilitate integration of the spare transformer and inter-station ties with Windsor TS. While not entirely non-discretionary, installation of the second 72 MVA bus, the spare transformer and the transfer bus at this time is considered the more prudent option. This would allow Toronto Hydro to fully utilize the space and infrastructure installed in phase 1 while eliminating the need and cost associated with re-entering the station (roof removal and redoing the landscaping). Additionally, the spare transformer is required given the uniqueness of the SF_6 transformers that will be installed

at the station and the long lead times to procure replacement units. Should a transformer fail before a spare is available, the station load would be under contingency for an extended amount of time. Adds 144 MVA and a significant number of feeder positions to allow for bus rebalancing in the area and to facilitate future switchgear replacements, particularly at Windsor TS. Installing two 72 MVA busses will enable utilization of all additional transformation capacity (installing one bus would still require installation of two transformers for contingency purposes).

- Provides additional security of supply to critical downtown customers.
- Would provide additional support for adjacent stations Terauley TS, Strachan TS and Cecil TS through load transfers (if necessary).
- Provides additional capacity to facilitate potential development of West Donlands area, east Waterfront and the Portlands.
- Minimal additional high volta$_g$e connection work will be required beyond what was completed as part of Copeland phase 1.
- This option involves no permanent visual disturbance to the area.
- Estimated total cost of $46M.

Alternative Option 1: CDM

- Toronto Hydro forecasts that cumulative incremental peak reductions of approximately 1.2 MW per bus at Esplanade TS and George and Duke MS and peak reductions of 1.1 MW per bus at Windsor TS and Copeland TS are achievable over the 2014 to 2019 timeframe.
- This level of reduction is insufficient to meet short and long term needs.
- Furthermore, the forecasted peak reductions include considerations for factors outside of Toronto Hydro's control, such as reductions through program which are as of yet unfunded and codes and standards initiatives which are driven by third parties.
- Given that there is currently no clear funding mechanism for this work, and the fact that it is inadequate as a stand-alone solution, this option is not preferred.

Alternative Option 2: Expansion of Esplanade TS

- This option would involve working with HONI to construct a new building on the existing Esplanade TS site, perform necessary transmission upgrades (as determined by HONI), install two new power transformers, installed two new 72 MVA distribution busses and complete the requisite high voltage connection work.
- This option is better positioned to serve areas of potential future development (West Donlands area, east Waterfront and the Portlands), it is located further from the existing load centre compared to Copeland TS.
- This project would involve construction on a new facility and could encroach on parkland that is adjacent to the station.
- Estimated cost of $48M, including necessary contributions to HONI. As this project could require as of yet undetermined work on the transmission system, the costs and schedule associated with this option would be subject to a significant amount of uncertainty.

Alternative Option 3: Load Transfers

- From a practical perspective, there are several technical barriers that would make this a costly and extremely complex exercise.
- This would require a very significant amount of investment in order to build the necessary infrastructure. This investment may be sufficient for five to ten years, yet it does not provide any relief for additional capacity needs in the longer term.
- Much of the load that would need to be transferred comes in indivisible, discrete chunks and requires dedicated feeder positions (i.e. secondary network load and large office or condo buildings). The busses that have capacity generally will not have sufficient feeder positions available to provide the dedicated feeders needed to supply these discrete loads.
- Load transfer potential is further limited by the 3-wire vs. 4-wire configuration issue described earlier in this narrative. For example, George and Duke busses A1-2GD and A3-4GD both require relief and Esplanade bus A1-2X has capacity. But, since A1-2X is a 3-wire bus and the George and Duke busses are 4- wire, load transfers are not possible.

- The stations immediately adjacent to Windsor, Copeland and Esplanade are approaching capacity as well and in the long term, will require capacity relief. Load transfers will not provide any long term support to relief of these stations.

- It should be noted that assuming it is feasible, Toronto Hydro anticipates the need to undertake some load transfer projects in order to defer the need for new area capacity to 2023.

(ii) Horner, Manby, Runnymede & Fairbank

Issue: As described in detail in Section E7.9.3, Toronto Hydro requires additional capacity in the area served by Horner TS, Manby TS, Runnymede TS and Fairbank TS stations to serve both near and long term system needs. In summary:

- In 2013 both Manby TS busses exceeded their peak ratings.

- Fairbank TS bus B&Q is forecasted to exceed its peak in 2014.

- Horner TS bus B&Y is forecasted to exceed its peak in 2019.

- Runnymede TS is currently at 92% capacity and is forecasted to reach 94% capacity in 2019 and 99% capacity in 2023.

- The combined capacity of all four stations is expected to be entirely exhausted by 2020.

- Toronto Hydro has observed significant redevelopment of some areas served by these stations. Further development is anticipated based on upcoming projects (the Eglinton Crosstown LRT) and the increased growth in annual connection requests and the gross MVA requested.

Toronto Hydro plans to pursue two projects to address these issues.

Chosen Option 1: Construct a New Toronto Hydro-Owned Transformer Station in the Manby TS Area

- This option involves construction of a transformer station in the Manby area (100 MVA) and purchase of the requisite land.

- Toronto Hydro is currently investigating potential areas for locating the proposed new transformer station. The preferred location would be within two kilometers of the existing 230 kV transmission lines (subject to availability) to simplify project approvals.
- This will provide sufficient capacity to relieve Horner TS, Manby TS and partially relieve Runnymede TS. It will also provide a number of new feeder positions to add redundancy to the system.
- This station would be supplied from the 230 kV system, which will provide relief to the 115kV circuits running from HONI's Manby East switchyard to Bridgman TS. This will improve restoration ability in the event of a major transmission event.
- Estimated cost is $72M.

FIGURE 14: 115KV LINES CURRENT SUPPLYING FAIRBANK AND RUNNYMEDE FROM MANBY EAST

Chosen Option 2: Install a New Bus at Runnymede TS

- This option would involve installation of a new bus and requisite transformation at Runnymede TS.
- As this is a HONI owned station, this work would most likely be completed by HONI and funded by Toronto Hydro.
- In 2012, Toronto Hydro submitted a formal Connection Application to HONI to study this option.

- This option is best suited to provide relief to Runnymede TS and Fairbank TS. Fairbank TS has no room for expansion and is adjacent to a 13.8kV area, making Runnymede TS the only practical load transfer option.
- This option may require significant transmission system upgrades – to be determined by HONI.
- Estimated cost to Toronto Hydro is $33 million.

Alternative Option 1: CDM

- Toronto Hydro forecasts that cumulative incremental peak reductions of approximately 2.4 to 5.2 MW over the 2014 to 2019 timeframe and 2.6 to 5.6 MW per bus over the 2019 to 2024 timeframe.
- This level of reduction is insufficient to meet short and long term needs.
- Furthermore, the forecasted peak reductions include considerations for factors outside of Toronto Hydro's control, such as reductions through program that are unfunded and codes and standards initiatives that are driven by third parties.
- Given that there is currently no clear funding mechanism for this work, and the fact that it is inadequate as a stand-alone solution, this option is not preferred.
- In parallel, Toronto Hydro is investigating targeted demand response initiatives in the Runnymede and Fairbank TS areas to provide interim support for the area between now and when a long-term permanent solution can be implemented.

Alternative Option 2: Expansion of Horner TS

- This option involves expansion of Horner TS to install a new 100 MVA bus and associated transformation supplied from the 230kV transmission system.
- Toronto Hydro submitted a formal Connection Application to HONI in 2013 to study the cost and feasibility of this option. Preliminary discussions indicate that the option is technically feasible.
- As this is a HONI owned station, the work would most likely be completed by HONI.

- The Horner TS service area is bordered by Lake Ontario to the south and Mississauga (Enersource) to the west and Manby TS to the north (separated by the Gardiner Expressway). Manby TS is the only station which borders the service territory of Horner TS to facilitate direct load transfers. a result there is only one station service area that it borders for direct load transfers (Manby TS).

- Should this option be undertaken, Toronto Hydro would look to relieve Manby TS through direct load transfers.

- Runnymede TS and Fairbank TS are located a significant distance away from Horner TS and the Gardiner Expressway and the Humber River are also located between Horner and these stations. These physical barriers significantly increases the complexity, cost and long term reliability risk associated with potential transfers load transfers, assuming that it is even feasible.

- Estimated cost to Toronto Hydro is $33M.

Alternative Option 3: Load Transfer to Richview TS

- Richview TS, located north of highway 401 near Highway 27 and Dixon Road, is a HONI owned station. Currently there is a significant amount of spare capacity available.

- Toronto Hydro has considered the option of utilizing this capacity to provide relief to Manby TS and Horner TS.

- The estimated cost to address the capacity issues is approximately $148 million, consisting of $38 million in electrical work and $110 million in civil work.

- Such a load transfer would be costly and complex. It would not result in any permanent incremental capacity and the infrastructure may eventually be abandoned once new capacity is added on a permanent basis.

- Richview TS is located approximately eight kilometers from Manby TS. This is a significant distance to run 27.6 kV distribution feeders and presents potential issues with voltage drop and reliability.

- A portion of this work would be considered as a short term mitigation action should Toronto Hydro receive a committed large customer request in the area which could not be served through other means.

(iii) Bathurst TS New Feeder Positions

Issue: A large customer has requested a dedicated feeder at Bathurst TS

Chosen Option: Request that HONI Expand the Bus

- This option involves paying a capital contribution to HONI to install a pair of new circuit breakers at Bathurst TS to provide a dedicated feeder position to supply the customer.
- Estimated cost is $1.5M.

Alternative Option: Connect Customer to an Existing Feeder

- Based on information provided by the customer with respect to anticipated load, reliability requirements and potential DG resources, connecting to an existing or shared feeder may not meet their requirements.

(iv) Basin TS Short Circuit Upgrades

Issue: Short circuit capacity limitation at Basin TS is preventing connection of proposed DG resources.

- Currently, the A7-8BN at Basin TS is rated to interrupt 470 MVA of short circuit current.
- A customer recently connected a set of mobile generators. When these generators are in service and connected to the grid, the available short circuit current at Basin A7-8BN is 470 MVA.

No further DG resources can be connected. Toronto Hydro is proposing to connect a new generator (located at Ashbridges Bay) in 2015, which would contribute approximately 60 MVA of short circuit current and exceed the short circuit rating of the bus.

Chosen Option: Reconfigure supply to Basin TS

- It is technically feasible to overcome short circuit capacity issues by reconfiguring the normal operating state of the transformer windings at Basin TS. This would involved protect and control upgrades and potentially installation of auto-transfer switches and protective relates to enable the bus to be operated in auto-transfer mode.
- This option may impact the reliability of the bus.

- Toronto Hydro plans to pursue this option with HONI.
- Estimated cost to Toronto Hydro is $2 million.

Alternative Option 1: Install a four position outdoor open air bus with a (750 MVA short circuit rating)

- This will involve a tap off of the secondary winding of one of the Basin TS power transformers.
- Toronto Hydro would install a four position bus rated with the ability to interrupt 750 MVA of short circuit current and work with HONI to make the requisite protection and control changes.
- Preliminary discussions with HONI indicate that this option is not feasible.

Alternative Option 2: Expand Basin TS

- This option would involve installation of a new 72 MVA bus and the required transformation, rated to interrupt 750 MVA of short circuit current.
- This bus would provide thermal capacity and feeder positions to the area as well.
- Basin TS bus A5-6BN will be at 95% capacity in 2022. Additionally, there is potential for significant redevelopment of the surrounding area (Portlands).
- At this point in time additional capacity at Basin TS is not justified.
- Estimated cost to Toronto Hydro is $35 million.

Alternative Option 3: Do nothing

- This option would require Toronto Hydro to reject the DG connection, and is not considered an acceptable or prudent approach.

(v) Strachan TS Transformer T12 Upgrade

Issue: HONI is planning to replace their T12 transformer at Strachan TS due to asset condition and age. Toronto Hydro forecasts a long term need for additional capacity at Strachan TS. By 2023, Strachan TS is expected to be at 96% capacity.

Chosen Option: Request that HONI replace the existing 75 MVA T12 with a standard 100 MVA unit and contribute the incremental cost, rather than allow HONI to replace like-for-like.

- Toronto Hydro would be responsible for the incremental cost difference between a 75 MVA unit and a 100 MVA unit.
- Given the long term need for additional capacity, this represents an opportunity to align Toronto Hydro plans with HONI plans.
- Capacity would be increased when the other transformer paired with the T12 is upgraded as well at some point in the future.
- Estimated cost to Toronto Hydro in 2018 is $0.5 million.
- Upon determining that additional capacity is required at Strachan TS, Toronto Hydro would request that HONI upgrade the remaining transformer (assuming they have no prior plans based on asset condition/age) at an estimated cost of $5.5 million. Total cost to Toronto Hydro to increase capacity by 64 MVA is $6.0 million.

Alternative Option: Allow HONI to replace its transformer like-for-like.

- No cost to Toronto Hydro at this time.
- When Toronto Hydro determines that additional capacity is required, Toronto Hydro would be responsible for the entire replacement cost of both transformers supplying the bus. Based on the load forecast, this is expected to occur 5 to 10 years from now. At that time, Toronto Hydro would request that HONI replace both transformers (one of which would be very new, having been installed in 2018) with 100 MVA units. Toronto Hydro would be responsible for the entire project cost which is estimated at $10.0M.

E7.10 Local Demand Response

E7.10.1 Summary

Program Description

The objective of the Local Demand Response (Local DR) program is to support Toronto Hydro's Stations Expansion activities. Toronto Hydro has identified limitations and constraints imposed upon the distribution system by Cecil transformer station (Cecil TS). The utility has identified a capacity relief requirement in the Cecil TS service territory because peak load is expected to approach infrastructure capacity in the medium-term (five to ten years), first at the individual bus level, and then at the total station thresholds. Providing capacity relief normally entails major capital investment in new and/or upgraded assets. However, this situation is somewhat unique because the load duration curve of Cecil TS generates short-run capacity concerns; issues are apparent for only a few hours over the summer months. Under these conditions, typical DR actions would address the need with minimal impact on affected customers.

The Local DR program consists of a targeted and localized demand response strategy – primarily leveraging new and existing DR resources – to reduce peak demand, and extend the planning and implementation timelines associated with future system upgrade projects. Through the Local DR program, Toronto Hydro expects to be afforded greater flexibility in assigning system upgrade resources. The program is expected achieve approximately 9.5 MVA of peak demand reduction over the course of the investment. Using strategic load balancing, the capital investment required

to address bus relief that would have otherwise been required in 2020 can be delayed to approximately 2025-2026. Total costs for the Local Demand Response program are estimated to be $4.1 million over the period of 2015 to 2019. Table A summarizes the benefits associated with the Local Demand Response program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Facilitates long-term service reliability at Cecil TS. ƒ Participant energy cost savings, financial incentives, and equipment upgrades. ƒ Positive long-term impact on customer rates.
Reliability	ƒ Enhances spare capacity to facilitate replacement of aging switchgear. ƒ Supports long term plan to install inter-station ties in downtown core. ƒ Increasing station capacity in downtown core load centre reduces feeder lengths.
Safety	ƒ Operating station equipment within design parameters increases equipment life, lowers failure rates, and associated physical risks to personnel .
Efficiency	ƒ Facilitates flexibility in scheduling planned outages for maintenance purposes. ƒ Enables system reconfiguration to optimize supply to customers situated in Cecil service area, but who are currently supplied from other stations. ƒ New customers in station area more likely to be served from closest station, reducing connection costs.
Other (e.g. cyber-security, environment)	ƒ Environmental benefits, including reduced emissions associated with offsetting generation and transmission of electricity through DR load curtailment. ƒ Provides insights into new capacity relief alternative. ƒ Wider applicability based on project outcome. ƒ Public policy responsiveness: Ministry of Energy's new CDM framework directs LDCs to consider demand management alternatives to capacity expansion

Program Drivers

The Local DR program is driven by capacity constraints at Cecil TS, which directly impact system reliability and efficiency. Constraint issues are forecast to begin affecting system operation and planned maintenance by 2020. The trigger and secondary drivers for this program are provided in Table B.

TABLE B: PROGRAM DRIVER

Trigger Driver	Reasoning
Capacity Constraints	ƒ Bus capacity shortfalls anticipated by 2020; total station shortfall anticipated as early as 2025. ƒ Limited capacity available to connect large new customers (including large office towers, condos and data centers). ƒ Potential to be forced to operate outside of design parameters.
Secondary Driver	**Reasoning**
Reliability	ƒ System capacity under an N-1 contingency (where service is maintained when any single system component is out of service) is compromised if all remaining system components are already at capacity. ƒ Limited capacity to support planned switchgear renewal, where space limitations prevent direct load transfers from old to new equipment. ƒ Lack of spare capacity limits Toronto Hydro's ability to complete maintenance (increasing failure risk) and increases the likelihood of customer outages in the event equipment failure. ƒ Reduced ability to effectively manage contingency situations

Preferred Alternative

Toronto Hydro considered the following options for addressing the capacity constraints at Cecil TS:

(i) No Action

(ii) "Status Quo" Capacity Expansion

(iii) Local DR Program

The Local DR program is the preferred option due to its strong financial case in comparison to the station expansion alternative and the difficulties anticipated with respect to the only feasible station expansion option at Cecil TS.

Financial analysis of the deferral demonstrates that the Local DR program will produce a positive net present value from the point of view of affected stakeholders, including the province, Toronto Hydro, program participants, and rate-payers. Toronto Hydro finds current policy support in the recently released and updated provincial CDM framework, "Conservation First – A Renewed

Vision for Energy Conservation in Ontario"[1], which notes that Local Distribution Companies (LDCs) will be able to make rate applications to the Ontario Energy Board (OEB) for local targeted DR if cost-effective/deferring infrastructure investments.

Timing and Pacing

The Local DR program is based on a system need at Cecil TS that is expected to produce a number of operational and reliability risks by 2020 if not addressed. The implementation of the Local DR solution in 2015 is justified by the amount of lead time required to minimize program risk and produce the intended outcome. Currently, the conventional station expansion solution is not considered an optimal option due to feasibility issues, and failure to address system constraints at Cecil TS entirely could result in Toronto Hydro being forced to undertake costly, complex and impractical load transfer projects, or to operate the system in violation of its design parameters. This could result in rotating blackouts, voltage reductions, inability to execute planned work (maintenance or capital), and reduced reliability. Regardless, whether considering a conventional station expansion solution – which will require longer lead time than usual due to the need for property/facility procurement and the corresponding extensive approvals and construction processes – or the Local DR project, which carries longer capacity procurement realization, the planning stages for future relief must begin now.

The timing, pace, and magnitudes of the annual program investments are appropriate considering the nature of the strategy. Capital spending is largely incremental to procured DR capacity, and therefore, the pace of the investment is directed by the level of anticipated program success. Historical CDM program analysis suggests that typical uptake should slowly increase from the first year to the next 2-3 years, where it is expected to peak, and then market saturation would result in a certain level of decline. The projected program potential has been modeled with this uptake curve as the main guideline. The noteworthy spending exception is the considerable anticipated increase in 2016, relative to the other program years. The majority of the 2016 capital spend is allocated for the battery storage unit planned for installation at Cecil TS. The components of this unit are anticipated to cost over $2 million. This strategy is planned for year two of the program due to the length of time it may take to procure, design, install, and commission the system: it is unlikely to be in place and energized for 2015.

[1] The Government of Ontario, "Conservation First – A Renewed Vision for Energy Conservation in Ontario," 2013. http://www.energy.gov.on.ca/docs/en/conservation-first-en.pdf

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	-	-	-	-	-	0.17	2.4	0.60	0.50	0.35

E7.10.2 Program Description

Demand Response Overview

Demand Response (DR) typically refers to any program that induces a change in electricity usage by end-use customers, in response to changes in the price of electricity or other economic incentives. The purpose of DR programs is generally to encourage a shift in electricity consumption from on-peak periods – when electricity demand is highest and therefore the generation and delivery systems are most likely to approach the capacity of supply – to off-peak periods when grid capacity is less of a concern.

Since the size of generation, transmission, and distribution equipment needed to serve a customer base is dictated by peak demand rather than the overall consumption of energy, DR programs can play an important role in managing the reliability of power supply. This is particularly true in instances where system peaks only occur for short intervals a few times each year. Choosing to increase peak demand can be expensive and typically entails providing permanent additional capacity, even if the additional capacity is only required for a limited time throughout the year. Conversely, an effective DR program can address small and infrequent intervals of system stress so that permanent expansions can be delayed and reserved for when a more permanent solution is warranted.

Toronto Hydro has identified some regions within its overall service territory where peak load will approach infrastructure capacity in the medium-term (five to ten years), either at the individual bus or total station thresholds. This condition typically results in the planning and implementation of a major capital investment in new and/or upgraded assets. Toronto Hydro expects the proposed Local DR program to allow the utility to defer these system upgrade projects by introducing a targeted and localized DR strategy – primarily leveraging new and existing DR resources – to reduce peak demand. The deferral assists medium- and long-term capacity relief efforts because it is forecasted to extend the timeline for projected station upgrade investments at locations where the need for additional capacity is projected for 2020 and beyond. This would provide Toronto Hydro with greater flexibility in assigning system upgrade resources, and as is demonstrated in this program's financial analysis, is expected to help optimize Toronto Hydro's capital allocation strategy by deferring the need for capital expenditure and facilitating alternative short to medium-term investment considerations. The combination of deferring work and avoiding costs is a fiscally prudent approach that will benefit ratepayers. However, it should be noted that this program will not replace near-term capacity relief efforts, since the lead time associated with

targeted reductions under the Local DR program extends beyond the period by when these near-term needs must be addressed.

In Ontario, DR programs have traditionally been offered province-wide to address any provincial peak demand constraints. However, Toronto Hydro understands that sufficient provincial capacity exists into the medium-term as a result of existing and committed CDM activities and investments in generation. As such, the relief needs that do exist are primarily regional, as are the cases in the Toronto Hydro service areas. These DR utilization trends have encouraged Toronto Hydro to assess the potential for targeted DR efforts to mitigate localized capacity constraints currently projected in transformer station load forecasts. So, while DR solutions have been extensively proven to effectively reduce peak demand for the province – as well as many other jurisdictions, worldwide – this program presents an instance where DR resources can produce a significant benefit when directed at a singular distribution point and its corresponding service area, relative to immediate system renewal investments.

Local DR Program – Cecil TS

The objective of Toronto Hydro's Local DR program is to complement the work of the utility's Stations Expansion program by addressing the distribution system's increasing capacity constraints. Local DR provides an approach to relieving demand on Transformer Station (TS) by extending the period in which the station can safely operate within intended design limitations, making it possible to defer otherwise necessary (and more costly) infrastructure renewal at Cecil TS. This program is expected to reduce the risk of future contingency situations which, in turn, mitigates critical constraints and security-of-supply concerns.

The Local DR program targets the area served by Cecil TS (Figure 1). Cecil TS serves a relatively confined geographical space, affording a smaller scale site that can increase the efficiency of localized efforts. Cecil TS is located in the downtown core, and serves as a strategic centre for inter-station load balancing as it is largely surrounded by TS service areas projecting shorter-term constraints. Finally, it offers little to no room for physical expansion. All of these factors strengthen the case to apply a strategic alternative at Cecil TS rather than a conventional station upgrade.

FIGURE 1: MAP OF CECIL TS SERVICE AREA

This program targets to help control and reduce peak demand. The annual load profile for Cecil TS demonstrates short and infrequent system peaks. These temporary "spikes" in customer demand typically occur during the hottest weekday afternoons in summer when maximized cooling loads amplify the normal daily peaks that result from electrical building system and operational end-uses. The vast majority of historical and current applications of DR programs have been dedicated to the reduction of these summer peaks; as a result, the solutions for achieving the targeted peak load relief in summer are already well-developed, including both the technologies and implementation guidelines. The Local DR program is currently positioned to defer a permanent infrastructure improvement at Cecil TS.

Currently, Toronto Hydro's capacity forecasts project a need for load relief in up to 14 of 35 TS service areas by 2025, with the majority of these falling within the short-term planning horizon, i.e. by 2019. Figure 2 identifies candidate station areas based on their need for relief. While the application of the Local DR program is limited to Cecil station for the purpose of this application, any success and/or program lessons will be directly applicable to other locations within Toronto

Hydro's service area as new TS load constraint projections materialize. The impact of this program may also serve as a useful reference for other LDCs faced with similar constraint issues.

FIGURE 2: MAP OF LOAD RELIEF FORECASTS

When the load on a station bus is forecasted to exceed capacity, planners identify and assess the available options, giving consideration to the magnitude of the problem, the timeframe, and the long-term needs of the area. A summary of typical solutions is provided in Table 1.

The Local DR program includes targeted DR resource procurement, focusing on customers served by Cecil TS. Toronto Hydro also intends to assess utility-side load relief options, and to develop locally targeted marketing and sales programs to further promote existing and new DR technologies and energy storage applications.

The following table sets out the options that a utility typically considers when responding to capacity constraints, as well as the Local DR approach proposed in this program.

TABLE 1: TYPICAL CAPACITY RELIEF OPTIONS

Option	Prerequisites	Comments
Transfer load to a different bus within the station	ƒ Requires an existing bus at the same station that possesses sufficient capacity and feeder positions to accept the new load.	ƒ Generally the most cost effective option when available. ƒ Technical restrictions may arise: 3-wire vs. 4-wire busses, ability to segment existing load, etc.
Transfer load to a bus at a different station	ƒ Requires an existing bus at a nearby station with sufficient capacity and feeder positions to accept the new load. ƒ Must be feasible to construct the necessary distribution infrastructure to permanently transfer the load (for example, there must be spare civil infrastructure between the new station and the load to be transferred).	ƒ Can require significant amount of new infrastructure ƒ Can be very expensive ƒ Technical limits on feeder length must be respected in order to maintain system within design parameters. ƒ Investment does not actually result in an increase in capacity – rather, it simply means available capacity is being utilized sooner than it would have been otherwise.
Replace and upgrade limiting component at station	ƒ Typically requires coordination with Hydro One Networks Inc. (HONI). ƒ There must be a specific component or set of components which is exclusively limiting capacity (i.e. a cable section, a transformer, etc.).	ƒ Some elements can be replaced at relatively low cost and result in incremental capacity. ƒ Some Toronto Hydro switchgear replacement projects will result in additional capacity. ƒ Toronto Hydro often requests that HONI upgrade transformer ratings to provide additional capacity when they renew their assets.
Expand an existing station by installing a new bus and/or new transformation and/or new transmission infrastructure	ƒ Requires sufficient physical space at the station to facilitate expansion. ƒ Requires sufficient upstream (transmission) capacity.	ƒ Can be very costly. ƒ Requires coordination with HONI. ƒ Existing ownership of these assets (HONI vs. Toronto Hydro) varies throughout the city of Toronto. ƒ Costs highly dependent on requisite transmission upgrades.
Build a new station	ƒ Requires a site located sufficiently close to serve the new load of offload the existing station.	ƒ Can be very costly. ƒ Requires coordination with HONI. ƒ Costs highly dependent on requisite transmission upgrades. ƒ Generally lengthy approvals and lead times.

Option	Prerequisites	Comments
Peak reduction through demand management or distributed generation initiatives	ƒ Potential for peak reduction must be sufficient to mitigate shortfall. ƒ Must be persistent. ƒ There must be a guaranteed funding mechanism (i.e. the load or generation customer has signed an agreement and paid the requisite deposit to connect to the system).	ƒ Reductions must be realized before forecasted overload of bus. ƒ Only impact on peak demand is relevant. Impact on energy consumed is irrelevant.

The Local DR program provides a compelling financial case for supporting and strengthening station expansion investment. In addition, from an operational perspective, DR resources which are known with certainty to be available at system peak are practical alternatives to adding capacity. Of course, in order to ensure the desired outcome and demonstrate the full benefit of the DR solution, the program must cost-effectively procure the maximum amount of peak load reduction. Moreover, since the area served by Cecil TS comprises a diverse combination of residential, commercial & institutional (C&I), and industrial customers, the project must include a suite of alternative DR initiatives to deliver maximum area uptake. As such, the following combination of programs has been chosen based on its collective ability to attract all customer sectors and sizes.

PeaksaverPLUS®

Target Market : Single Family Residential & Small C&I Customers

The peaksaverPLUS® program is open to residential and small commercial consumers. These customers participate by allowing a one-way paging network to control either a programmable communicating thermostat (PCT) or a load control switch to curtail electricity demand for central air conditioners, electric water heaters or pool pumps during the peak period on high electricity demand days. PeaksaverPLUS® also offers consumers an in-home display (IHD), which enables participants to monitor their electricity consumption and associated cost in real-time. Ontario's LDC's are responsible for procuring the equipment offered and for the marketing of the program (jointly with the OPA); however, it should be noted that Toronto Hydro currently does not contribute any capital expenditures: the purchase of all physical assets is fully refunded by the Ontario Power Authority (OPA). As of December 2012, approximately 180,000 control devices

have been installed on central air conditioners in Ontario, nearly all in residential premises. Participants in the Toronto Hydro service territory accounted for over 70,000 of these devices. In addition, nearly 50,000 IHDs had been installed at participant premises.

Often, the appliances contributing to afternoon summer peak demand operate in unoccupied homes and can be managed by direct load control without significant customer disturbance. Currently, typical penetration rates by TS service areas in the city of Toronto are approximately 20-25%. According to Freeman, Sullivan & Co., the OPA's PeaksaverPLUS® evaluation contractors, achievable penetration rates for well-established residential DR programs can reach nearly 50%, suggesting that there is ample room for growth using a geographically-specific initiative.

Multi-Unit Residential DR (MURB) – SuiteSaver

Target Market : Multi-Unit Residential Buildings

The MURB DR program is designed to offer MURBs the opportunity to participate in DR initiatives. This sector presents a provincial peak demand of approximately 1 GW, and a considerable demand reduction potential of more than 20 MW in the Toronto Hydro service region alone. The installation of load control devices on common area systems and programmable communicating thermostats in individual suites would facilitate savings during activation periods, and in turn, building and suite owners would receive payment for their load control availability. Also included in the program is a comprehensive energy efficiency strategy, made up of system audits and retrofit incentives that further increase the demand reduction and annual energy savings impact in the MURB sector. With the increasing number of MURBs being constructed in the city of Toronto and in the province more generally, this program offers a complimentary load relief strategy through increased load densification that can have a positive impact on local service constraints.

This program was piloted in the summer of 2013 and is currently being considered for additional testing this summer. The Total Resource Cost (TRC) analysis submitted with the initial proposal assumed a 4% penetration in the MURB sector and 40% suite penetration in participating buildings. These projections were derived from current Peaksaver participation evaluations and took into account the more attractive incentives being offered to both building owners and participating suite owners.

Toronto Hydro projects that the thermostat and occupancy setback controls would provide between 0.3 – 0.5 kW/suite in curtailment and approximately 65-80 kW in curtailment for common area load controls. The targeted uptake in the MURB sector is 25% or approximately 19 buildings over the course of the 5-year plan.

Commercial Energy Management & Load Control (CEMLC) – GridSaver

Target Market : C&I and Industrial Customers (> 50KW)

The CEMLC pilot is designed to produce peak demand reductions in the 50-999 kW commercial, retail, institutional, and hospitality sectors, where facility heating, ventilation, and air-conditioning (HVAC) systems include rooftop units (RTUs). The strategy involves the installation of load control devices on RTUs and programmable communicating thermostats that offer the opportunity for energy and demand reductions during DR events. The provincial peak cooling load in these sectors is nearly 2000 MW, and contributes a reduction potential of approximately 60 MW in the Toronto Hydro service area alone. The program design also recommends a facility energy management strategy, incorporating occupancy sensors to further improve the peak demand reduction and annual energy savings impacts.

Savings projections were developed with the use of the U.S. Department of Energy setback calculator and resulted in an estimated 12% reduction in cooling load. It is proposed that facilities in this load class could produce an average of approximately 24 kW of summer peak reduction. Though anticipated penetration is relatively low at 5-10%, this market is virtually untapped, with the previous DR opportunity consisting solely of the OPA's DR3 program, discussed below. Therefore, the potential DR resource that these customers represent is considerable.

Demand Response Three (DR3)

Target Market : C&I and Industrial Customers (>50 kW)

For customers capable of meeting the minimum availability commitments of the OPA's DR3 program, the flexibility to choose a curtailment strategy and the level of incentive payment may make this program the most favourable option. DR3 is a contractual DR program that offers large C&I and industrial consumers reserve payments for making themselves available to provide load reductions when requested by the OPA. Participants are required to meet contractual reductions when instructed, or payments are reduced or eliminated. In addition, DR3 participants must notify the OPA and Independent Electricity System Operator (IESO) of any short-term fluctuations in

load reduction capability due to facility maintenance or down-time. Scheduled non-performance days lead to reductions in the participant payments. Unscheduled non-performance – failure to deliver scheduled load reductions during events leads to even larger payment reductions.

Current DR3 penetration rates are virtually non-existent in the Toronto Hydro service territory, with less than 100 customers having opted to participate to date. However, the anticipated changes to the DR3 program should lead to higher customer uptake and considerable load curtailment. With almost the entire segment of large C&I and industrial customers available for enrolment, and in a situation where a relatively small number of these participants can have a major impact during a curtailment event, this program is expected represent a key focus in the local DR strategy. While there is currently a level of uncertainty regarding the availability of DR3 participants for localized events, if available, Local DR could maximize the contracted hourly availability currently under-utilized by provincial DR3 event frequency.

Energy Storage [2]

The Local DR program will include energy storage initiatives, which will be implemented at participant facilities, in the form of thermal storage units integrated into RTUs, and in the form of battery storage units. Energy storage applications optimize the supply and demand of distribution system energy by loading the energy accumulator (storage device) during off-peak times when supply is cheaper and more readily available, and then releasing that stored energy during high demand, thereby relieving the equivalent amount of system stress. Sizes and capacities of energy storage systems vary; however, the units planned for Local DR are expected to offer four continuous hours of peak demand relief, at approximately 4-kW/unit for the thermal storage applications, and 50 – 250-kW/unit for the battery storage installations.

An overview of the planned capital assets is included in Table 2.

[2] The planned implementation of energy storage mentioned in this narrative is not accounted for in the Energy Storage program section of the DSP. The thermal storage devices which will be promoted in the Local DR project are separate technologies not used in the Energy Storage program; and the battery storage units proposed are accounted for only in this section of the DSP. The Local DR program is interested in leveraging the technology used by the Energy Storage program to the same desired effect, but in the case of Local DR, battery storage is simply one strategy incorporated into the suite of proposed measures.

TABLE 2: A BASIC OVERVIEW OF CAPITAL ASSETS

	Number of Installations						Cost
	2015	2016	2017	2018	2019	Total	($M)
PeakSaver	84	336	589	420	253	1,682	$0.3
Load Control Devices In-Home Displays							
SuiteSaver	2	4	6	5	3	20	$1.2
Communicating Thermostats Door Contacts Network Infrastructure Load Control Devices							
GridSaver	2	6	11	8	5	32	$0.1
Communicating Thermostats							
Thermal Storage	2	2	2	2	2	10	$0.3
Ice Storage Units							
Battery Storage	-	1	-	-	-	1	$2.0
Battery Storage Unit Inverter							

Toronto Hydro is developing the Local DR program in parallel with the ongoing Toronto Integrated Regional Resource Plan (IRRP), an exercise which Toronto Hydro is also engaged as an active participant. Any outputs or conclusions from the IRRP which directly or indirectly impact this program will be incorporated in this program's scope. Toronto Hydro understands that the Toronto IRRP will primarily focus on system adequacy at the transmission level. While Toronto Hydro's stations relief plan is driven primarily by the urgent nature of the issues Toronto Hydro faces with respect to distribution system capacity constraints, Toronto Hydro expects that it will be aligned with the conclusions of the Toronto IRRP.

Toronto Hydro recognizes that by undertaking a collaborative design effort and a strategic approach that serves both local and provincial system needs, there is a valuable opportunity to maximize existing DR assets and program impact.

The following table provides a high-level summary of the Local DR program benefits:

TABLE 3: PROGRAM BENEFITS

Customer Value	ƒ Ensure long-term service reliability at Cecil TS. ƒ Participant energy cost savings, financial incentives, and equipment upgrades. ƒ Positive long-term impact on customer rates.
Reliability	ƒ Enhances spare capacity to facilitate replacement of aging switchgear. ƒ Supports long term plan to install inter-station ties in downtown core. ƒ Increasing station capacity in downtown core load centre reduces feeder lengths.
Safety	ƒ Operating station equipment within design parameters increases equipment life, lowers failure rates, and associated physical risks to personnel.
Efficiency	ƒ Ensures flexibility in scheduling planned outages for maintenance purposes. ƒ Enables system reconfiguration to optimize supply to customers situated in Cecil service area, but who are currently supplied from other stations. ƒ New customers in station area more likely to be served from closest station, reducing connection costs.
Other (e.g. cyber-security, environment)	ƒ Environmental benefits, including reduced emissions associated with offsetting generation and transmission of electricity through DR load curtailment. ƒ Provides insights related to new capacity relief alternative. ƒ Wider applicability based on project outcome. ƒ Public policy responsiveness: Ministry of Energy's new CDM framework directs LDCs to consider demand management alternatives to capacity expansion

The Local DR program enhances the reliability of Cecil TS as follows:

- ƒ Helps secure spare capacity necessary to facilitate future replacement of aging switchgear at a location where there is currently no physical space to install new switchgear next to the existing one.

- ƒ Securing available capacity in the form of reduced existing peak load at Cecil will support Toronto Hydro's long term plan to install inter-station ties. In order to make effective use of these ties, the "back-up" stations would need to have sufficient capacity to support both their normal load as well as the temporary load from the stations taken out of

service. Currently, with many stations close to 100% utilization – including stations adjacent to Cecil – ties would not be as effective as they could be if there was more available capacity.

- Increasing station capacity near/within the downtown core load centre will enable reduced feeder lengths and more straightforward network configurations; in general, this results in a more simple and reliable system.

Execution of this program is also expected to result in certain operational efficiencies, including the following:

- New customers located within the station area are more likely to be served from the station that is geographically closest.

- Maintaining or increasing station capacity will enable system reconfiguration to optimize the supply to customers who are situated in the Cecil service area, but who are currently supplied from other stations. This occurs when there is not sufficient capacity to connect a customer to the closest station. This is expected to reduce line losses and improve reliability.

While this program is not expected to have a direct impact on worker or public safety, there are inherent safety benefits associated with operating station equipment within their respective design capacities:

- Overloading equipment reduces equipment life and increases failure rates, which, in the extreme cases, can lead to events that can impact public or worker safety.

- Equipment wear and tear on a capacity-constrained station, expected to be mitigated by the proposed program leads to higher potential for events such as arc flashes during switching operations and racking out breakers, which are among the highest operational risks under normal conditions.

Thus, continuing to operate Cecil under its standard operating N-1 contingency design standard as contemplated by this program helps mitigate physical risks to the personnel responsible for the operation and maintenance of the assets.

E7.10.3 Why the Program is Needed

The Local DR program is needed to mitigate forecasted system constraints in the Cecil TS service area and acts as an alternative to undertaking immediate expansion. Toronto Hydro has experienced a significant amount of load growth in recent years, growth that is generally concentrated in areas of the city where densification and redevelopment are the primary drivers of increased electrical load. The projected impact of Toronto Hydro continuing to receive connection requests requiring incremental distribution system is that the existing system is approaching its limit at several locations, including the area served by Cecil TS. Either load relief or expansion is necessary to help ensure that Toronto Hydro is able to operate the distribution system in a safe and reliable manner.

E7.10.3.1 Program Drivers

The Local DR program is driven by capacity constraints at Cecil TS, which directly impact system reliability and efficiency. Constraint issues are forecast to begin affecting system operation and planned maintenance by 2020. A summary of program drivers is presented in Table 4.

TABLE 4: PROGRAM DRIVERS

Trigger Driver	Reasoning
Capacity Constraints	ƒ Bus capacity shortfalls by 2020; total station shortfall as early as 2025. ƒ Limited capacity available to connect large new customers (including large office towers, condos and data centers). ƒ Potential to be forced to operate outside of design parameters.
Secondary Driver	**Reasoning**
Reliability	ƒ System capacity under an N-1 contingency (where service is maintained when any single system component is out of service) is compromised if all remaining system components are already at capacity. ƒ Limited capacity to support planned switchgear renewal, where space limitations prevent direct load transfers from old to new equipment. ƒ Lack of spare capacity limits Toronto Hydro's ability to complete maintenance (increasing failure risk) and increases the likelihood of customer outages in the event equipment failure. ƒ Inability to effectively manage contingency situations

The following is a discussion of the station and service area risks that are addressed by this program:

Medium and long term forecasted capacity shortfalls at Cecil TS

By the year 2020, it is expected that two of the four existing buses at Cecil will surpass 95% of firm capacity, as illustrated in Table 5.

TABLE 5: CECIL STATION LOAD FORECAST

STATION:	CAPACITY (MVA)										
	100 %	95%	2015	2016	2017	2018	2019	2020	2021	2022	2023
A1-2			32	32	32	33	33	34	34	35	35
A3-4			41	43	43	44	44				
A5-6			60	61	62	63	64	64	65	66	67
A7-8			64	64	65	66	67				
Total Station (No CDM)	238	226	197	200	202	206	208	211	214	217	220

Bus A1-2 is a dedicated bus that supplies load to the University of Toronto, and therefore is not an option for accepting load from other buses as they reach capacity. Buses A3-4 and A7-8 will reach their load capacity by 2020, at which point the load from these buses can be shared with A5-6 bus. However, A5-6 is projected to approach 90% of its rated capacity in the same year. Excluding the dedicated bus A1-2, the remaining load will approach 93% of station capacity in 2020. So despite the fact that total station threshold concerns are not projected to materialize until 2026, the status quo scenario – including maintaining bus A1-2 as dedicated University of Toronto capacity – is troublesome and demonstrates a need for earlier load relief.

Generally, the first option considered to relieve bus capacity is to transfer load to an adjacent bus at the same station. The second option is to find relief at a nearby station. For the downtown core, where Cecil TS is located, the second option is often more technically complex and costly than in other circumstances. The distribution system in downtown Toronto operates at a primary voltage of 13.8 kV and is operationally unique compared to the rest of Toronto Hydro's service territory, which is served by the 27.6 kV system. The 13.8 kV area – the oldest part of Toronto Hydro's system – is currently comprised of feeders radiating from 18 central Toronto stations that supply customers located in their geographic service areas. There are very few interconnections between the stations in the area; in the case of Cecil, there are currently no effective inter-station ties, meaning that load transfers to another station would require construction of new civil and electrical infrastructure. These load transfers can be extremely costly and challenging to implement given the space limitations and the congested nature of the existing utility infrastructure in the area. Load transfers also require available spare feeder positions on the bus

receiving the load transfer. Spare feeder positions are increasingly scarce in the vast majority of downtown stations given that Toronto Hydro continues connecting new customers.

Inability to facilitate load transfers to enable switchgear renewal work in the downtown core

Cecil TS has a maximum capacity of 238 MVA. This limit is derived from the 10-day limited time rating of the lowest rated element at the station. The 10-day limit signifies that the station can operate with any specific element out of service for up to 10 days without permanently compromising the life of the remaining equipment. This is a long standing industry practice and is typically referred to as "N-1" design. Failure to maintain this arrangement may significantly lengthen the time required to restore power after a station outage, as Toronto Hydro could be forced to wait until the failed equipment can be procured and replaced. In addition to providing redundancy in the event of unplanned outages, it also enables Toronto Hydro to undertake planned outages for equipment upgrades or repairs. In these situations, Toronto Hydro will need to transfer existing load elsewhere for the duration of the project. Thus, the Local DR program is required to ensure sufficient spare capacity is available to facilitate these future replacements of aging switchgear, where there is currently no physical space to install a new switchgear next to the existing one. Without this investment, planned outages would likely pose significant issues at Cecil TS as the total station load begins to approach threshold capacity. Faced with limited spare capacity and a planned equipment outage, Cecil could compromise the N-1 contingency design standard; the result would be risking permanent damage to the existing assets by accepting station design overload conditions, while the alternative would be to force customers to endure planned outages in the form of brownouts (intentional drops in supplied voltage which negatively impact the functionality of customer end-uses) or rolling blackouts (complete power outages scheduled to rotate throughout the service area, impacting all customers for pre-determined periods of time) .

Inability to support installation of backup capabilities

Toronto Hydro's long term capital plan will help ensure greater system reliability by enhancing the backup capabilities of the distribution grid. This is a particularly critical concern in the downtown core where station inter-connections are at a minimum. In correcting this issue, "back-up" stations – where load can be temporarily redirected – would need to have sufficient capacity to support both their normal load as well as the additional load from the buses and/or stations taken out of service. Currently, the majority of the stations adjacent to Cecil TS exhibit either more immediate

capacity relief needs, or, at a minimum, similar capacity relief projections. The Local DR program is expected to produce additional capacity relief at Cecil TS in order to provide the spare capacity in which to potentially allocate adjacent station loads during the construction of critical inter-station ties.

Inability to accommodate new customer connections

An important indicator of load growth is the number of new connection requests that are received from customers. These requests are submitted by existing and potential customers who will be increasing their load and/or require entirely new connection points. The number of new connections requested for Cecil TS over the past several years is shown in Figure 3[3]:

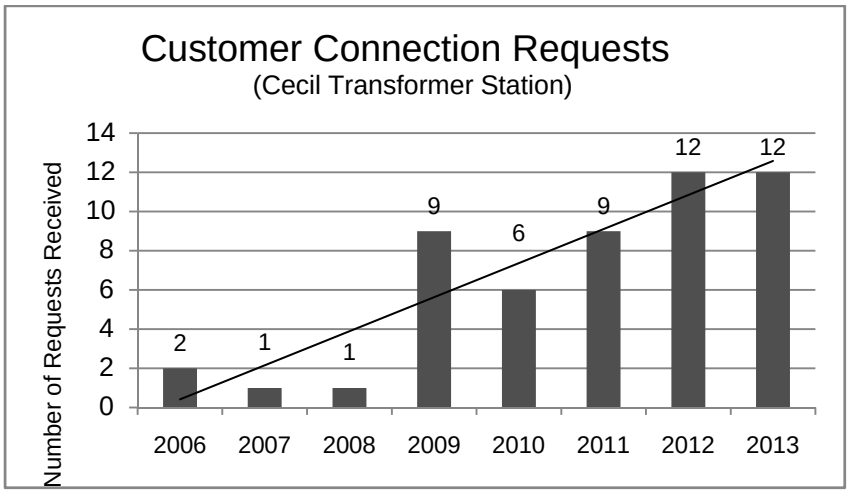


FIGURE 3: CECIL STATION CONNECTION REQUESTS

The data demonstrates an increasing trend in new customer connections, which directly contributes to the medium-term forecasted load constraint. For planning purposes, Toronto Hydro considers 95% of a bus capacity for the downtown stations to be overloaded. This figure takes into account the lead time required to offload a bus and implement a permanent solution, as well as the fact that the station must keep sufficient spare capacity on each bus to accommodate new customer connection requests. Customers typically request connection anywhere from one to three years in advance, whereas a load relief solution can take anywhere from one to four years to implement, depending on the nature of the existing configuration. This extended lead time

[3] Data represents gross number of feeder connection requests received for connection in each year. The source data was filtered to include only those requests which as of 2014 are in the "Approved", "Completed" or "Energized" state.

highlights the need for critical planning and approval as early as 2015 to accommodate for new load in 2020. Much of the Cecil TS service area is made up of large commercial and institutional buildings, multi-unit residential buildings and secondary networks. In these cases, individual loads from the primary distribution system's point of view are larger and indivisible, load that need to be wholly accommodated by a single feeder position. Assuming similar types of customers and corresponding new load make up future new connection requests, new applications may drastically impact the load forecast, and in the worst case, critically impact future capacity. It is imperative to develop a solution to create necessary spare capacity in place to mitigate 2020 load capacity risks.

Limited Opportunity for Station Expansion

As mentioned previously, capacity constraints are typically addressed by station expansion planning. However, these "wires solutions" require physical space for additional equipment, or space to install replacement equipment adjacent to assets in operation. Currently, Cecil TS has no remaining room for capacity additions. Moreover, installing new transformers at Cecil TS wouldn't increase the station's capacity since it is limited by the existing bus ratings. Accordingly, the only feasible solution would be to add new switchgear at a different Toronto Hydro-owned building that can be used for load relief from Cecil TS buses to new buses. However, this would require a site located sufficiently close to Cecil TS to offload the existing station. This option is usually the most costly and it requires considerable coordination with HONI, usually involving prolonged approval and lead times. Given these considerations, it is imperative that the work associated with the Local DR program at Cecil TS begin as soon as possible. Based on the fact that the conventional wires solution is very limited, and even if possible, it can only be relied upon within the medium to long term planning horizon, Local DR offers a valuable complimentary strategy to the task of ensuring that this service area is protected by effective short and medium-term demand management, which in turn will provide the necessary time to plan for long-term capacity solutions without negatively impacting the system's service and reliability.

E7.10.4 Timing & Pacing of the Program

The Local DR program is based on a system need at Cecil TS that is expected to produce a number of operational and reliability risks by 2020 if not addressed. The implementation of the Local DR solution in 2015 is justified by the amount of lead time required to minimize program risk and produce the intended outcome. Currently, the conventional station expansion solution is not considered an attractive option due to feasibility issues, and failure to address system

constraints at Cecil TS entirely could result in Toronto Hydro being forced to undertake costly, complex and impractical load transfer projects, or to operate the system in violation of its design parameters. As mentioned above, this could result in rotating blackouts, voltage reductions, inability to execute planned work (maintenance or capital), and reduced reliability. Irrespective of an ultimate solution (i.e. a conventional station expansion or Local DR project), the planning stages for future relief must begin now, as both options require long lead times for approvals, procurement, construction and/or customer uptake.

The following table represents the capital allowance which must be committed to effectively implement Local DR at Cecil TS:

TABLE 6: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	-	-	-	-	-	$0.17	$2.4	$0.60	$0.50	$0.35

The timing, pace, and magnitude of the annual program investments are appropriate considering the nature of the strategy. Capital spending is largely incremental to procured DR capacity, and therefore, the pace of the investment is directed by the level of anticipated program success. Historical CDM program analysis suggests that typical uptake will slowly increase from the first year to the next 2-3 years, where it is forecast to peak, and then market saturation will result in a certain level of decline. The projected program potential has been modeled with this uptake curve as the main guideline. The noteworthy spending exception is the considerable increase in 2016, relative to the other program years. The majority of the 2016 capital spend is allocated for the battery storage unit planned for installation at Cecil TS. The components of this unit are anticipated to cost nearly $2 million. This strategy is planned for year two of the program due to the length of time it may take to procure, design, install, and commission the system: it is unlikely to be in place and energized for 2015.

With respect to the program's overall operational window, Local DR is a strategic solution that is not commonly implemented to address distribution system constraint; as such it requires additional completion time for the following reasons:

- The Local DR program is comprised of a number of distinct design, implementation and evaluation efforts – all of which leverage effective customer outreach, acceptance, and participation as well as varying customer contributions that must be procured and

aggregated in order to address actual capacity constraint. In addition, the program may need to deviate from planned action if early lessons indicate a more effective alternative approach (e.g. adjusted/enhanced marketing and/or DR program offerings, etc.). This differs considerably from the conventional station expansion solution where the incremental capacity is pre-determined and definite, with limited uncertainty around timing and appropriate availability.

- While the ultimate goal is similar to the "wires solution", the necessary system relief will manifest incrementally over the course of at least the next five years.

Given these timing considerations, Cecil TS is an ideal candidate for this program, as the forecasted program achievement will require approximately five years to materialize, which aligns with the projected localized load constraint at Cecil TS. Furthermore, this program deserves strong consideration for immediate implementation when compared to other investment solutions due to the following factors:

- The financial model developed for this project produces a strong financial case for Local DR. The results, which are discussed below, indicate that immediate implementation of the Local DR program and the corresponding deferral of capital investment in station expansion of five to six years will produce both short-term and long-term financial benefit both to Toronto Hydro's ratepayers and the province as a whole. Overall, the financial model justifies the prioritization of Local DR over station expansion from a business planning perspective.

- The Cecil TS service area is strategically located in the densely populated downtown core and is surrounded by station service areas with more severe and more immediate relief needs. These adjacent areas have surpassed the lead time necessary for considering a Local DR solution. If Toronto Hydro does not begin this work immediately, Cecil TS is also expected to find itself in such a position, leaving no alternative but the most costly form of station expansion.

- If implemented immediately, this program is expected produce valuable insights with considerable planning implications on future system service decisions for both Toronto Hydro and the wider planning audiences. The program's financial model demonstrates convincing financial evidence for the implementation of Local DR in service areas which exhibit load relief requirements in the five to 10 year planning horizon. Toronto Hydro's submits that confirming this applicability would also be instructive to the OEB, as it may

undertake the evaluation of capital investment strategies in future rate applications. The importance of initiating this type of complimentary alternative positions Local DR as a higher-priority project when compared against traditional station upgrade.

E7.10.4.1 Ranking & Prioritization

When selecting the list of potential TS candidates for the Local DR program, Toronto Hydro's developed a list of stations with short- to medium-term projections of load constraints:

TABLE 7: CANDIDATE STATIONS WITH PROJECTED LOAD RELIEF REQUIREMENTS

Transformer Station	Year of Load Relief Requirement
Basin	2022
Carlaw	2019
Cecil	2020
Charles	2018
Dufferin	2014/2016
Esplanade	2018
Fairbank	2014
Horner	2019
Leslie	2018
Main	2016
Manby	2013
Strachan	2016
Terauley	2019
Windsor	2019

When determining best-suited service areas from this list, the following factors are considered:

- Load constraint forecast – when is load relief required? This is initially relied upon for station prioritization.
- Time to implement vs. need – what is the risk factor associated with overvaluing program potential? (unrealized projected demand reduction)
- Limitation on conventional station expansion – are there physical/logistical barriers with respect to station expansion that support DR alternatives?

- Asset life & condition – are there additional benefits of wires solution (possibly greater long-term reliability if current infrastructure is also nearing end of life), which Local DR does not address?
- Greater system need – what are the adjacent station capacities and are there future requirements for load balancing (incoming or outgoing) to satisfy overall system need?
- Cost of investment – is Local DR cost-effective compared to wires solutions and does it benefit the rate-payer?
- Demand response potential:
    - What is the DR potential based on customer and facility types?
    - What DR resources are already in place (the OPA's Peaksaver PLUS® and/or DR3 compared with the required additional capacity?

From these factors, four main guidelines were developed:

1) What are the consequences of unrealized projected demand reduction?

From the point of view of risk mitigation, TS service areas with near-term load relief requirements are sub-optimal candidates. If a locally targeted DR program falls short of the projected relief, a wires solution would then be then be prioritized. A program evaluation period of two to three years[4] is required to establish the success of local DR strategies and practices, while the approximate lead time necessary to coordinate a secondary station expansion solution is one to two years at minimum. Taking both into account, areas with near-term load relief requirements do not offer the flexibility to test this solution against real and imminent system capacity issues. Therefore, it was determined that this program should focus on a TS service area identified as requiring capital investment in the next five to 10 years. This would guarantee enough time for careful consideration and evaluation of DR implementation methods, while at the same time affording Toronto Hydro the opportunity to re-evaluate without system performance impact.

Taking the above into account, all stations demonstrating constraint issues before 2020 were considered too high-risk for Local DR investment. If a mid-term program evaluation identified a shortfall in program impact, it would be too late to begin the process of developing and installing a wires solution. This eliminated all stations with the exception of Cecil TS and Basin TS.

[4] The new provincial CDM framework ,'Conservation First' mandates mid-term reviews to be conducted three years after implementation, to assess program effectiveness, targets, budgets, and performance-incentive mechanisms.

2) Can DR potential meet future load constrain in a timely fashion?

The following Table 8 presents a comparison of DR potential for the two remaining candidate stations:

TABLE 8: DR POTENTIAL FOR REMAINING CANDIDATE STATIONS

Cumulative Curtailment Capacity (MVA)	2015	2016	2017	2018	2019
Cecil TS	0.9	2.5	4.4	7.2	9.5
Basin TS	0.7	1.7	3.1	5.2	6.9

Based on these projections, Local DR implementations would defer the need for capital upgrade or expansion for a minimum of five years in both service areas. However, the need is more urgent in the Cecil service area, which supports the decision for initial implementation there, but also suggests that early program success identified in the Cecil TS project may allow for secondary implementation in the Basin service area.

3) Does the financial case present a sensible business alternative to the wires solution and does it benefit the various stakeholders?

Both candidate stations present a series of positive benefits when compared against station expansion alternatives, and the Cecil TS results are presented in the Evaluation of Alternatives section of this narrative. However, due to the fact that there is greater potential for peak load reduction at Cecil TS, the fixed cost portion of the Local DR investment is allocated more favourably, and as a result, the magnitude of the net present values for the cost-effectiveness tests are higher in the Cecil TS case.

4) Do additional factors limit either the wires or DR solutions?

A key factor supporting the decision for Cecil TS is the physical space available for upgrade and/or expansion assets at each station:

- Basin TS is located in the “Portlands” area of Toronto south-east of the downtown core where physical space for additional capacity equipment is readily available.
- Cecil TS has no remaining room for capacity additions. Moreover, installing new transformers at Cecil TS with added capacity wouldn't increase the bus capacity since they are limited by the bus ratings. Hence, the only feasible solution is to add new switchgear at a different Toronto Hydro-owned building that could then be used for load

relief from Cecil TS buses to new buses. Additional costs would be incurred to acquire new real estate and to perform the necessary building changes for transformer station suitability.

The projected program potential for 2015 – 2019 is summarized in Table 9.

TABLE 9: SUMMARY OF PROJECTED PROGRAM POTENTIAL

Program Offering	Total Number of Participants	Total Demand Reduction (MVA)
peaksaver PLUS® – Legacy Residential Customers	270	0.19
peaksaver PLUS® – Legacy Small Commercial Customers	47	0.06
peaksaver PLUS® – New Residential Customers	1,617	1.11
peaksaver PLUS® – New Small Commercial Customers	65	0.09
SuiteSaver	19	2.68
GridSaver	32	0.86
DR3: 50kW – 1MW Customers	5	1.72
DR3: > 1MW Customers	2	2.40
Thermal Storage	10	0.13
Battery Storage	1	0.28
TOTAL	2,068	9.51

E7.10.5 Program Execution

To carry out the Local DR program, Toronto Hydro is required to fully develop, implement, and evaluate a targeted DR strategy for serving the Cecil TS service area and the diverse set of customers it supplies. In addition to the operational requirements, this project includes an annual capital program expenditure reflecting the costs associated with the DR assets being installed at end-user facilities as well as at Cecil TS.

E7.10.5.1 Proposed Work Plan

No major changes in design standards or planning methodologies are anticipated over the course of the five-year program; as such, there are no additional capital requirements expected beyond what is presented in the table above. There are unique scopes of work with respect to program operation that are scheduled in the long-term planning window, including mid-term evaluation exercises and enhancements, as well as the final program evaluation and reporting. Table 10 provides an overview of the annual operational requirements.

1 TABLE 10: PROJECT EXECUTION

Project Milestones	Milestone Tasks	Timing
Establish Local DR Enabling Policy	1. Seek approval to implement Local DR. 2. Work with external stakeholders to secure availability of Peaksaver assets (OPA) and DR3 participants (IESO) to reduce initial delivery costs. 3. Work with external stakeholders to confirm authorization to develop and activate new local DR programs.	Late 2014 – Early 2015
Develop DR Programs	1. Based on consultations and negotiations above, develop suite of DR programs: a. Develop program proposals for approvals, and b. Develop participant contracts.	Late 2014 – Early 2015
Market DR Strategies to Cecil Service Area	1. Assign dedicated Marketing and Sales staff to Local DR. 2. Conduct demographic analysis to identify key participant opportunities, barriers, and program drivers, and to efficiently manage promotional costs. 3. Create marketing and sales materials addressing findings from demographic analysis. 4. Promote appropriate DR program offerings to customer segments: a. Retain existing Peaksaver and DR3 customers to leverage installed assets and minimize cost of program delivery, and b. Attract new DR participants.	2015 – 2019 (Annual)
Develop DR Operations Experience	1. Procure Local DR operational systems and integrate with Toronto Hydro Grid Operations to reduce cost and task redundancies. 2. Develop and implement participant connection mapping protocol and evaluate load reduction potential by Cecil bus to maximize impact. 3. Examine Cecil load duration curve and station load profile to determine event timing and frequency. 4. Review DR operating strategy and assess unique local system needs to maximize value of event activation. 5. Develop activation protocol. 6. Develop and distribute program participation guide to better manage participant relations and deliver more efficient programming.	Early 2015 (Annual assessment of load profile for event activation schedule)
Enable Technologies	1. Identify existing DR inventory. 2. Install and commission new DR technologies. 3. Activate DR events during times of projected station peak load.	2015 – 2019 (Annual)

Project Milestones	Milestone Tasks	Timing
Monitor Program Implementation	1. Determine strategy for program development and impact monitoring. 2. Define key performance indicators. 3. Monitor local DR program impact.	2015 – 2019 (Annual)
Verify Program Impacts	1. Develop strategy for measurement and verification of load reduction and program cost-effectiveness. 2. Verify program impacts above.	2015 – 2019 (Annual)
Conduct Mid-term Program Review	1. Assess reported measurement and verification results. 2. Identify key lessons and refine processes to deliver more efficient and impactful programming. 3. Recommend course of action to Capacity Planning: a. Continued Local DR will relieve load relief requirement and defer capacity expansion project, or; b. A wires solution should be planned and implemented to address station need.	2017
Develop Future Guidelines	1. Compile lessons learned from Local DR pilot to minimize cost of future program testing and reduce costs. 2. Develop planning guide for potential future implementations of program to improve efficiency of wider application.	2019

E7.10.5.2 Program Risks

There are a number of risks to the implementation of the program:

TABLE 11: PROJECT RISKS AND MITIGATION STRATEGIES

Risk	Mitigation Strategy
Existing DR assets (Peaksaver PLUS® and DR3) may not be available to program	Alternatively develop Toronto Hydro-specific strategies mirroring existing DR programs and promote CEMLC more aggressively for GS >50kW customers; re-consider implementation of energy storage applications currently excluded.
Implementation of new DR programs not authorized/approved	Focus on localized energy efficiency alternatives similar to ConEd targeted DSM program; re-consider implementation of energy storage applications currently excluded.
Participant uptake lower than projected	Mid-term review will identify program inefficiency and to the necessary extent, recommend program enhancements or the planning of a wires solution.
Incremental DR contribution lower than expected	Mid-term review will identify program inefficiency and to the necessary extent, recommend program enhancements or the planning of a wires solution.
Targeted customers and	Further evaluation of participant mapping strategy with

Risk	Mitigation Strategy
corresponding participants do not address Cecil load constraint	recommendation for more effective identification methods.
Unexpected DR resource uptake/mix resulting in costlier provision of load reduction	Work within approved budget; mid-term review will identify unexpected program outcomes and to the necessary extent, recommend program accommodations or the planning of a wires solution.

E7.10.5.3 External Constraints

Successful delivery of the program must address two external constraints:

- Availability of existing DR resources – Uncertainty surrounding the future management of provincial DR resources presents issues with respect to confirming the types of DR programming available for Local DR and the potential load impact. As this program presents a valuable opportunity for all provincial stakeholders, it is recommended that responsible parties engage in the necessary consultations to obtain maximum value from DR assets for both provincial and regional benefit.

- New conservation mandate – the updated legislative framework promotes an "energy-first" approach to CDM planning as system capacity constraints shift from provincial to regional in the short- to medium-term. Given this underlying strategic direction, Toronto Hydro identifies a potential risk in that decision-makers may not currently prioritize peak constraint issues and corresponding investment solutions; however, to the same point, this may also offer an opportunity for positive strategic alignment with the implementation of a regional strategy.

E7.10.6 Evaluation of Alternatives

E7.10.6.1 Quantification/ Evaluation of Options

The forecasted capacity problem at Cecil TS may be seen as presenting three potential courses of action: (1) take no action and monitor the situation further; (2) plan conventional station capacity expansion; or (3) initiate the Local DR program being proposed by this application. However, planners are not required to choose between these options. Rather, this project will demonstrate that Local DR may serve as a cost-effective first step in addressing capacity constraint issues, and will ultimately serve to support the longer term plan; that is, to eventually acquire additional service area capacity when it's required on a more constant and therefore technologically and financially sensible basis. By first enabling Local DR, planners are provided with more time to determine the most suitable course of action; and furthermore, Toronto Hydro shareholders are offered an opportunity to optimize capital allocation strategy with more short and medium-term investment flexibility.

Nevertheless, for the purpose of evaluating the three directions as individual actions, the following outlines are provided:

(1) No Action – Cecil TS load constraint projections present relief needs in two of four buses by 2020, and total station relief in 2025. As with any forecast, the possibility exists that the forecast overestimates future loading, and thus, load relief is not necessary even in the medium term. However, failure to act may result in the following, should the load constraint materialize as expected:

- reduced reliability,
- costly short-term load transfer projects,
- suboptimal connection points for new customers,
- reduced flexibility to schedule outages for maintenance ,
- compromised ability to restore power under contingencies,
- inability to accommodate DG connections,
- forced voltage reduction and/or scheduled blackouts and
- increased risk of equipment failure and threat to worker safety.

(2) "Status Quo" Capacity Expansion – The more likely alternative is to address projected load relief requirements with traditional wired solutions. However, as mentioned in this narrative, there is little to no room for upgrading or installing new physical assets at Cecil TS, so this would present a costly alternative due to property and building purchase and design, and one constrained by the ability to obtain a suitable location. The specific forecast costs for this work are addressed below.

(3) Local DR Program - The Local DR program is positioned as the preferred option due to the strong financial case derived from the model, the difficulties anticipated with respect to station expansion at Cecil TS and a number of other societal benefits mentioned in this narrative. The choice of Cecil TS as candidate station was based on careful consideration of key factors and represents the best opportunity for Toronto Hydro and the wider planning audiences to obtain an alternative capacity planning guideline with minimal risk to real system operation, reliability, and employee and customer safety. Based on available information, implementation of this program will benefit the rate-payer and province in the long-term, and if the LDC lost revenues are sufficiently addressed, the LDC perspective will be more favourable due to stronger and more flexible investment opportunities.

As part of the financial analysis required for Local DR consideration, Toronto Hydro contracted an external consultant, ICF International, to develop a financial model capable of evaluating the business case for localized DR initiatives. The model was explicitly designed to support Ontario LDCs in their decisions as to whether Local DR should cause distribution and transmission asset upgrades to be deferred. It determines the value of such deferral (or full avoidance) and builds it in the business case, as well as other benefits, such as provincial avoided energy supply costs and provincial avoided generation capacity costs.

The model incorporates a series of cost-effectiveness tests which represent the business cases and financial impacts from the perspective of all stakeholders. Table 12 briefly summarizes these tests.

1 TABLE 12: INTRODUCTION TO THE COST-EFFECTIVENESS TESTS INCLUDED IN THE LOCAL DR MODEL

Test	Perspective	Question Answered
Total Resource Cost Test (TRC)	All ratepayers	Whether rate mitigation will be achieved in the long term as a consequence of DR being preferred to supply-side options; accounting for the deferral of local distribution and transmission asset upgrades.
Program Administrator Cost Test (PAC)	LDC & OPA, in their joint effort to administrate DR program(s)	Whether local DR is a cheaper alternative than supply-side options, including incoming local distribution and transmission asset upgrades.
Participant Cost Test (PCT)	Ratepayers participating in the local DR	Whether participating in the program will yield more benefits over time for the participating ratepayers than it will cost them; accounting for any cash incentive, bill credit or direct-install they will benefit from when they sign up in the program and/or as they stay in the program.
Rate-Impact Measure Test (RIM)	Non-participating ratepayers	Whether rates will go up in the short term as a consequence of DR being preferred to supply-side options; accounting for the deferral of local distribution and transmission asset upgrades.
Net benefit for distribution under the RIM test (RIM-d)	Non-participating ratepayers	Whether the distribution portion of the rates will go up in the short term as a consequence of DR, accounting for the deferral of local distribution asset upgrades, as well as incentive, direct-install cost and program administration cost incurred directly by the LDC and not refunded by the OPA.
Net benefit for transmission under the RIM test (RIM-t)	Non-participating ratepayers	Whether the transmission portion of the rates will go up in the short term as a consequence of DR, accounting for the deferral of local transmission asset upgrades.
Net benefit for generation under the RIM test (RIM-g)	Non-participating ratepayers	Whether the generation portion of the rates will go up in the short term as a consequence of DR, accounting for the provincial avoided cost of generation capacity.

Test	Perspective	Question Answered
Present value of provincial CDM costs (RIM-pc)	Non-participating ratepayers	Whether the regulatory fees and debt retirement portion of the rates will go up in the short term as a consequence of the provincial incentive handouts, direct-install costs as well as program administration costs of OPA-contracted DR programs, if any. The RIM-pc is needed to balance the following equation: NPV_RIM = RIM-d + RIM-t + RIM-g + RIM-pc The RIM-pc also factors in the lost revenues otherwise allocated to regulatory fees and debt retirement.
Local Distribution Company Test (LDCT)	LDC's shareholders	Whether rolling out the program and deferring the local asset upgrade optimizes the LDC shareholder's capital allocation strategy

Using the financial model described above, Toronto Hydro examined the business case for Local DR implementation in the Cecil TS service area. The model inputs and outputs are presented here:

Capacity Expansion

- Cecil TS contains four buses
  - Bus A1-2 is a dedicated bus for supplying load to University of Toronto.
  - Bus A3-4 and A7-8 will both reach their load capacity in 2020.
  - Bus A5-6 will be at 88% capacity in 2020, offering little room for load transfer from A3-4 and A7-8
- Even though entire station load will reach its 95% capacity in 2026, load relief will be required in 2020.
- Excluding Bus A1-2, total station loading will approach 93% in 2020.
- The projected station expansion solution would cost approximately $29.5M and provide a maximum of 72 MVA of additional capacity.
- For model comparison, the defending investment program was forecasted to begin in 2019 and energize in 2020.

Local DR

- A DR potential analysis was conducted for the Cecil TS service area, and the following projections were developed as inputs to the model:

TABLE 13: PROJECTED DR EXPENDITURE AND LOAD IMPACT

Cecil TS – DR Potential Analysis	2015	2016	2017	2018	2019
Cumulative Curtailment Capacity (MVA)	0.9	2.5	4.4	7.2	9.5
OPEX Expenditure ($'000)	$1,382	$1,079	$978	$1,052	$1,040
CAPEX Expenditure ($'000)	$167	$2,445	$596	$503	$346
Total Expenditure ($'000)	$1,549	$3,524	$1,574	$1,555	$1,386

- Based on the peak demand impact and financial analyses conducted by the model, the following results were produced for the work proposed at Cecil TS:

TABLE 14: COST-EFFECTIVENESS TEST RESULTS

Test Results	B/C Ratio	NPV ($'000)	LUC ($/kW-yr)
Total Resource Cost Test (TRC)	1.9	$7,557	$166
Program Administrator Cost Test (PAC)	1.7	$6,339	$191
Participant Cost Test (PCT)	1.8	$2,226	$58
Rate-Impact Measure Test (RIM)	1.5	$5,329	$211
Local Distribution Company Test (LDCT)	N/A	($418)	N/A
Station Expansion Project Deferral	5 – 6 years		

A review of the test results presents a convincing financial case for Local DR investment from the perspective of the ratepayer. Additionally, the TRC, PAC, PCT, and RIM tests demonstrate positive overall cost-benefit ratios for the majority of relevant stakeholders. Setting aside the LDCT result momentarily, the other four tests clearly advocate for Local DR project initiation at Cecil TS. More specifically, the total societal benefit, the project administration benefit, the Local DR participant benefit, and finally, the overall rate-payer benefit, all identify the deferral of station expansion by five years as a more financially attractive investment strategy than the conventional investment that would be carried out in 2019 and 2020. To interpret the model's output in the opposite way, if the model calculations identified the station expansion investment as the more

optimal strategy for any one of the four types of stakeholders, that specific NPV result would be negative. A more comprehensive outline of the model's design and functionality, as well as a discussion of the interpretation of its results can be found in Appendix A.

At this point, it is important to note that the negative LDCT net present value represents the amount that must be recovered to remain "whole" when compared to the planned capital investment. The model recognizes that by deferring investment, the creation of a new revenue stream and a new component of regulated rate of return are also deferred by Toronto Hydro. Therefore, one of the key assumptions accounted for during the design of the Local DR financial evaluation model was that, the model's output would highlight the need for a cost-recovery mechanism in order to encourage Local DR investments in place of immediate station upgrade and expansion projects, but this need would be justified by the anticipated total societal and overall ratepayer benefits also presented by the model.

It is also necessary to address the choice of evaluating this project investment with an external model, rather than the standard Business Case Evaluation (BCE) normally adopted for the purpose of Toronto Hydro rate application narratives. The justification for a new model includes the external factors not captured by the Toronto Hydro standard BCE. Primarily, the Local DR program produces avoided transmission and generation costs that are considerable variables when introduced to the ratepayer cost-benefit analysis. These financial impacts are incorporated into the benefit side of the equation, while the associated transmission and generation revenue losses are added to the cost side of the equation, and together these become significant factors in identifying the overall value of this solution.

While it is not a driver of this program, Toronto Hydro recognizes its commitment and ensuing responsibility toward the achievement of government mandated provincial CDM targets; especially considering Toronto Hydro's share of those provincial targets is currently greater than 20% and is expected to remain at this level. Recently, the Ministry of Energy released the new provincial CDM framework, "Conservation First – A Renewed Vision for Energy Conservation in Ontario", which suggests that LDCs should be able to consider and employ demand management alternatives to capacity expansion. Some of the key messages taken from this planning act in support of Local DR include the following:

- In the Conservation First stakeholder presentation, implementation plans noted that LDCs will be able to make rate applications to the OEB for local targeted demand response if cost-effective/deferring infrastructure investments.

- In discussing the current state of DR in the province, with a view toward greater impact, the Minister's Message states that, "Innovative demand response could enable faster, regionally targeted deployment, for periods that directly correspond with system needs."[5]

- In evaluating conservation's place in the supply mix: "it makes sense to invest as much to save a megawatt of power as it would cost to generate that same megawatt. When other benefits are factored in – conservation does not involve construction or the industrial processes that generation requires, it saves consumers money and relieves stress of the system – the arguments in favour become even stronger"

Finally, DR is a proven method for reducing peak demand that has produced a noticeable and positive impact on the provincial power system. During a heat wave in the summer of 2011, Ontario businesses and residential consumers provided 400 MW of DR to help manage the peak in demand for electricity[6]. In the Toronto Hydro service territory alone, there is a verified total of 63 MW of DR capacity available to address provincial system needs. While the Local DR program is positioned as a unique solution to local distribution system constraint, both the technology and customer acceptance have been comprehensively evaluated and proven to support peak demand reduction. A pilot project in New York City is one of the better known programs, and demonstrated considerable success in the targeting of DR.

CECONY's Targeted Demand Side Management (DSM) Program [7]

With limited potential for capacity expansion or generation imports in New York City, Consolidated Edison Company of New York, Inc.'s (CECONY) targeted DSM program was designed to alleviate peak demand in the most highly constrained networks, until permanent system relief could be established. The program employed energy efficiency measures to proactively reduce demand on specific circuits beginning in 2004. Third-party vendors were allowed to bid for load curtailment contracts and successful parties were then required to guarantee installation of equipment and future load reduction before summer peaking months. These vendors were only credited with projects in targeted networks, and paid only for measures that would directly impact peak loads. Through April 2013, CECONY had achieved approximately 107 MW of demand reductions and 278 GWh of annual energy savings. The program has

[5] Ontario, Ontario Ministry of Energy, Conservation First – A Renewed Vision for Energy Conservation in Ontario, (Ontario: Queens Printer for Ontario, 2013), online: Ontario Ministry of Energy <http://www.energy.gov.on.ca/docs/en/conservation-first-en.pdf>.
[6] Independent Electricity System Operator, Demand Response, online: Independent Electricity System Operator <https://www.ieso.ca/imoweb/siteShared/managing_demand.asp?sid=ic>.
[7] R.A. Craft, Demand Side Management as a Distribution Resource, online: Switchboard: National Resources Defence Council Staff Blog<http://switchboard.nrdc.org/blogs/lettenson/ConEdison%20Presentation%20(April%202013).pdf>.

created $464M in net customer benefits, including $221M in avoided T&D capital, on $145M in total costs. Other benefits identified by the CECONY experience were reduced regulatory risk, reduced electricity costs for consumers, and a complementary alternative to load rejection.

Appendix A	LOCAL DEMAND RESPONSE VALUATION MODELS REPORT

Toronto Hydro-Electric System Limited

Local Demand Management Pilot Study

Phase 1 – Development of the Local Demand Response Valuation Models

Phase 1 Report

Submitted to:

Ontario Power Authority

Submitted on February 5, 2014

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1. Introduction

Through the Conservation Fund, the OPA has agreed to fund and support Toronto Hydro in evaluating a demand management protocol that specifically targets local areas of high constraint. Toronto Hydro has identified certain geographical segments within its overall service territory where peak load regularly approaches the local distribution infrastructure's capacity. Typically, this would result in the planning and implementation of a major capital investment in new and upgraded assets.

Toronto Hydro is exploring the idea of ramping up a portfolio of local demand side management programs, that will target areas of high constraint.

The purpose of this study is assessing the potential for demand response alternatives to offset capital investments, and to create a financial model which supports this approach. The study focuses on customers served by transmission and/or distribution systems identified as requiring significant capital investment in the next 5 to 10 years.

At term, the key outcomes of this study will include the following:

1. Phase 1
    a) To determine the most effective approach to reducing peak load in highly constrained areas, to the extent with which major capital investments can be significantly delayed or even offset entirely.
    b) To develop a financial model for such strategies which can be applied to similarly challenged areas, both in the THESL region and province-wide.
2. Phase 2:
    a) To develop a guideline for determining when activations are necessary, and the protocols for the implementation of future events.

Toronto Hydro has completed the first phase of the project, and this document outlines these preliminary outcomes.

As part of phase 1 of the study, Toronto Hydro developed an Excel based financial and business analysis model that was given the following a provisional name: the "CDM Challenger". The CDM Challenger builds the business case for localized DSM initiatives that specifically target areas of high system constraint in a local distribution company's (LDC) service territory; this includes, but may not be limited to demand response (DR) programs.

The CDM Challenger was designed to support Toronto Hydro in making a sound decision as to whether local DSM can and should cause distribution and transmission asset upgrades to be deferred or offset entirely. It determines the value of such deferral (or full avoidance) and builds it in the business case, as well as other benefits, such as provincial avoided energy supply costs, and provincial avoided generation capacity costs.

The model was initially built for targeted demand response programs. It was later found that regular conservation programming might also be of interest in areas of high constraints to curtail peak load. The model was therefore modified to encompass both types, demand response and regular conservation, hence the shift towards using the more inclusive acronym, DSM, rather than DR.

So far the development and testing of the CDM Challenger focused on Toronto Hydro customers served by Toronto Hydro distribution systems. However, at term, the CDM Challenger could be used to evaluate the need for investment in similarly challenged areas in other Ontario LDCs service territories.

The purpose of this report is to provide a high level description of the capabilities, purposes and uses of the CDM Challenger; to document and explain the model architecture and the algorithms; and to guide CDM staff on the use and interpretation of the model's inputs and outputs. OPA CDM Cost Effectiveness Guide and California Standard Practice Manual

The CDM Challenger builds the business case for local DSM based on the results of standard cost r effectiveness tests as defined by the 2010 OPA CDM Cost Effectiveness Guide[1], as applicable, and the 2001 California Standard Practice Manual[2] (SPM); the former being an Ontario specific offshoot of the latter. Both protocols were used as guidelines for the development of the financial and economical analysis algorithms of the CDM Challenger.

The California SPM is a sturdy economical analysis platform; however, the CDM Challenger had to be augmented with new tests to capture the nuanced market position of certain Ontarian stakeholders. For example, a key perspective is that of Toronto Hydro. Toronto Hydro is an investor owned LDC that earns a regulated return on equity from constructing or upgrading distribution assets that would be deferred by the local DSM programs. Similarly, introducing "Transmitters'" and "Generators" perspectives would facilitate identifying and allocating the system and network benefits from local DSM.

The method developed as part of this study and built in the CDM Challenger includes the most important benefits associated with CDM, which include avoided cost of generation, avoided or deferred cost of transmission and distribution capacity, and avoided cost of energy. As such, the model will carry out a set of tests, each of which represents the business case of local DSM alternative from a distinctive perspective as laid out in Exhibit 1.

Exhibit 1 Introduction to the Cost Effectiveness Tests Included in the CDM Challenger

Test	Perspective of	Applicable Guidelines, if Any	Question Answered

[1] Ontario Power Authority, OPA Conservation and Demand Management Cost Effectiveness Guide, October 15 2010, Canada [ONLINE] Asseen on November 4, 2013, URL: http://www.powerauthority.on.ca/sites/default/files/OPA%20CDM%20Cost%20Effectiveness%20Test%20Guide%20-%20101015%20F.pdf

[2] California Public Utilities Commission, California Standard Practice Manual, Economic Analysis of Demand Side Programs and Projects, October 2001, USA [ONLINE] Asseen on November 4, 2013, URL: http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

Test	Perspective of	Applicable Guidelines, if Any	Question Answered
Total Resource Cost Test (TRC)	All ratepayers	2010 OPA CDM Cost Effectiveness Guide	Whether rates will go down in the long term as a consequence of CDM being preferred to supply side options, accounting for the deferral of local distribution and transmission asset upgrades.
Program Administrator Cost Test (PAC)	LDC & OPA, in their joint effort to administrationister CDM program(s)	2010 OPA CDM Cost Effectiveness Guide	Whether local DSM is a cheaper alternative than supply side options, including incoming local distribution and transmission asset upgrades.
Participant Cost Test (PCT)	Ratepayers participating in the local DSM	2001 California SPM	Whether participating in the program will yield more benefits over time for the participating ratepayers than it will cost them, accounting for any cash incentive, bill credit or direct install they will benefit from when they sign up in the program and/or as they stay in the program
Rate Impact Measure Test (RIM)	Non participating ratepayers	2001 California SPM	Whether rates will go up in the short term as a consequence of CDM being preferred to supply side options to refund incentive being handed out, program administration cost, and lost revenues; accounting for the deferral of local distribution and transmission asset upgrades.
Net benefit for distribution under the RIM test (RIM d)	Non participating ratepayers	New test – Augmented SPM	Whether the [distribution portion of the rates] will go up in the short term as a consequence of CDM, accounting for the deferral of local distribution asset upgrades, as well as incentive, direct install cost and program administration cost incurred directly by the LDC and not refunded by the OPA, if any.
Net benefit for transmission under the RIM test (RIM t)	Non participating ratepayers	New test – Augmented SPM	Whether the [transmission portion of the rates] will go up in the short term as a consequence of CDM, accounting for the deferral of local transmission asset upgrades.
Net benefit for generation under the RIM test (RIM g)	Non participating ratepayers	New test – Augmented SPM	Whether the [generation portion of the rates] will go up in the short term as a consequence of CDM, accounting for the provincial avoided cost of generation capacity.

Test	Perspective of	Applicable Guidelines, if Any	Question Answered
Present value of provincial CDM costs (RIM pc)	Non participating ratepayers	New test – Augmented SPM	Whether the [regulatory fees and debt retirement portion of the rates] will go up in the short term as a consequence of the provincial incentive handouts, direct install costs as well as program administration costs of OPA contracted CDM programs, if any. The RIM pc is needed to balance the following equation: NPV_RIM = RIM d + RIM t + RIM g + RIM pc The RIM pc also factors in the lost revenues otherwise allocated to regulatory fees and debt retirement.
Local Distribution Company Test (LDCT)	LDC's shareholders	New test – Augmented SPM	Whether rolling out the program and deferring the local asset upgrade optimizes the LDC shareholder's capital allocation strategy
Transmission Company Test (TCT)	Transmission Company's shareholders	New test – Augmented SPM	Whether rolling out the program and deferring the local asset upgrade optimizes the transmission company shareholder's capital allocation strategy

The tests account for the provincial average avoided cost of energy, as well as generation capacity as provided by the OPA in its Cost Effectiveness Guide. Optionally, the users can use provincial averages for avoided distribution and transmission capacity instead of using the deferred localized asset upgrade projects.

The platform could be expanded in the medium term to include other benefits that are more challenging to quantify such as increased reliability, greenhouse gas abatements, etc. Furthermore, the model as it currently stands does not capture fuel savings and their associated avoided cost.

All the aforementioned cost effectiveness tests will be presented and defined in greater details in Section 2 and 3.

1.1. Users, Audiences and Contributors to the Model

The primary users of the CDM Challenger will be Toronto Hydro CDM staff, at first, and then the CDM staff of any other LDCs who choose to adopt. However, the current version of the model has not been tested by anyone other than Toronto Hydro CDM staff members.

All users are assumed to have a high level of proficiency with Excel. Users are provided with seamless access to both the front and back ends of the models. The workbook might be locked and some tabs, columns and rows are hidden to reduce the clutter and improve ergonomics, but the workbook can be unlocked without any password and any hidden tabs and ranges can be easily revealed.

All future users should be provided with a training session along with the model, to reach a level of understanding of the inputs and outputs, algorithms, and purpose. The scope of this project resulted in the development of a methodology to value Local DR case studies and pilot programs in THESL service territory that might be transferrable to other LDC territories. The resulting model exceeds expectations with respect to the initial project scope; however, THESL also recognizes that it is necessary to identify the inputs and portions of the model that are LDC specific before future dissemination.

Inside (and outside) Toronto Hydro, the following teams/groups had interest in the CDM Challenge for the reasons stated below:

- CDM Team:
  - The CDM team will be the main users of the models. They will share the results of the modeling with other teams.
  - They are designing the local DSM programs and therefore they will have a large portion of the information to feed in the models, and at the same time they will need immediate feedback from the model to allow them to tune their assumptions, establish the incentive levels and program administration costs.
  - The CDM Team wants to build the business case for each local DSM programs targeting various rate classes for areas of high constraints from the perspective of Toronto Hydro, of the society, of the participating rate payers (participants), and of the non participating ratepayers (non participants).

- Toronto Hydro Finance Department:
  - To start with, they need to compare the local DSM programs financial performance with that of other opportunities.
  - They also need specific streams of information, on an annual basis, to feed in their own modeling, forecasting and regulatory filing work. They agreed on an "incremental" approach; the model would output incremental cash flows caused by the DR initiatives against the business as usual approach to address capacity constrained areas (that is: upgrading the substation, or switching load to another substation).

- Toronto Hydro Capacity Planning, Investment Modeling & System Performance:
  - The capacity planning staff holds the information about what areas to focus on, what stations are to be upgraded, when are the upgrades planned, and how much capital investment is planned for each upgrade.
  - The capacity planning staff provide decision criteria whether a distribution asset upgrade can be deferred, and by how many years. It is expected that this decision criteria will take the shape of a level of impact that the CDM alternative(s) will need to achieve for a given location on a given year that would make the deferral of the asset upgrade acceptable.
  - The capacity planning staff will also be part of the final decision whether the projected impacts of the CDM alternative(s) for a given location are sufficient and robust, and whether the CDM alternative(s) as planned can trigger the deferral of upgrade project(s)

and by how many years. They will be responsible for effectively accounting for the decisions made in the distribution infrastructure investment plan.
    - The investment modeling & system performance staff is interested in the outputs of the model in a similar fashion than the finance department.

- Asset Management
    - The asset management team will support the CDM team with load control technology and how Toronto Hydro's advanced metering infrastructure will be leveraged to do direct load control, for instance.
    - Moreover, the asset management team is interested in the model themselves because of their involvement in distributed energy projects (for instance: PV, local energy storage). The CDM Challenger as it stands today cannot handle distributed energy projects before the meter. The asset management would be interested in this feature being added in the medium term.

- Transmission Company (the transmitter)
    - The transmitter will be interested in working with Toronto Hydro to roll out local DSM programs in areas where transmission asset upgrades are needed in the medium term as a result of high constraint.
    - The transmitter's finance department, as well as its capacity planning, investment modeling & system performance staff will have similar needs and roles than that of Toronto Hydro.

- Other external audiences like the OPA and the OEB
    - External audiences will want to see the business case of local DSM programs from the perspective of the society, the participating ratepayers, and the Ontarian ratepayers in general. They will also want to compare local DSM with supply side alternatives.

2. Incorporating Local DR into an LDC Rate Filing

(This section was added after the first draft of the Challenger model and corresponding report were completed. These first drafts did not incorporate the case for Local DR funding through distribution rate application, and therefore, the sections which follow this will not reference any of this information.)

The Challenger model is also capable of assessing the financial case for Local DR should it be incorporated into an LDC rate application and filed with the Ontario Energy Board (OEB). If the OEB was to approve this type of application and fund Local DR directly through the distribution rates, the benefits would include the following:

- The LDC would be refunded for all Local DR operational expenses (Opex) through distribution rates
- The depreciation of the of Toronto Hydro's Local DR capital assets (Capex) would be refunded through rates, as well as produce a regulated rate of return on investment for the LDC shareholder

The return on Local DR Capex would offset the negative impact of deferring infrastructure upgrade investment, and the model could determine whether the offset was beneficial enough to compensate for the delayed/foregone return on infrastructure investment.

To assess the financial case for Local DR funding through distribution rates, the following adaptations were made to the Challenger model:

- In the TP sheet, a distinction was added to differentiate Capex LDC direct install cost and Opex LDC direct install costs. It should be noted that the LDC's DR Capex is only for direct install, and can only be inputted in the TP sheet – which means it needs to be allocated to specific typical participants. Each Capex item needs to be provided with its specific book life (typically 1 to 20 years).
- In the TP sheet – and in a new, hidden, companion sheet for each TP sheet, ie. the TP Cashflows sheet – financial modeling was added that was needed to establish the incremental equity contribution, revenue requirement, ROE, depreciation, PILs, interest, and net income triggered by each typical participant. The same financial model was used for capital improvement projects that can be found in the DI and TI sheet, and their respective companion sheets, ie. the DI and TI Cashflows sheets.
- In the TP sheet, the TP level cost effectiveness tests were modified to reflect the new funding structure for DR (this is expanded upon below). Changes made to the TP level tests in the TP sheet are reflected in the Projections sheet, and thus in the Portfolio level test results, as well.
- In the Budget sheet, the LDC's Opex direct install cost was separated from Capex direct install cost, and from other LDC's incentive and program admin costs (which will be Opex by default).

The implications on the cost effectiveness test structure were as follows:

- The implications on the TRC were such that the Capex portion of the LDC's DR direct install cost (by definition, direct install is summed up as "incremental cost" in the TRC test) had to be replaced by the present worth of the full incremental revenue requirements to fund the DR Capex – which means the model now has to add PILs, interest and a return for the shareholders.
- Similarly, the implications on the PAC and the RIM were such that the Capex portion of the LDC's DR direct install cost (by definition, direct install is summed up as "incentive cost" in the PAC and the RIM tests) had to be replaced by the present worth of the full incremental revenue requirements to fund the DR Capex.
- The implications on the PCT were such that the Capex portion of the LDC's DR direct install cost (by definition, direct install is summed up as an "incremental cost" and an "incentive cost" in the

PCT test) had to be replaced by the present worth of the full incremental revenue requirements to fund the DR Capex.
- The implications on the LDCT test were such that the DR incremental equity contribution was added as a cost, and the DR incremental net income was added as a benefit.
- There were no implications on the TCT.

Overall, the impact of these adaptations on the test results for the TRC, PAC, and RIM should be minor. The impacts on the LDCT, however, can be significant – but likely still not enough to present DR as worthwhile for Toronto Hydro's shareholders without an additional cost recovery mechanism.

Another adaptation to the Challenger model was the inclusion of the LDC Report sheet. The LDC Report fundamentally aggregates data from all other sheets in the workbook. The LDC reports present annual figures for a 41 year time window – from the portfolio design year (Year00), through the five years of active program operation (Year01 to 05 inclusively), and all the way to 40 years after the start of the program portfolio (Year40). The LDC report can be used by the LDC Financial Department to extract outputs of the model to be added to their own financial models, which usually contemplate a 40 year window.

Most figures are in dollars; however, certain results are presented in units such as kW, MWh/yr, kVAR, kVA, and power factor percentages. All monetary figures are nominal; therefore, inflation is reflected in the table. All figures/values are broken down by rate class (Residential, Multi res, General Service, Large and so on). The upper table is a summary of all other rate class specific figures. The impacts and cash flows that are triggered by all "included" typical participants (where included/excluded is defined in the Projections Sheet) are reflected in the LDC Report, including an allocation of all indirect program administration costs that commensurate with the total curtailment at the end of the last year of active program operation.

Items that were retained in the LDC report include the following:
- Number of new sign ups in the DR programs, as well as cumulative participant numbers that account for persistence in the programs;
- Impact figures in kW, MWh/yr, kVAR and kVA;
- OPA's program administration budget, and OPA contracted incentives;
- Total DR incremental cost, total DR incentive, direct install costs, and program administration cost;
- All lost revenues at the distribution, transmission, generation levels, and as well as regulatory fees (GAM and others), based on actual LDC rates;
- The LDC's lost revenue adjustment mechanism expected cash flows (LRAM);
- LDC's deferred/avoided infrastructure upgrade Capex, equity contribution, incremental revenues, as well of the sub component of that incremental revenue (ROE, net income, PILs, interest, Opex, and depreciation); and

- LDC's incremental DR Opex and Capex, as well as the incremental funding triggered by the DR Capex (equity contribution, incremental revenues, ROE, net income, PILs, interest, Opex, and depreciation).

All monetary items above are not necessarily mutually exclusive; many are overlapping. Again, all figures are broken down by rate class, and projected through the 41 year window, as applicable.

The LDC Report contains certain sets of formulas which can be computationally demanding; therefore, a toggle button on top of the report was included to disable these when possible. Disabling the LDC Report significantly reduces the time Excel needs to refresh all calculations in the workbook. It is recommended to disable the report when not in use.

3. Research and Review of DR Alternatives

This study presents a financial and technical case for localized demand side management (DSM) in place of costly investment in new or upgraded infrastructure. Though many of the concepts of DSM are well documented and practiced, it is important to provide a general overview of the technologies and implementations being considered.

The term DSM was introduced by the Electric Power Research Institute in the 1980s. Typically, the purpose of DSM is to reduce electric demand during peak periods: while this doesn't necessarily reduce overall consumption, it can offset the need for investments in distribution and transmission infrastructure, and ultimately, avoid new and often expensive peaking generation sources.
There are three general strategies employed to reduce demand:

- Energy Efficiency (EE) – simply refers to using less power to perform the same tasks, and typically includes the permanent installation, replacement, or upgrade of customer electricity using equipment.

- Demand Response (DR) – includes all actions that reduce, flatten, or shift peak demand. DR refers to usage adjustments which can be carried out voluntarily or involuntarily, by the customer or the utility, in response to grid stress or high prices.

- Distributed Generation (DG) – refers to the utilization of smaller scale, non-centralized power generation sources as an alternative to, or as an enhancement to, the current grid supply. These sources are typically closer to the end use customer, and help improve transmission and distribution reliability by reducing losses and congestion on the power lines.

There are many different strategies encompassed by the groups listed above. These alternatives depend on the characteristics of the utility jurisdiction, including, end use equipment, utility

equipment, and energy storage and distributed generation potential. Table 1 provides a detailed list of these alternatives.[3]

Table 1 – Strategies for DSM

End Use Equipment Control	Utility Equipment Control
1. A/C—Residential and Commercial Package Units a. remote control cycling b. local controller c. thermostat control d. remote on or off control 2. AIC—Commercial and Industrial Chillers a. water column temperature control b. remote control cycling c. capacity reduction 3. Water Heater—Residential and Commercial a. remote on or off control b. timers 4. Pumps a. timers b. remote on or off 5. Heating a. alternate source heating b. remote on or off control c. remote cycling d. smart thermostat 6. Multiple Loads a. equipment interlock b. demand limiter c. energy management system d. demand controller e. peak alert f. timers 7. Processing Loads a. interlocks	1. Voltage Reduction 2. Feeder Control 3. Power Factor Control **Energy Storage** 1. Cool storage 2. Heat Storage 3. Storage Water Heater 4. Waste Heat Utilization **Incentive Rates** 1. Time Differentiated 2. Interruptible **Distributed Generation** 1. Wind 2. Solar Thermal 3. Solar Cells 4. Fuel Cells 5. Standby Generators 6. Cogeneration 7. Small Hydro **Performance Improvement or Equipment and Systems (Conservation)** 1. High Efficiency Equipment 2. Heat Pumps 3. Evaporative Boost Cooling for Air Conditioners 4. Improved Building Construction 5. Improved Process 6. Utility System Improvements

[3] R.M. Delgado, Demand Side Management Alternatives", Proc. IEEE, Oct. 1985.

b. alternate source c. pre arranged	

There are many inherent benefits associated with selecting a DSM alternative to increased grid capacity,:

- Energy savings – using less energy results in a direct cost savings to customers.
- Capacity savings – when load reduction is coincident with the system peak, new supply may be avoided.
- Transmission and distribution (T&D) savings – if the reduction is coincident with network peak, investments in distribution assets can often be deferred.
- Line loss savings – delivering less energy avoids losses in the wires. This tends to enhance the benefits of avoided generation and T&D mentioned above.
- Environmental benefit – avoided energy consumption minimizes the environmental and health impacts associated with many forms of generation, as well as the related life cycle costs of T&D infrastructure.
- Improved grid reliability

3.1. The LDC Perspective

Despite the obvious societal benefits, it is important that this study positions the concept of localized DSM as a financially viable alternative to all stakeholders, not the least of which, the local distribution companies (LDCs) who are largely responsible for the final decisions regarding capacity planning and meeting supply needs. This is a unique position because LDCs have an inherent motive to increase revenues from the generation, transmission and/or distribution of electricity. Furthermore, increased capital investment in capacity provides new potential revenue streams, and a positive rate of return on the investment; whereas, momentarily disregarding regulatory compensation mechanisms, decreasing an LDC's total load results simply in lost revenue. So even though the total societal benefits resulting from energy saving investments can be greater than traditional expenditures on new supply, these utilities often don't fully capture the benefits of conservation and efficiency in terms of revenues. Therefore, despite being the right decision for the public as a whole, it is not always optimal to do so from the view of the parties providing the commodity. So it is not uncommon for regulators to encounter resistance from LDCs with respect to conservation alternatives.

Thus, the LDC perspective is that which narrows the scope of this study. In the Toronto Hydro (TH) case, for the areas where local DSM may be considered in place of expanded distribution capacity, relief is often only required for a tiny fraction of the year. In one example, a transformer station being examined surpassed 95% loaded capacity for less than 20 hours in 2012. In a situation such as this, a program designed to offer effective relief for these smaller intervals of time, while minimizing the impact on an LDC's opportunity to earn maximum revenue during the rest of the year would be the strategy most widely accepted by LDC decision makers. Hence, the focus of this study and the likely strategies that would first be considered in a local DSM pilot include demand response programs before energy efficiency and conservation concepts. While distributed generation also fits the criteria presented here, early discussions with the TH Asset Management team suggest that it is not currently a viable option for pilot study implementation, due to equipment availability in the service region. For the purpose of this report, we presume this situation can be extended to other LDC jurisdictions.

3.2. The Landscape of Demand Response

In various forms, DR has been practiced in the electric utility sector for many years. With the increasing modernization of electricity grids, technologies, tools, and techniques are available that assist DSM in optimizing grid operations and resources to ensure service reliability. Smart grid infrastructure, distribution system modeling, consumer behaviour modeling, as well as high speed computational analysis are combining to further improve the results of DSM efforts. Today, there are demand response strategies and programs available to all sectors, and can generally be divided between two categories:

1) Price-based Programs – strategies which vary the price of electricity over time, to better align customer energy consumption and the costs they impose on the electric utility system.

2) Incentive/Event-based Programs – strategies which reward customers for reducing their electric loads upon request or for giving the program Administrator some level of control over their electricity using equipment.

Table 2 presents a summary of the types of programs that fall within these two categories:

Table 2 – Demand Response Program Types[4]

Price-Based Options	Incentive or Event-Based Options
Time of Use (TOU) Rates	Direct Load Control
Real-Time Pricing (RTP)	Demand Bidding/Buyback Programs
Critical Peak Pricing (CPP)	Interruptible/Curtailable
Peak Time Rebates (PTR)	Emergency Demand Response Programs
	Capacity Market Programs
	Ancillary Services Market Programs
	Critical Peak Pricing (CPP)
	Peak Time Rebates (PTR)

Table 3 summarizes the United States Federal Energy Regulation Commission's (FERC) brief explanations of the DR programs mentioned above.

Table 3 – FERC DR Program Classifications[5]

Type of Demand Response	FERC Definition
Direct Load Control or Direct Control Load Management	A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment on short notice. Direct load control programs are primarily offered to residential or small commercial customers.
Interruptible Load	Electric consumption subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.
Critical Peak Pricing with Load Control	Combines direct load control with a pre-specified high price for use during designated critical peak periods triggered by system contingencies or high wholesale market prices.
Load as Capacity Resource	Pre-specified load reductions when system contingencies arise.
Spinning/Responsive Reserves	Demand-side resource that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an Emergency Event.
Non-Spinning	Demand-side resource that may not be immediately available, but may

[4] Table 1 is based on a table in a report for the National Action Plan for Energy Efficiency, NAPEE 2010, p 2.2, with a modification. The source document categorized CPP and peak time rebates as price-based options only. The modification identifies CPP and peak time rebates as incentive or event-based options because the structure of CPP or peak time rebates may reward customers for reducing their electric loads upon request or for giving the program administrator some level of control over their electricity-using equipment.

[5] Federal Energy Regulation Commission, "2010 Assessment of Demand Response and Advanced Metering, Staff Report," February 2011.

Reserves	provide solutions for energy supply and demand imbalance after a delay of ten minutes or more.
Regulation Service	A type of demand response service in which a demand resource increases and decreases load in response to real-time signals from the system operator. Demand resources providing Regulation Service are subject to dispatch continuously during a commitment period. This service is usually responsive to Automatic Generation Control to provide normal regulating margin.
Demand Bidding and Buyback	A program which allows a demand resource in retail and wholesale markets to offer load reductions at a price, or to identify how much load it is willing to curtail at a specific price.
Time of Use Pricing	A rate system where usage unit prices vary by time period. Time of use rates reflect the average cost of generating and delivering power during those time periods.
Critical Peak Pricing	Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours. The total number of critical peak periods is typically capped for a calendar year.
Real-Time Pricing	Rate and price structure in which the retail price of electricity typically fluctuates hourly or more often to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.
Peak Time Rebate	Peak time rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days. Like Critical Peak Pricing, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.
System Peak Response Transmission Tariff	The terms, conditions, and rates and/or prices for customers with interval meters who reduce load during peaks as a way of reducing transmission charges.
Other Demand Response Program/Tariff	A company or utility's service/product/compilation of all effective rate schedules general terms and conditions and standard forms related to demand response/AMI services for customers that are not residential, commercial and industrial, or other.

3.3. Demand Response by Sector

There are unique opportunities for demand response in the residential, commercial and institutional (C&I), and industrial sectors. Certain strategies have proven more effective for each, in terms of program participation and corresponding load curtailment and reliability. However, the landscape is constantly

evolving and adapting to make participation more inclusive.

Residential – demand response in the residential sector is primarily delivered through direct and automated load control. Devices such as central air conditioners, domestic hot water heaters, and pool pumps can be short cycled or turned off during summer peak times, with little to no impact on customer comfort. This also provides the participant reduced costs as a result of consumption savings or usage being shifted to mid r and off peak pricing intervals. In other examples of residential DR, automated thermostat setbacks may be used to induce load curtailment.

Commercial & Institutional – DR programs in the C&I sector can sometime be more challenging from an inclusive design perspective. End uses and facility operations vary more widely, and therefore, it is often difficult to fit this group of customers into the parameters of a direct load control or interruptible program. However, developments in technology and the increased need to address the large peak demand loads stemming from this sector, has created a new focus and marketplace for C&I demand response.

There is such a variety of electrical loads in C&I sectors that utilities and 3rd party firms are tasked with identifying specific curtailment strategies that achieve the maximum load reduction with the least amount of operational disturbance. Common strategies may include slowing down variable speed motors, reducing a portion of non-essential lighting, raising HVAC set points, and temporarily shifting load to on-site generation.

Industrial – Historically, the industrial sector has been considered as the lowest hanging fruit in the market for DR, because, on a per capita base, these facilities are usually able to provide higher load curtailment. Industrial customers typically secure lower energy rates through "interruptible tariffs" in exchange for load reductions during system peak. These programs are commonly implemented manually, with notification of an event taking place over the phone or by email, and traditionally, this has meant relatively low participation rates. However, automated DR strategies designed for the industrial sector are being reviewed and tested within the context of the opportunities and barriers presented by current and future market structures. Automated DR systems for industry could provide customers with online pricing signals, capabilities to program customized events, and provide the utilities with dispatchable supply alternatives similar to conventional resources. Of course, the barriers to automated event control include load scheduling that can be dictated by external factors such as customer demands or time sensitive production, the perceived lack of control presented by the term "automated", and aversion to risks such as unplanned downtime.

3.4. The Cost Effectiveness of Demand Response Programs

The main deliverable of this study is a modelling tool capable of producing the key financial outputs necessary to determine the cost-effectiveness of localized DSM. While there are a number of examples of cost-effectiveness test results available through both theoretical and practical investigation, the

advantage of this model is its ability to adapt and be tailored to a particular suite of DSM programs, and to the unique characteristics of the user's service region and potential participants. As such, cost benefit analyses are not included in the review of DR alternatives.

However, it should be noted that a number of widely accepted studies present DR as a viable alternative, both financially and technologically, to conventional supply resources. These studies extend the range of benefits to both the participant and non-participating rate payers, as well as to the T&D companies, the generators, and ultimately, society as a whole. For example, a report addressed to the United States Congress in 2006[6] included a literature review of ten demand response cost effectiveness studies. Examining various types and combinations of demand response programs, both illustratively and practically, all ten studies produced positive cost benefit ratios and a range between $0.88 – $2.07 of normalized gross benefit in $/kW-year. This metric represents net benefits ($) per unit of avoided capacity (kW); this is how the industry typically quantifies the value or cost of demand response. According to the OPA's CDM annual reports, the delivery cost of DR programs to date in Ontario has been approximately $10,000/MW-month, comparable to the cost of many conventional alternatives, but with more attractive societal benefits. Furthermore, a pilot offering in New York City has even demonstrated success in the targeting of DSM.

CECONY's Targeted Demand Side Management (DSM) Program[7]

With limited potential for capacity expansion or generation imports in New York City, CECONY's targeted DSM program was designed to defer the need for transmission and distribution upgrades in the most highly constrained networks. The program employed energy efficiency measures to proactively reduce demand on specific circuits beginning in 2004. Third-party vendors were allowed to bid for load curtailment contracts and successful parties were then required to guarantee installation of equipment and future load reduction before summer peaking months. These vendors were only credited with projects in targeted networks, and paid only for measures that would directly impact peak loads. Through April 2013, CECONY had achieved approximately 107 MW of demand reductions and 278 GWh of annual energy savings. The program has created $464M in net customer benefits, including $221M in avoided T&D capital, on $145M in total costs. Other benefits identified in CECONY's experience were reduced regulatory risk, reduced electricity costs for consumers, and a complementary alternative to load rejection.

These studies include reduced consumption and the avoided costs of capital investment as benefits, while from the LDC perspective, energy savings and avoided expenditure can represent lost revenue streams. So while these earlier analyses and experiences in other jurisdictions are valuable in portraying the societal benefits of demand response, this study is unique in that it may provide the final and more elusive piece in the argument in favour of load curtailment and capital deferral from the point of view of the distributor.

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[6] U.S. Department of Energy, "Benefits of demand response in electricity markets and recommendations for achieving them". 2006.

[7] Craft, R.A., Consolidated Edison "Demand Side Management as a Distribution Resource" April 24, 2013. http://switchboard.nrdc.org/blogs/lettenson/ConEdison%20Presentation%20(April%202013).pdf

3.5. Demand Response in Ontario

It has been proposed[8,9] that successful CDM policies are those which leverage existing equipment, program experience and understanding, and current regulatory frameworks, while at the same time fostering innovation and new ways to provide more effective offerings. In a 2009 report, McKinsey & Co.[6] recommended CDM portfolios that utilize proven, piloted and reliable CDM strategies, while arguing that continued innovation is essential to generating advanced results. Applying the same principles to the planning of a new suite of DR programs for localized implementation, it would seem clear that the same path is the most prudent. Furthermore, given the current state of the electricity sector and governing framework in Ontario, certain DR strategies mentioned in the list above would require considerable changes and flexibility to today's rules and methods of doing business.

So rather than develop a local DR program – which may be tested as early as the summer of 2014 – based upon strategies which have not been fully developed, applied for, approved, or necessarily even feasible under the current framework, the proposed suite of measures includes a combination of tested OPA province-wide programs, and OPA-approved pilots which may further benefit from a localized introductory rollout. However, this selection is only a recommended suite of solutions which will be entered into the model as a functionality test: as each LDC contains a unique combination of customers, geographic characteristics, and potential supply uncertainties, the model contains complete flexibility in allowing any suite of programs to be tested individually, or in aggregate. The same flexibility applies should the provincial CDM framework or technological landscape evolve.

3.6. Proposed Demand Response Programs for Local DR

The intent of a local DR program is to reduce peak load in a highly constrained service area, in times of distribution system need. In the Toronto Hydro case, and likely in most others, these constrained service areas are made up of various combinations of residential, C&I, and Industrial customers, who require a suite of alternative demand response initiatives. As such, the following combination of programs has been chosen based on its collective ability to attract all customer sectors and sizes.

[8] Sciortino, M. (2010). States Stepping Forward: Best Practices for State-Led Energy Efficiency Programs. Retrieved from the American Council for an Energy-Efficient Economy's web site http://www.aceee.org/research-report/e106

[9] McKinsey & Company (2009). Unlocking Energy Efficiency in the U.S. Economy. Retrieved from the McKinsey & Company web site http://www.mckinsey.com/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/Unlocking_energy_efficiency_in_the_US_economy.aspx

3.6.1. peaksaverPLUS®

- Target Market: Single-family Residential & Small C&I

The peaksaverPLUS® program is open to residential and small commercial consumers who participate by allowing a one-way paging network to control either a programmable communicating thermostat (PCT) or load control switch to curtail electricity demand for central air conditioners, electric water heaters or pool pumps during the peak period on high electricity demand days. peaksaverPLUS® also offers consumers an in-home display (IHD) which allows participants to monitor their electricity consumption and associated cost in real time. Ontario's local distribution companies (LDCs) are responsible for procuring the equipment offered and for marketing the program (jointly with OPA). As of December 2012, approximately 180,000 control devices were installed on central air conditioners in Ontario, nearly all of them at residential premises. Participants in the THESL service region accounted for over 70,000 of these devices. In addition, nearly 50,000 IHDs had been installed at participant premises[10].

The single family residential and small C&I sectors comprise over 700,000 individual accounts, and represent more than 20% of Toronto's peak demand and more than 30% of its annual consumption. In some of the highly constrained areas in the west end of Toronto, residential load is even higher than the Toronto average, and represents an important target market for effective demand management. Often the appliances contributing to afternoon summer peak demand are running in unoccupied homes and can be managed by direct load control without significant customer disturbance.

According to Freeman, Sullivan & Co., the OPA's peaksaverPLUS® evaluation contractors, achievable penetration rates for well-established residential DR programs can reach nearly 50%. Currently, typical penetration rates by transformer station service areas in Toronto are approximately 20-25%, suggesting plenty of remaining potential available for target in a geographically specific initiative.

3.6.2. Multi-Unit Residential Demand Response (MURB DR) – SuiteSaver

- Target Market: Multi-Unit Residential Buildings and Suite Owners

The MURB DR program is designed to offer multi-unit residential buildings (MURBs) the opportunity to participate in the provincial load control peaksaverPLUS® events. This sector presents a provincial peak demand of approximately 1 GW, and a considerable demand reduction potential of more than 20 MW in the THESL service region alone. The installation of load control devices on common area systems, and programmable communicating thermostats in the individual suites would facilitate these savings during activation periods, and in turn, building and suite owners would receive payment for their load control availability. Also included in the program offering is a comprehensive energy efficiency strategy, including system audits and retrofit incentives that will further increase the demand reduction and annual energy savings impact in the provincial MURB sector. With the increasing number of MURBs being constructed in Toronto and in the province as a whole, this program offers a complimentary load relief strategy to a form of development which, through increased load densification, could have one of the more profound impacts on local service constraints.

[10] Freeman, Sullivan, & Co. "peaksaverPLUS® Program Load Impact and Process Evaluation". September, 2013.

This program was piloted in the summer of 2013, and is currently in the final evaluation stage. The Total Resource Cost (TRC) analysis submitted with the proposal assumed a 4% penetration in the MURB sector and 40% suite penetration in participating buildings. These projections were derived from current peaksaver participation evaluations and incorporated the more attractive incentives being offered to both the building owner and participating suite owner. It was projected that the thermostat and occupancy setback controls could provide approximately 0.3 – 0.5 kW/suite and common area load controls could produce approximately 65 – 80 kW in curtailment, on average.

3.6.3. Commercial Energy Management & Load Control – GridSaver

- Target Market: C&I and Industrial Customers (50 – 400 kW)

The CEMLC pilot and program is designed to produce peak demand reductions in the 50 – 400 kW commercial, retail, institutional, and hospitality sectors. The strategy involves the installation of load control devices on rooftop cooling units, and programmable communicating thermostats that offer the opportunity for energy and demand reductions during peaksaver PLUS activation periods. The provincial peak cooling load in these sectors is nearly 2000 MW, offering a reduction potential of approximately 60 MW. The program design also recommends a facility energy management strategy, incorporating occupancy sensors to further improve the peak demand reduction and annual energy savings impacts.

Savings projections were developed with the use of the U.S. Department of Energy setback calculator, and resulted in an estimated 12% reduction in cooling load. It is proposed that facilities in this load class could produce an average of approximately 24 kW of summer peak reduction. Though anticipated penetration is low at 3 – 4%, this market is virtually untapped, with the previous DR program opportunity consisting solely of the OPA's Demand Response 3 program. Therefore, the potential DR resource that this customer represents is considerable, if marketed effectively. Furthermore, this program can essentially be expanded to include nearly any sized customer possessing rooftop cooling units. While it is assumed that customers larger than the somewhat arbitrary upper limit will more likely possess centralized cooling systems, should they not, this opportunity would be available and potentially even more effective.

3.6.4. Demand Response 3 (DR3)

- Target Market: C&I and Industrial Customers (>400 kW)

For those customers capable of meeting the minimum availability commitments of the OPA's DR3 program, the flexibility in choice of curtailment strategy and level of incentive payment may present this program most favourably. DR3 is a contractual demand response (DR) program that offers large commercial and industrial consumers reserve payments for being available to provide load reductions when called by the OPA. Participants are required to meet contractual demand reductions when called, or else payments are reduced or eliminated. In addition, DR3 participants notify OPA and the IESO of any short term fluctuations in load reduction capability due to facility maintenance or down time. Non r

performance days lead to reductions in the participant payments. Unscheduled non performance – failure to deliver scheduled load reductions during events – leads to even larger payment reductions[11]. Current DR3 penetration rates are virtually non existent in the Toronto Hydro service region, with less than 100 customers choosing to participate; however, individual load curtailment contributions can be quite considerable. With almost the entire segment of large C&I and industrial customers available for enrolment, and in a situation where a relatively small number of these participants can have a major impact during a curtailment event, this program should represent a key focus in any local DR strategy.

4. Project Finance of Distribution or Transmission Asset Upgrades

The CDM Challenger will be used to compare a DSM portfolio (i.e.: the challenger) that would target specific locations served by distribution and transmission infrastructures that are capacity constrained to infrastructure upgrade projects (i.e.: the defenders) that are currently planned to solve the problem under the baseline scenario.

To achieve this, the CDM Challenger models the finance of distribution or transmission infrastructure projects. Key outputs of the project finance modeling that are needed to value deferral or avoidance of such project include the following:

- Additional revenue requirements or capital recovery funding – these incremental revenues that would have to be generated through rates.
- Incremental earnings, net of any incremental O&M expenses (if any), net of debt services, and net of net of payments in lieu of taxes (PILs).

The intricacies of the utility infrastructure project finance that are captured by the CDM Challenger include the following:

- Financing Structure – e.g. debt & equity ratio, debt terms and interest rate.
- PILs and Capital Cost Allowance.
- Regulated Return on Equity Rate (ROE).
- Multi Year Capital Cost Schedule – Capital costs are incurred during multiple financial years, and for every given year investors are assigned a specific regulated ROE that might differ from the year before or the year after.

The model ultimately determines the level of capital recovery funding that will result in earnings that commensurate with the regulated ROE.

The capital recovery funding is the sum of the following components:

- Asset Depreciation
- PILs

[11] Freeman, Sullivan, & Co. "2012 Impact Evaluation of Ontario Power Authority's Commercial & Industrial Demand Response Programs" August, 2013.

- Incremental O&M expenses (if any)
- Interest payments
- Allowance for Funds Used During Construction (AFDUC)[12]
- ROE

The funding thereby follows a declining profile rather than equal installments; the profile of asset depreciation + interest payments.

The CDM Challenger as it stands, assumes that the finance of a transmission infrastructure upgrade project is modeled in an identical way than that of a distribution infrastructure upgrade project. This assumption will need to be validated with the transmitter.

4.1. Local DSM Benefit Valuation Options

Using the aforementioned output of the project finance model, the CDM Challenger can value the local DSM portfolio based on one of the following approaches for any given distribution or transmission project,[13] serving the areas where the portfolio will be rolled out, and based on the user's preferences or objectives.

Exhibit 2 Local DSM Benefit Valuation Options

Benefit Valuation Options	Discussion
Full Project Deferral – The present worth of the deferral of the full distribution or transmission project for a user defined number of years.	This method uses the difference between the present worth of the incremental revenues associated with the project(s) if they were to be accrued as planned, and that if they were to be accrued X years after (i.e. a user defined number of years). The model supports the decision of the user by computing the total curtailment capacity (in kW and kVA) for every given location/project, for every given year. The latter is indeed worth less than the former because of the time value of money. This should be the preferred option.
Full Project Avoidance – The present worth of the avoidance of the full distribution or transmission project.	This method uses the present worth of the incremental revenues associated with the project(s) if they were to be avoided all together because the local DSM portfolio made the upgrade project unnecessary. It is as accurate as the full project deferral option, but less likely.

[12] Reimbursement of interest paid during construction.

[13] The CDM Challenger can handle up to six distribution projects and six transmission projects in any given workbook.

Benefit Valuation Options	Discussion
Unitary Deferral – The unitary present worth of the deferral of distribution or transmission capacity for the specific area of constraint served by the infrastructure for a user defined number of years ($/kW for a 1 year deferral).	This method is based on the assumption that every kW curtailed as a result of the local DSM portfolio for a given area of high constrained, and for a given year will result in the unitary value of that kW to be accrued. This is the "usual" working assumption when valuing CDM on a provincial basis, because somehow the curtailment will cause projects to be deferred across multiple LDC territories, and the value will be averaged out. When narrowing down the scope to a few specific areas of high constraint, this option is indeed less accurate than full project deferral and full project avoidance. Under this option, however, the CDM Challenge attributes a value to any given kW curtailment capacity only starting when the distribution of transmission project is planned to be finalized. This option is suitable for a first pass, quick modeling, or when no decision can be made whether the CDM impact are sufficient to defer the project, by how many years or whether the CDM impact are sufficient to avoid the project altogether.
Provincial Average – The value of avoided generation, transmission and distribution capacity and avoided energy supply is established by using the OPA's provincial average avoided supply cost assumptions for demand and energy.	The users are provided with the option of using OPA provincial averages avoided supply cost assumptions for transmission and/or distribution capacity ($/kW yr). That being said, using exclusively provincial average avoided supply cost assumptions for both transmission and distribution would be missing the point of the model. It is expected that users will use one of the other. LDC's CDM staff would typically use this option to value avoided transmission capacity if they were on working a local DSM portfolio in areas where the constraints came from, for example, distribution stations exclusively, and/or if information on transmission project were not available. Likewise, transmitter' staff would use provincial avoided distribution capacity to value a local DSM portfolio delivered in areas served by a transmission transformer station in need of an upgrade, whereas distribution stations might or might not need to be invested in. This is option is the only one available for avoided generation capacity and avoided energy supply cost.

The provincial average avoided supply cost assumptions were determined by the OPA for 2007[14]. The OPA is currently working on updating these provincial averages. Users of the CDM Challenger should be able to input the new values in a seamless fashion.

5. Cost Effectiveness Tests Performed by the CDM Challenger

The cost effectiveness tests results are the main output of the CDM Challenger and the main indicators to make decisions. This section provide a thorough explanation of the tests, with a focus of the particularities of the tests as interpreted in the CDM Challenger, to accommodate particularities of local DSM, and the particularities of Toronto Hydro's regulatory and CDM framework. The purpose of this

[14] See Appendix A. Ontario Power Authority, OPA Conservation and Demand Management Cost Effectiveness Guide, October 15 2010, Canada

section is to provide to the readers the tools to understand the tests, interpret the results, and anticipate the effects of the inputs.

5.1. Potential Sources of Local DSM Funding

Toronto Hydro is exploring the following three funding options. The model accommodates all three options, and will therefore allow Toronto Hydro to assess the value of each, and thus, support sound decision making.

- Provincial OPA Contracted CDM Programs, Emphasized in the Areas of High Constraint: The local DSM program will be, in fact, a provincial OPA contracted program that will be vigorously emphasized by Toronto Hydro in a targeted area of high system constraint. All of the cost involved (incentive and non incentive) will therefore come from the OPA, and, ultimately, from all Ontarian ratepayers. Examples: the OPA's PeakSaver, and DR3. All administration cost (i.e. non incentive cost) would come from the OPA's Program Administration Budget (PAB).
- Stand Alone Local DSM Program: The local DSM program will stand completely alone. Toronto Hydro may seek additional revenues to fund the new incentives, as well as the program administration costs, through rate adjustment(s). No funding would come through the OPA; all of it would come directly from Toronto Hydro's ratepayers. The program would have its own set of eligibility criteria, incentive level, participation process, administrationistrative procedures, and measurement and verification rules.
- Enhanced or Extended Provincial OPA Contracted CDM Program (Hydrid): The local DSM program will build on a provincial OPA contracted program, but will consist of one or many additional offering(s) – like an incentive adder, or additional technical assistance – that would be available to ratepayers in the areas of high constraint. Alternatively, the local DSM program might be based on a provincial OPA contracted program, but extend the existing offerings to ratepayers that are not currently eligible in the OPA programs as long as they are located in the areas of high constraint. In both cases, Toronto Hydro would seek to increase the penetration of the OPA provincial programs in these areas. Toronto Hydro's might seek additional revenues to fund the additional offerings or extended eligibility criteria through a rate adjustment.

The CDM Challenger captures input and provides results that account for the three aforementioned funding options (Provincial, Stand Alone and Hybrid). Exhibit 3 shows the implications of two of the three funding options (Provincial, and Stand Alone) on the cost effectiveness tests. The Hybrid option, indeed, sits somewhere between.

Exhibit 3 Matrix Defining the Costs Included in the Definition of Each of the Proposed Tests

Column # →	1	2	3	4	5	6	7	8	9
Funding Options →	N/A	Provincial OPA Contracted CDM Programs				Stand Alone Local DSM Program			
		Incentive		Program Administration		Incentive			Prog. Ad.
Cost Items → / Cost Effectiveness Tests ↓	Install, Equipment, & O&M Cost Paid by Participants	Install, Equipment & O&M Cost Paid by the OPA	Cash Incentive Paid by the OPA	Program Administration Cost Paid by the OPA (PAB)	Direct OPA Administration Cost	Install, Equipment & O&M Cost Paid by the LDC	Cash Incentive Paid by the LDC	Credit on Energy Bills, Lost by the LDC	Program Administration Cost Paid by the LDC
TRC - Total Resource Cost test	Cost	Cost		Cost	Cost	Cost			Cost
PAC - Program Administrator Cost test		Cost	Cost	Cost	Cost	Cost	Cost	Cost	Cost
PCT - Participant Cost Test	Cost	Cost & Benefit	Benefit			Cost & Benefit	Benefit	Benefit	
RIM – Rate Impact Measure Test		Cost	Cost	Cost	Cost	Cost	Cost	Cost	Cost
RIM d – Net Benefit for the Distributor						Cost	Cost	Cost	Cost
RIM t – Net Benefit for the Transmitter									
RIM g – Net Benefit for the Generator									
RIM pc – Provincial Administration Cost		Cost	Cost	Cost	Cost				
LDCT - Local Distribution Company Test						Cost	Cost	Cost	Cost
TCT - Transmission Company Test									

Exhibit 3 is an excerpt from a much larger matrix shown in section 4.5, which also shows the avoided or deferred costs, the bill savings, and the lost revenues. Items shown in the column were selected because they all represent costs.

With respect to Exhibit 3, the following might seem counter intuitive and therefore deserve more explanation:

- Direct install cost such as installation and equipment, and "after sale" service offered free of charge to participating ratepayers through a CDM program (Column #2 & 6) should be considered an incentive and therefore accounted for as such in the PAC, the PCT and under the RIM.
- Cash incentives or credit on energy bill (Column #3, 7 and 8) do not constitute costs under the TRC because such costs are considered to be money changing hand yet staying in the province, thereby having no net economic impact. One of the key implications is that: CDM cost r

effectiveness modellers cannot improve the TRC by reducing the cash incentive levels. Their only levels include, finding ways to reduce the direct install cost, or to reduce the program administration costs.

- x Aforementioned direct install cost (Again, Column#2 & 6) should also be considered to be part of the "incremental CDM measure cost" (or DR program participation cost) along with similar cost paid by the participant (Column#1), and therefore must be accounted as such in the TRC and the PCT.
- x Under the PCT, the same direct install costs (#2 & 6) will be counted as a both an incremental cost and as a benefit. It is expected that in addition to the direct install cost, the participant might have to incur other costs that will not be provided through direct install (Column#1).
- x Direct OPA administration cost (Column#5) is the portion of OPA's operation cost that can be attributed to the local DSM portfolio. In the CDM Challenger, it needs to be inputted as a % of the total incentive.
- x Technical assistance and enabling activities such as customer education, marketing, energy audits, trainings offered to trade people or field visits for verification, auditing or measurement purposes usually all go under program administration costs (Column#4, 5, or 9).

5.1.1. Variable versus Fixed Program Administration Cost

It is useful to differentiate fixed administration costs from variable costs in order to (later) be able to test the sensitivity of the cost effectiveness test results to variations in the local DSM portfolio uptake.

Moreover, users of the CDM Challenger will be able to allocate a portion of the fixed program cost directly to certain programs or components of the local DSM portfolio. For another portion of the cost, the allocation will not be direct – i.e. the unallocated fixed program administration cost. As required, the model automatically allocates the unallocated fixed program administration cost to compute the cost effectiveness tests by using curtailment capacity (kW) as the driver.

The CDM Challenger had to capture all of the degrees of nuances with regard to incentive costs and program administration costs that were laid out in section 4.1.

5.2. Cash Incentive, Bill Credit or Direct Install Costs

The CDM Challenger supports the LDC CDM staff in establishing the incremental benefits being offered to the participating ratepayers. These benefits can be in the form of an initial cash incentive, a "gift" of some sort (a new in home display, for instance), direct install of some equipment, a stream of cash incentive payment, some adjustment on the rate, or some regular credits on the utility bill to compensate participants. Usually, all of the aforementioned benefits are rolled in under the term "incentive".

The CDM Challenger supports the LDC CDM staff in establishing the incentive levels by allowing the users to see the impact of the level of incentive that they input in the model on the cost effectiveness test results. A common approach to establishing the incentive levels relies on an iterative process in which the users test multiple incentive levels until test results are deemed satisfactory.

This iterative process takes the following form: [guessing an incentive level -> seeing the impacts on the tests -> repeat] until optimal win-win results are obtained from the perspective of most of stakeholders.

The CDM Challenger allows the users to effectively and quickly go through this process to establish the appropriate incentive levels.

Incentive levels will surely have impact on the PAC, the PCT and the RIM. They may have impact on the LDCT, the RIM-d, and the RIM-pc tests depending on where the funding for these incentives will come from, as shown in Exhibit 3. Similarly, if the funding comes from the OPA because the local DSM programs being modeled are OPA-contracted programs, then the incentive levels will have impact on RIM-pc only. If the funding comes from the LDC's ratepayers because it is a stand-alone local DSM program, then it will have impact on the LDCT and the RIM-pc.

5.3. Time Value of Money and Discount Rates

All benefits and costs under the cost-effectiveness test must be compared on the same basis because the promise of future benefits cannot be deemed as valuable as current cost. All future cash flows (cost or benefits) thereby get discounted.

The OPA CDM Cost-Effectiveness Test guide stipulates that a real discount rate of 4% and an inflation rate of 2% shall be used to discount future benefits and costs for the purpose of assessing cost effectiveness. These values are consistent with the discount rate and inflation rate used to develop the Integrated Power System Plan[15].

OPA-prescribed discount and inflation rates are directly applicable to the TRC and the PAC. Toronto Hydro has therefore decided to use the same discount rate for the PCT, RIM and all other tests attached to the RIM because it makes comparison between them easier.

Toronto Hydro made the decision of working with nominal cash flows as much as possible in its model because it is the common practice in its finance department. The prescribed real discount rate of 4% therefore becomes a nominal discount rate of 6.08%.

The CDM Challenger offers the option of using a differentiated discount rate for every given test, although Toronto Hydro is not currently using this option for the TRC, PCT, PAC and RIM. Differentiating the discount rate might be an attractive option in the future, because it would model how each set of stakeholders value future cash flows against current cash flows in a more realistic manner. For example, given that TRC looks at the cost-effectiveness of CDM from the perspective of the society, then arguably the discount rate used for the TRC could be closer to inflation. The matter is the subject of debates among CDM experts, and for the moment Toronto Hydro is following the lead of the OPA.

[15] Ontario Power Authority. Integrated Power System Plan. EB-2007-0707. Exhibit D Tab 4 Schedule 1 Attachment 3. Available at: http://www.powerauthority.on.ca/Storage/53/4868_D-4-1_Att_3_corrected_071019.pdf

5.3.1. Choice of the Discount Rate under the LDCT and the TCT

The discount rate being used in the LDCT and the TCT is a critical decision, and these discount rates should not be that of the TRC, the RIM or the PAC. The discount rates used in the LDCT and the TCT should notionally hover around the distributor's and the transmitter's regulated return on equity[16], respectively; because both tests compare the delayed or forgone future earnings, attached to the distribution or transmission infrastructure upgrade projects being deferred or avoided as a result of local DSM, with deferred or avoided equity capital contributions. This will become clearer to readers when they review the detailed definition of the tests in Section 4.5. When using the regulated ROE as a discount rate for the LDCT and/or the TCT, then the present worth of earnings should be equal to the present worth of equity capital contributions, regardless of how many years they will both be delayed or if they will be avoided altogether. This is a consequence of the very approach to establishing earnings, as laid out in Section 3, based on a specific project finance under the current regulatory framework,

The choice of the discount rate shall therefore be in line with the investment strategy of the distributor's or transmitter's shareholders:

- If the chosen discount rate is above the utility's regulated ROE, then the deferred/avoided equity capital contribution will be worth more than the delayed/foregone earnings. It would be the result of the utility's shareholders valuing their equity higher than the regulated ROE, perhaps because they have other investment opportunities that yield higher return than regulated infrastructure upgrade. It could also be because the shareholders deem the local DSM alternative to be riskier than the baseline scenario. It could also be the result of the shareholders' funding to be tight; therefore they do value the deferral/avoidance of the capital contribution.
- If the chosen discount rate is below the utility's regulated ROE, then the deferred/avoided equity capital contributions will be worth less than the delayed/foregone earnings. It would be the result of the utility's shareholders wanting to invest more or quicker in regulated distribution or transmission infrastructure; maybe because they have no other investment opportunities that yield as much and/or that are as safe.

5.4. Net Present Value, Benefit/Cost Ratio and Other Indicators

In Section 1.1, a set of cost-effectiveness tests was introduced that Toronto Hydro has used to depict the business case of its local DSM portfolio. The results of each test can be expressed using one or many

[16] It is recommended to use the regulated return on equity instead of WACC because the LDCT and the TCT look at the deferral of capital equity contribution as a benefit (i.e. the portion of the investment funded by THESL shareholders' money) and compare it with the delay of incremental net income as a cost (i.e.: after tax after debt r service cash flows going back to THESL shareholders).

indicators, each of which as a specific use. Toronto Hydro has built the most common indicators in the CDM Challenger. They are presented in the Exhibit 4 below.

Exhibit 4 Proposed Benefit Cost Analysis Indicators

Indicator	Acronym	Summary Approach	Key Question Answered
Benefit/Cost ratio	B/C ratio	Present worth of benefits divided by present worth of costs	Are benefits outweighing the costs?
Net Present Value	NPV	Present worth of benefits minus the present worth of costs	How worthwhile is it to undertake the program?
Levelized Unitary Cost of Demand	LUC ($/kW)	Present worth of cost divided by levelized impact. In the CDM Challenger, we have used the curtailed kW as the denominator.	How much is being paid for load curtailment?

What we seek to illustrate in Exhibit 5 is that all of the aforementioned "indicators" are cross cutting of the cost effectiveness tests.

Exhibit 5 Matrix Illustrating How Test Results Can be Presented through Multiple Indicators

Indicators W Cost Effectiveness Tests Y	B/C ratio	NPV	Levelized Cost
TRC – Total Resource Cost test	X	X	X
PAC – Program Administrator Cost test	X	X	X
PCT – Participant Cost Test	X	X	X
RIM – Rate Impact Measure Test	X	X	X
RIM d – Net Benefit for the Distributor		X	
RIM t – Net Benefit for the Transmitter		X	
RIM g – Net Benefit for the Generator		X	
RIM pc – Provincial Administration Cost		X	
LDCT – Local Distribution Company Test	X	X	X
TCT – Transmission Company Test	X	X	X

All tests can be computed at the measure or project level, for one typical participant, for a subset of participants, for a program and/or for a portfolio of program. The CDM Challenger can produce test results for multiple levels of aggregation, from the program participant level and up.

5.5. Detailed Definition of the Cost Effectiveness Tests and Cashflows

The complexity of the financial and economic analysis needed to build a comprehensive business case of local DSM lies in the number of stakeholders involved, the variety of cost categories (the reader had a taste of this in Section 4.1), the variety of sources of funding, the breakdown of the rates and of the

avoided cost between generation, transmission and distribution, and other considerations such as the Lost Revenue Adjustment Mechanism available to the distributors – but not for the transmitter or the generators.

The matrix shown in Exhibit 6 is an attempt to capture all of the complexity of the financial and economic model in one page. Benefits are shown as "Bs" and costs are shown as "Cs".

Exhibit 6 Definition of All Tests in the CDM Challenger

Column # →	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Categories →	Rates				N/A	Stand Alone Local DSM			OPA Contracted Programs				Determined Through Project Finance Modeling						Prov. Avrg	
Cash flows → / Cost Effectiveness Tests ↓	Volumetric Distribution Rate, for Demand and/or Energy	Volumetric Regulatory Debt Retirement Rate	Volumetric Transmission Rate, for Demand and/or Energy	Volumetric Energy Supply Rate, for Demand and/or Energy	Install and O&M Cost Paid by Participating Ratepayers	Install and O&M Cost Paid by LDC	Cash Incentive or Bill Credit Paid by LDC	Program Administration Cost Paid by LDC	Install and O&M Cost Paid by the OPA	Cash Incentive or Bill Credit Paid by the OPA	Program Administration Cost Paid by the OPA (PAC)	Direct OPA Costs	Deferred/Avoided Additional Revenue Requirements for Distribution Project(s)	Deferred/Avoided Additional Revenue Requirements for Transmission Project(s)	Deferred/Avoided Equity Capital Contributions, for Distribution	Delayed/Foregone Earnings for Distribution Project(s)	Deferred/Avoided Equity Capital Contributions, for Transmission	Delayed/Foregone Earnings for Transmission Project(s)	Avoided Cost of Generation Capacity (Provincial Average)	Avoided Cost of Energy (Provincial Average)
TRC - Total Resource Cost test					C	C		C			C	C	B	B					B	B
PAC - Program Administrator Cost test						C	C	C	C	C	C	C	B	B					B	B
PCT - Participant Cost Test	<row n/a> Bill Savings - Benefit row n/a				C	C & B	B		C & B	B										
RIM – Rate Impact Measure Test	<row n/a> Lost Revenues - Cost row n/a					C	C	C	C	C	C	C	B	B						
RIM d – Net Benefit for the Distributor	C					C	C	C					B							
RIM t – Net Benefit for the Transmitter			C											B						
RIM g – Net Benefit for the Generator				C															B	B
RIM pc – Provincial Administration Cost		C							C	C	C	C								
LDC T - Local Distribution Co. Test	Cancelled out by LRAM					C	C	C	<Flow through, ignored>						B	C				
LRAM - Lost Revenue Adjustm't Mechan'm	B																			
TC T - Transmission Company Test			C														B	C		

Regaring Exhibit 6, and looking at the cash flows from column #1 to #20:

- The incremental CDM measure cost as defined by the California SPM is the sum of the installation, equipment and additional O&M cost paid for by the participants, or directly by the LDC or the OPA, respectively Columns #5, 6, and 9.
- The incentives as defined by the California SPM are the sum of the installation, equipment and additional O&M cost if directly paid for by the LDC or the OPA (Columns #6 and 9), and all cash or bill credit incentive whether they are paid for by the LDC or paid by the OPA through existing OPA contracted programs (Columns #7 & 10).
- The program administration cost as defined by the California SPM is the sum of the program administration expenses that will have to be absorbed by the LDC as operation cost (perhaps funded through rates), the program administration expenses that will get reimbursed by the OPA with the LDC's Program Administration Budget (i.e. PAB money), and the actual OPA operation expenses once allocated to the local DSM initiative; respectively Columns #8, 11 and 12.
- The CDM Challenger uses the actual rates to compute bill savings or lost revenues. The users can pick any one of all of Toronto Hydro's rate classes. The modeling team has singled out all volumetric items of the rate structures (i.e. ¢/kWh or $/kW) for all rate classes, and aggregated all the items sorted in the four following categories: distribution, transmission, generation, and regulatory fees & debt retirement – respectively Columns #1, 3, 4 and 2. The last category includes the Global Adjustment Mechanism. The Generation category (Columns #4) requires the annual kWh savings (or increases) to be disaggregated using the time of use brackets: Summer On Peak, Mid Peak and Off Peak; and Winter On Peak, Mid Peak and Off Peak
- Deferred or avoided additional revenue requirements as a result of local DSM pushing back or entirely offsetting distribution or transmission capital project(s) – respectively Column #13 and 14 – are CDM benefits that can be established using the project finance model built in the CDM Challenger or using OPA's provincial averages. If using the built in project finance model, then the users can pick between unitary deferral ($/kW for one year of deferral), full project deferral (for 1, 2, 3 up to 10 years), or full project avoidance. The LDC's CDM staff will have to decide on an approach and scenarios with the capacity planning staff.
- Delayed or foregone earnings due to local DSM pushing back or entirely offsetting distribution or transmission capital project(s) – respectively Column #15 and #17 – are established using the project finance model built in the CDM Challenger. The same applies to deferred or avoided equity capital contributions for distribution or transmission capital project(s) – respectively Column #16 and #18. Consequently, wherever the modellers were to decide to use the provincial averages for distribution avoided cost, the LDCT would then become void. Likewise, if the modellers decided to use the provincial averages for transmission avoided cost, the TCT would then become void.
- The avoided cost of generation capacity and energy – respectively Column #19 and 20 – can only be established using OPA's provincial averages. Computing the avoided cost of energy supplies requires the annual kWh savings (or increases) to be disaggregated using the time of use brackets.

5.5.1. Interpretation of the Cost Effectiveness Tests

Cost effectiveness tests were introduced in Section 1.1. Each test represents a specific definition of the cost and benefit cash flows being considered, as laid out in detail in Section 4.5. The purpose of this section is to help reader deepen their understanding of the tests and how to interpret them Exhibit 7.

Exhibit 7 Interpretation of the Proposed Cost Effectiveness Tests

Test	Summary Approach
TRC – Total Resource Cost test	Comparison of program administration and customer costs to resource savings. This test tells you if local DSM is the right thing to do for the "greater good". Cash incentive or bill credits are invisible in this test, because they are simply a change in who pays, not how much is paid. Key Question Answered: Will the total costs of electricity in Ontario decrease in the long term?
PAC – Program Administrator Cost test	Comparison of local DSM program Administrator costs to supply side resource costs. This includes any incentives or costs that the program Administrator pays, and that goes behind the meter. A CDM program Administrator should seek to design and deliver a portfolio that maximizes impact in the short, medium and long term while minimizing cost (i.e. incentive + program administration costs), while still achieving other policy goals (e.g. low income programs, etc.). The PAC measures how effective the program Administrator was at optimizing its portfolio. The program Administrator cost test used to be known as the Utility Cost Test or UCT. Key Question Answered: How much will the Ontario Power System pay for load curtailment?
PCT – Participant Cost Test	Comparison of costs and benefits to the ratepayers that decide to partake in the local DSM program – i.e. the participant. This test tells you if participating in the program is genuinely a good thing to do for the participants, and by how much. The modellers should use the PCT to appreciate how much the incentive is improving the business case of CDM from the perspective of participants; an ideal (yet rare) situation being when the CDM incentive makes projects economically feasible which otherwise would not. In DR, often projects do not yield any bill savings from energy conservation or from shaving the facility's monthly peak demand, and thereby a constant stream of incentive might be needed to get ratepayers to sign in, and then participants to stay in the program. Key Question Answered: Will the local DR participating ratepayers benefit over the duration of their participation in the DR program?

Test	Summary Approach
RIM – Rate Impact Measure Test	Comparison of administration costs and lost revenue to supply side resource costs. If the RIM test is "passed" then the rates will decrease as a result of the program/measure in the short term. This is a critical test for anyone interested in minimizing rate increases in the near term. The ratepayer impact measure test is often referred to as the non participant test, because the ratepayer is on average not participating in any given program. The RIM results are often negative; which does not necessarily preclude a CDM program from being taken to market as long as the TRC and the PAC are positive. Computing the RIM regardless only show that the short term rate increases are not undue. However, in local DSM, in areas of high constraint, we expect the RIM to be positive. Key Question Answered: How will utility rates be affected in the short term as a result of the local DR program, in comparison to other infrastructure upgrades?
The RIM test is more comprehensive than the PAC because it includes lost revenues. It has been decided to disaggregate the RIM in four different tests: one for the distributor, one for the transmitter, one for the generators, and one last test to capture all costs that are incurred neither by the distributor, transmitter nor the generators. These tests are respectively the RIMd, RIMt, RIMg, and RIMpc. Arithmetically, the disaggregated RIM test offshoots were constructed so that the sum of their net present value would result in the net present value under the RIM test.	
RIMd – Net Benefit for the Distributor	The RIMd shows the present worth of deferral of avoidance of distribution capacity cost against all costs (incentive and program administration) that will be incurred by the LDC, and not reimbursed by the OPA. The RIMd also factor in the distribution component of the lost revenues as a cost. If the regulator was to authorize the program cost to be funded by LDC's customers through local rates, then the RIMd would actually represent the impact on non participant's rate. If not, then the RIMd just shows how bad of a financial idea delivering the local DSM portfolio would be.
RIMt – Net Benefit for the Transmitter	The RIMt is the present worth of deferral of avoidance of transmission capacity cost avoided cost of transmission capacity due to local DSM, minus the lost revenues that would otherwise be paid to the transmitter. The transmitter incurs no direct incentive or program administration costs (as part of its transmission business).
RIMg – Net Benefit for the Generator	The RIMg is the present worth of avoided cost of generation capacity and avoided cost of energy supply due to Local DSM, minus the lost revenues that would otherwise be paid to the generators. The generators incur no direct incentive or program administration costs.

Test	Summary Approach
RIM pc – Provincial Administration Cost	The RIM pc is the present worth of OPA's and OPA contracted program costs, as well as the lost revenues otherwise allocated to fund regulatory mechanisms, debt retirement and GAM. These are required to balance the following equation: NPV_RIM = RIM d + RIM t + RIM g + RIM pc
LDCT – Local Distribution Company Test	The LDCT is a comparison between the present worth of shareholders' equity capital contributions being deferred/avoided and earnings being delayed/foregone as a result of local DSM and that would otherwise be triggered by capital distribution projects to serve areas of high constraint. The LDCT also factors in cash incentive, bill credits, direct incentive and/or program administration cost directly incurred by the LDC, if any. The LDCT does not include lost distribution revenues because it assumes that these will be repaid through the Lost Revenue Adjustment Mechanism (LRAM). The LDCT does not include OPA contracted program incentive, direct r install or program administration costs because they will be repaid by the OPA. The choice of the discount rate is critical for the LDCT as discussed in 4.3.1. Key Question Answered: Is local DSM optimising the shareholders' investment plan considering the availability of equity and what they want to do with it to maximize return?
TCT – Transmission Company Test	The TCT is a comparison between the present worth of shareholders' equity capital contributions being deferred/avoided and earnings being delayed/foregone as a result of local DSM and that would otherwise be triggered by capital transmission projects to serve areas of high constraint. The TCT does not factor any program cost because none would actually be directly incurred by the transmitter. The TCT includes lost transmission revenues because there is not a LRAM for transmission. The choice of the discount rate is critical for the TCT as discussed in 4.3.1. Key Question Answered: Similar to that of the LDCT, but from the perspective of the transmitter's shareholders.

6. Main Characteristics and Architecture of the CDM Challenger

The purpose of this section is to guide users through the CDM Challenger model.

6.1. High level Description of the Model

The CDM Challenger is built around a set of worksheets that appear in the workbook as TP01, TP02, to TP40; each one of which represents a typical participant in the local DR portfolio. A TP sheet computes all cost effectiveness tests for one typical participant; the lowest level of aggregation of the results.

Each typical participant is defined as, pertaining to one program/offering, pertaining to one rate class, pertaining to one distribution location, and pertaining to one transmission location, inclusively. "Location" refers to an area of constraint which is in need of capital improvement upstream on the distribution and/or on the transmission system. There can be more than one TP sheet per program, more than one TP sheet per rate class, and more than one TP sheet per location. There are 40 TP sheets; each one is a placeholder for one typical participant.

One single CDM challenger workbook can therefore handle multiple permutations of programs, rate classes, and locations as defined by users, and then aggregate and breakdown results accordingly. The model can handle both prescriptive and custom CDM measures, although the model is exclusively forward looking.

The TP sheets draw key data about the benefits and value of local DSM from the following sheets:

- The Provincial sheet: The Provincial sheet contains the OPA's provincial average avoided cost assumption for energy supply, generation capacity, transmission capacity and distribution capacity. It currently stores 2007 information from Appendix A of the OPA CDM Cost Effectiveness Guide[17]. This data is expected to be updated by the OPA in the short term.
- The rate class sheets, namely RES, MULTIRES, GS<50, GS<1000, GS<5000, LARGE, UNMETERED and STLIGHT[18]: Rate class sheets contain data about the volumetric portion of the rate ($/MWh & $/kW month), broken down by energy supply, transmission, distribution, and regulatory fees & debt retirement.
- The DI and TI sheets: Respectively the distribution investment sheets and the transmission investment sheets.
- The Deferral sheet: The Deferral sheet contains the present worth of the deferral or the

[17] Ontario Power Authority, OPA Conservation and Demand Management Cost Effectiveness Guide, October 15 2010, Canada [ONLINE] Asseen on November 4, 2013, URL: http://www.powerauthority.on.ca/sites/default/files/OPA%20CDM%20Cost%20Effectiveness%20Test%20Guide%20-%20101015%20F.pdf

[18] Corresponding to the following rate classes, respectively: Residential, Multi Unit Residential, General Service < 50 kW, General Service 50 - 999 kW, General Service 1,000 - 4,999 kW, Large Use, Unmetered Scattered Loads, and Street Lighting.

DI and TI sheets represent a critical component of the CDM Challenger. Each one DI or TI sheet models the finance of one capital distribution or one transmission improvement project that supplies a location of high constraint. The approach to capital improvement project modelling was laid out in section 3. There are six DI sheets and six TI sheet; each one is a placeholder for one capital improvement project.

The Projection sheet is where the aggregation of the data and results contained in the TP sheets happens; and this is also where the main output of the CDM Challenger, the program level cost r effectiveness test results, is displayed. This is the worksheet where users have to input forecast uptake in the program portfolio – that is: number of new ratepayers signing in the DR or conservation program.

The modeling period is bound by a 5 years program operation window, and participants can persist in the program up to 20 years, which makes the modeling window span inclusively from Year 00 (now), through Year 01 to Year 05 (the program operation window), all the way to Year 24 (Year 05 + 20 1).

From the Projections sheet, users can obtain rest results for different slices of the local DSM portfolio by excluding and including typical participant. For example, users could single out the following:

- One program across all rate classes and locations,
- One rate class across all programs and locations,
- One transmission location or one distribution location across all programs and rate classes, or even
- One typical participant.

The Projection sheet also draws information from the Budget sheet. The Budget sheet is where users can input information about fixed program administration costs. Users can input both fixed program administration expenses that will paid for by the OPA (PAB money), and fixed program administration expenses that will not. Users can directly allocate the fixed cost to specific typical participant, or not. The Budget sheet gathers incentive and program administration cost information from all TP sheets to compute the Grand Total for the local DSM program portfolio contained in one CDM Challenger workbook.

The Deferral sheet is the worksheet were users get to decide whether the local DSM portfolio will achieve the deferral (or even avoidance) of distribution or transmission capital improvement upstream of locations of high constraint, and by how much. In order to support decisions, the Deferral sheet draws information from the Projections sheet and the TP sheets to aggregate the kW and kVA curtailment capacity for every year from Year 01 to Year 24, and broken down by location (up to six distribution locations and up to six transmission locations). Users can then choose the preferred valuation option. There are three valuation options offered in the Deferral Sheet.

- Full Project Deferral
- Full Project Avoidance
- Unitary Deferral

The valuation options above were explained in Section 3.1.

The Deferral Sheet also presents the total program impact outputs from Year 01 to Year 24 such as total participant, total kW and kVA curtailment, and total kWh savings broken down per Time of Use bracket. The Deferral Sheet shows aggregated results behind the meter, and then results that include distribution losses, and then that include distribution & transmission losses.

6.2. Before You Get Started

Before they get started, new users will need to gather the following information.

- For each individual incoming distribution and transmission capital improvement projects due to capacity constraint:
  - Investment start year – when investment starts
  - Investment end year – when overhauled/modified station is planned to come online
  - Investment for each year – the data will need to be inputted in real $.
  - First guess power factor of the curtailment
  - Capacity used for levelizing (MVA). Either:
    - Incremental capacity sought by the LDC (if available)
    - Current spare capacity (if the incremental capacity is not available)
  - Load forecasting or trend at the substation to inform the decision whether it is possible to defer the project, and by how much.
  - Financial Information for the capital improvement project such as:
    - Debt/equity ratio, for each investment year
    - Debt rate, debt term
    - Interest rate for the bridge financing (before project completion)
    - Book life
    - Regulated after tax nominal return on equity (ROE) – for every investment year
    - Rate for the payment in lieu of tax (PILs)
    - Incremental O&M cost, if any.
    - Capital Cost Allowance rate (CCA rate) – for every investment year
    - Weighted percentage applicable on year 1, to model the 50% rule – for every investment year
    - Depreciation rate
  - Decision criteria, agreed with capacity planning staff, on how much on peak curtailment is needed for every given year to defer the incoming investment – perhaps including a safety factor.

- Discount rates
  - From the perspective of the LDC's shareholders, to be used in the LDCT. We suggest for the rate to be close to the regulated ROE.
  - From the perspective of the transmitter's shareholders, to be used in the TCT. Similarly, we suggest for the rate to be close to the regulated ROE.

- For the TRC, the PAC, the PCT, and the RIM, we suggest using the OPA prescribed nominal discount rate of 6.08%. (Real discount rate: 4%. Inflation: 2%.)

x For each typical participant in a local DSM program (conservation or DR)
  - Rate class
  - Distribution location (or local distribution capital improvement project)
  - Transmission location (or local transmission capital improvement project)
  - Average coincident peak curtailment in kW
  - Power factor for the above
  - On peak demand savings seen on participants' bill (in kW/month)
  - Incremental redistribution of energy use for each TOU bracket, that is: winter on peak/mid peak/off peak, summer on peak/mid peak/off peak, and then shoulder mid peak/off peak.
  - Persistence in the CDM program in years – average duration of the participation in the DR program or, alternatively, the effective conservation measure life.
  - Installation, equipment and incremental O&M cost
    - Portion paid for by the participant
    - Portion paid for by the OPA as part of an OPA contracted province wide program
    - Portion paid by the LDC in a stand alone local DSM program or portion paid by the LDC over and above what was already made available by the OPA.
  - Variable administration cost ($ per typical participant, initial, and then on going)
    - Portion paid for by the OPA as part of an OPA contracted province wide program.
    - Portion paid by the LDC in a stand alone local DSM program or portion paid by the LDC over and above what was already made available by the OPA.
  - As applicable, fixed administration cost, directly allocated to one or a subset of typical participants.
  - Level of OPA contracted initial cash incentive, and on going cash incentive, if any.
  - Transmission system losses for this typical participant
  - Distribution system losses for this typical participant

x For each local DSM program in the portfolio:
  - Annual uptake (# of ratepayers signing in, for each typical participant)
  - Fixed program administration cost that cannot directly be allocated to any TP or subset of TPs – the model will thereby allocate it using curtailment (kW) as the driver.

x Information related with the cost of energy:
  - Future rate updates – the models are pre loaded with rates as per December 2013 and assumptions about their evolution in nominal $ (i.e. an escalation rate). If there were any updates later on to the rates and prediction, that will need to be uploaded.

- Future province-wide assumptions related with avoided cost of transmission and generation capacity and energy – the models will be pre-loaded with the 2007 OPA assumptions. We know the 2013 assumptions are coming soon.

6.3. Getting Started

The purpose of this section is to help Toronto Hydro first time users to use the CDM Challenger.

To start with, all cells in the CDM Challenger workbook are color coded as shown in Exhibit 8. This should make the cells where an input is needed very obvious.

Exhibit 8 Cell Color Code in the CDM Challenger



Exhibit 9 walks a new user from the beginning to the end of a modeling exercise with the CDM Challenger.

Exhibit 9 Getting Started with the CDM Challenger – Chronological Sequence

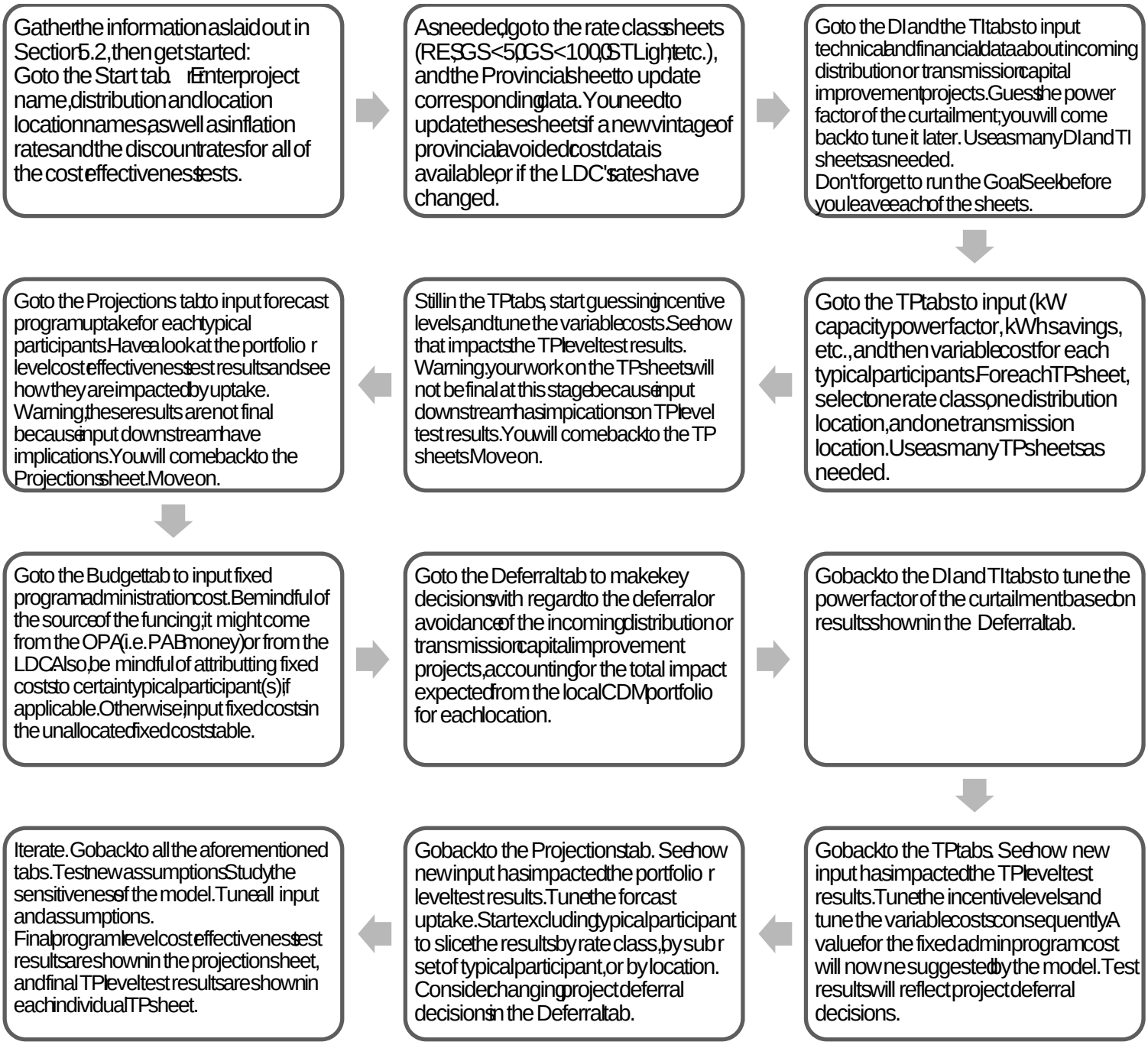
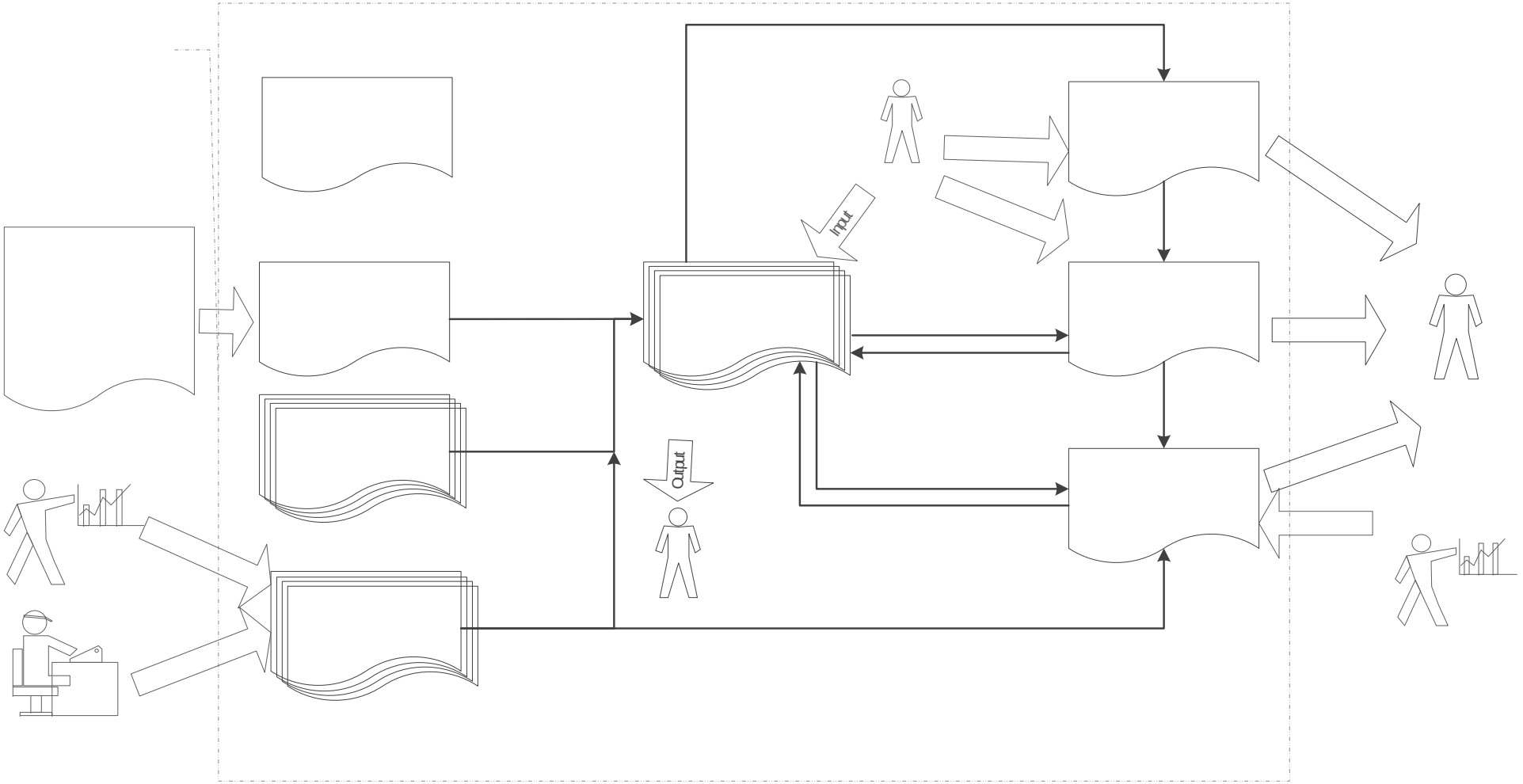


Exhibit 9 shows one possible path. There are many other paths, and the users, as they get familiar and comfortable in the model, will likely jump around freely from one tab to another.

6.4. Model Architecture Block Diagram

Exhibit 10 lays out most critical sheets in the Challenger workbook, and how they are linked together. It also gives an idea of where key data is inputted and where key output can be retrieved.

Exhibit 10 Detailed Architecture of the Model



6.5. Detailed Description of Each Worksheet

All sheets referred to in section 5.1 to 5.4 find their description in the next paragraphs. This section was drafted for the advanced users who want complete visibility.

6.5.1. Start Sheet

The Start sheet is a repository of most of reference information regarding the local DSM portfolio being modeled. It is the front page of the model.

Key inputs in the Start Sheet include:

- Project Title / Local DSM portfolio title
- Full names of the distribution and transmission locations where capital improvement projects are planned
- Current year
- Inflation rate
- Discount rate for all of the cost effectiveness test

Section 4.3 provides guidance about the choice of the discount rates and the inflation rate.

6.5.2. DI and TI Sheets

The purpose of the Distribution Investment (DI) and Transmission Investment (TI) sheets is to model the project finance of incoming distribution or transmission capital improvement projects to relief areas of high constraints. One DI or TI sheet is needed for each project. The full names of these projects were entered in the Start sheet.

The DI and TI sheets convert technical and financial information about the projects into additional revenue requirement as result of the projects, as well as incremental shareholders' equity capital contributions, and incremental earnings. Section 3 presents a more thorough description of the finance modeling of capital projects.

Table (A) is where all parameters need to be inputted. Table (B) contains primary outputs. Table (C) and (D) contain unitary present worth of local project deferral depending on, alternatively, when the participant will sign off the DR program, or at the end of the useful conservation measure life. Table (E) contain the actual annual cash flows of interest (revenue requirement, equity capital contributions and earnings) from the investment start year all the way until the end of the project book life (up to 80 years).

Key inputs in the DI and TI Sheets include:

- Investment start year – when investment starts

- Investment end year – when overhauled/modified station is planned to come online
- Investment for each year – the data will need to be inputted in real $.
- Power factor of the curtailment
  - At first, users will enter an initial most likely guess.
  - The actual power factor of the curtailment capacity can actually be retrieved from the Deferral sheet once most of the workbook will be populated. The users should probably come back at the end of their modeling work and replace the initial guess, as suggested in Section 5.3.
- Capacity used for levelizing (MVA). Either:
  - Incremental capacity sought by the LDC (if available)
  - Current spare capacity (if the incremental capacity is not available)
- Financial Information for the capital improvement projects such as:
  - Debt/equity ratio, for each investment year
  - Debt rate, debt term
  - Interest rate for the bridge financing (before project completion)
  - Book life
  - Regulated after tax nominal return on equity (ROE) – for every investment year
  - Rate for the payment in lieu of tax (PILs)
  - Incremental O&M cost, if any.
  - Capital Cost Allowance rate (CCA rate) – for every investment year
  - Weighted percentage applicable on year 1 CCA, to model the 50% rule – for every investment year
  - Depreciation rate

DI and TI sheets have direct downstream implications on the following sheets:

- TP Sheets – Unitary value of project deferral ($/kW for 1 year of project deferral)
- Deferral sheet – The full schedule of the additional revenue requirements to fund the capital project, that of the shareholders' equity capital contributions and that of the earnings.

Tip: All DI and TI sheets can be renamed to something more meaningful to ease navigation in the workbook. We recommend keeping the new tab name under 12 digits or letters.

Developers: Each DI and TI sheet is linked with a corresponding Cashflows sheet. Usually, the Cashflows sheet will be hidden to reduce clutter in the workbook.

6.5.3. TP Sheets

The purpose of the Typical Participant (TP) sheets is to store all information on the TP, and output the participant level cost effectiveness test results, namely: TRC, PAC, PCT, RIM, RIM nd, RIM nt, RIM ng, RIM npc, LDCT and TCT. They were extensively discussed in Section 1.1, and 4.5. Each of the test results are presented in term of Benefit/Cost ratio (B/C ratios), Net Present Value (NPV), and levelized unitary cost (LUC) – $/kW. These indicators were introduced in Section 4.4.

Table (A) and (C) is where all parameters need to be inputted. Table (B) presents the participant level cost effectiveness test results. Table (D), below, shows the details of the present worth of all costs and benefits for all of the tests. These present worth of costs and benefits are pushed into the Projections sheet, were they will be aggregated to compute the portfolio level results.

Key inputs in the TP Sheets include:

- Rate class
- Distribution location (or local distribution capital improvement project)
- Transmission location (or local transmission capital improvement project)
- Average coincident peak curtailment in kW
- Power factor for the above
- On peak demand savings seen on participants' bill (in kW month) – The users should beware that:
  - The on peak demand savings is measured in kW month, not in kW year like the curtailment. For example, if on peak demand savings were to occur during three months, then the kW value would need to be multiplied accordingly.
  - The on peak demand savings might not correspond to the average coincident peak curtailment because the demand might snap back after the curtailment during the on peak period, and/or the curtailment might not be triggered every day of the month. The peak demand charge might be incurred on the day after a DR event.
- Incremental redistribution of energy use for each TOU bracket, that is: winter on peak/mid peak/off peak, summer on peak/mid peak/off peak, and then shoulder mid peak/off peak.
- Persistence in the CDM program in years – average duration of the participation in the DR program or, alternatively, the effective conservation measure life.
- Transmission system losses for this typical participant
  - The suggested average value is 2.5% as per the 2007 IPSP.
  - However, the users might decide to decide to use a higher or lower percentage depending on who the rate payer is. For example, industrial ratepayer might have a lower percentage of transmission losses.
- Distribution system losses for this typical participant (Suggested average value: 4.2% per the IPSP)
  - The suggested average value is 4.2% as per the 2007 IPSP.
  - However, the users might decide to decide to use a higher or lower percentage depending on who the rate payer is. For example, a residential ratepayer might have a higher percentage of distribution losses.
- Installation, equipment and incremental O&M cost
  - Portion paid for by the participant
  - Portion paid for by the OPA as part of an OPA contracted province wide program
  - Portion paid by the LDC in a stand alone local DSM program or portion paid by the LDC over and above what was already made available by the OPA.

- Variable administration cost[19] ($ per typical participant, initial, and then on going)
  - Portion paid for by the OPA as part of an OPA contracted province wide program.
  - Portion paid by the LDC in a stand alone local DSM program or portion paid by the LDC over and above what was already made available by the OPA.
- As applicable, fixed administration cost, directly allocated to one or a subset of typical participants.
- Level of OPA contracted initial cash incentive, and on going cash incentive, if any.

Users should read Section 4.1 to get a better understanding of the funding options, as well as the concept of variable versus fixed costs.

Users will use the TP sheet, and the preliminary participant level cost effectiveness test results to establish incentive levels. The process is described in Section 4.2.

OPA's or the LDC's fixed administration costs are to be inputted in the Budget sheet, not the TP sheet. Once the Budget sheet will be completed, users will be suggested a value for fixed administration cost in term of percentage of incentive in the TP sheet. Before then, users must guess their own percentage. The fixed administration costs percentages inputted in the TP sheet are used exclusively to compute the participant level cost effectiveness tests shown in Table (B); they are not carried into the Projections sheet and they do not influence portfolio level test results. Only fixed cost data inputted in the Budget sheet do.

Given the above, the users will probably have to populate the TP sheets in at least two passes as described in Section 5.3.

- During the first pass, they will have to guess the fixed administration cost as percentage of the incentive level. Also, at that stage, they will probably have to use unitary deferral or provincial average as the method to valuate the avoided distribution and/or transmission capacity.
- During the second pass, they will have had populated the Projections sheet, the Budget sheet and the Deferral sheet, and thereby they will have test results that are more accurate. They might have had selected the full project deferral or avoidance in the Deferral sheet. They will also use fixed administration costs as suggested by the model, based on data entered in the Budget sheet. Users will be able to tune the incentive level and variable administration cost accordingly.

In order to compute all costs and benefits, the TP sheets draw data from the following sheets:

- The Provincial sheet – Provincial average cost of energy and capacity, as applicable.
- The Rate Class sheets – Actual rates used to compute bill savings and lost revenues.

[19] Technical assistance and enabling activities such as customer education, marketing, energy audits, trainings offered to trade people or field visits for verification, auditing or measurement purposes usually all go under program administration costs; not under install, equipment & O&M costs.

- The DI and TI sheets – Unitary present worth of local distribution or transmission project deferral, as applicable
- The Deferral sheet – Present worth of local distribution or transmission project deferral or avoidance.
- The Projections sheet – Suggested fixed administration cost percentages, used exclusively in participant level cost effectiveness tests as desired by the users.

TP sheets have downstream implications on the following sheets:

- Projections sheet – Curtailment and the present worth of benefits and costs for every typical participant. The present worth of costs does not include fixed administration cost.
- Budget sheet – Incentive cost and Variable Administration cost.
- Deferral sheet – kW curtailment, non productive kVAR curtailment (to re build the kVA, and the power factor), kWh savings broken down per TOU bracket, distribution losses, and T&D losses.

Tips:

- All TP sheets can be renamed to something more meaningful. We recommend keeping the new tab name under 12 digits or letters.
- Use a TP sheet to model cash incentive or bill credit offerings that do not result in a direct impact – example: incentive to offset the cost of an energy audit.
  - Analysts will want to use this tip because it will allow them to disassemble pre investment incentive from investment incentive so that they can model pre investment that will be disbursed but that will not result in actual implementation. This tends to happen when participants abandon the program before they reach implementation, thus they never get to receive the implementation incentive and their participation never result in program impact claim.
  - If you wanted to do this, then you would have to set the average curtailment and all other participant level impact estimates to zero, and ignore the participant level test results in Table (B). These results will not have implications downstream, like in the Projections sheet; only the incentive data will. The “investment incentive(s)” would have to be inputted in another TP sheet.

6.5.4. Projections Sheet

The Projections sheet draws present worth data for benefits and costs from all TP sheets, then multiply by the number of new participants who sign in (uptake) on every given year of the program operation window (Year01 to Year05), and sum them up to build the program level cost effectiveness test results. The Projections sheet is where the program portfolio forecast uptake is inputted.

Table (A) is where portfolio uptake needs to be inputted. There are no other input cells in this sheet beyond Table (A).

Table (B) presents the portfolio level cost effectiveness test results, which are the most critical outputs of the CDM Challenger. They were extensively discussed in Section 1.1, and 4.5. Each of the test results are presented in term of Benefit/Cost ratio (B/C ratios), Net Present Value (NPV), and levelized unitary cost (LUC) – $/kW. These indicators were introduced in Section 4.4.

Table (C) shows key incremental program level impact during the program operation window such as total new participants signing in, incremental curtailment, total present worth of benefits and costs under the TRC, etc. All results presented in Table (C) are incremental values for every given year of the program operation window. For example, incremental kW curtailment projected on Year 01 has no implication on the cumulative kW curtailment for year 02 and onward. Users interested in the cumulative curtailment achieved by the local DSM portfolio at the end of the program operation window shall either look at the total column of Table (B), or, for more details, go see cumulative results in the Deferral sheet.

Table (D) draws data from the Budget sheet. The purpose of table (D) is to proceed with a few arithmetic manipulations to allocate the unallocated fixed administration cost to the subset of included participants, using behind the meter kW curtailment as a driver.

Table (A) is where the users can include or exclude each typical participant individually to single out subset of key participants. For example, users could use this feature to single out typical participants from a single rate class, or single out all typical participants for a single location. Unless specified, all results shown in Table (B) and (C) are for the "included" typical participant exclusively. This is the reason why fixed administration costs that are not directly allocated to specific typical participants must be re allocated to the subset of included participant. This explains the purpose of the arithmetic manipulations shown in table (D).

Table (F) is where the data drawn from all TP first lands in the Projections sheet Sheets (e.g. kW curtailment, present worth of costs and benefits for every test, etc.). This is also where the values for every individual typical participant are multiplied by the forecast uptake.

One key principle of the CDM Challenger engine is visible in Table (F). Only present worth values of benefits or cost are transferred to the Projections sheet to be aggregated, instead of transferring the full 20 year nominal cash flow schedule, for every given stream, and for participants signing in on Year 01 to 05. It makes the calculation clearer, and more condensed. For instance, uptake, benefits and costs shown non Year 01 have no implications on that for Year 02 and onward.

Key input in the Projections sheet includes the annual uptake (# of ratepayers signing in, for each typical participant) for the 5 year program operation window. This is also where the users can choose for what subset of typical participants they want to see results in Table (B) – That is: for which "aggregation scenario".

In order to compute all costs and benefits at the portfolio level, the Projections sheet draws data from the following sheets:

- TP Sheets – Curtailment and the present worth of benefits and costs for every typical participant. The present worth of costs does not include fixed administration cost.

- Budget sheet – Fixed administration cost; directly allocated or not.

Projections sheet has direct downstream implications on the following sheets:

- Deferral sheet – # of new participants signing in for every given year, and aggregation scenarios.
- TP Sheets – Fixed administration cost. The Projections sheet sends the fixed CDM administration cost resulting from Table (D) into the TP Sheets. It gets allocated using kW curtailment as the driver, and then it gets converted in % of incentive. It is shown in the TP sheet as a "Suggested" Fixed Administration Cost. This data does not loop back in the Projections sheet.

Tip:

- In Table (A), the users can list the typical participants in whatever sequence that suits their need.
  - By default, it is going to be sorted out using the original placeholder sequence (TP01, 02, 03, etc).
  - Users can later change the sequence shown in Table (A) by selecting the name of the typical participant in the drop down lists for every given row of the table.
  - Users should however beware: typical participants that will not be listed in Table (A) will be completely ignored by the model. This makes sense: if the uptake figures were not listed in Table (A), then they are deemed to be zero, and a typical participant with no uptake should logically have no implication on the total impact.

6.5.5. Budget sheet

The Budget sheet is where the users must enter the fixed administration costs for the program portfolio. Besides, the Budget sheet draws incentive and variable administration cost information from all TP sheets, sum all of these up to build Grand Totals and other useful tables.

Input cells in the Budget sheet can be found in Table (B) and Table (C). Beware that certain input cells, those in Table (C), are not shown at first glance on a 17 inch screen. Users will have to scroll down.

Table (A) is a useful output of the Budget sheet. It shows the Grand Total for the Local DSM portfolio, for every year from Year00 (i.e. current, planning year) to Year24 (for a participant signing in the program on Year05, and staying in the program for 20 years inclusively).

Table (A) presents the budget using the following breakdown structure:

- Fixed administration, variable administration and incentive cost. – This is a standard breakdown structure in the CDM field.
- LDC cost vs OPA cost – Illustrative of the funding structure. The former would show costs of stand alone local DSM programs and a portion of the cost pertaining to the hybrid funding programs, if applicable. The latter would show costs attributed to the OPA contracted province wide local DSM program and a portion of the cost pertaining to hybrid funding programs. See Section 4.1.

Aggregation scenarios as defined in the Projections sheet do not have implications on Table (A). Table (A) will always show the grand total for all typical participants with some uptake.

Table (B) is where users must input all fixed costs that are not directly allocated to specific typical participants. Inputs must be sorted whether they are cost that are incurred by the LDC without expected reimbursement by the OPA (LDC cost), or if they are cost incurred as part of the OPA contracted province-wide programs (i.e. the fixed cost portion of the PAB). Further breakdown suggested under the LDC Cost and the OPA Cost categories is not mandatory. That suggested breakdown came from the OPA Conservation Program Resource Planning Tool. Other breakdown might make more sense; such as that for the Board-Approved Programs.

Table (C) is where most of the incentive and variable administration cost land from the TP sheets. Table (C) is where these numbers are multiplied by participation figures and then summed up for each typical participant.

Costs shown in Table (C) can be variable or fixed. They all share the following: they are directly allocated to each individual typical participant. For variable administration cost and the incentive cost, this concept is relatively straightforward.

Table (C) is where to input the fixed administration costs that are directly allocated to each typical participant, as applicable or as desired by the users. Users will want to do that to achieve a greater degree of accuracy of the test results when singling out sub-sets of typical participants, or to achieve a greater accuracy of rate-class cost allocation. They will want to input directly allocated fixed administration costs if and for portions of the fixed administration cost that they know would have significant impact on the results for the corresponding TP or subset of TPs, and thereby that they believe should not be split between the typical participants using the kW curtailment as the only driver. Whether direct fixed cost allocation is used or not will not have influence on the test results for the total portfolio.

Key inputs in the Budget sheet include:

- Fixed program administration costs that cannot directly be allocated to any TP or sub-set of TPs – the model will thereby allocate it using curtailment (kW) as the driver.
- Fixed program administration costs must be directly be allocated to any TP or sub-set of TPs, as applicable

The Budget sheet draws data from the following sheets:

- TP sheets – Incentive cost, variable administration cost

The Budget sheet has direct downstream implications on the following sheets:

- Projections sheet – Unallocated and directly allocated fixed administration cost. Ultimately, that same information gets passed to the TP sheets.

6.5.6. Deferral Sheet

The Deferral sheet is where users must input decision with regard to the deferral or avoidance of the local distribution or transmission capital improvement projects of interest as a result of the local DSM. The Deferral sheet shows the total cumulative curtailment forecast for every location in kW and kVA to support the decision. The Deferral sheet also presents the cumulative impact of the program for every given year from Year 01 (First year of the program operation window), all the way to Year 24 (for one participant signing in on Year 05 and persisting in the program for 20 years.). The impacts are shown in term of kW, kVAR, kVA, power factor, and kWh for each TOU bracket. Impacts are also shown straight from behind the meter, then with distribution losses, and with transmission and distribution losses.

The Deferral sheet (Table (A) and (B)) obey the inclusion/exclusion rules set in the Projections sheet, or aggregation scenario.

Table (A) is where full project deferral decisions are made, as applicable. By default, the sheet will show the "Unitary Deferral" option for all the locations. Users will be able to switch it to full project deferral of full project avoidance A discussion about these three options was provided in Section 3.1.

Once the decision is made, and if that decision is either full project deferral or full project avoidance, then Table (A) will unveil the present worth of such deferral/avoidance at the right hand side of the table. For the TRC, PAC and RIM, the present worth is that of the deferred/avoided expected revenue requirements associated with the project. For the LDCT and the TCT, the model computes the present worth of the delayed/foregone earnings, and the deferred/avoided equity capital contribution.[20]

In addition, in both cases (full project avoidance of deferral), table (A) will also unveil the following item: Allocation denominator which corresponds to kW curtailment with distribution losses (or T&D losses for the transmission projects) one year before the deferred investment schedule end year (for deferral) or one year before the end year of the planned investment schedule (for avoidance). kW curtailment is used as the driver to allocate the present worth to each typical participant, hence the need for a denominator.

At the very right hand side of the table, users will find curtailment power factor for the end year of the planned investment for each specific location. If the users were to use the "unitary deferral" option, then those users would be encouraged to feed back this power factor into the corresponding DI or TI sheet to increase the accuracy of the results.

Table (B) shows the full schedule of the total annual impacts from Year 01 to Year 24. These are cumulative impact – that is Year 02 impact cumulates impacts achieved on Year 01. The impact shall ramp up during the program operation window, Year 01 to 05, and then ramp down as participants abandon the programs or as the conservation measures go over their effective useful life.

[20] If the discount rate used is identical to the regulated ROE, then the present worth of delayed/foregone earnings will be nearly equal to the present worth of the delayed/foregone capital contributions.

Key inputs in the Deferral sheet include:

- Decisions whether distribution or transmission capital improvement project can be avoided or deferred, and if it is deferred, then by how many years.

The Deferral sheet draws data from the following sheets:

- TP sheets – Curtailment in kW, kVAR, kWh for all TOU brackets, distribution losses and T&D losses.
- Projections sheet – Uptake, and aggregation scenarios

The Deferral sheet has direct downstream implications on the following sheets:

- TP sheets – Present worth of full project deferral/avoidance, as applicable. Three items get passed: deferral/avoidance revenue requirements, delayed/foregone earnings, and deferral/avoidance equity capital investment. The present worth gets allocated using curtailment as the driver.[21] Ultimately, these values get their way back in the Projections sheet through the test benefits and costs.

6.5.7. Provincial Sheet

The provincial sheet stores the 2007 provincial avoided supply cost assumptions for demand and energy from the Appendix A of the OPA CDM Cost Effectiveness Guide. The OPA is working on updating this information.

The OPA data is stored in Table (A). Table (B) and (C) turn the cost assumptions into coefficients that represent the unitary present worth of avoided cost of energy or capacity depending on, alternatively, when the participant will sign off the DR program, or at the end of the useful conservation measure life.

The Provincial sheet has direct downstream implications on the following sheets:

- TP sheets – Present worth coefficients used to value avoidance of energy supply, generation capacity, and transmission or distribution capacity as applicable.

6.5.8. Rate Class Sheets

The Rate Class sheets – namely RES, MULTIRES, GS<50, GS<1000, GS<5000, LARGE, UNMETERED and STLIGHT[22] – store the volumetric portion of the rates ($/MWh and $/kW month). All rate components

[21] [Present worth / Curtailment denominator as per Table (A) x Average curtailment for that participant] IF that participant is online the year before the end year of the deferred investment schedule. Otherwise, that typical participant gets allocated $0.

[22] Corresponding to the following rate classes, respectively: Residential, Multi Unit Residential, General Service < 50 kW, General Service 50 – 999 kW, General Service 1,000 – 4,999 kW, Large Use, Unmetered Scattered Loads, and Street Lighting.

were consolidated to fit into Table (A) by aggregating all volumetric components together, then broking them down by segment of the supply chain: generation, transmission and distribution, as well as regulatory fees and debt retirement. The Rate Class sheets were pre loaded with Toronto Hydro rate data from December 2013. We made assumptions regarding the escalation of the rates and used these to forecast the nominal value of these rates all the way until the end of the modeling window – Year 00 to Year 24.

The rate data and escalation scenarios are stored in Table (A). Table (B) turns the rates into coefficients that represent the unitary present worth of lost revenues depending on, alternatively, when the participant will signoff the DR program, or at the end of the useful conservation measure life.

The Rate Class sheets have direct downstream implications on the following sheets:

- TP sheets – Present worth coefficients used to value bill savings and lost revenues.

7. Main Findings and Conclusions

Toronto Hydro is studying the potential and the business case for local demand response and conservation alternatives to offset capital investments. These local DSM alternatives would target customers served by transmission and/or distribution systems identified as requiring significant capital investment in the next 5 to 10 years.

There are two phases to this project and this report laid out the achievement made during Phase 1. In short, these achievements are:

- Toronto Hydro created a financial model to support this approach – the CDM Challenger.
- Toronto Hydro provided a review of DSM alternatives, as laid out in Section 2.
- Toronto Hydro documented both its methodology and the architecture model, as laid out in Section 3, 4 and 5 of this report.
- Toronto Hydro started testing options in multiple sites, and using a variety of program options – although Toronto Hydro is not ready to present its result yet.

During Phase 2, Toronto Hydro will achieve the following:

- Carry on the testing and fine tuning of the portfolio of programs it intends to roll out. It will show the result of that work in the final report, in the form of a Toronto Hydro case study.
- Design activation protocols
- Facilitate the necessary knowledge transfer – including a final report, summary of results, lessons learned, and formal presentation.

Future extensions and add ins to the CDM Challenger that might be worked on in the future, beyond the scope of the current project include:

- Adding other resource savings (such as natural gas, heating oil, water), and their respective consumer cost and avoided cost.

- Valuation of other utilities' benefit:
  - Improved economic efficiency in the provision of operating reserves
  - Improved reliability – perhaps through evaluating lost loads in case of blackouts
  - Environmental benefits – perhaps per unit CO_2
- Before meter distributed energy options such as energy storage – or utility capital investment in distributed energy (that would earn a return in exchange) that would defer other, larger capital improvement projects.
- Development of a Wizard – Some buttons and macros that would help first time users to skip from one sheet to another in chronological order, along with a commentary.
  - Perhaps including: building in extensive documentation and directions directly into the workbook. Similar to that of RETScreen.

E7.11 Energy Storage Systems

LITHIUM ION BATTERY ES INSTALLATION

E7.11.1 Summary

Program Description

The Energy Storage Systems (ESS) program was developed to provide Toronto Hydro with strategic ancillary capabilities to address system efficiency, reliability and power quality, as well as Distributed Generation (DG) and Electric Vehicle (EV) enablement in targeted areas of the Toronto Hydro distribution system. Energy storage refers to the process of storing electrical energy for future use. An ESS can be constructed using various technologies and can be classified as either a centralized or decentralized system. By placing ancillary ESS strategically throughout the distribution system, localized issues can be addressed. This approach allows for a minor augmentation of the distribution system, rather than an expensive rebuild or major asset replacement. In this way, ESS deployments can be a creative and prudent approach to system risk mitigation.

Toronto Hydro plans to install 24 energy storage systems during the 2015-2019 forecast period. This represents a total installed aggregate capacity of approximately 4.4 MW with a total energy output of 10,000 kWh

Table A summarizes the anticipated benefits associated with the ESS program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Provides backup power during emergency situations for critical customers (e.g. emergency services, hospitals, government buildings etc.).
Reliability	ƒ Facilitates increased reliability and power quality. ƒ Provides the system with dynamic voltage support, low harmonics and uninterrupted service. ƒ Reduces demand fluctuations with peak shaving during peak demand periods and load leveling during off peak periods.
Safety	ƒ Improves asset utilization, which extends the service life of distribution assets (e.g. transformers, conductors etc.), ensuring that equipment operates within nominal system parameters and helps to prevent catastrophic equipment failures.
Efficiency	ƒ Station based ESS provide backup power for ancillary station services in case of an interruption or an emergency situation, enabling remote monitoring and control is maintained (e.g. station service for protection systems, communication system, station lighting etc.)

Program Drivers

The trigger and secondary drivers for this program are summarized in Table B.

TABLE B: PROGRAM DRIVER

Trigger Driver	Reasoning
System Efficiency	ƒ Enhances system performance by storing electricity at off-peak times, and releasing it into the distribution system during peak times. These capabilities are expected to help Toronto Hydro manage the increasing variability of distribution system load. ƒ Capacity in certain areas of the system is strained due to load growth. ESS can help defer the need for large scale asset replacements that would otherwise be required to maintain sufficient capacity to meet demand through peak load reduction. ƒ ESS can increase the utilization and lifespan of existing distribution assets through peak load reduction. ƒ Assists in reducing the overall impact of routine maintenance programs carried out at MS. ƒ Helps dynamically correct phase imbalances. ƒ Enablement of DG & EVs.
Secondary Drivers	**Reasoning**
Reliability	ƒ Increases the resiliency of the distribution system by providing reliable power for essential services over an extended period of time during emergency situations.
Power Quality	ƒ Delivers consistent service voltage, low harmonics and uninterrupted service.

	ƒ Provides dynamic voltage regulation/reactive power support.

Preferred Alternative

Toronto Hydro evaluated this program against the alternative of excluding ESS from the suite of possible technological distribution system solutions for the 2015-2019 period. Executing the ESS program as described is the preferred alternative as it would provide Toronto Hydro with strategic capabilities to address specific issues relating to system efficiency, reliability and power quality, and DG and EV enablement in targeted areas of the Toronto Hydro distribution system in a cost-effective manner.

The difference in the cost of ownership between existing and renewed assets ("COO) for the first year of the program is $1.1 million, representing a reduction in negative impacts to customers (in this case represented by a $/kW benefit cost) over the life of the assets (see Section E7.11.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $0.58 million, confirming the economic prudence of the investments (see Section E7.11.7).

Timing and Pacing

Based on experience gained through current and past ES implementations, the ESS program will proceed at a gradual and methodical pace. In 2015, technology selection, detailed engineering and design work and site selection are planned for all ESS, followed by the installation and commissioning of one Local Support Energy Storage (LSES) and one Grid Support Energy Storage (GSES) unit. For 2016, Toronto Hydro plans to install and commission two LES and GSES units and one Municipal Substation Energy Storage (MSES) unit. From 2017 to 2019, Toronto Hydro plans to install and commission three LSES units per year, two GSES units per year, and one MSES unit per year.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	-	-	-	-	1.02	0.54	1.10	2.20	3.20	3.80

E7.11.2 Program Description

The Energy Storage Systems (ESS) program provides Toronto Hydro with the capabilities needed to address specific issues relating to system efficiency, reliability and power quality, and distributed generation (DG) and electric vehicle (EV) enablement in targeted areas of the distribution system. The program is expected to achieve the benefits listed Table 1 by installing 24 ES systems from 2015 through to 2019. This represents a total installed aggregate capacity of 4.4 MW with a total energy output of 10,000 kWh. The objective of the program is to enable Toronto Hydro to address specific issues and limitations within the distribution system with a prudent alternative to existing solutions and methods.

TABLE 1: APPLICATIONS AND BENEFITS OF ESS

Application	Benefit
Peak shaving/Load Levelling	ESS supply energy during peak hours ('peak shaving') and store excess energy during low demand hours ('load levelling') improving asset utilization and efficiency, deferring the need for large scale asset upgrades (e.g. power transformers, stations switch gear, etc.).
Reliability & Power Quality Improvements	ESS can improve the overall power quality for customers by counteracting variations in voltage and harmonics, and the effects of switching.
DG & EV Enablement	ESS can enable the connection DG & EV to the Toronto Hydro distribution system by addressing local system constraints.
Phase Balancing	ESS can help rebalance feeders that exceed the threshold for single phase imbalances, decreasing the return current on the neutral conductor.
Critical Load Emergency Service	As a last resort during an emergency, ESS can provide backup power for critical loads (e.g. emergency services, hospitals, government buildings etc.).
Temporary Station Maintenance Load Displacement	ESS can help with maintenance that is carried out at the station level by acting as a temporary supply for downstream customers during work execution, negating the need for a scheduled outage.
Station Ancillary Services	ESS can provide power for ancillary services (protection system, communication system, station lighting, etc.) ensuring remote monitoring and control capabilities are maintained during emergency situations.

ESS can be constructed from various technologies, which can be deployed at strategic locations in Toronto Hydro's distribution system. These technologies include:

- lithium-ion,

- sodium-sulphur, and
- compressed air (under water).

Lithium-ion and sodium-sulphur are types of electrochemical battery cell technology that consist of an electrolyte chemical separating two electrodes. Lithium-ion batteries are useful for large centralized and small de-centralized applications mainly because of their high energy density and efficiency, lower self-discharge rate (i.e. the rate at which the batteries lose their charge capacity) and low maintenance requirements.[1] Comparatively, while sodium-sulphur batteries are highly energy efficient and are made from inexpensive/non-toxic materials, their high operating temperatures and highly corrosive nature limits their use to centralized settings[2]. Underwater Compressed Air Energy Storage systems (UCAES) use off-peak power to compress air underwater and during peak hours the compressed air is released to power a turbine/generator system for power production. UCAES systems are only feasible if deployed in Municipal Substations (MS) located near Lake Ontario.

ESS can be divided into two categories, which make up the proposed investments as part of this program:

- Centralized ESS, and
- De-centralized ESS.

Sections E7.11.2.1 and E7.11.2.2 provide further information with respect to the different ESS categories. Toronto Hydro forecasts that the ESS categories described in detail below will cost an estimated $10.8 million over the 2015 to 2019 period.

E7.11.2.1 Centralized ESS

Centralized ESS can utilize lithium ion or sodium sulphur battery cell technology or UWCAES (when located near Lake Ontario). Toronto Hydro intends to use centralized ESS by deploying them within municipal stations. As described in Section E7.11.4.1, the locations will be determined by the severity of the specific issue(s) present, and by assessing whether these issues can be prudently addressed with an ESS (e.g. peak demand shaving, reliability and power quality issues, DG & EV connections, etc.). Table 2 provides an overview of centralized ESS.

[1] L. Hadjipaschalis, A. Poullikkas, and V. Efthimiou, Overview of current and future energy storage technologies for electric power applications, (2009) 13 ScienceDirect at page 10. ["ScienceDirect"]
[2] ScienceDirect.

TABLE 2: CENTRALIZED ESS

Energy Storage System Type (Typical Size & Duration)	Energy Storage Technology
Municipal Substation Energy Storage (MSES) (400 kW & 3 hrs)	ƒ Lithium Ion ƒ Sodium Sulphur ƒ Under Water Compressed Air

Figures 1 to 2 provide examples of centralized ESS installations. Figure 1 shows the typical configuration of a Lithium Ion Battery ESS Installation. The entire solution is contained within large truck trailers. Similarly, Figure 2 shows the typical configuration of a Sodium Sulphur Battery ESS installation. Rather than truck trailers, the solution is contained within cabinets. A potential location for an MSES system within Toronto Hydro's distribution system is shown in Table 3 and Figure 3.

FIGURE 1: EXAMPLE OF LITHIUM ION BATTERY ES INSTALLATION [3]

[3] Martin LaMonica, "Giant batteries steady grid in New York", CNET (11 January 2011) online: CNET <http://news.cnet.com/8301-11128_3-20028148-54.htm>.

FIGURE 2: EXAMPLE OF SODIUM SULPHUR BATTERY ES INSTALLATION [4]

TABLE 3: MSES EXAMPLE LOCATION

Location Details	Location Name	Address	Feeder (Connection Voltage)
Intersection: Huntingwood Drive and Birchmount Rd.	Huntingwood Birchmount MS	754 Huntingwood Dr.	502-M29 (27.6 kV)

[4] NGK Insulators Inc., NAS Batteries, online: NGK Insulators Inc. <http://www.ngk.co.jp/english/products/power/nas/index.html>. [6] eCamion, Community Energy Storage (CES) Overview, online: eCamion <http://www.ecamion.com/portfolio/ces/>.

FIGURE 3: MSES EXAMPLE LOCATION

Table 4 below outlines the total units of equipment to be installed as part of this portion of the ESS program.

TABLE 4: TOTAL MSES INSTALLATIONS (2015 – 2019)

Assets	2015	2016	2017	2018	2019	Total (Units)
Municipal Substation Energy Storage (MSES)	0	1	1	1	1	4

E7.11.2.2 De-centralized ESS

Unlike centralized ESS, de-centralized ESS only utilizes lithium ion battery cell technology. De-centralized ES systems are deployed at various strategic locations within the distribution system. As described in Section E7.11.4.1. – Ranking and Prioritization, the locations are determined by the severity of the specific issue(s) present, which can be addressed with an ESS (e.g. reliability & power quality issues, phase imbalance, DG & EV connections etc.). As a result of different needs, de-centralized systems can be further subdivided into two categories:

- Grid Support ES (GSES) systems, and
- Local Support ES (LSES) systems.

GSES systems are placed at strategically determined points along the primary portion of a feeder (e.g. the beginning, mid-point or end of a feeder) and LSES systems are positioned on single phase laterals. Table 5 provides an overview of de-centralized ESS.

TABLE 5: DE-CENTRALIZED ESS OVERVIEW

Energy Storage System Type (Typical Size & Duration)	Energy Storage Technology
Grid Support Energy Storage (GSES) (200 kW & 2.5 hrs)	Lithium Ion
Local Support Energy Storage (LSES) (100 kW & 1 hr)	Lithium Ion

Figures 4 and 5 provide examples of de-centralized ESS installations. The ESS in both figures have a smaller size and foot print than centralized systems and are housed in pad-mount enclosures (similar to pad-mount transformers and switches). In Section E7.11.7 – 2015 Projects, two proposed project locations have been determined for an LSES and GSES installation within the Toronto Hydro distribution system.

FIGURE 4: EXAMPLE OF GRID SUPPORT ENERGY STORAGE INSTALLATION [6]

[6] eCamion, Community Energy Storage (CES) Overview, online: eCamion <http://www.ecamion.com/portfolio/ces/>.

FIGURE 5: EXAMPLE OF LOCAL ENERGY STORAGE INSTALLATION [7]

Table 6 below outlines the total units of equipment to be installed as part of this portion of the ESS program.

TABLE 6: TOTAL GSES & LSES INSTALLATIONS (2015 – 2019)

Assets	2015	2016	2017	2018	2019	Total (Units)
Grid Support Energy Storage (GSES)	1	1	2	2	2	8
Local Support Energy Storage (LSES)	1	2	3	3	3	12

The assets that make up an entire ESS are expected to last approximately 10-20 years. While each type of system requires maintenance, including inspections of the ESS itself and associated ancillary equipment (such as backup power supply for remote communication equipment etc.), maintenance programs would be tailored to each particular ESS.

It is anticipated that the ESS program will provide Toronto Hydro with additional capabilities to address system efficiency, reliability and power quality, and DG and EV enablement challenges. The program is inherently customer-driven as the proposed work would assist Toronto Hydro to improve the operating conditions of the distribution system in a targeted, strategic and prudent

[7] S&C Electric Ltd., Energy Storage Systems, online: S&C Electric Ltd. <http://www.sandc.com/products/energy-storage/ces.asp>.

manner, which would benefit the utility's customers now and in the future by helping deliver greater value for money from the existing system in light of evolving grid utilization and general economic growth and development.

The planned investments are expected to provide load relief for particularly constrained areas in the distribution system. Consistently operating close to the peak can lead to the accelerated deterioration of distribution system infrastructure. By having the ability to offset demand closer to the load, ES systems can help shave peak during high demand times, and level load during off peak hours. This can result in less strain on existing distribution system infrastructure, such as large power transformers, primary conductors, and distribution transformers. Figure 6 illustrates the concepts of peak shaving and load levelling.

FIGURE 6 PEAK SHAVING AND LOAD LEVELLING [8]

Toronto Hydro also plans to use ESS to improve the utilization of existing assets. For example, a large power transformer is selected to accommodate future load growth over a 15-20 year planning horizon. A large portion of the investment made into this asset is underutilized for most of the new equipment's life. The upgrade of this asset can be deferred by using an ES system to offload it during peak periods, extending its service life.

Reliability is expected to be positively affected by the addition of ESS. Recent adverse weather events have demonstrated the distribution system's vulnerability to large scale disruptions, which

[8] NGK Insulators Inc., NAS Batteries, online: NGK Insulators Inc. <http://www.ngk.co.jp/english/products/power/nas/index.html>.

can result in outages to critical infrastructure that may need to be relied on during emergency situations. These include interruptions to supply, and damage to the primary and lateral sections of a feeder. At this time, Toronto Hydro does not have the ability to quickly restore service to critical loads when there is a major outage event (e.g. major failure, loss of supply etc.). With appropriate switching and isolation, ESS can provide temporary backup power to critical infrastructure, ensuring continual service for critical loads while repairs take place. Some examples of critical loads include emergency services, hospitals, government buildings and financial institutions. ESS located at MS would facilitate routine maintenance activities. The ESS would be able to temporarily support the load from equipment taken out of service for maintenance purposes. More specifically, it would prevent a temporary outage and support the load with other feeders decreasing the temporary burden experienced by alternate feeds.

The projected levels of DG connections from 2015 through to 2019 are expected to increase by 450 MW, to 626 MW of connected DG. In addition, the Government of Ontario's aspiration is for one in 20 vehicles in the province to be an electric vehicle by 2020.[9] These developments would impact Toronto Hydro's distribution system by introducing additional dynamic two-way generation and mobile loads and this impact is expected to increase as the penetration of DG and EV increases. Toronto Hydro is already attempting to address system-wide issues to enable the connection of DG, as outlined in the Generation Planning Monitoring & Control program; however specific locations in the distribution system are expected to have additional technical issues that may prevent the connection of DG and EVs. ESS can help to alleviate these localised issues and enable the connection of DG and EVs. This is illustrated by the proposed projects in Section E7.11.7 – 2015 Projects. Table 7 provides an overview of the anticipated benefits associated with the ESS program.

TABLE 7: PROGRAM BENEFITS

Customer Value	ƒ Enables the integration of customer-owned DG and EVs ƒ Provides backup power during emergency situations for critical customers (e.g. emergency services, hospitals, government buildings etc.). x The difference in the cost of ownership between existing and renewed assets (ûCOO) for the first year of the program is $1.1 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E7.11.7). x Accounting for capital program costs, the first year's activities deliver a positive NPV of $0.58 million, confirming the economic prudence of the investments (see Section E7.11.7).

[9] Pollution Probe, Unlocking the Electric Mobility Potential of Toronto: Moving Toward an Electric Mobility Master Plan for the City (Toronto: Pollution Probe, 2010), at page 67, online: Pollution Probe < http://www.pollutionprobe.org/pdfs/EMMP.pdf>.

Reliability	ƒ Provides increased reliability and power quality. ƒ Provides the system with dynamic voltage support, low harmonics and uninterrupted service. ƒ Reduces demand fluctuations with peak shaving during peak demand periods and load levelling during off peak periods.
Safety	ƒ Improves asset utilization, which extends the service life of distribution assets (e.g. transformers, conductors etc.), ensuring that equipment operates within nominal system parameters and helps to prevent catastrophic equipment failures.
Efficiency	ƒ Station based ESS provide backup power for ancillary station services in case of an interruption or an emergency situation, enabling remote monitoring and control is maintained (e.g. station service for protection systems, communication system, station lighting etc.). ƒ Enables station maintenance for station assets (e.g. power transformer, switch gear, etc.) by providing temporary service for customer loads while the asset is isolated, negating the need for an extended planned service interruption. ƒ Defers the need for conventional infrastructure upgrades

E7.11.3 Why the Program is Needed

The ESS program is expected to provide Toronto Hydro with alternative methods to address specific issues relating to system efficiency, reliability and power quality, and DG and EV enablement. ESS deployments are planned to occur in targeted areas where ES can be a more prudent investment versus traditional solutions. The ESS program is expected to address the aforementioned issues by placing ESS strategically throughout the distribution system. This distributed approach would enable a minor augmentation of the performance of the existing distribution system to address localized technical limitations and issues, helping Toronto Hydro to mitigate the need for potentially expensive rebuilds or major asset replacements.

E7.11.3.1 Program Drivers

Table 8 presents the trigger and secondary drivers for the program.

TABLE 8: TRIGGER AND SECONDARY DRIVERS FOR ESS PROGRAM

Trigger Driver	Reasoning
System Efficiency	ƒ Enhances system performance by storing electricity at off-peak times, and releasing it into the distribution system during peak times. These capabilities would help Toronto Hydro manage the increasing variability of distribution system load. ƒ Capacity in certain areas of the system is strained due to load growth. ESS can help defer the need for large scale asset replacements that would otherwise be required to maintain sufficient capacity to meet

	demand through peak load reduction. ƒ ESS can increase the utilization and lifespan of existing distribution assets through peak load reduction. ƒ Minimizes overall impact of routine maintenance programs carried out at MS. ƒ Dynamically correct phase imbalances. ƒ Enablement of DG & EVs.
Secondary Drivers	Reasoning
Reliability	ƒ Increases the resiliency of the distribution system by providing reliable power for essential services over an extended period of time during emergency situations.
Power Quality	ƒ Delivers consistent service voltage, low harmonics and uninterrupted service. ƒ Provides dynamic voltage regulation/reactive power support.

Toronto Hydro creates capital projects to address issues within the distribution system. In specific cases, existing methods and solutions (e.g. capital replacement, major asset upgrades, etc.) may not be feasible for all issues related to system efficiency, reliability and power quality, and DG and EV enablement. This is when a targeted ESS installation can provide a more useful and prudent solution. Specific issues include peak load reduction, addressing customer power quality, and DG enablement. High peak loads on main and alternate feeders limit the ability of planned or emergency load transfers, resulting in stranded customers. Fluctuations in system voltage can cause issues for customers who have sensitive processes or equipment. This can lead to an interruption in customer operations by disrupting processes and may damage equipment. While Toronto Hydro has the Generation Protection Monitoring & Control program to address system-wide issues to enable DG, some localised areas would still have feeder phase imbalances, which can inhibit the connection of a DG project. The specific issues mentioned above can be addressed with a targeted deployment of ESS.

Peak Load Reduction

Currently there are areas in Toronto Hydro's distribution system that contain feeders that have large peak loads. Feeder 88M15, fed from Richview TS, is an example of this case. The issue with 88M15 is that the feeder is heavily loaded during summer months and the last section of the feeder contains a high concentration of that load. During a contingency situation, where a fault occurs upstream of the last section, customers may not be reconnected until after the fault has

been addressed. Capacity issues with potential tie feeders 88M18, 11M3, and 38M7 prevent supplying the last section of 88M15. An option to address this would be to run a new feeder into the area from nearby stations. This solution would be viable; however both Runnymede TS and Manby TS are close to capacity. Additionally, the Humber River is a natural barrier that makes it difficult to bring in feeders. Figure 7 provides a feeder print and map of the area described by the example above. ESS can be strategically placed along 88M15, or any of the tie-feeders, to provide peak load reduction and ensure that customers are not stranded during contingency situations.

FIGURE 7: FEEDER PRINT AND MAP OF 88M15 AREA

Addressing Customer Power Quality Concerns

Customer engagements by Toronto Hydro have identified over 100 customers who have expressed specific needs regarding power quality. These needs can include dynamic voltage regulation/reactive power support, harmonic mitigation, and uninterrupted service. These customers include health care and industrial manufactures, information technology service providers, and public service loads such as hospitals and water pumping stations. For example, a customer may have issues with their equipment and process, because they are sensitive to voltage fluctuations. One method to address voltage fluctuations is to change the tap position of

the service transformer, which would allow for voltage regulation. While this is a possible solution, the dynamic nature of the load along a feeder makes it virtually impossible to change a transformer's tap position dynamically in reaction to the load. Figure 8 illustrates and example of a voltage spike experienced by a customer. ESS can address this issue by dynamically counteracting voltage fluctuations through voltage regulation. This can minimize the voltage fluctuations that affect customer equipment and processes. Additionally, any negative power quality effects caused by any customers to the distribution system can also be mitigated by ESS.

FIGURE 8: VOLTAGE SPIKE EXPERIENCED BY CUSTOMER

DG Enablement

When assessing the potential to connect a DG project within Toronto Hydro's distribution system, planning engineers determine if a feeder's phase current imbalance exceeds 10% of the total load on the feeder (at the station) when DG is added to the feeder. If the DG causes the current imbalance to exceed the 10% threshold it must be corrected. Phase imbalances in general result in a return current on the neutral conductor. A return current typically causes line losses and in some cases, where the imbalance is exacerbated, cable splice failures due to overheating. A method of correcting phase imbalances is to redistribute load among the other phases of the feeder, which is technically and operationally complex. Additionally, 450 MW of generation is

forecasted to be connected to the distribution system over the 2015-2019 period. As a result, it is anticipated that situations will arise where local phase imbalances in sections of system will increase. ESS can address this issue by dynamically balancing phases to maintain the 10% threshold, without redistributing the load to different phases. Immediately and over time, this approach would address connection issues for many projects seeking connection in that local area. Additionally, if the EVs is significant in the future, ESS would help ensure they can be connected as well, as ESS can help charge EVs off peak. As is demonstrated with the proposed 2015 projects, detailed in section E7.11.7 – 2015 Projects, ESS is expected to help to enable the connection of DG to the distribution system.

Table 9 provides a summary of the proposed technologies of the ESS program and their targeted applications. Toronto Hydro anticipates that the successful implementation of the ESS program will allow Toronto Hydro to address specific issues in the distribution system with targeted applications of ESS. Figure 9 below provides a general schematic of the locations of centralized and de-centralized energy storage systems in a distribution system. (1) is an example of a centralized ESS, while (2) and (3) represent de-centralized ESS.

TABLE 9: SUMMARY ESS APPLICATIONS

Energy Storage System Type	Targeted Applications
Municipal Substation Energy Storage (MSES)	ƒ Peak Shaving/Load Levelling ƒ Reliability/Power Quality improvements ƒ DG & EV enablement ƒ Critical Load Emergency Service ƒ Temporary Station Maintenance Load Displacement ƒ Station Ancillary Services
Grid Support Energy Storage (GSES)	ƒ Peak Shaving/Load Levelling ƒ Reliability/Power Quality improvements ƒ DG & EV enablement ƒ Phase Balancing ƒ Single Load Emergency Service
Local Support Energy Storage (LSES)	ƒ Local Peak Shaving/Load Levelling ƒ Local Reliability/Power Quality improvements ƒ Local DG & EV enablement ƒ Phase Balancing

FIGURE 9: GENERAL SCHEMATIC OF ESS

E7.11.4 Timing and Pacing of the Program

The total cost of the ESS program over the 2015 – 2019 period is an estimated $10.8 million. During the five-year timeframe, Toronto Hydro plans to install a total of 24 ESS with a total aggregated capacity of 4.4 MW and a total energy output of 10,000 kWh. Table 10 summarizes historical and future program spending.

TABLE 10: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	-	-	-	-	$1.02	$0.54	$1.10	$2.20	$3.20	$3.80

The historical cost for the ESS program consists of the pilot projects. The projects are forecasted to incur a cost of $1.02 million in 2014. The costs are associated with the commissioning of two

ES pilot projects and the retrofit and commissioning of another ES pilot project. The pilot projects consist of:

- HydroStor Underwater Compressed Air Energy Storage (UWCAES) – Commissioning of a 700 kW Energy Storage System that utilizes underwater compressed air to charge and release energy back into the distribution system
- Ryerson Energy Storage System – Commissioning of a 300 kW Energy Storage System comprised of Lithium Ion batteries
- Community Energy Storage (CES) – Retrofit and commissioning of a 250 kW Energy Storage System comprised of Lithium Ion batteries

These pilot projects helped to define the technology, sizing and use of the proposed projects from 2015 through to 2019. Based on experience gained through the pilot projects, the ESS program will proceed at a gradual and methodical pace, targeting areas where an ES can be the most prudent solution to a significant localized technical issue or limitation. In 2015, technology selection, detailed engineering and design work, and site selection will take place for all ESS types. Work scheduling will ensure that the necessary personnel and resources are available. This will enable the installation and commissioning of one LSES and GSES unit each. For 2016, Toronto Hydro plans to install and commission two LSES and GSES units each and one MSES unit. From 2017 to 2019, Toronto Hydro plans to install and commission:

- three LSES units per year,
- two GSES units per year, and
- one MSES unit per year.

Table 11 summarizes the pace at which LSES, GSES and MSES units will be deployed.

TABLE 11: ASSETS TO BE INSTALLED AS PART OF THE ESS PROGRAM

Assets (Units)	2015	2016	2017	2018	2019	Total (Units)
Local Support Energy Storage (LSES) System	1	2	3	3	3	12
Grid Support Energy Storage (GSES) System	1	1	2	2	2	8
Municipal Station Energy Storage (MSES) System	0	1	1	1	1	4

E.7.11.4.1 Ranking & Prioritization

Sequencing of work within the ESS program is determined by several factors, which are used independently of one another and are based on the desired application for the ESS. These factors include:

- Station Capacity: Stations that are currently overloaded would be given higher priority of selection for an MSES in order to extend the life of these assets in a timely manner.
- Reliability Issues: Feeders that are experiencing reliability issues would be prioritized. Toronto Hydro will study whether reliability issues can be addressed by a LSES or GSES system (e.g. phase imbalance, voltage stability issues, etc.) Where applicable, feeders in the FESI program will be examined to see if LSES or GSES have any potential applications to improve reliability.
- Power Quality Issues: Areas of the distribution system that are experiencing power quality issues will be prioritized for an ESS (depending on the required size).
- DG & EV Enablement: Areas of the distribution system that are experiencing issues connecting DG & EVs to the grid will be prioritized for an ESS (depending on the required size).

E7.11.5 Program Execution

In general, the ESS program will be executed in accordance with following process:

(1) System Requirements: Identify the technical and operation requirements of the various ESS (this includes a high level site selection analysis).

(2) Technology Selection: Identify suitable technology that can meet Toronto Hydro requirements and specifications.

(3) Detailed Site Selection: Based on the criteria mentioned in Section E7.11.4.1, select candidate sites for ESS deployment.

(4) In-depth Engineering and Design: Conduct detailed engineering analysis and system design work required for ESS deployment.

(5) Material Sourcing and Construction: Taking lead times into account, source the required materials for ES system and create construction schedule.

(6) Project Commissioning: Once construction is completed, commission the ESS and bring it into service.

E7.11.5.1 Proposed Work Plan

TABLE 12: 2015-2019 LONG TERM PLAN

Year	Feeder	Station
2015	LSES Unit 1 – H9M24	LSES Unit 1 – Elesemere TS
2015	GSES Unit 1 – SS68F1	GSES Unit 1 – Leslie MS
2016	LSES Unit 2 – Feeder TBD	LSES Unit 2 – Station TBD
2016	LSES Unit 3 – Feeder TBD	LSES Unit 3 – Station TBD
2016	GSES Unit 2 – Feeder TBD	GSES Unit 2 – Station TBD
2016	MSES Unit 1 – Feeder TBD	MSES Unit 1 – Station TBD
2017	LSES Unit 4 – Feeder TBD	LSES Unit 4 – Station TBD
2017	LSES Unit 5 – Feeder TBD	LSES Unit 5 – Station TBD
2017	LSES Unit 6 – Feeder TBD	LSES Unit 6 – Station TBD
2017	GSES Unit 3 – Feeder TBD	GSES Unit 3 – Station TBD
2017	GSES Unit 4 – Feeder TBD	GSES Unit 4 – Station TBD
2017	MSES Unit 2 – Feeder TBD	MSES Unit 2 – Station TBD
2018	LSES Unit 7 – Feeder TBD	LSES Unit 7 – Station TBD
2018	LSES Unit 8 – Feeder TBD	LSES Unit 8 – Station TBD
2018	LSES Unit 9 – Feeder TBD	LSES Unit 9 – Station TBD
2018	GSES Unit 5 – Feeder TBD	GSES Unit 5 – Station TBD
2018	GSES Unit 6 – Feeder TBD	GSES Unit 6 – Station TBD
2018	MSES Unit 3 – Feeder TBD	MSES Unit 3 – Station TBD
2019	LSES Unit 10 – Feeder TBD	LSES Unit 10 – Station TBD
2019	LSES Unit 11 – Feeder TBD	LSES Unit 11 – Station TBD
2019	LSES Unit 12 – Feeder TBD	LSES Unit 12 – Station TBD
2019	GSES Unit 7 – Feeder TBD	GSES Unit 7 – Station TBD
2019	GSES Unit 8 – Feeder TBD	GSES Unit 8 – Station TBD
2019	MSES Unit 4 – Feeder TBD	MSES Unit 4 – Station TBD

E7.11.5.2 Program Risks

The risks associated with the installation and commissioning of ESS include:

- Limited technical resources with knowledge on ESS are available to design, install and commission the systems, which can lead to a delay in program implementation and increase costs.

- Transferring existing customer loads to standby feeders during system installation may be challenging due to system constraints and other capital project and planned maintenance work, which can lead to a delay in program implementation.
- Labour availability and project prioritization with other capital project and planned maintenance work could lead to delays in program implementation.

To mitigate the above risks, Toronto Hydro will:

- Provide in-depth training to crew members who will take part in the installation and commissioning of ESS in advance of the actual field work.
- Schedule work to be completed during off-peak periods in order to manage the impact to standby feeders.
- Undertake advanced planning and co-ordination between applicable Toronto Hydro departments to address resource availability issues and constraints.

E7.11.5.3 External Constraints

For LSES and GSES systems Toronto Hydro will need to co-ordinate its activities with the City of Toronto and/or private land owners in order to obtain site permits and to arrange lease agreements (if required; site specific). In order to manage these external constraints and plan the program in general, Toronto Hydro will dedicate its efforts in 2015 to selecting suitable locations and obtaining permits and/or lease agreements. Successful completion of these initiatives will help to ensure that the construction and commissioning of the program will be carried out in accordance with the five-year planning period.

E7.11.5.4 Standards & Regulation Adherence

The proposed ESS conforms to best utility practices and adhere to industry standards such as IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems, CSA C22.3 No. 9 Interconnection of distributed resources and electricity supply systems and CSA C22.2 No. 257 Interconnecting inverter-based micro-distributed resources to distribution systems. There are no applicable construction standards for LSES, GSES and MSES. Toronto Hydro will co-ordinate among its various departments in order to develop these standards.

E7.11.6 Evaluation of Alternatives

E7.11.6.1 Quantification/ Evaluation of Options

Toronto Hydro evaluated two options in order to determine the optimal choice to help realize the potential benefits of the ESS program. These options are explained in detail below.

(i) Status Quo

If Toronto Hydro maintained the status quo, it would not have the ability to utilize ESS as a viable alternative to existing methods and solutions (e.g. capital replacement, major asset upgrades, etc.) to existing and emerging technical issues and limitations on the distribution system. Problems may continue to exist within the distribution system or may require more expensive solutions in the short-term. Additionally, by not implementing the ESS program, Toronto Hydro will not realize the benefits of the applications noted in Table 1.

(ii) Energy Storage Systems (ESS)

The planned ESS program will provide Toronto Hydro with strategic capabilities to address specific issues relating to system efficiency, reliability and power quality, and DG and EV enablement in targeted and areas of the Toronto Hydro distribution system. It will allow Toronto Hydro to mitigate the problems described in Section E 7.11.3 and realize the additional benefits listed in Table 1. The overall cost of this option is an estimated $10.8 million over the 2015 to 2019 period.

The cost of ownership (COO) and program net benefit (NPV) associated with the ESS program is further detailed in Table 15. The cost of ownership for the existing state (COO_E) is zero since there are no ES units with the status quo and no quantifiable benefits or risks associated with the existing state. The cost of ownership for the new state (COO_N) is comprised of additional quantifiable benefit (AQB). Any quantifiable benefit that is associated with the program that is external to asset and non-asset related risk evaluation is quantified for the new state (AQB_N). The benefits used in determining the AQB_N for the first year of activities include deferred distribution upgrades, area regulation, voltage support, congestion relief, supply reserve capacity, power quality, and renewable energy integration. Table 14 provides a summary of the benefits. For further details on the COO approach, please refer to Section D3.3. When the difference in cost of ownership (ûCOO) is compared to the associated program costs (PC) for the first year of activities, the ESS program produces a net benefit (NPV) value of $0.58 million, as shown in Table 14.

TABLE 14: BENEFITS [11] USED FOR AQB_N

Benefit Type	Benefit ($/KW)
Defer Distribution Upgrade	$919
Area Regulation	$1,398
Voltage Support	$400
Congestion Relief	$86
Supply Reserve Capacity	$535
Power Quality	$669
Renewables Integration	$750
Total Benefits	$4,757

This cost of ownership for the new state (COO_N) was calculated using information from Sandia National Laboratories Study on Energy Storage.[12] The report was commissioned by the United States Department of Energy and was meant to provide a high-level framework for assessing the potential benefits of energy storage from an economic perspective. Toronto Hydro mapped the benefits in the Sandia report to the ESS types mentioned in Section E7.11.2 and utilized the average $/kW benefit cost to determine the total $/kW value of each installation during the first year of activities. The values in the report were obtained using standard assumptions for storage power and discharge duration, a 10% discount rate, a 2.5% escalation factor and calculated based on a 10 year life cycle.

TABLE 15: ENERGY STORAGE SYSTEMS PROGRAM BUSINESS CASE EVALUATION (BCE)

Business Case Element	Cost (in Millions)
Option 1: Energy Storage Systems	
Asset Risk [AR_N]	$0
Non Asset Risk [NAR_N]	$0
Maintenance Cost [MC_N]	$0
Additional Quantifiable Benefits [AQB_N]	-$1.1*
Cost of Ownership of New Assets [COO_N]	-$1.1*
Option 1: Project Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\hat{u}COO_1 = (COO_E - COO_N)$]	$1.1
Program Cost [PC_1]	$0.54
Program Net Benefit [$NPV_1 = (\hat{u}COO_1 - PC_1)$]	$0.58

*negative value only for calculation purposes, AQB_N benefit is positive

[11] Jim Eyer and Garth Corey, Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide (Sandia Report SAND2010-0815) (Albuquerque: Sandia National Laboratories, 2010). ["Energy Storage for the Electricity Grid"]
[12] Energy Storage for the Electricity Grid

E7.11.7 2015 Projects

Table 16 lists all projects expected to be partially or completely executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred after 2015.

TABLE 16: 2015 PROJECTS

Project Number	Project Name	Cost	Start Date
E31557	LSES Unit 1 – H9M24	$0.10	2015
E31558	GSES Unit 1 – SS68F1	$0.44	2015

E7.11.7.1 E31557 Project Description

Portfolio: System Service

Program: Energy Storage Systems

Project Title: LSES Unit 1 – H9M24

Project Number: E31557

Project Year: 2015

Estimated Cost: $100,000

(i) Objective

To install a LSES system on feeder H9M24 in order to dynamically mitigate an existing phase imbalance and enable the connection of DG.

(ii) Scope of Work

The scope of work involves the installation and commissioning of an LSES system on feeder H9M24. The LSES system will be deployed in to distribution grid and will be interconnected through a radio communication network system that will interface with Toronto Hydro's Control Room. It will serve the purpose of providing dynamic phase balancing. Figure 10 illustrates a map of the project area.

TABLE 17: E31557 SCOPE OF WORK DETAILS

District Neighbourhood	East Toronto
Station(s)	ELLESMERE TS
Feeder(s)	H9M24

TABLE 18: E31557 ASSETS INSTALLED

Assets (Units)	2015
LSES System	1

FIGURE 10: E31557 MAP OF PROPOSED PROJECT AREA

(iii) Justification & Benefits

There are significant numbers of single phase laterals across Toronto Hydro's distribution system. It is difficult to balance load across three phases because it is impossible to accurately predict the usage pattern for every customer and as a result, a phase imbalance of 10% (at the station level) is allowed. A phase imbalance in a three-phase system would result in a return current on the neutral conductor. A return current typically causes line losses and in some cases splices failures (due to overheating). In this specific project, a feeder has a DG unit that will be commissioned on a single phase. A study was conducted after Toronto Hydro was notified of a connection request for a Feed-in-Tariff (FIT) DG contract. The study identified an existing phase imbalance of 13% at the station which does not conform to the 10% threshold. Adding DG at the customer site could potentially exacerbate a phase imbalance, leading to increase in the imbalance along the three phases and larger line losses (increase in the return current). When the DG site was added to the study, the resulting phase imbalance went above the threshold to 17.8%. To mitigate the effects of this DG connection and facilitate the connection itself, Toronto Hydro plans to install LSES system. It is expected that the LSES system will reduce the phase imbalance by 88%, allowing the connection of the DG and reducing the phase imbalance.

E7.11.7.2 E31558 Project Description

Portfolio: System Service

Program: Energy Storage Systems

Project Title: GSES Unit 1 – SS68F1

Project Number: E31558

Project Year: 2015

Estimated Cost: $440,000

(i) Objective

To install a GSES system on feeder SS68F1 in order to dynamically mitigate an existing phase imbalance and enable the connection of DG.

(ii) Scope of Work

The scope of work involves the installation and commissioning of a GSES system on feeder SS68F1. The GSES system will be deployed in to distribution grid and will be interconnected through a radio communication network system that will interface with Toronto Hydro's Control Room. It will serve the purpose of providing dynamic phase balancing. Figure 11 illustrates a map of the project area.

TABLE 19: E31558 SCOPE OF WORK DETAILS

District/Neighbourhood	UPTOWN/Toronto
Station(s)	LESLIE MS
Feeder(s)	SS68F1

TABLE 20: E31558 ASSETS INSTALLED

Assets (Units)	2015
GSES System	1

FIGURE 31: E31558 MAP OF PROPOSED PROJECT AREA

(iii) Justification & Benefits

There are significant numbers of single phase laterals across Toronto Hydro's distribution system. It is difficult to balance load across three phases because it is impossible to accurately predict the usage pattern for every customer and as a result, a phase imbalance of 10% (at the station level) is allowed. A phase imbalance in a three-phase system would result in a return current on the neutral conductor. A return current typically causes line losses and in some cases splice failures (due to overheating). In this specific project, a feeder has a DG unit that will be commissioned on a single phase. A study was conducted after Toronto Hydro was notified of a connection request for a Feed-in-Tariff (FIT) DG contract. The study identified an existing phase imbalance of 8.3% at the station which does not conform the 10% threshold. Adding DG at the customer site could potentially exacerbate a phase imbalance, leading to increase in the imbalance along the three phases and larger line losses (increase in the return current). When the DG site was added to the study, the resulting phase imbalance went above the threshold to 10.4%. To mitigate the effects of this DG connection while facilitating the connection itself, Toronto Hydro plans to install GSES

system. It is expected that the GSES system will reduce the phase imbalance by 73%, allowing the connection of the DG and reducing the phase imbalance.

sustaining Toronto Hydro's operations by providing its employees with a safer environment to operate in an efficient and reliable manner and to provide quality service for customers. Table 1 provides the trigger drivers for capital investments in this category.

TABLE 1: TRIGGER DRIVERS FOR GENERAL PLANT CATEGORY

Driver	Description
Functional Obsolescence	*f* The asset is no longer aligned to Toronto Hydro processes and practices such that it can no longer be maintained (e.g., lack of vendor support) or utilized as intended in support of the utility's business processes.
Safety	*f* Assets are an integral part of maintaining safe work practices, and the failure or lack of support of those assets would likely result in safety-related hazards or risk exposure.
System Maintenance and Capital Investment Support	*f* Required investments to support day to day business operations activities; sustaining operations by providing its employees with a safer environment to operate in an efficient and reliable manner.

Table 2 provides a brief description for each investment program within the General Plant narrative along with total expenditures for each program from 2015 onwards to 2019. Individual section numbers for each investment program can also be accessed from this table.

TABLE 2: DESCRIPTION OF INVESTMENT PROGRAM

Program Index and Name		Brief Description	Total (5 years)	
E8.1	**Fleet and Equipment Services**	As Toronto Hydro's fleet ages, regular vehicle replacement and repair is necessary. This program replaces 24-95 vehicles a year as well as installing new equipment on existing vehicles requiring refresh or replacement, all to ensure the fleet is safe, reliable, and cost-efficient.	**$17.9 M**	
E8.2	**Facilities Management & Security**	Security enhancements are necessary to ensure assets, employees, and the general public are protected by up-to-date security equipment and technologies. Additionally, facilities program is needed to improve the safe, reliable and efficient operation of the work centers and stations as well as increase the overall asset value for all of Toronto Hydro.	**$31.8 M**	/C
E8.3	**Operating Centers Consolidation**	Consolidation of Toronto Hydro's operating centers is required to secure tenure for Toronto Hydro in the northwest and northeast areas of the City while delivering benefits to ratepayers. Toronto Hydro plans to vacate four facilities, two of which it currently owns, and relocate staff, equipment and operations to three facilities already owned by Toronto Hydro to achieve efficiencies and improve space utilization. The utility plans to sell the two surplus Toronto Hydro-owned facilities, crediting the net after-tax gains on sale and related	**$52.2 M**	/C

Program Index and Name		Brief Description	Total (5 years)
		tax savings to ratepayers through rate riders.	
E8.4	IT Hardware Refresh	The program addresses the renewal and maintenance of core backend infrastructure (e.g. servers, storage disks) and endpoint assets (i.e. laptops, desktops) that enable Toronto Hydro to plan and execute capital and operational programs and to fulfill its obligations to customers and applicable regulatory bodies.	$36.7 M
E8.5	IT Software	The Software program covers planned IT upgrades to more than 70 software applications that support Toronto Hydro's core functions and processes. Toronto Hydro must upgrade these applications to ensure their availability to meet operational needs, and to protect itself against cyber threats that could jeopardize the security of the distribution system and the privacy of sensitive operational, customer and employee information. The program also includes initiatives to enhance, modify or implement new software applications that are necessary to optimize business operations, or to comply with external requirements imposed by entities such as Measurement Canada, the OEB and the IESO.	$81 M
E8.6	ERP Implementation	The current end-of-life ERP, Ellipse, will soon no longer be supported by its vendor, introducing a number of technical risks. The program will replace Ellipse and 30 other legacy applications with a new ERP that meets functional requirements.	$51 M
E8.7	Voice Radio System Upgrade	The voice radio system is critical to Toronto Hydro's ability to safely and effectively deliver its planned capital and maintenance programs and to respond to trouble calls in a safe, timely and efficient manner. The current voice radio system cannot be supported by the vendor beyond 2016 and must be upgraded to mitigate safety and operational risks.	$20 M
E8.8	Program Support	This program will perform two studies to enhance the asset management process and improve the long-term and short-term strategy. The first will be a climate adaption study, focusing on at risk areas to extreme weather and climate change. The second will be a customer interruption study to estimate outage costs.	$1.7 M

1 The following Sections E8.1 though to E8.8 contain the details and justification for each capital
2 investment program contained within the General Plant investment category.

E8.1 Fleet and Equipment Services

TORONTO HYDRO BUCKET TRUCKS

E8.1.1 Summary

Program Description

The Fleet and Equipment Services program proposed for 2015 to 2019 funds the acquisition of new vehicles and equipment to replace existing units in accordance with Toronto Hydro's fleet replacement criteria (see Table 4 in Section E8.1.3.2). This program also includes required on-vehicle equipment.

Toronto Hydro plans to maintain a steady vehicle replacement plan focused on minimizing total vehicle life cycle costs. Routine vehicle retirement and replacement is necessary so that Toronto Hydro's fleet remains safe, reliable and cost-efficient. A proactive and timely replacement program ensures that Toronto Hydro will continue to have access to the number and types of vehicles needed to accomplish its distribution function.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Optimal replacement to minimize overall costs to the utility and ultimately, for the rate payer. ƒ Decrease maintenance time and repair costs, and reduced cost to the rate payer.
Safety	ƒ New vehicles resolve potential safety risks that increase as vehicles age ƒ New safety features and devices that improve overall vehicle safety

	ƒ Modern GPS/Telemetry systems include risk management features to monitor vehicle speed, and log safety system performance. ƒ Continuous replacement of rubber line covers ensures product availability
Efficiency	ƒ Vehicles more fuel efficient than older units ƒ Newer vehicles require less maintenance, lowering overall maintenance costs, and increasing overall fleet reliability. ƒ GPS/Telemetry systems enable more rapid outage response.

Program Drivers

The trigger driver and secondary drivers for the Fleet and Equipment Services program are described in the following table.

TABLE B: PROGRAM DRIVER

	Drivers	Reasoning
Trigger Driver	System Maintenance and Capital Investment Support	ƒ Toronto Hydro vehicles transport equipment and personnel to the field, and are used to perform maintenance and investment activities. ƒ Over time, units are subject to wear and tear that will directly impact vehicle safety, reliability, and operational efficiency. ƒ Toronto Hydro requires access to vehicles and equipment that meet current and/or future functional requirements. Over time, operational needs and requirements may change in a manner that necessitates certain vehicle and equipment types, technologies and configurations that are not found in the current fleet.
Secondary Drivers	Safety	ƒ As a vehicle ages, there is an increased potential risk of safety issues such as rust on vehicle structural members, component failure, and electrical faults. These issues can pose a risk to both operators and the public. ƒ Over time and with continued use, rubber cover up units can fail inspection/testing. Failed units must be immediately removed from service and replaced.
	Reliability	ƒ Field failures and unreliable and/or unavailable vehicles can adversely impact Toronto Hydro's ability to provide acceptable levels of reliable customer service. ƒ Rubber that fails visual or electrical testing must be disposed of. Toronto Hydro must have access to cover-up material at all times to ensure that it can perform system maintenance and complete capital investment work in a timely manner.

	Drivers	Reasoning
	Business Operations Efficiency	ƒ Toronto Hydro's policy is to replace vehicles in line with a life cycle assessment, which is intended to minimize the total cost of ownership of Toronto Hydro's fleet, and thus, minimize the costs of the fleet for the rate payer. ƒ As vehicles age, performance – including, but not limited to fuel economy, emissions, acceleration, lifting speed – tends to decline.

Preferred Alternative

Toronto Hydro considered the following options for investing in critical fleet and equipment assets.

(i) Run to failure (i.e. reduce capital spending to zero during the 2015-2019 period)

(ii) Status quo (i.e. spending in line with IRM/ICM years, which would be lower than the planned program for 2015-2019)

(iii) Managed fleet replacement (i.e. the proposed Fleet and Equipment Services program)

Under the "run-to-failure" option, vehicle performance would decline significantly, failures would increase, and crew ability to execute programs and emergency event responses would decrease. Using the status-quo approach is also not preferred due to units being replaced at intervention times which are suboptimal, resulting in higher total lifecycle costs. The preferred managed fleet replacement incorporates modeling which considers multiple lifecycle and resource constraints to maximize utilization and minimize costs.

Timing and Pacing

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Forecasted Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	10.6	11.8	0.79	2.9	2.6	3.6	3.3	3.8	3.6	3.7

Toronto Hydro plans to maintain a consistent vehicle replacement plan that is focused on minimizing total lifecycle costs.

Spending pre-2012 was significant due to increasing support required for work programs. Spending from 2012-2014 was significantly lowered, due to realignment with the IRM/ICM regulatory criteria in that period.

Toronto Hydro is electing to replace the on-vehicle GPS/Telemetry system in 2015 as it is the final year of the support contract for the current system due to maturity and limited support of the existing system.

E8.1.2 Program Description

As of April 30th, 2014, Toronto Hydro's fleet is composed of 660 units, including cars, pickups, bucket trucks and other vehicles, such as sweepers, backhoes and forklifts. The Fleet and Equipment Services program proposed for 2015 to 2019 funds the acquisition of new vehicles and equipment to replace existing units in accordance with Toronto Hydro's fleet replacement criteria (see Table 4 in Section E8.1.3.2). Program expenditures will also include the purchase of required on-vehicle equipment.

FIGURE 1: BUCKET TRUCKS IN THE FIELD

Toronto Hydro plans to maintain a steady vehicle replacement plan focused on minimizing total vehicle life cycle costs. Routine vehicle retirement and replacement is necessary so that Toronto Hydro's fleet remains safe, reliable and cost-efficient. A proactive and timely replacement program facilitates Toronto Hydro having access to the number and types of vehicles needed to accomplish its distribution function. In building the program, Toronto Hydro must primarily consider the inventory of vehicles and equipment that will be needed to support functional needs and performance requirements associated with dynamic capital and maintenance programs. For example, a change in long-term capital plan work mix may require an increase in the number of

transformer installations, which in-turn, requires the vehicle capacity, reach, and cargo-carrying capability of a material handling bucket truck as opposed to that of an auto crane-equipped truck.

FIGURE 2: CUBE VANS PARKED AT 500 COMMISSIONERS STREET

Execution of a proactive and timely replacement plan based on the fleet replacement criteria can also result in the following benefits:

- minimization of total vehicle costs;
- minimization of fleet downtime due to repairs, and a corresponding increase in fleet reliability;
- increases in vehicle efficiency – i.e. lower fuel consumption, and idle reduction via available on-board technology;
- improvements in shop efficiency – as less labour is required to maintain new vehicles, more labour can be allocated to maintain older, less reliable vehicles;

- reduction in environmental impacts – improvements in emissions standards and engine design on newer vehicles will result in a reduction in green house gases emitted by Toronto Hydro vehicles, as well as a reduction in maintenance fluids used – such as engine oil – to maintain them; and,

- safer vehicles – both due to new safety technology offered on newer vehicles, and to a reduced likelihood of field failures that could result in injury to an employee, the public, and/or damage to property.

Toronto Hydro also plans to invest in necessary on-vehicle equipment, including rubber power line covers and a replacement telemetry system. An example of a rubber power line cover is seen below in Figure 3.

FIGURE 3: RUBBER POWER LINE COVER

In accordance with Electrical Utilities Safety Rule 129,[1] workers must comply with safe limits of approach and use equipment - such as rubber power line covers – as protection against electrical shock or burns. These covers require visual inspection prior to each use as well as annual

[1] Infrastructure Health and Safety Association, Electricity Utilities Safety Rules, (Mississauga: Infrastructure Health and Safety Association, 2014) Rule 129. ["EUSR"]

electrical and visual testing by a certified laboratory. Over time and continued use, units will fail inspection/testing, which necessitates immediate removal from service and replacement.

Toronto Hydro vehicles are equipped with a telemetry system (i.e. remote monitoring and measurement system) that provides real-time visibility of vehicle locations and facilitates multiple utility functions such as vehicle dispatching, productivity analysis, vehicle maintenance, public trust reviews (e.g. customer reports) and vehicle risk-management (e.g. accident reconstruction, and tracking of stolen assets for recovery purposes). In the four years since installation, telemetry technology has continued to advance, incorporating new features such as the tracking of trailers (typically a platform or piece of equipment on wheels pulled by a powered vehicle) that do not have onboard power sources, advanced routing, real-time speed vs. speed limit analysis, and enhanced acceleration monitoring capabilities that are not available on the currently installed system. Advanced routing will enable dispatch to direct Toronto Hydro vehicles along specific routes to field assets, helping them to find asset locations faster, and thus maximizing crew efficiency. Identification of more direct routes to assets will also likely result in a reduction in fuel use and green house gas emissions. Real-time speed vs. speed limit analysis and enhanced acceleration monitoring capability will enable improved risk management for licensing purposes, and more focused driver training programs to address driver performance.

Toronto Hydro plans to replace the current telemetry system in 2015, which will require purchase and installation of new hardware in/on vehicles and equipment, integrate new server or front-end software, and implement a new telemetry service licensing agreement. With replacement of the units, it is possible that monthly licensing fees could be reduced – perhaps significantly – from current levels.

The planned total capital expenditures for the Fleet and Equipment Services program are estimated at $17.9 million over the period of 2015 to 2019. Table 1 summarizes projected capital investment by vehicle type between 2015 and 2019. All vehicles selected for replacement meet Toronto Hydro replacement criteria. The ‘Number’ column indicates the number of vehicles to be purchased within each particular vehicle description class. The ‘Cost’ represents the estimated total cost to purchase the ‘number’ of vehicles indicated for that class. Per plan, spend related to vehicle purchases has been limited to approximately $3.6 million year-over-year to avoid spending variation and to limit planning challenges associated with commissioning and decommissioning a high number of vehicles.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS ($ MILLIONS)

	2015		2016		2017		2018		2019	
Vehicle Description	Number	Cost	Number	Cost	Number	Cost	Number	Cost	Number	Cost
Car	6	0.1	13	0.3		0.0	3	0.1	2	0.0
Cube Van	10	1.1	1	0.1	6	0.7	2	0.2	4	0.4
Double Bucket up to 50'		0.0		0.0	3	1.0	1	0.3	1	0.3
Full Size Van - Cargo	4	0.1	7	0.2	8	0.3	2	0.1	2	0.1
Line Truck	1	0.1		0.0		0.0	3	0.3		0.0
Minivan – Cargo	16	0.4	32	0.9		0.0	7	0.2	19	0.5
Minivan - Passenger	12	0.4	4	0.1		0.0		0.0	2	0.1
Pickup		0.0	20	0.7		0.0	2	0.1	4	0.1
Single Bucket - Van Mounted	1	0.1	1	0.1		0.0		0.0		0.0
Single Bucket Truck	4	0.9	1	0.2	7	1.6	7	1.6	7	1.6
Small Digger Truck	1	0.2		0.0		0.0	1	0.2		0.0
SUV		0.0	16	0.5		0.0	10	0.3	8	0.3
Vehicle Sub-Total	55	3.5	95	3.1	24	3.6	38	3.4	49	3.5
On Vehicle Equipment	-	0.4	-	0.1	-	0.1	-	0.1	-	0.1
Grand Total	55	3.9	95	3.2	24	3.7	38	3.5	49	3.6

The following table provides a summary of anticipated Fleet and Equipment Services program benefits:

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Replacement of Toronto Hydro fleet assets per the replacement criteria is expected to minimize overall costs to the utility and ultimately, for the ratepayer. ƒ The purchase of new vehicles is expected to decrease maintenance time and repair costs, as well as improve reliability, efficiency and safety providing the opportunity for improved service, and reduced cost to the rate payer.
Safety	ƒ New vehicles resolve potential safety risks that increase as vehicles age (e.g. frame corrosion, critical component failure, and electrical failure). ƒ New vehicles include new safety features and devices that improve overall vehicle safety (e.g. additional airbags, advanced stability and traction control). ƒ Modern GPS/Telemetry systems include risk management features to monitor vehicle speed, and log

	safety system performance. These features can be used to create and enhance driver safety programs. ƒ Continuous replacement of rubber line covers ensures product availability for ongoing maintenance and capital investment
Efficiency	ƒ New vehicles are notably more fuel efficient than older units, and include technology that further enhance manufacturer legislated reductions in fuel use. ƒ Newer vehicles require less planned and unplanned maintenance than older vehicles, lowering overall maintenance costs, and increasing overall fleet reliability. The result is that mechanic labour can be redirected to better maintain older vehicles. ƒ GPS/Telemetry systems incorporate advanced routing and dispatching functions that may enable more rapid outage response.
Other Benefits	ƒ Newer vehicles generally include new technologies that can improve field efficiency such as stability protection and idle reduction devices. ƒ Data provided by modern telemetry systems enable improved asset monitoring – such as unpowered trailer tracking – as well as enhance risk management and asset maintenance. ƒ New telemetry systems may entail new licensing, which could result in lower fees.

E8.1.3 Why the Program is Needed

Toronto Hydro requires vehicles and equipment to transport employees and materials to and from job sites, to perform work onsite, provide an onsite working area and to provide shelter. The principal driver for this program is the need to ensure that Toronto Hydro continues to have access to vehicles that support system maintenance and capital investment during the 2015-2019 period and beyond. Secondary drivers include safety, reliability, and operational efficiency.

E8.1.3.1 Purpose

TABLE 3: VEHICLE REPLACEMENT PROGRAM DRIVERS

	Drivers	Reasoning
Trigger Driver	System Maintenance and Capital Investment Support	ƒ Toronto Hydro vehicles transport equipment and personnel to the field, and are used to perform maintenance and investment activities. ƒ Over time, units are subject to wear and tear that will directly impact vehicle safety, reliability, and operational efficiency. ƒ Toronto Hydro requires access to vehicles and equipment that meet current and/or future functional requirements. Over time, operational needs and requirements may change in a manner that necessitates certain vehicle and equipment types, technologies and configurations that are not found in the current fleet.
Secondary Drivers	Safety	ƒ As a vehicle ages, there is an increased potential risk of safety issues such as rust on vehicle structural members, component failure, and electrical faults. These issues can pose a potential risk to both operators and the public. ƒ Over time and with continued use, rubber cover up units can fail inspection/testing. Failed units must be immediately removed from service and replaced.
	Reliability	ƒ Field failures and unreliable and/or unavailable vehicles can adversely impact Toronto Hydro's ability to provide acceptable levels of reliable customer service. ƒ Rubber that fails visual or electrical testing must be disposed of. Toronto Hydro must have access to cover-up material at all times to ensure that it can perform system maintenance and complete capital investment work in a timely manner.
	Business Operations Efficiency	ƒ Toronto Hydro's policy is to replace vehicles in line with a life cycle assessment, which is intended to minimize the total cost of ownership of Toronto Hydro's fleet, and thus, minimize the costs of the fleet for the rate payer. ƒ As vehicles age, performance – including, but not limited to fuel economy, emissions, acceleration, lifting speed – tends to decline.

System Maintenance and Capital Investment Support

Toronto Hydro's fleet consists of many types of vehicles that are designed for multiple purposes. Fleet vehicles are used to transport both materials and personnel to and from the field. On the job-site, unit uses include, but are not limited to, lifting and positioning material, storing material, preparing material for installation, acting as a planning station and serving as shelter. Fleet vehicles must be available to support these functions in a safe, reliable, and operationally efficient manner.

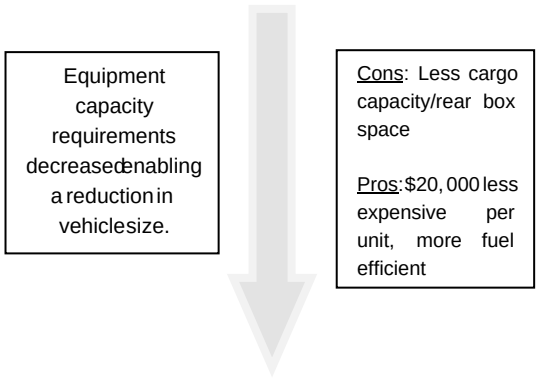


FIGURE 4: EXAMPLE OF A VEHICLE TYPE CHANGE DUE TO A CHANGE IN FUNCTIONAL REQUIREMENTS AT THE TIME OF REPLACEMENT

A consistent replacement cycle enables Toronto Hydro to commission new vehicles that may better meet current and/or future functional requirements, as demonstrated in Figure 8. Toronto Hydro vehicle replacement cycles currently span six to 16 years depending on vehicle type/class. During this period, there is potential that operational needs and requirements change, which necessitates the introduction of vehicles and equipment with new and/or different capabilities and configurations. A fluid vehicle replacement schedule ensures continuous review and commissioning of vehicles that both support, and improve Toronto Hydro's operational efficiency in the performance of its distribution function.

Safety

The following factors can directly impact the safety of a vehicle as it ages.

Corrosion

Toronto Hydro vehicles are used continuously throughout all four seasons and spend much of their operating lives in the outdoors, exposed to the elements. Road salt is commonly used to control snow and ice on City of Toronto roads. Exposure to road salt and moisture eventually leads to vehicle corrosion, which can damage and weaken the frame of the unit over time. The frame is the main structure of a unit, and all vehicle running gear are fastened to it. Thus, the frame supports the entire weight of the vehicle except for the wheels, suspension, and some steering components. Severe rust can lead to frame breaks while under load, e.g., while a unit performs a lift, while performing a cable pull, or while loading material. Frame weakness can also decrease the ability of the vehicle to withstand crashes.

FIGURE 5: UNDERBODY RUST ON A UNIT THAT HAS CHANGED THE SHAPE OF THE FRAME, AND WILL COMPLICATE COMPONENT REMOVAL

Corrosion can also appear on vehicle body panels, weakening them and making them brittle. Brittle panels are then subject to breaking, leaving sharp edges, or presenting a potential fall hazard if the rusting occurs on a step, handle, or vehicle floor.

Corrosion may also occur on components that are critical to the operation of the vehicle, such as transmission and brake lines, that are often not observable between vehicle services. Rust on these components results in weak spots that have the potential to rupture and leak, and/or catastrophically fail while in use. For example, a transmission line rupture could result in a seized transmission. If this occurs while in motion, the operator is at risk of losing

FIGURE 6: CORROSION HAS INFILTRATED INTERFACE BETWEEN AERIAL ELECTRICAL INSULATION AND AERIAL. THE BOOM CANNOT BE USED SAFELY IN THIS CONDITION AND IS VERY COSTLY TO REPAIR

control of the vehicle. Brake line leaks can result in brake failure, possibly leading to a loss of control.

Critical Component Failure

Regular use of the fleet over time can lead to the failure of critical components that are not readily serviceable or observable by maintenance staff. Components such as the hydraulic hoses running through an aerial cannot be directly inspected at service intervals. As the hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaks to the environment, and could also result in an inability to lower an employee operating a bucket to the ground. Rescuing an employee from an aerial bucket presents a potential risk to both the employee in the bucket, and other field employees who are assisting with the matter.

FIGURE 7: EMPLOYEES PERFORMING FORESTRY WORK IN A TRUCK EQUIPPED WITH AN AERIAL

Electrical Failures/Faults

Manufacturing measures designed to protect electrical circuitry can become compromised as a vehicle ages and wears with regular use, leading to electrical failures. The longer a vehicle is in service, the more likely it is that this will occur. Electrical failures could lead to the disabling of auxiliary safety lighting systems and onboard equipment required as field staff perform their distribution functions.

As noted earlier, in accordance with EUSR 129 workers must comply with safe limits of approach and use equipment - such as rubber power line covers – as protection against electrical shock or burns. It is essential that this material be available for Toronto Hydro to continue to perform all of its intended functions and conform to the law. Further, their use significantly decreases potential exposure risk for Toronto Hydro employees and the public when near exposed conductors.

Reliability

Field crews require vehicles to perform Toronto Hydro's distribution function. Field failures and unreliable and/or unavailable vehicles adversely impact Toronto Hydro's ability to provide acceptable levels of reliable customer service, and could also result in lost productivity or a

disruption to the construction and/or maintenance plans. As is discussed later in this evidence, Toronto Hydro vehicles generally require increasing maintenance as they age; yet, even with these activities, vehicles are more likely to fail while in use or will need to be held out of service for repairs following an inspection as time goes on. Furthermore, parts availability decreases over time. As a result, as a vehicle ages, there is an increased probability that it will taken out of service, and for longer periods of time, while Toronto Hydro procures necessary parts.

Operational Efficiency

A well timed vehicle replacement strategy is required in order to minimizing total fleet costs over time and to ensure the correct vehicles are available to support system maintenance and capital investment plans. As a fleet unit ages, ownership costs (such as purchase cost and cost of capital) decrease as operating costs (such as fuel, maintenance costs, downtime) increase. At a point in the asset's life cycle, the operating costs begin to outweigh ownership costs; total life cycle vehicle costs are at a minimum at a point in time just before operating costs overtake ownership costs. Vehicle replacement at that point in time minimizes total vehicle costs. The optimal time for replacement can be determined by performing a LCA, which has been completed for Toronto Hydro's fleet and is later detailed in sections E8.1.3.2 (ii) and E8.1.4.1.

New vehicles tend to be associated with low maintenance costs in early years, as they tend to experience fewer failures that require repair. As a result, repair staff can be re-allocated to focus older units. In all, this focus can improve unit reliability, which reduces the likelihood of field failures and/or the number of units that need to be taken out of service and repaired.

Field operational efficiency can also be improved with the use of new equipment. Over time and with regular usage, the performance of equipment can decline. Examples of reduced performance include slower equipment acceleration, lower lifting power/speed, braking responsiveness, and operability under load. These issues are largely non-existent in newer units.

E8.1.3.2 Asset Details

(i) Asset Lifecycle

Vehicles

Toronto Hydro vehicles are replaced in accordance with the vehicle replacement criteria outlined in Table 4 below. Prior to 2013, vehicle replacement criteria were two-tiered, with vehicles being categorized as light or heavy. The two categories had unique replacement periods that were determined based on past Toronto Hydro maintenance and replacement experience. Effective 2013, the ages and kilometers of the vehicles drive the replacement timelines for Toronto Hydro's vehicles; these timelines were derived from a third-party life cycle analysis (LCA).[2]

TABLE 4: 2013 VEHICLE REPLACEMENT CRITERIA

Vehicle	KM	Age	Special Considerations
Light Vehicle (Car, SUV, Minivan-Passenger)	>120,000	6-7 years	Exceptions: above average maintenance costs, obsolescence, and unsuitability for the task, poor reliability, excessive downtime and non-availability of parts
Light Vehicle (Minivan - Cargo)	>140000	7-10 years	Exceptions: above average maintenance costs, obsolescence, and unsuitability for the task, poor reliability, excessive downtime and non-availability of parts
Light Vehicle (Pickup, Full Size Van – Passenger/Cargo)	>180000	9-10 years	Exceptions: above average maintenance costs, obsolescence, and unsuitability for the task, poor reliability, excessive downtime and non-availability of parts
Heavy Duty (Single Bucket - Van Mounted)	>160,000	8-9 years	Heavy vehicle replacements are routinely evaluated on an individual basis
Heavy Duty (Cube Van)	>240,000	12-14 years	Heavy vehicle replacements are routinely evaluated on an individual basis
Heavy Duty (Line Truck)	>260,000	13-16 years	Heavy vehicle replacements are routinely evaluated on an individual basis

[2] Richmond Sustainability Initiatives, Toronto Hydro Life Cycle Cost Analysis & Peer Fleet Comparison (Element 2) – Final Report (Report prepared for Toronto Hydro-Electric Limited, 23 May 2013). ["Life Cycle Cost Analysis & Peer Fleet Comparison Report"]

Vehicle	KM	Age	Special Considerations
Heavy Duty (Single Bucket)	>210,000	14-16 years	Heavy vehicle replacements are routinely evaluated on an individual basis
Heavy Duty (Small Digger Truck)	>260,000	13-14 years	Heavy vehicle replacements are routinely evaluated on an individual basis
Heavy Duty (Double Bucket, Large Digger Truck, Small Crane Truck, Small Dump Truck)	>280,000	14-16 years	Heavy vehicle replacements are routinely evaluated on an individual basis
Heavy Duty (Cable Truck)	>320,000	16-18 years	Heavy vehicle replacements are routinely evaluated on an individual basis
Heavy Duty (Large Crane Truck)	>320,000	16-19 years	Heavy vehicle replacements are routinely evaluated on an individual basis
Non-Transportation Equipment			Major overhauling and remounting of hydraulic units including aerial devices, cranes and radial booms derricks is an alternative to replacement. This decision is based on the cost and technical considerations

The LCA identifies the approximate age at which a vehicle's total costs – e.g. ownership, maintenance, driver productivity loss due to reduced vehicle reliability – are minimized. Figure 8 illustrates the lifecycle analysis concept.

FIGURE 8: LIFE CYCLE ANALYSIS CONCEPT

As vehicle age increases, ownership costs decrease, and the cost of vehicle operation (operating costs) increases. LCC (Life Cycle Cost) represents the sum of all ownership and operating costs over the life of a vehicle. LCC is determined by modeling actual and anticipated ownership and operating cash flows for a particular vehicle over multiple years. The projected costs are then used to determine the replacement cycle that results in the lowest overall total cost of ownership (i.e. operating costs plus ownership costs). The period in the cycle in which this occurs is the optimal point at which to replace a vehicle.

Total LCCs and the optimal period of replacement will differ from vehicle to vehicle due to variability in factors such as the vehicle's make, model year, equipment design, initial cost, maintenance costs, and operator usage. Due to this variability, the optimal period is an estimation of the optimal replacement time for most units within the class. Specific vehicles identified by the analysis also require qualitative analysis in the year of tender to ensure that vehicles that are unsafe or are in poor condition are prioritized for replacement, while those that are in excellent condition are not prematurely replaced.

On-vehicle Equipment

Rubber line covers require visual inspection on each use, and at minimum, annual electrical and visual testing by a certified laboratory. Over time and continued use, units can fail inspection/testing, which necessitates immediate removal from service and replacement. Rubber cover-up life is variable, and highly dependent on handling, and use.

Toronto Hydro plans to replace the GPS/Telemetry system in 2015 as it is the final year of the support contract for the current system. Further details on the timing and purpose of GPS/Telemetry system replacement can be found in section E8.1.4.

(ii) Asset Failure Impacts

Toronto Hydro requires an adequate number of vehicles that are safe, reliable, and can be operated and maintained at reasonable cost to accomplish its distribution function. Among other things, vehicle failures could potentially result in the following:

- increasing maintenance costs that, over time, are consistently greater than, or escalate at a faster rate than, a comparable peer vehicle within the fleet;
- potential safety risks to both employees and the public; and,
- failure to meet Toronto Hydro's functional needs or performance requirements, with potential impacts on system reliability and operational efficiency.

As previously stated, EUSR 129 requires that workers comply with safe limits of approach and use equipment - such as rubber power line covers – as protection against potential electrical shock and burns. It is essential that this material be available for Toronto Hydro to continue to perform all of its intended functions and conform to law. When rubber cover-up fails in the field or fails when certified, it is removed from service. If rubber cover-up inventory is not maintained and thus not available when required by field workers, Toronto Hydro may be unable to perform necessary overhead line work.

E8.1.4 Timing & Pacing of the Program

Toronto Hydro plans to maintain a consistent vehicle replacement plan that is focused on minimizing total LCC. Table 5 outlines Toronto Hydro's forecasted cost of unit replacement over the 2015-2019 period, as well as projected on vehicle equipment costs in the same period.

As explained in section E8.1.3.2 (i), the optimal age of replacement is essentially an estimate for a particular vehicle class, and can be interpreted as an optimal age range within which replacement should occur to minimize LCCs. All vehicles were identified as having one- to three-year optimal replacement windows. Total annual projected operating and capital replacement costs were modeled across the age range of replacement for all eligible vehicles with a view to leveling annual capital spend, while also ensuring that the number of vehicles planned for in-service/decommissioning over the year were planned at a rate that can be efficiently managed.

TABLE 4: HISTORICAL AND FORECASTED SPENDING

	Historical Spending					Future Spending				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M) Vehicle Sub-Total	10.1	11.4	0.67	2.00	2.00	3.2	3.2	3.7	3.5	3.6
CAPEX ($M) On-Vehicle Equipment	0.25	0.15	0.06	0.10	0.0	0.4	0.1	0.1	0.1	0.1
CAPEX ($M) Total	10.6	11.8	0.79	2.9	2.6	3.6	3.3	3.8	3.6	3.7

In 2011, Toronto Hydro expanded its plans to renew the fleet per the vehicle replacement criteria in order to reduce the average age of the fleet, while further increasing fleet count. This expansion was driven by concerns about deteriorating unit condition across the fleet, and projected increased operating costs to support maintenance/repairs and expected growth in capital program execution.

Spending from 2012-2014 was significantly lowered, due to realignment with the IRM/ICM regulatory criteria in that period. Toronto Hydro reduced its staff in early 2012, and with this reduction came a corresponding drop in need for vehicles. Over the course of 2012, Toronto Hydro decommissioned and did not replace 66 units that had reached the end of their service lives. As a result of the fleet renewal investments made in 2011, Toronto Hydro had also significantly reduced the average age of the fleet. This age reduction increased overall reliability, which reduced the need for capital investments between 2012 and 2014.

Toronto Hydro plans to replace the GPS/Telemetry system in 2015 as it is the final year of the support contract for the current system. Telemetry technology has developed significantly since the current system was installed, and there is an increase in the number of vendors that now offer this service. For this reason, it is prudent to review hardware options at this time, since a new

system may result in hardware costs and ongoing subscription fees that are significantly less expensive than the services available for the current hardware. Toronto Hydro will issue a Request for Proposal (RFP) to ensure that the vendor(s) with the best value proposition is/are selected for network access and system support. The complexity of performing this upfit, the variability in the features of the telemetry systems available, and the variety of subscription services available to support the system make an RFP process the best method of selecting a vendor.

E8.1.4.1 Ranking & Prioritization

As mentioned in section E8.1.3.2 (i), the replacement criteria were derived from the results of a third-party LCA. The LCA was based on actual Toronto Hydro vehicle ownership data from 2008-2012. As shown in Figures 9 and 10, the analysis indicated that both age and distance traveled (odometer) were strongly correlated with increasing maintenance cost for Toronto Hydro's fleet. Both were ultimately used as principal inputs and outputs for determining the optimal time at which to replace a Toronto Hydro vehicle.

Due to the geographic footprint of the operating territory, Toronto Hydro vehicles travel, on average, 12,000 km per year. 88% of vehicles travel less than 20,000 km per year and 12% of vehicles travel more than 20,000 km per year. If kilometers were to be used as the primary parameter for selection of vehicles for replacement, the variation in annual vehicle travel from year to year would make the task both complex and exceptionally time consuming. At minimum LCC, there could be a number of vehicles that are all the same age but with widely varying odometer readings. Within the kilometer ranges considered, vehicle condition (which must be assessed to validate vehicle replacement) would also likely be highly variable, and a review of a large number of vehicles within a given odometer range would be required before a replacement list could be finalized. Analysis by age provides a common parameter of analysis that progresses in the same manner for all vehicles in the fleet. Therefore, LCC analysis is focused on asset age as the primary replacement criterion. Kilometers travelled are used as a secondary criterion to prompt condition review if a vehicle has exceeded 20,000 km of travel per year.

FIGURE 9: TORONTO HYDRO FLEET MAINTENANCE COST AND RELIABILITY VS. AGE

FIGURE 10: TORONTO HYDRO FLEET MAINT. COST VS. ODOMETER

Toronto Hydro generally conducts quantitative and qualitative analysis of vehicle condition for units identified for replacement in the year prior to the year of replacement. Criteria include:

- Unit safety – an assessment of the safety equipment installed on the unit and how well it continues to accomplish its intended function. Safety equipment includes, but is not limited to, seatbelts, anti-lock brakes, and stability control.

- Body and chassis integrity – an assessment of the unit's appearance and how well the body and chassis have, and will continue to, resist corrosion/wear and tear. Note that significant corrosion/wear can affect body and chassis integrity to the degree that user and public safety is compromised.

- Vehicle Reliability – an assessment of the relative propensity for a part failure and/or total unit failure against units of similar class in the fleet, as well as an assessment of the availability of parts and equipment to service the unit.

- Maintenance – an assessment of the relative cost of maintaining a unit, and/or a determination of the cost required to return a vehicle to a condition that will ensure ongoing productive use.

- Fitness for current function – an assessment of whether the unit is still capable of, or required to, performing the functions for which it was purchased.

The results of the qualitative assessment are used to adjust and determine vehicle replacement priority. Following qualitative assessment, one vehicle may be assessed as poor in multiple categories above (e.g. heavy corrosion on the body and frame, repair costs are above the class average) whereas another may be assessed as excellent in multiple categories. In such a case, the first vehicle will be prioritized for replacement, and replacement of the second vehicle can be deferred and re-assessed in the following year.

E8.1.5 Program Execution

Toronto Hydro usually procures vehicle by drafting a specification and circulating an RFP is to prospective vendors. Vendor submissions are then evaluated across multiple criteria, including cost, compliance with specification, and unit availability. One or multiple vendors may be awarded a bid to supply the requested vehicles. Pre-production meetings are then held as necessary through to delivery of the units. The complete process, from specification through to vehicle delivery – including internal collaboration and approvals – can range from approximately four months to more than one year.

(i) Program Risks

The most significant risk to the successful completion of the program within the planning period is product lead time. Once a vehicle has been technically specified, and the procurement process has been completed, vendors must be awarded the bid and a purchase order must be issued with

sufficient time for the vehicle to be delivered in the current plan year. While unit order size and vendor relationship can at times reduce product lead time, many variables such as the manufacturer's inventory of the requested vehicle, vendor time availability to perform upfits/customizations, and specification complexity, are not controlled by the successful RFP bidder. For example, the successful bidder may only perform the upfit portion of the delivery in-house, and may order all other parts of the unit specified in the tender from another party.

Typical vendor lead times are shown below:

TABLE 5: DELIVERY LEAD TIMES

Vehicle Description	Delivery Lead Time (Months)
Car/SUV/Pick Up/Van	3-6
Cube Van/Line Truck	6-9
Bucket Truck/Cable Truck	9-12
PPE Description	
Rubber Power Line Covers	0-4

The lead-time risk can be mitigated by awarding plan submissions well in advance of the calendar year of purchase. Doing so requires that vehicle review, specification, and RFP distribution are largely complete in the first half of the prior calendar year.

E8.1.5.1 Quantification/Evaluation of Options

Toronto Hydro considered three options for renewing its fleet: run to failure, maintaining previous IRM-level spending, and managed fleet replacement. Each of these options is discussed below.

(i) Run to Failure (Reduce Capital Spending to Zero)

Running the fleet to failure would involve replacing a vehicle only when it could no longer perform its intended functions. Depending on the vehicle type, design, and use, the point of total failure could be several years later than the time prescribed by Toronto Hydro's replacement criteria. While capital costs would be at a minimum (see Table 8 below) during the 2015-2019 period, this is not a viable alternative for the following reasons:

- Vehicle performance is likely to decline significantly over time – though the vehicle may be periodically maintained and capable of performing the intended function, it may do so more slowly, or with compromised precision that will affect Toronto Hydro's productivity and operational effectiveness.

- Unit field failures will likely increase as vehicles age – these field failures will adversely affect field crew productivity, and in some cases result in Toronto Hydro's inability to conduct system maintenance and capital investment as planned. This in turn will lead to higher labour and support costs (such as permits, penalties for late work completion, additional fuel on account of more frequent trips to and from a work location, etc.).

- The severity of failures is likely to increase, and these failures could potentially become more catastrophic, leading to safety risks, injuries, damage to property and/or equipment and environmental spills. For example, hydraulic hoses are more prone to failure over time. A catastrophic hydraulic line failure could, at minimum, result in an employee becoming trapped in a bucket, as well as result in a significant hydraulic fluid spill on to a roadway.

- Toronto Hydro operating costs for repairs are likely to significantly increase as parts fail and are replaced. As the vehicle ages, parts will likely become less available, resulting in increasing costs with respect to their purchase. Furthermore, to keep pace with increasing failures, it may be necessary for Toronto Hydro to increase the frequency of preventative maintenance tasks, as well as the number of mechanics it employs and/or the additional external resources it commissions.

- Perception of Toronto Hydro's level of service, to the extent it is affected by the appearance of Toronto Hydro vehicles and as perceived by Toronto Hydro's customers, may decline as vehicle appearances deteriorate (e.g. rust and fading paint) over time.

- Toronto Hydro may have to significantly increase vehicle/unit count to maintain similar vehicle availability levels to deliver equivalent service levels to customers – as vehicles age, out of service time will likely also increase due to repair challenges that increase as a vehicle ages (such as rusted bolts). This will increase repair complexity as failure modes increase and as needed parts become scarcer over time. To ensure that vehicles are available for use, Toronto Hydro would likely require the use of 'spare' vehicles should the main service vehicles become unavailable on account of maintenance and/or repairs. Toronto Hydro may have to rent or lease new equipment at significant cost.

- Replacement for units that have reached total failure require a lead time of between 3-12 months for purchase and delivery. In that time, Toronto Hydro's ability to perform system maintenance and capital investment may be impaired and/or delayed if alternate units cannot be sourced internally, or via a temporary path such as renting or leasing.

Though total spend for this option is significantly lower than the preferred Managed Fleet Replacement scenario described below, deferring the purchase of all vehicles from 2015-2019 and then implementing a vehicle replacement plan in accordance with the replacement criteria outlined above in section E8.1.3.2(i) will require a minimum investment of $17 million, and the purchase of over 302 units following the forecast period. Generally, due to limited labour availability, limited on-site storage and service space and limited administrative capacity, Toronto Hydro can only reliably in-service and decommission approximately 100 units per year. Under this scenario, it would take over three years before Toronto Hydro's fleet would fully comply with the replacement criteria.

Total cost of the Run Total Failure option (TCTF) is shown below in Table 7.

TABLE 6: TOTAL COST – SCENARIO (I) – RUN TO TOTAL FAILURE

Business Case Element	Cost (in Millions)
Run To Total Failure (Reduce Vehicle Capital Spending to Zero)	
Capital Cost of vehicle and equipment purchases [TC_{TF}]	$0.8

(ii) Status Quo (maintain previous IRM-level spending)

For 2013 and 2014, Toronto Hydro forecasted Fleet and Equipment Services capital program spending of $2.0 million each year. By maintaining this status quo, Toronto would continue to replace vehicles as per the new fleet replacement criteria, but capping replacement purchases at approximately $2.0 million per year.

In executing the status quo, the rate at which vehicles will be replaced will result in an increase in the average age of the fleet by 2.5 years. Operating costs are anticipated to steadily increase over the five-year planning period. Reliability will likely be impacted as the vehicles age, potentially leading to an increase in the number of vehicles that need to be removed from service for repairs, and/or an increase in the number of vehicle failures in the field. As discussed in section E8.1.3.1, this vehicle unavailability and a decrease in reliability will likely have an impact on Toronto Hydro's ability to perform system maintenance and execute capital investment. Like Option 1, the total spend for this option is lower than that of the preferred Option 3. However, to bring the fleet in line with the replacement criteria outlined above in section E8.1.3.2(i), a $12.0 million investment will be required by 2020. The needed pace of investment would be subject to the same resource, storage, and other constraints detailed in Option 1.

Total cost of the Status Quo option (TCQ) is shown below in Table 8.

TABLE 7: TOTAL COST – SCENARIO (II) – STATUS QUO/EXISTING STATE OF INFRASTRUCTURE

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Capital Cost of vehicle and equipment purchases [TC_Q]	$10.4

(iii) Managed Fleet Replacement

Toronto Hydro recommends the Managed Fleet Replacement alternative. Under this alternative, Toronto Hydro would undertake a like-for-like replacement of vehicles in line with the fleet replacement criteria outlined in section E8.1.3.2(i), capping vehicle replacement expenditures at an average of $3.4 million per year.

Replacing vehicles precisely to the minimum or maximum recommended replacement ages in the plan will result in capital spending that could swing by up to $4 million from year to year. The number of vehicles to be replaced would also vary greatly year to year, creating logistical challenges with in-servicing and disposing of decommissioned vehicles. Toronto Hydro therefore prefers to adopt a consistent investment spending level of $3.4 million per year to ensure that:

- operating expenses remain relatively stable over the plan years;
- the number of vehicles processed in any given year are manageable by the operation; and,
- the investment required to comply with the fleet replacement criteria post-2019 does not increase suddenly or rapidly.

With the selection of this option, Toronto Hydro ensures that replacement of vehicles identified per the criteria will optimize the total cost of vehicle ownership on average over time, which translates into maximum value for money for customers. Replacement at recommended intervals will likely also generate several benefits, including:

- greater overall vehicle reliability, translating to less downtime, fewer failures in the field, and resulting improved field personnel productivity,
- reduced shop load leading to improved shop productivity,

- likely increases in fleet vehicle and equipment performance,
- improved overall safety of fleet due to new/improved safety systems, and
- improved fuel efficiency leading to reduced green house gas emissions and fuel spend.

This option will result in a $7.5 million increase in total costs – made up of capital costs for asset purchases and maintenance costs – when compared to a Status Quo investment over the 2015-2019 period. However, following this initial level of investment, Toronto Hydro's vehicle replacement cost in accordance with the fleet replacement criteria is projected to remain consistent at approximately $3 million per year following the forecast period.

TABLE 8: TOTAL COST – SCENARIO (III) – MANAGED FLEET REPLACEMENT

Business Case Element	Cost (in Millions)
Managed Fleet Replacement	
Capital Cost of vehicle and equipment purchases [TC_{MF}]	$17.9

E8.2 Facilities Management and Security

E8.2.1 Summary

Program Description

Through the Facilities Management and Security program, Toronto Hydro plans to invest in building improvements that are integral to the proper functioning of Toronto Hydro's electricity system. The operation centers addressed by this program are specialized buildings, each with unique footprints and functions. Investments in this program are classified into five categories according to the relevant building system: security, mechanical, electrical, civil and architectural. Examples of material investments that are planned for the 2015-2019 period in each of these categories include the following.

- Security: Security enhancements are necessary to protect Toronto Hydro's assets as well as its employees and the general public with up-to-date security equipment and technologies. For example, Toronto Hydro plans to continue installing pan-tilt-zoom (PTZ) cameras and access control equipment to improve security infrastructure within stations. Toronto Hydro also plans to replace cameras that have reached or exceeded their life expectancy and are functionally obsolete at 500 Commissioners, 60 Eglinton, and 14 Carlton. Toronto Hydro also plans to install new cameras and security devices to reinforce protection and the safety of critical functions at 500 Commissioners.

- Mechanical: The Building B HVAC system at Toronto Hydro's 500 Commissioners location has reached its end-of-life and requires replacement. Mechanical renewal and modernization projects are also required at 14 Carlton and 60 Eglinton.

- Electrical: The 50-year old panel boards, disconnects and transformers installed at 14 Carlton and 60 Eglinton are obsolete, as many of the breakers, relays and switches are very difficult to source and maintain. These panel boards, as well as the Building Automation Systems at 14 Carlton and 500 Commissioners, must be upgraded during the planning horizon.

- Civil: Toronto Hydro must improve storm water management at 14 Carlton by grading and paving the parking lot to stop water infiltration. Currently, the lobby at this location floods during major storms.

- Architectural: Toronto Hydro plans to address issues regarding the foundation and building envelope – in particular, the brick masonry walls, windows and roofs at various locations. For example, roof replacements at 500 Commissioners, 60 Eglinton and 14 Carlton are required, as Toronto Hydro expects these assets to exceed their respective useful lives within the 2015-2019 period.

The anticipated benefits from these investments are summarized in the following table.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	• Addressing security issues and facility issues can mitigate safety risks to the public and ensures that Toronto Hydro employees are well equipped to provide timely and effective customer service.
Reliability	• Addressing of obsolescent systems which are not functional and unreliable such as BAS upgrades and HVAC/Boiler repair. • Managing risk at facilities reduces risk to system operations and system reliability during event response
Safety	• Security enhancement is a visual deterrent and also increases employee and public safety. • Addressing operational centre issues which pose safety risks (e.g. increased lighting)
Efficiency	• Renovations, heating/cooling to enable greater productivity of employees.

Program Drivers

The following table summarizes the trigger and secondary drivers of the investments in this program.

TABLE B: PROGRAM DRIVERS

	Drivers	Reasoning
Trigger Driver	System Maintenance and Capital Investment Support	ƒ Toronto Hydro's various facilities house support functions that are critical to the effective and efficient operation of all facets of the utility's business, including the planning and execution of maintenance and capital investment programs. ƒ A number of critical building assets have reached the end of their expected useful lives and/or are obsolete (i.e. no longer vendor supported). ƒ Failure of old and/or obsolete building assets can hinder the productive operation of Toronto Hydro's business functions. The failure of certain critical facilities assets could directly impact Toronto Hydro's ability to respond effectively to power interruptions or emergency situations. ƒ Toronto Hydro's facilities continue to require investments in security infrastructure in order to align with NERC standards and to help eliminate potential threats to the visiting public and to utility personnel and property.
Secondary Drivers	Safety	ƒ Employees must be safe in the workplace. ƒ Floors at 500 Commissioners are not smooth or free of potential hazards, which can result in injury. ƒ Unauthorized personnel may be able to enter certain buildings. ƒ Carbon monoxide warning levels are not linked into the BAS system at 500 Commissioners, so a cracked heat exchanger could potentially expel carbon monoxide into the workplace. ƒ The general public should be protected from power outages due to accidental exposure to equipment or deliberate attempts to destroy equipment. ƒ There are 50 stations that are not monitored by CCTV. ƒ Toronto Hydro is at risk of an accidental or deliberate breach that can result in equipment failure. ƒ Occupational Health and Safety compliance. ƒ The temperature of office space at 500 Commissioners and 14 Carlton was not consistently above 18 degrees Celsius during the 2013/14 winter due to several heat exchangers cracking and malfunctioning. ƒ asbestos and other designated substances need to be treated and handled via strict procedures when work commences on these project.

	Drivers	Reasoning
	Failure Risk	ƒ Toronto Hydro buildings feature components that have reached or exceeded their expected useful lives and/or are functionally obsolete. ƒ Maintenance costs for old and obsolete assets are expected to continue to increase over time. ƒ The potential impact on safety and system reliability of certain assets failing is notable. For example, a cracked heat exchanger may allow carbon monoxide (CO) to enter the workplace.
	Reliability	ƒ The capital investment program is required to help ensure that all work centers, stations and the power systems operate as required. ƒ Gates and dock levelers are breaking down due to age, which can delay trucks from getting equipment and leaving the work centers. ƒ Roof top heating units are failing due to age and design and can create unsatisfactory conditions for employees. ƒ Security cameras and equipment are continually breaking down and are not always functioning as required. As of May 23, 2014, there have been 38 camera failures that have been documented for the year.

Preferred Alternative

Maintaining the current state (the "do-nothing" option) is expected to result in a number of consequences requiring emergency attention. These include major facility failures causing flooding and compromised civil structures. The results of the failures could result in injury and interruptions to customer service and business operations. Toronto Hydro's preferred alternative is to proceed with the proactive investments as planned in order to ensure continuity of business operations and efficient delivery of customer service and capital and maintenance programs.

Timing and Pacing

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Forecasted Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	12.1	8.1	6.6	6.8	7.5	16.5	9.4	2.0	2.0	1.9

/C

Facilities Management and Security investments are forecasted to increase in 2015 and 2016 compared to the spending in previous years. Investment is then expected to drop considerably. The initial increase is due to the infrequent replacement of several large building components. These components (such as HVAC systems) are prone to malfunction and/or they put Toronto Hydro at risk of experiencing significant water damage (e.g. roofing systems). These projects are considered urgent and highly non-discretionary for the years scheduled. Routine facilities capital investment is expected to taper off in the later years, in part due to the execution of the Operating Centers Consolidation Program (E7.3).

The total cost of the program over the 2015 to 2019 period is projected to be approximately $32 million. /C

E8.2.2 Program Description

Through the Facilities Management and Security program, Toronto Hydro plans to invest in building improvements that are integral to the proper functioning of Toronto Hydro's electricity system. The operation centers addressed by this program are specialized buildings, each with unique footprints and functions. The buildings are mixed-use facilities, containing warehousing, fleet garage, office space and training centers. Each operations center is described below.

500 Commissioners

FIGURE 1: 500 COMMISSIONERS STREET

500 Commissioners complex is Toronto Hydro's primary service center located on the northeast corner of Carlaw Avenue and Commissioners Street. It is comprised of four buildings (A, B, C and D) and was built in November 1996. 500 Commissioners is Toronto Hydro's Central Service Centre. The buildings are located on 16.8 acres of land and include 94,717 square feet of warehouse space, 213,854 square feet of office space, 51,497 square feet of garage space, 384,299 square feet of parking space and 192,898 square feet of yard space. The structure is a multi-use facility for many divisions, including warehouse, fleet, facilities, call center, engineering and field operations. The complex houses over 700 employees and over 280 system vehicles. 500 Commissioners must be accessible throughout the year at all hours of the day and evening; it is an integral hub in the operation and control of the distribution grid.

500 Commissioners is now 18 years old and, due to its location and other nearby industrial work centers, has shown major signs of aging. To maintain efficient operations, several of the building's systems that are approaching their end of life should be replaced because maintenance can no longer satisfactorily address problem areas. These systems have already undergone repeated repairs and have reached the point at which capital replacement is essential.

14 Carlton

14 Carlton Street is a ten-story office building that was constructed in 1932 to act as Toronto Hydro's original corporate head office. The building was designated a historical site in 1991. It is made up of 179,895 square feet of office space and houses more than 325 employees who work in areas including human resources, finance, law and information technology areas. Like most high rise office buildings, 14 Carlton contains elaborate electrical and mechanical systems spread throughout the building. Over the decades, 14 Carlton has undergone two significant renovations, the most recent of which was completed in 1972.

FIGURE 2: 14 CARLTON STREET (LEFT: FRONT ENTRANCE, RIGHT: REAR ENTRANCE AND PARKING LOT)

Renovating 14 Carlton involves a number of challenges, the most difficult of which is the need to contain and remove asbestos. Asbestos containing materials (ACMs) are found in drainage piping, insulation, floor coverings, wall finishes, electrical panels and heating and cooling systems. Many of these systems need to be replaced, which entails extra cost because of the

legally mandated steps to address ACMs. The renovations to 14 Carlton planned for the 2015-2019 period are needed in order to maintain building comfort, improve safety and decrease costs associated with emergency repairs and maintenance.

60 Eglinton

60 Eglinton Avenue West was constructed in 1954 and operates as a satellite facility that houses 30 employees. The system response group works out of this building throughout the year at all hours of the day and evening. This facility functions as Toronto Hydro's backup control center and houses specialized equipment for power switching functions. The three-storey, 19,626 square feet office building is aging and major system requires replacement, such as the roof, elevator, HVAC and electrical equipment, and interior renovation. Much of the interior to be addressed is known to be affected by ACMs. Investments at 60 Eglinton is designed to maintain occupant safety and comfort and to decrease the cost associated with repairing equipment that lacks readily available replacement parts.

FIGURE 3: 60 EGLINTON AVE. WEST

Stations Facilities

Toronto Hydro has over 215 substations ranging from large scale buildings that house multiple transformers to facilities that resemble small homes with transformer pockets (Figure 4). Toronto Hydro's Distribution System Plan (DSP) includes a separate Stations Building Infrastructure Renewal program (Exhibit 2B, Section E6.18) that addresses the reliability and safety risks associated with aging building infrastructure across the distribution system. The Facilities Management and Security program will focus on security enhancements at a number of stations. Security within these stations is a high priority because they are predominantly unoccupied and remotely monitored. Trespassing on Toronto Hydro properties needs to be prevented in order to maintain public safety and grid integrity.

FIGURE 4: EXAMPLES OF STATIONS FACILITIES

Work in the Facilities Management and Security program can be organized into five major building systems: security, mechanical, electrical, civil and architectural, further explained below.

E8.2.2.1 Security Enhancement

Security enhancements are necessary to protect Toronto Hydro's assets as well as its employees and the general public with up-to-date security equipment and technologies. Toronto Hydro is moving towards North American Electric Reliability Corporation (NERC) standard compliance and is working to implement recommendations noted in the standard surrounding physical security.

Toronto Hydro plans to continue installing pan-tilt-zoom (PTZ) cameras and access control equipment to improve security infrastructure within stations. Since June 2010, Toronto Hydro has been installing cameras and swipe card access at stations to enhance the safety of the facilities, deter crime and provide continuous monitoring. To improve the network, Toronto Hydro intends to expand and install 50 additional cameras at various stations.

In addition, Toronto Hydro plans to replace cameras that have reached or exceeded their life expectancy and are functionally obsolete at 500 Commissioners, 60 Eglinton, and 14 Carlton. These old analogue cameras are set to be replaced with new Internet Protocol (IP) based cameras that have better resolution and offsite, real-time data storage. IP cameras are beneficial because they house data on servers that are centrally located offsite, meaning that the data they collect is protected and easy to monitor remotely. There are a total of 54 Fixed Cameras and 30 PTZ Cameras that Toronto Hydro intends to replace during the 2015-2019 period. Toronto Hydro also plans to make required improvements to the infrastructure that supports these cameras.

Toronto Hydro also plans to install new cameras and security devices to reinforce protection and the safety of critical functions at 500 Commissioners. Toronto Hydro plans on installing the additional cameras in areas that require security improvement such as gate access points, lobbies, entrances, upper level floors and parking lots.

Other projects are needed to prevent and deter unauthorized entries onto Toronto Hydro properties. Toronto Hydro plans to install equipment such as locking hardware, card readers, fencing/gates, lighting, and intercom systems. Toronto Hydro also plans on upgrading vehicle transponders to include the use of a Toronto Hydro badge to open work centre gates. Furthermore, Toronto Hydro plans to renovate the security lobby at 500 Commissioners to accommodate turnstiles and swipe card readers to prevent unauthorized access.

Installing cameras, locking mechanisms, fencing, lighting and signage are expected to provide the following benefits:

- a visual deterrent in crime prevention;
- assists in evidence gathering;
- ensures unauthorized personnel cannot enter restricted areas; and
- helps to improve employee and public safety.

A summary of the forecasted investments for the security projects described in this sub-section is shown below in Table 1.

TABLE 1: SECURITY ENHANCEMENT BUDGET REQUIREMENTS

	2015	2016	2017	2018	2019
SECURITY	$ 2,104,270	$ 2,055,125	$ 202,125	$ 447,125	$ 355,125

/C

E8.2.2.2 Mechanical

Mechanical systems refer to the plumbing, heating, air conditioning, and elevators within a building. A number of mechanical systems and equipment are approaching or have exceeded their life expectancy. Replacing these items is important for reliability, safety and operational readiness. Toronto Hydro plans to replace the mechanical systems and infrastructure at the three buildings outlined below.

500 Commissioners

The Building B HVAC system has reached its end-of-life based on industry standards and requires replacement. Toronto Hydro plans to replace the existing system with a variable air volume (VAV) system. The VAV system is typically found in large office buildings like 500 Commissioners and provides many benefits; it supplies a constant air temperature within the interior of the building while the perimeter zones are heated or cooled as needed, which is a much more efficient design than the existing HVAC system. Maintenance costs are expected to decline because less equipment will be necessary; 35 roof top units in building B are set to be replaced by a few air handling units with a chiller and boiler. Also, a VAV system is more flexible for modifications and expansions purposes if required. To install this type of system, Toronto Hydro needs to remove the existing roof top units and aging Variable Volume and Temperature (VVT) system. Once the existing system is removed, the new air handling system is installed with cooling coils, hot water heating coils, heat recovery wheel, humidification and a fresh air damper.

The emergency exits, overhead doors, dock levelers and yard gates at 500 Commissioners are also in need of replacement. The exits have failed to open during fire drills and the overhead doors and yard gates are frequently breaking down.

Other smaller scale projects include installing new hot water heaters and a steam boiler control. The existing steam boiler control has been turned off due to over humidification.

14 Carlton

The mechanical projects at 14 Carlton focus on replacing items that past end-of-life, functionally obsolete and have a small part supplier network. The projects include:

- Removal and replacement of cast iron drainage. This drainage piping is over 70 years old and there are many cracks that result in leaking sewage. The odour is unpleasant for employees and customers and there is a potential risk of a spill occurring.
- Replace HVAC components that are over 40 years old. These are functionally obsolete as they lack parts and a service network.

60 Eglinton

The projects at 60 Eglinton are smaller in nature and focus mainly on replacing obsolete parts that lack a large supplier network for parts and service. The projects include:

- Replace the parking gate and 10 emergency exit doors. The exit doors are rusted and do not open freely. The doors should be replaced to ensure they open in an emergency. The gate has also reached its end of life.
- Replace condenser and roof top unit. Both are end of life assets that should be replaced since parts are scarce and not available.
- Freight elevator modernization. This will bring the elevator up to current Technical Standards and Safety Authority (TSSA) standards and provide controls and parts that are readily available since the current system is outdated and expensive to maintain.
- Replace chiller and Liebert unit that are at end of life and impacting operating budgets for repairs.

A summary of the estimated cost requirements for all mechanical systems investments is provided in Table 2.

TABLE 2: MECHANICAL PROJECT BUDGET REQUIREMENTS

	2015	2016	2017	2018	2019
MECHANICAL	$ 5,546,000	$ 3,704,500	$ 305,000	$ 165,000	$ 175,000

E8.2.2.3 Electrical

Electrical systems refer to the power distribution system, building automation system (BAS) and the fire and security monitoring system in Toronto Hydro's buildings. The 50-year old panel boards, disconnects and transformers installed at 14 Carlton and 60 Eglinton are obsolete, as many of the breakers, relays and switches are very difficult to source and maintain. Toronto Hydro should not risk using non-standard components in lieu of the Original Equipment Manufacturer (OEM) components since they can potentially cause fires, electrocution and/or additional power outages. Toronto Hydro is also at risk if a failure occurs on one of these long lead, which are special order items that are not found in stock at the wholesalers.

The BAS is an integral part of each facility, as it monitors critical systems and flags issues before failure or damage to other components. The BAS at 14 Carlton and 500 Commissioners is outdated, not centrally located and is difficult to service due to a lack of vendor support. This system has not been very effective in flagging a number of issues within Toronto Hydro buildings. It is the utility's intent to improve the base BAS to expand its capabilities and measure and monitor critical systems within the building with a true BACnet (Building Automation Control)/IP system. This BACnet/IP system is the new industry standard amongst all equipment available on the market. Examples of additional alarms proposed to be installed include:

- floats on sewage ejectors;
- water sensors in critical rooms;
- warning alarms on carbon monoxide levels;
- temperature and humidity probes in critical rooms;
- power failures on critical systems; and
- security breaches.

The potential benefits of a BACnet system include:

- being notified via alarms of critical systems such as floods, sewage back up, high temperatures and system faults;
- scheduling for efficiencies to minimize utility costs during non-business hours;
- trend logs and statistics to help find efficiencies and system faults before failure; and

- connecting all buildings, which helps productivity and efficiency since only one person will be needed to monitor all buildings and flag issues to the building operators.

Other potential electrical projects include the relocation of the emergency lighting and enunciator panel and the replacement of a motor control center panel at 14 Carlton.

The electrical projects within this program are vital to the reliable operation of Toronto Hydro's core business. The BAS upgrades are expected to allow for quicker response times to potential emergencies, and the panel upgrades will minimize risk in buying and waiting for obsolete parts with a shrinking supplier network. The estimated annual costs for the electrical activities in this program are summarized in Table 3.

TABLE 3: ELECTRICAL PROJECT BUDGET REQUIREMENTS

	2015	2016	2017	2018	2019
ELECTRICAL	$ 520,000	$ 22,000	-	$ 170,000	$ 66,000

E8.2.2.4 Civil Work

Civil work refers to the interior and exterior coverings and surfaces of the buildings, access ways, walk ways and windows. The civil work activities in this program are designed to address concerns related to building footprint issues. The projects are also expected to address poor drainage at 14 Carlton where the lobby floods during major storm events, see Figure 17. In 2013, Toronto experienced two particularly severe rain storms, both of which resulted in the main lobby being flooded, where rainwater pooled in the rear stairwell and penetrated through the door opening. In the interim, Toronto Hydro has scheduled expedited and higher frequency catch basin pumping and has sand bags available to seal the rear doorway; however, these are not permanent solutions.

The civil programs Toronto Hydro plans to undertake include:

- Improve storm water management at 14 Carlton by grading and paving the parking lot to stop water infiltration.

- Improve barrier free access at 14 Carlton to allow access for wheelchairs through the rear parking lot. Section 200.15.1.5 of City of Toronto Zoning Bylaw [3] states that accessible parking spaces must be located closest to a main pedestrian access to a

[3] City of Toronto, by-law No. 569-2013, Zoning By-law (9 May 2013). ["City of Toronto Zoning By-law"]

building (specific dimension is not defined). Currently, the barrier-free access directs pedestrians from the rear of the parking lot, through the adjacent alley, and to the front entrance on Carlton Street. Due to the distance between the rear and front of the building, this is not the ideal route for barrier free access.

- Asphalt repair at 14 Carlton's loading dock since it continues to erode, causing large holes. Toronto Hydro plans to initiate a study to determine the cause of the erosion, which could be a damaged water line or artesian well.

- Painting of parking spots and spot numbers at 500 Commissioners.

The forecast cost for the civil works projects are summarized in Table 4 below.

TABLE 4: CIVIL WORKS BUDGET REQUIREMENTS

	2015	2016	2017	2018	2019
CIVIL	$ 395,000	-	-	-	$ 125,000

E8.2.2.5 Architectural

Architectural systems refer to the volumes and functions of a building. Toronto Hydro plans to address issues regarding the foundation and building envelope – in particular, the brick masonry walls, windows and roofs. The described replacement campaigns focus on end of life assets that are becoming increasingly costly to maintain. Proposed projects include:

- Roof replacements at 500 Commissioners, 60 Eglinton and 14 Carlton since Toronto Hydro expects them all to exceed their respective useful lives within the 2015-2019 period. Roof replacements should minimize continuous, expensive and sometimes unsuccessful repairs. Replacing the membranes is expected to provide years of improved protection for the buildings' occupants and assets.

- Repair of the exterior masonry walls and foundation at 14 Carlton; this is expected to eliminate water infiltration into the basement and refresh the appearance of the building, as the exterior walls are severely stained (Figure 25).

- Replacement of the windows at 14 Carlton, as they are producing condensation that stains the masonry walls and creates the conditions for mould growth in the window sills.

Toronto Hydro also plans to renovate the floors at 14 Carlton. The renovation will address issues such as:

- Renewing office space that is past its useful life and no longer suitable for use.
- Populating the now empty 6th floor that has also been stripped to base building foundations in the process of prior asbestos remediation (Figure 18).
- Optimizing the space to the current Toronto Hydro Office Standards.
- Refurnishing the building with standard office furniture, fixtures and finishes.

Each floor currently varies in both age and degree to which ACM's are present. Depending on the floor in question, the construction work required will range from refreshing current finishes that are past their life expectancy to full floor demolition and renovations (Figure 18), which is explained in detail below. Furthermore, the 2nd floor at 14 Carlton houses critical equipment and the floor has many signs of wear including large cracks. The floor must be repaired and reinforced to ensure it can continue supporting this equipment. Floor repair in this room will require special measures to ensure that nearby computer rooms remain free of dust and vibration. /C

The third floor of 60 Eglinton is currently in an inoperable state. It has not been renovated in more than 30 years and the equipment in place is obsolete and not required. The office standards that Toronto Hydro plans to implement at 14 Carlton and 60 Eglinton is currently in place at 500 Commissioners and as a result, the capacity of the building has increased, with the number of occupants in the building rising by approximately 200 employees.

The remaining proposed architectural projects include a number of small scale projects that focuses on common building improvements. These include:

- replacing broken floor tiles and concrete floors at 500 Commissioners to provide clean, smooth floor finishes, which minimize the risk of slips, trips and falls,
- painting at 500 Commissioners,
- washroom renovation at 60 Eglinton,
- removing an abandoned brick chimney at 14 Carlton, and
- structural review at 60 Eglinton, triggered by the fact the building is 60 years old. Performing the study will provide confidence in the buildings integrity and highlight issues Toronto Hydro is not equipped to assess.

The estimated cost of the architectural projects within this program are shown in Table 5 below.

TABLE 5: ARCHITECTURAL PROJECTS BUDGET REQUIREMENTS

	2015	2016	2017	2018	2019
ARCHITECTURAL	$ 7,768,500	$ 3,400,000	$ 1,445,000	$ 1,175,000	$ 1,095,000

/C

In summary, the facilities capital plan focuses on improving building envelopes, properties, equipment and systems. These replacement programs are required to allow Toronto Hydro's core business to operate reliably, efficiently and to comply with legislation.

The following table summarizes the anticipated benefits of this program.

TABLE 6: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Addressing security issues and facility issues can mitigate safety risks to the public and ensures that Toronto Hydro employees are well equipped to provide timely and effective customer service.
Reliability	ƒ Addressing of obsolescent systems which are not functional and unreliable such as BAS upgrades and HVAC/Boiler repair. ƒ Managing risk at facilities reduces risk to system operations and system reliability during event response
Safety	ƒ Security enhancement is a visual deterrent and also increases employee and public safety. ƒ Addressing operational centre issues which pose safety risks (e.g. increased lighting)
Efficiency	ƒ Renovations, heating/cooling to enable greater productivity of employees.

E8.2.3 Why the Program is Needed

Toronto Hydro's Facilities Management and Security program is required to help maintain the safe, reliable and efficient operations of work centers and stations facilities.

E8.2.3.1 Program Drivers

The trigger and secondary drivers of capital investment in this program are summarized in Table 7.

TABLE 6: SUMMARY OF PROGRAM DRIVERS

	Drivers	Reasoning
Trigger Driver	System Maintenance and Capital Investment Support	x Toronto Hydro's various facilities house support functions that are critical to the effective and efficient operation of all facets of the utility's business, including the planning and execution of maintenance and capital investment programs. x A number of critical building assets have reached the end of their expected useful lives and/or are obsolete (i.e. no longer vendor supported). x Failure of old and/or obsolete building assets can hinder the productive operation of Toronto Hydro's business functions. The failure of certain critical facilities assets could directly impact Toronto Hydro's ability to respond effectively to power interruptions or emergency situations. x Toronto Hydro's facilities continue to require investments in security infrastructure in order to align with NERC standards and to help eliminate potential threats to the visiting public and to utility personnel and property.
Secondary Drivers	Safety	x Employees must be safe in the workplace. o Floors at 500 Commissioners are not smooth or free of hazards, which can result in injury. o Unauthorized personnel may be able to enter certain buildings. o Carbon monoxide warning levels are not linked into the BAS system at 500 Commissioners, so a cracked heat exchanger could potentially expel carbon monoxide into the workplace. x The general public should be protected from power outages due to accidental exposure to equipment or deliberate attempts to destroy equipment. o There are 50 stations that are not monitored by CCTV. o Toronto Hydro is at risk of an accidental or deliberate breach that can result in equipment failure. x Occupational Health and Safety compliance. o The temperature of office space at 500 Commissioners and 14 Carlton was not consistently above 18 degrees Celsius during the 2013/14 winter due to several heat exchangers cracking and malfunctioning. o It should be noted that asbestos and other designated substances need to be treated and handled via strict procedures when work commences on these project.

	Drivers	Reasoning
	Failure Risk	x Toronto Hydro buildings feature components that have reached or exceeded their expected useful lives and/or are functionally obsolete. x Maintenance costs for old and obsolete assets are expected to continue to increase over time. o The potential impact on safety and system reliability of certain assets failing is notable. For example, a cracked heat exchanger may allow carbon monoxide (CO) to enter the workplace.
	Reliability	x The capital investment program is required to help ensure that all work centers, stations and the power systems operate as required. o Gates and dock levelers are breaking down due to age, which can delay trucks from getting equipment and leaving the work centers. o Roof top heating units are failing due to age and design and can create unsatisfactory conditions for employees. o Security cameras and equipment are continually breaking down and are not always functioning as required. As of May 23, 2014, there have been 38 camera failures that have been documented for the year.

Each of Toronto Hydro's facilities houses unique support functions that are critical to the ongoing operation, control and administration of the distribution system and other important business functions such as customer service and communications. Every building has specific needs relating to comfort, design and controls depending on the functions housed within. Toronto Hydro believes that it needs to maintain certain basic standards with respect to building attributes so that the employees can continue operating and improving the distribution system and so that they can deliver timely and effective customer service. These standards include:

- a workplace that is heated and cooled to acceptable temperatures;
- building envelopes that do not leak and protect against the elements;
- fresh air that is free of particulates and carbon monoxide;
- hot water faucets and showers for those employees working with controlled substances such as lead;

- unobstructed flooring that does not present tripping hazards;
- properties that are secure against intruders, vandalism and potential injuries; and
- a workplace that is secure and protected from unauthorized individuals.

The following subsections provide a more detailed discussion of the investment drivers behind the planned Facilities Management and Security program, with reference to the trigger and secondary drivers presented in Table 8 above.

Security Deficiencies

Toronto Hydro believes that security enhancement are required to improve public and employee safety, as well as grid integrity. The statistics in Table 8 represent Toronto Hydro's experience with crimes and injuries at all utility sites, including stations. Toronto Hydro is a safety driven organization, the ultimate objective of additional security investments is to eliminate these incidents altogether given the safety and security risks they represent.

TABLE 7: SECURITY INCIDENTS ON TORONTO HYDRO PROPERTY

	2011	2012	2013
Theft	14	21	6
Forced Entry	3	3	5
Vandalism	5	5	6
Injury	14	24	13
Trespass	8	14	5
Threats to Employees	1	7	1

To address critical security and safety concerns at multiple properties and work centres, Toronto Hydro plans to undertake the following projects:

- Installing additional cameras at 500 Commissioners to further improve security of critical functions that cannot be affected.
- Installing additional card swipe access and CCTV camera's at stations. Toronto Hydro should be in a position to monitor the stations and react to safety issues and criminal acts as soon as possible. Card swipe access provides history to track who has been in and out of high voltage areas

- Improve signage at Toronto Hydro stations to ensure the public knows it is private property and cannot be used for recreation, gardening and neighbourhood parties, all of which occurs regularly.
- Install lights to deter break and enters on Toronto Hydro property and neighbouring property.
- Improve and install fencing to ensure people off Toronto Hydro potentially dangerous property.
- Improve security functions in the lobbies and the procedures therein to ensure unauthorized people cannot enter the buildings and areas containing critical components and valuable equipment.

Toronto Hydro has been continuously improving physical security and security policy. It is Toronto Hydro's intent to carry on with upgrades to move toward NERC standards. NERC standards play a significant role in protecting critical infrastructure such as Supervisory Control and Data Acquisition (SCADA) gear and also by layering physical security barriers. Two of the most critical components of the standard ensure that there are video monitoring and access control to monitor who is accessing the equipment and to prohibit unauthorized personnel from entering restricted areas.

Aging and Obsolete Mechanical Systems

Several mechanical systems at 500 Commissioners, 14 Carlton and 60 Eglinton require replacement due to age, lack of parts and functional obsolescence. The major planned projects within this program are the HVAC retrofit at 500 Commissioners, drainage piping at 14 Carlton and doors and gates at 500 Commissioners.

HVAC Systems

Space heating and cooling for the office areas in all three Toronto Hydro owned work centers (500 Commissioners, 14 Carlton and 60 Eglinton) are primarily provided by rooftop HVAC units and VVT damper controls. Most of these units were installed in 1995 or 1996 at 500 Commissioners and in 1970 for 60 Eglinton and 14 Carlton. The existing HVAC units are associated with a number of issues related to age, design and function. Poor design, aging components (Figure 5 below), cracked heat exchangers (Figure 6 below) and high maintenance costs are driving the need to replace this equipment in the 2015-2019 period.

FIGURE 5: RUSTED HEAT EXCHANGERS PRONE TO SPLITTING. COMBUSTION GASES WILL ENTER THE OFFICE SPACE

FIGURE 6: CRACKED HEAT EXCHANGER

From 2011 to 2013, total repair costs associated with HVAC equipment was $472,268 due to over-cycling conditions, further explained below, and the equipment being near its end-of-life based on industry standards.

Problems with the 500 Commissioners HVAC system include:

(1) The duct system is zoned incorrectly between perimeter zones and interior zones. This forces cycling between heating and cooling on a single floor due to the fact that it is hotter near windows in the summer and colder near the windows in winter. The system is satisfying the perimeter temperature needs at the expense of the interior temperatures.

(2) The system is stacked vertically and the three floors continually battle one another between heating and cooling floor to floor, which can affect equipment longevity.

(3) The rooftop units and VVT controls are obsolete and lack a qualified supplier network, making it difficult to obtain spare parts and resulting in extended repair times.

As previously discussed in section E8.2.2.2, to address these issues and provide consistent and comfortable temperatures and functional controls, Toronto Hydro plans to replace the system with a modern VAV system.

Renewal of the HVAC system at 14 Carlton is also recommended. The equipment at 14 Carlton is comprised of central plant equipment, piping distribution of heating and chilled water, and air handling equipment. The air handling systems encompass several outdoor air units, compartment units (one per floor), and perimeter fan coil units for heating and cooling throughout each floor (over 400 units in total). The majority of the air handling equipment was installed in the 1970s and is well past its expected service life. In addition, refurbishment of the chillers are necessary since they are obsolete and past their expected useful life. This was captured on a lifecycle analysis performed in late 2013.

FIGURE 7: CHILLER REPLACEMENT / REFURBISHMENT

Drainage Piping at 14 Carlton

14 Carlton's plumbing systems are insulated with coverings that include ACM's. The drainage piping is, in most cases, the original cast iron piping from 1932 and has become prone to cracking, leading to leaks. Figure 8 shows an example of cracking. The leaks not only produce unsightly stains and spills as shown in Figure 9, but also produce unbearable odours. The drainage system network includes multiple risers throughout the floor plates and is estimated to consist of over 1.25 km of pipe. Due to the age of the drainage piping system, there is also a significant amount of remediation of designated substances such as lead, oakum and asbestos required as part of the replacement work. Failure to replace the piping in a timely manner raises the risk of a major break that could result in a spill that is larger than the one documented in Figure 9.

FIGURE 8: CRACKED DRAINAGE PIPING AT 14 CARLTON.

FIGURE 9: CRACKED DRAINAGE PIPING RESULTS IN STAINS AND SPILLS BASEMENT

Doors, gates and dock levers

Overhead doors are located throughout buildings A, B, and D at 500 Commissioners and were installed in 1995. The automatic doors and associated closing mechanisms that lead to the loading docks and storage areas are showing signs of aging as depicted in Figure 10. Corrosion at the bottom of the door frame can eventually lead to wider door closing gaps and doors not closing completely. Smoke and fire can potentially seep through these gaps, which can possibly undermine the proper fire rating requirements needed to protect individuals and assets. In addition, gaps from doors not fully closed can release heat in the winter. This can create ice, which poses a slipping hazard, strains the heating units, and causes increased demand on natural gas utilities. There are 18 overhead doors in various sizes that Toronto Hydro plans on replacing between 2016 and 2018.

FIGURE 10: CORROSION OF OVER HEAD DOOR FRAME AND RAIL AT 500 COMMISSIONERS.

Exterior doors, which include both single and double doors, are located throughout 500 Commissioners and were installed in 1995. Due to the harsh weather conditions near the lake and the salting of ice, the exterior doors show significant wear and tear, including corrosion. Figure 11 depicts one such example, where both the door and frame are rusted. This type of corrosion resulted in three doors not opening during the 2013 annual fire drill. The affected doors were in the main office and did not open when the occupants were in the stairwell trying to exit. Failing to replace these doors can pose a potential safety risk in the event of a fire.

Figure 12 depicts a door that will not close due to rust. This is a security concern, as these doors can potentially be used to gain unauthorized entry to the building, which in turn puts Toronto Hydro employees and assets at potential risk. There are 44 exterior doors located throughout 500 Commissioners that Toronto Hydro plans to replace during the 2015-2019 timeframe.

FIGURE 11: RUSTED DOOR AND FRAME. THE DOOR PICTURED DID NOT OPEN EASILY AND ONCE OPEN IT DID NOT CLOSE.

FIGURE 12: RUSTED DOOR THAT WILL NOT CLOSE IS A SECURITY AND FIRE HAZARD.

Dock levelers are height-adjustable platforms that are used to bridge the gap between the dock and a truck. Once engaged, fork trucks can load and unload the trucks. Toronto Hydro currently has nine dock levelers and each of them is corroded and have gone through years of wear and tear, as seen in Figure 13 below. Toronto Hydro intends to replace all of these dock levelers between 2015 and 2019 in order to minimize the risk of malfunction and the cost of repair. Figure 14 depicts a locked out dock leveler that is jammed due to corrosion. The parts that are stocked in the warehouse and delivered to the distribution workers rely on the dock levelers daily. In addition, dock leveler design has improved to include better safety features for service.

FIGURE 13: 1 OF 9 DOCK LEVELER'S AT 500 COMMISSIONERS. THEY ARE FAULTING OUT REGULARLY SINCE THEY ARE CORRODING.

FIGURE 14: ONE OF THE DOCK LEVELLERS IS LOCKED OUT DUE TO CORROSION / JAMMING

The gates, like the one shown in Figure 15, and the associated drivers and control units at 500 Commissioners, were installed in 1996 and are expected to reach the end of their useful lives in 2016. The drivers and control units should be replaced to ensure that the eight gates currently in service do not malfunction due to wear and tear, which could cause a delay to construction, line crews and other personnel who rely on fleet vehicles to carry out the day-to-day business of the utility. The gates provide access to Toronto Hydro vehicles and assets such as copper and aluminum, and are therefore critical in preventing trespassing and theft. From January 1 to May 15, 2014 there were 44 work orders to repair four gates at 500 Commissioners, see Table 9 below for details. Of those, 16 of them needed a visit from a gate repair company that resulted in $6,600 worth of repair costs.

TABLE 8: WORK ORDERS TO REPAIR GATES AT 500 COMMISSIONERS

WO #	Description	WO #	Description
964185	INVESTIGATE AND REPAIR GATE 4	918229	REPAIR CABLE @ GATE CONTROL BOX
964181	INVESTIGATE AND REPAIR GATE #2	917017	RMVE LOCKS FRM GATE CNTRL BOX
963502	GATE 2 DOES NOT CLOSE PROPERLY	916426	INVESTIGATE AND REPAIR GATE 4
959531	TROUBLE SHOOT GATE 4	915598	GATE 4 NOT CLOSING
959524	GATE 2 NOT WORKING	914008	GATE 2 STUCK OPEN
959471	GATE 4 NOT WORKING	914004	GATE 4 NOT CLOSING ALL THE WAY
959459	REBUILD CONTROL BOXES GATE 3	913638	DISCONNECT JAMMED ROLLER GATE 2

WO #	Description	WO #	Description
956944	GATE 4 STUCK OPEN	913145	REPAIR DISCONNECT FOR THE GATE
952601	REPLACE DISCONNECT TO GATE 3	909066	REPAIR ROCK LATCH ON MAIN GATE
946509	GATE 3 NOT CLOSING	905458	BROKEN LATCH ON MAIN GATE.
939338	GATE 3 NOT OPERATING REMOTELY	905438	GATE VALVE LEAKING WATER SUPP
939197	GATE 3 PARTIALLY OPENING	903055	GATE #3 NOT WORKING CALL #2
937485	GATE 2 NOT RESPONDING	903032	GATE THREE NORTH WEST
937352	GATE 3 DISCONNECT NOT WORKING	902477	EXTERIOR GATE 3 MALFUNCTIONG
937339	GATE ARM WILL NOT CLOSE	901222	GATE 3 IN ALARM NOT CLOSING
937211	GATE #2 OUT NOT CLOSING	887136	RELOCATE ACCESS BUTTON 4 GATE
937206	GATE #2 OUT NOT CLOSING	883554	GATE 3 NOT OPENING PROPERLY
934950	E. VEHICLE GATE LVL 0 NOT RESP	883252	GATE 3 INOP CAR LAW
923178	GATE 4 NOT CLOSING PROPERLY	882940	BUILDING D GATE NOT CLOSING
920407	GATE 2 OUT	881600	GATE #1 FAILED
919386	GATE 3 NOT OPENING	881443	BRKN CANE BOLT ON SECURITY GATE
918729	GATE 4 NOT FUNCTIONING	881394	GATE 3 IS MALFUNCTIONING

FIGURE 15: GATE 3 AT 500 COMMISSIONERS IS ONE OF FOUR GATES TO KEEP UNAUTHORIZED EMPLOYEES AND VEHICLES OUT. THEY NEED TO OPERATE FLAWLESSLY TO ALLOW GRID RESPONSE TEAMS TO ENTER AND EXIT THE YARDS.

Insufficient and Obsolete Electrical Systems

The electrical systems at 500 Commissioners and 14 Carlton are in need of repair and improvement. The projects listed below are required due to functional obsolescence of existing systems and the need for more efficient and effective proactive maintenance planning.

Electrical panel replacements

The 416/240V and 120/208V power distribution system at 14 Carlton is comprised of a number of step-down and step-up transformers, distribution panels, Machine Control Centers (MCC's), panel boards and bus duct with disconnect switches. This equipment was manufactured and installed in the 1960s and has been operating for more than 50 years. The equipment is past its useful life and replacement is needed in order to help avoid power failures and costly maintenance issues. Failure of any part of the components of the system can result in the loss of power to an entire floor, critical mechanical systems or the entire building. Replacement of breakers or disconnect switches is costly and time consuming due to their age, since only refurbished breakers of the same type can be used and obtained from companies specialized in refurbishing old equipment.

The emergency lighting enunciator panel should be moved and consolidated into one panel for certification and permitting.

Building Automation Systems

The BAS is an integral part of each facility, as it monitors critical systems and flags issues before other components experience failure or suffer damage. The current system is outdated and tying in new points and equipment is challenging. When buying and installing new equipment, Toronto Hydro needs to purchase specialized controllers that can communicate with the old BAS. New BAS runs on a BACnet/IP software, which is supported by all current equipment that is available at the present time. Many of the new BASs are capable of tying in more equipment and control. An example of where Toronto Hydro would have benefited from additional controls was a sewage back up at 500 Commissioners. The sanitary sewer was blocked on the city side of the property. The sewage backed up into the central holding tank and overflowed into the parking lot. There were no sensors and alarms available to notify facilities managers before the spill occurred. BACnet compliant high water level sensors could have prevented the spill and improved the utility's response time. This particular example had to be reported to the Ministry of Environment since some of the sewage water entered the storm drains and could have closed the employee

parking lot for remediation. Vehicles around the sewage tank and ejector were evacuated and a comprehensive cleanup was performed. This would most likely cause delays in core services if it was a larger flood, as there are over 500 employees that park their cars in the parking lot.

The BASs at 500 Commissioners and 14 Carlton require improvements in order to tie the new data center and control room into the base building BAS. This process involves new software, controls and equipment. In addition, the current HVAC system is now obsolete and the controls will not tie into the required replacement systems. For instance, the VAV air dampers at 500 Commissioners should be replaced with BACnet/IP controlled equipment that will allow wireless control and monitoring.

Deficient Civil Infrastructure

Storm water retention at 14 Carlton

The employee parking lot at 14 Carlton should be re-graded to more effectively drain storm water away from the building. In 2013 there were two occurrences where the storm drains could not drain the water fast enough (Figures 16 and 17). The water levels increased and water made its way through the rear employee entrance, flooding the lobby. New drainage piping and asphalt surfaces are expected to prevent future disruptions. Since these floods took place, Toronto Hydro has increased the frequency of catch basin cleaning and purchased sand bags as a preventative measure; however, a permanent solution is required.

FIGURE 16: REAR EMPLOYEE ENTRANCE AT 14 CARLTON WHERE WATER POOLS AT THE REAR STAIRWELL.

FIGURE 17: RAINWATER THAT ENTERED THE LOBBY THROUGH THE STAIRWELL

Aging Architectural Systems

The main Architectural projects within this program are: floor renovations at 14 Carlton, roof system replacements at 500 Commissioners and 60 Eglinton, foundation and building envelope repairs at 14 Carlton and renovation of 60 Eglinton's third floor.

Floor Plate Finishes at 14 Carlton and 60 Eglinton

Toronto Hydro believes that floor renovations are required since many of the finishes and furnishings are past their useful lives and are no longer suitable for use. There are also mixtures of furnishing and fixtures that are not readily available and are not standardized throughout 14 Carlton. In order to amalgamate the finishes throughout Toronto Hydro, the facilities group developed standard finishes, colors, coverings, fixtures and furniture that can be implemented at 14 Carlton and 60 Eglinton. Toronto Hydro plans to introduce these new standards wherever existing legacy finishes and furniture are in need of renewal due to age, deterioration or obsolescence. Currently the floors are not common or standard at both buildings. The new standards are illustrated in Figures 18 and 19. 500 Commissioners is the first building that has started to accommodate these standards.

FIGURE 18: COMMON OFFICE AND DESK

FIGURE 19: COMMON OFFICE LAYOUT CONSISTING OF COMMON FURNITURE, LAYOUT AND EQUIPMENT.

Applying these standards corporate wide is needed for several reasons:

- Due to a lack of standardization, Toronto Hydro often faces challenges when trying to adequately addressing ergonomic, light quality and other safety concerns brought forward as safety concerns or WSIB investigations. Having a library of common parts that

passed a rigorous approval process by experts in lighting, ergonomics, interior design and Engineering allows for greater efficiencies in planning future projects and dealing with employee concerns.

- There is inconsistency in floor and office layouts. Common office layouts for managers, supervisors, professional staff, clerks and students are expected to help alleviate the requests for furniture, fixtures and changes.

- The facilities storage rooms are littered with many uncommon parts including lights, ceiling tiles, filters and belts, making them difficult to sort, standardize and clean. Standardizing the components are expected to enable Toronto Hydro to use the warehouse and stock one common part instead of a wide variety.

- Current wayfinding is inadequate, meaning that visitors to Toronto Hydro's various work centers, including employees, customers and service providers, often waste time reaching their destinations.

- Purchasing items in small quantities can be expensive. The reduction in the variety of required equipment and parts could lead to procurements savings from buying bulk items in larger quantities.

Figure 20 depicts the 6th floor at 14 Carlton, which has been renovated to remove ACMs. Toronto Hydro plans to implement the new floor plate finishes described above in this space.

FIGURE 20: 14 CARLTON 6TH FLOOR, MAY 2014.

/C

FIGURE 20: 14 CARLTON 6TH FLOOR, MAY 2014.

The third floor of 60 Eglinton is currently in an inoperable state (see Figure 21 below). This floor was abandoned in places and needs to be improved to allow for planned future occupancy. The doors do not close properly and the finishes, such as tiles and carpets, are deteriorating and have passed their life expectancy. The third floor has not been renovated in more than 30 years and houses critical back-up systems. The renovation is designed to conform to the new standards for square foot optimization and floor plate finishes.

FIGURE 21: 3RD FLOOR OF 60 EGLINTON

Roof Systems

The roof system may be most critical component of a building. There are many important objectives that a roof's design and construction are meant to achieve, including:

- protection of the building and its occupants from wind, rain, sun, snow and ice;
- retention of heat in the building during winter months; and

- drainage of water that accumulates on the roof.

The roof systems at 500 Commissioners, 14 Carlton and 60 Eglinton are in dire need of replacement or repair, as they exhibits many issues including:

- standing water;
- increase in the number of leaks and service calls;
- stained ceiling tiles; and
- cracked and peeled flashing and bubbles in the membrane.

The existing roofs uses an ethylene propylene diene monomer (EPDM) membrane covered with stone ballast (Figures 23 and 24). This design should have a life expectancy of 25 years, but due to the weather conditions at the building's location and the premature wear of the membrane and flashing, the roof should be replaced before 2017. Failing to replace the roof is expected to increase the risk of a failure, which can result in damage to critical infrastructure, systems or functions.

FIGURE 22: CRACKS ALONG FLASHING

FIGURE 23: STONE BALLAST

FIGURE 24: EPDM COMPOSITION.

The roof membranes are tenting around the perimeter and roof leaks are occurring along the flashing and in the central membrane. This has subsequently caused damage to surfaces and assets below. Over the years, many repairs have been done to address the issue but it has now reached a point where repairs are no longer efficient in maintaining the structural integrity of the building. Furthermore, it is very difficult to trace the location of the leak since water will sometimes bypass the membrane under the stone ballast and travel along the vapour barrier and insulation. The leak can then enter the building through a seam in the metal deck a significant distance away

from the actual break in the membrane. Finding and fixing the leaks is time consuming, costly and not always successful.

Foundation and Envelope Repair

The foundation and building envelope at 14 Carlton – in particular, the brick masonry walls and windows – are in need of repair, as observed in Figures 25, 26 and 27. The foundation is leaking and the building envelope (exterior walls, windows, and roof) is deteriorating.

FIGURE 25 - EVIDENCE OF SUSPECTED WATER INFILTRATION IN THE BASEMENT, ADJACENT TO AN AIR HANDLING UNIT

FIGURE 26 - CLOSE-UP OF PEELED PAINT AND DETERIORATED MORTAR JOINTS OF BRICK MASONRY WALL

FIGURE 27 - DETERIORATED BRICK AND MORTAR NEAR THE ROOF LINE ON THE NORTH ELEVATION

The specific issues that Toronto Hydro plans to address are:

- water infiltration into the basement and crawlspace through the exterior wall;
- deterioration of the brick masonry wall on the north elevation and of the penthouse;
- staining of sandstone panels on exterior walls; and
- failure of the glazing seals of the windows.

Repairs are required to mitigate potential hazards such as falling bricks. Replacement of the windows is expected to minimize air/water infiltration into the building and formation of icicles. Failure to address these issues through asset renewal may force Toronto Hydro maintenance staff to handle an increasing number of reactive building maintenance issues. For example, cleaning up problems such as spills, peeling paint and mould are reactive courses of action that use facilities resources. The maintenance staff could otherwise be focusing on preventative

maintenance tasks that keep the critical systems such as the HVAC systems operating without issues.

Interior Renovations

The third floor of 60 Eglinton is currently in an inoperable state since it housed the old critical equipment that is no longer in use. Certain portions of this floor were abandoned and should be improved to allow for future occupancy. The third floor has not been renovated in more than 30 years and houses critical back-up systems. The doors do not close properly and the finishes, such as tiles and carpets, are deteriorating and have passed their life expectancy.

E8.2.4 Timing & Pacing of the Program

As per Table 10 below, Facilities Management & Security investments are forecasted to increase in 2015 and 2016 compared to the steady rate of spending in previous years. Investment is then expected to drop considerably. The initial increase is due in large part to the infrequent replacement of many large building components set to take place in the first two years of the program, as described earlier. For example, the 500 Commissioners roof replacement is estimated to cost $4.8 million, which is nearly equal to the forecasted total expenditures for the program in 2014. Some of the building components, like the drainage piping at 14 Carlton and the roof system at 500 Commissioners have never been replaced or upgraded. They are prone to malfunction and/or they put Toronto Hydro at potential risk of experiencing significant water damage caused by a crack in drainage piping or a leak in the roof system. The increase in spending in 2015 and 2016 is also due to the fact that some of these projects are widespread in nature and address multiple buildings.

TABLE 9: HISTORICAL AND FORECASTED PROGRAM EXPENDITURES

	Historical Spending					Future Spending				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	12.1	8.1	6.6	6.8	7.5	16.5	9.4	2.0	2.0	1.9

/C

Toronto Hydro considers these early program investments to be urgent in nature. A primary concern is that safety is potentially compromised given the current state. In order to provide a safer environment for Toronto Hydro employees and the general public, security enhancements should be undertaken. Currently there are 49 stations with no access control or CCTV cameras. There are no visual deterrents preventing trespassers from entering Toronto Hydro premises.

Trespassers are potentially at risk of injuring themselves, Toronto Hydro employees and the general public by gaining unauthorized access to Toronto Hydro facilities. In addition, with the ongoing consolidation of Toronto Hydro buildings outlined in the Operating Centres Consolidation program (refer to section E8.3), security is of greater concern, as many critical functions will be under one roof and will be in need of enhanced protection.

Major, infrequent equipment replacements (such as the planned HVAC renewal) should be completed as scheduled in order to provide a safer working environment, comply with OHSA standards and minimize the cost of repairs.

E8.2.4.1 Ranking & Prioritization

The sequencing of work within this program is based on the following factors:

- Safety – Projects that are necessary to protect the safety and health of Toronto Hydro employees and customers are generally categorized as highest priority. In particular, the security-related investments planned for 2015-2019 respond to identified gaps in existing security infrastructure, and failure to address these gaps in a timely manner could potentially put the safety and health of employees and customers at risk.

- Protecting Critical Functions and Assets – Toronto Hydro's buildings house many functions and equipment that are essential to the distribution system and the utility's ability to serve its customers. In order to provide these functions, Toronto Hydro employees should be located in buildings that are structurally sound and that provide a safe working environment. In addition, equipment should be secure and protected. Facilities investments that are required to protect the most critical system assets (e.g. stations assets) and utility functions (e.g. control room) will generally be prioritized ahead of less critical capital investments.

- Age and Condition – Equipment and systems that have exceeded their life expectancy, are in poor condition or are otherwise defective or performing to a suboptimal level require timely replacement to avoid the potential service interruptions and costs associated with reactive replacement following failure and growing maintenance costs. Failure to plan and implement replacement in a timely manner can potentially put employee health and safety at risk as well critical business functions and assets. Therefore, assets with the most significant failure risk (i.e. the combination of probability of failure and magnitude of failure impact) are expected to be replaced first. The HVAC

replacements and roof system replacements are two major examples of end of life or poor performing assets that require timely replacement.

- Cost-efficiency: All other factors being equal, Toronto plans investments in a manner that maximizes value, leveraging the pacing of other projects. The timing of the HVAC system replacement at 500 Commissioners is an example of this, where Toronto Hydro's forecast costs include anticipated capital cost savings from engaging the facility contractors who will already be on site in connection with the Operating Centers Consolidation program.

E8.2.4.2 Program Execution

Toronto Hydro maintains strict standards for the execution and construction of facilities-related capital projects. Contractors should be ISNetworld certified, which ensures they maintain strong safety records with minimal lost time injuries, remain in compliance with regulatory standards and possess up-to-date insurance. Competitive bid processes are typically used to tender design firms and construction managers. The current proposed structure utilizes a prime design consultant who manages designs, permits and scope documents. The prime design consultant was awarded the contract via a competitive bid process and is responsible for planning, interior designs, structural engineering, move management, mechanical engineering, electrical engineering and architects. Their work is expected to produce construction prints and scope documents that are handed over to a construction manager. The construction manager is also typically tendered using a competitive bid process. This company is typically responsible for tendering the project to a reputable, preferably low cost bidder, and manages the construction project. The construction manager oversees all trades and sub-contractors.

E8.2.5 Evaluation of Alternatives

The Facilities Management and Security program is needed to help maintain a safe and reliable environment for employees and consumers. The status-quo alternative to carrying-out the investments described throughout this program narrative is explored below.

E8.2.5.1 Quantification/Evaluation of Options

Status Quo Alternative

By maintaining the status quo, Toronto Hydro would delay necessary investments in buildings and stations and instead, would continue to maintain and service the facilities as required. This alternative is not recommended because many assets, such as HVAC equipment, have exceeded their useful lives. In addition, Toronto Hydro would not be able to properly address issues with respect to the safety of Toronto Hydro employees and customers, since some stations would continue to be unequipped with cameras and access control. In addition, maintenance and repair costs are expected to increase. For example, in a four month period, the cost of repairing four gates at 500 Commissioners Street was $6,600. Extrapolating this data, Toronto Hydro can conservatively conclude that it will cost approximately $19,800 per year to repair the gates going forward, and costs would likely increase in future years. This is not an efficient use of Toronto Hydro's resources, as replacing a gate entirely would cost approximately $25,000.

A summary of the issues of maintaining the status quo is provided below.

Not replacing the roof systems at 500 Commissioners and 60 Eglinton can put the continued operations of critical functions at risk, as follows:

- In the event of a major leak, Toronto Hydro may not be able to relocate the call center since it has a specific backup power supply that cannot be duplicated or moved in a timely manner.
- Water leaks could damage critical equipment in the warehouse and transformer rooms.
- Highly specialized equipment that is integral to Toronto Hydro cannot be displaced from their current locations.

Not replacing the drainage piping at 14 Carlton may increase the cost of, and risk the continued operations of critical functions as follows:

- Additional operating expenses related to emergency repairs, displacements and controlled substance removals would be incurred.
- Risk to all building occupants related to water, sewage and controlled substances.

- Risk associated with a major break that can result in damage and/or injury.

A failure to improve and enhance security measures could increase the following potential risks:

- Increasing threat of accidental injuries when individuals access electrical equipment at stations. In addition, service disruptions may occur.
- High security areas like the control center, data center, metering and accounts receivable are susceptible to unauthorized entry putting distribution system operations at risk.
- Failure to meet the recognized need to strengthen efforts to ensure grid security.

E8.2.6 2015 Project Details

The following table lists all of the projects that constitute Toronto Hydro's planned 2015 budget for the Facilities Management & Security program.

TABLE 10: 2015 PROJECTS

500 Commissioners	2015	Reason/Explanation
Base building BAS upgrade	250,000	Obsolete/addition alarms required
floor tile replacement	60,000	Damaged and pose a safety risk
Roof system Building B	2,800,000	Reached end of life and leaking
HVAC Units – Perimeter RTUs	180,000	End of useful life and high repair cost
HVAC system retrofit	1,500,000	End of useful life and high repair cost
Double Exterior Doors	16,000	Rusted and high maintenance cost
Steam Boiler Control	50,000	Equipment is not functional without it
Total	$4,856,000	
14 Carlton	2015	
Due diligence to support parking lot improvement	50,000	Consulting cost
Asphalt settlement near loading dock	60,000	Potential risk for slip, trips and fall
Removal and replacement of parking surface to address drainage/debris	250,000	To prevent flooding inside the building
Concrete ramp for barrier-free access	35,000	To prevent potential risk of injury
Study – Foundation(Subsurface Investigation)	10,000	Identify scope of work for foundation
Repair – Foundation and concrete at grade level	220,000	Insure the foundation is secure
Exterior Brick Wall- Masonry Repainting	10,000	Prevent water infiltration
Exterior Brick Wall- Repainting	40,000	Prevent water infiltration
Exterior Wall-East Penthouse- Partial Brick Replacement	11,000	Repair damaged bricks
Scaffolding to address the above deterioration	80,000	

Study to minimized staining observed on the sandstone panels beneath the windows	10,000	To identify potential water infiltration
Abandoned brick chimney enclosure	7,500	Room required for utilities
Floor plate finishes	800,000	To resurface the old floor plates
drainage Piping	2,900,000	Steel cast drainage system that does not meet standards and contains ACM
2nd floor structural improvement	2,800,000	Remove ACM and concrete floor below a computer room and replace the structural beams and concrete flooring.
Ventilation Equipment	675,000	For better distribution of heat and AC
Cooling/Heating Equipment	110,000	Improve the temperature of building
Cafeteria Exhaust	115,000	Currently obsolete
Total	**$8,453,500**	
60 Eglinton	**2015**	
Structural Review	20,000	Ensure building is structurally sounds
3rd Floor Renovation	900,000	To provide work space for employees
Total	**$920,000**	
Security	**2015**	
Equipment / Install stations	1,500,000	Access control and cameras in stations
Signage	8,550	Increase number of visual deterrents
Cameras Buildings	138,000	Increase security
Cost of Lighting	65,000	Increase safety
Security Infrastructure upgrade	240,000	Improve existing infrastructure for safety
Building Upgrades	93,500	Improve existing infrastructure for safety
	$2,045,050	
Total for internal labour to support projects	**$186,272**	
	$16,460,822	

The list above includes large programs, such as the replacement of the roof, drainage pipe, HVAC equipment and installation of access control and cameras. Delaying these large projects will likely add to the cost of replacement in the future, and the cost of maintenance and repair is expected to increase. For example, the cast steel drainage pipes at 14 Carlton have many cracks, as indicated earlier in Figures 8 and 9; if they are not replaced immediately, the risk of flooding will likely increase and many business units could be affected.

E.8.3 Operating Centers Consolidation Program

E8.3.1 Summary

Program Description

This Operating Centers Consolidation Program (OCCP) concerns the consolidation of Toronto Hydro's operating centers it maintains in the City of Toronto that support core distribution activities. Toronto Hydro's distribution system and business support facilities consist of geographically dispersed, functionally integrated buildings and lands that house customer care, system control, operations and maintenance, distribution engineering and design, system response, business support, and other functions.

Toronto Hydro proposes to exit from four facilities it currently occupies in order to secure tenure at its major northwest and northeast operating centers and mitigate the costs and risks arising from having to relocate its operations in the event that a lease cannot be renewed in the future. Two of the four properties are owned by Toronto Hydro and would be sold, the benefits of which would be returned to ratepayers. The other two properties are under leases set to expire during the 2015 to 2019 period and would be terminated. Staff, equipment and operations at those locations would be relocated to three properties already owned by Toronto Hydro. These facilities require capital investment to be adequately prepared to house these new functions.Program Drivers

The trigger and secondary drivers for this program are summarized below.

TABLE A: PROGRAM DRIVERS

Trigger Driver	Reasoning
System Maintenance and Capital Investment Support	ƒ Securing tenure for Toronto Hydro's major northwest and northeast operating centers. ƒ Transferring uninterruptible Data, Control and Call Centers to locations with certain access to fibre-optic communication facilities.
Secondary Driver	**Reasoning**
Business Operations Efficiency	ƒ Two Toronto Hydro-owned facilities would be sold, the benefits of which would be returned to ratepayers. ƒ Operating costs at disposed properties would be shed. ƒ Utilization of existing facilities would be increased.

Preferred Alternative

Toronto Hydro considered three approaches to this program:

1. **Operations Centres Consolidation (Proposed)**

2. **Status Quo (Base Case):** A general continuation of the status quo, subject to the requirement that Toronto Hydro continue to respond to changing circumstances (e.g., the expiry of existing leases) as well as meeting evolving requirements, such as upgrading and expanding its Data Centre.

3. **Do Nothing**

On a net present value (NPV) basis, the OCCP is expected to reduce Base Revenue Requirements (BRRs) by $23.9 million by the end of 2019 and by $145.3 million over the expected 50 year useful life of the facilities. In contrast, the Base Case scenario increases BRRs over both horizons. /C

Timing and Pacing

This OCCP would be executed in four phases:

(1) The sale of the facility at 5800 Yonge and the transfer of staff, equipment and operations to 500 Commissioners;

(2) The termination of the existing lease at 601 Milner and the transfer of staff, equipment and operations to Toronto Hydro's 715 Milner location subsequent to required capital investment;

(3) The termination of the existing lease at 6 Monogram and the transfer of staff, equipment and operations to Toronto Hydro's 71 Rexdale Boulevard location subsequent to required capital investment; and,

(4) The sale of the facility at 28 Underwriters.

The reduction in BRR includes the costs of making up-front capital investments to adequately prepare the retained facilities for their new use. These investments total $52.2 million during the DSP, as summarized in Table B, and are discussed in further detail on a phase-by-phase basis in Section 8.3.3. /C

TABLE B: HISTORIC AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CAPEX ($M)	**0.0**	**17.3**	**0.0**	**7.7**	**82.7**	**37.4**	**14.8**	**0.0**	**0.0**	**0.0**

/C

E8.3.2 Program Description

E8.3.2.1 Background

The Operating Centers Consolidation Program concerns the consolidation of operating centers to achieve security of tenure at Toronto Hydro's major operating centers supporting distribution system construction and maintenance programs, and to permanently and significantly lower operating center costs. It is also expected to resolve existing requirements and constraints related to expiring leases on existing facilities, and the cessation of critical fibre-optic services at Toronto Hydro's main Data Center. The primary driver for the OCCP is System Maintenance and Capital Investment Support. The secondary, but nevertheless important driver is Business Operations Efficiency.

This program does not involve facilities such as transformer stations, municipal stations, or substations that are integral parts of the distribution system itself. Also it does not pertain to ongoing capital and operating expenditures related to the maintenance and improvement of existing facilities, apart from activities related specifically to the OCCP. Please refer to Facilities Management and Security program (E8.2) for evidence pertaining to distribution system facilities and ongoing support facilities programs.

Toronto Hydro's current operational facilities are described in further detail in the following sub-section. The retained facilities are described in section E8.3.3. Figure 1 below depicts the properties that would be retained and those that would be vacated.

RETAINED  VACATE - SELL / EXIT LEASE

FIGURE 1: TORONTO HYDRO MAJOR OPERATING CENTERS

E8.3.2.2 Toronto Hydro Facilities

Toronto Hydro's distribution system and business support facilities consist of geographically dispersed, functionally integrated buildings and lands that house customer care, system control, operations and maintenance, system response, and other functions.

The OCCP facilities are functionally integrated in that Toronto Hydro conducts various operations and activities to serve its customers, and the overall collection of operations and activities must be housed in suitable facilities. To the extent a given facility is vacated or enlarged, the requirements for the remaining facilities in the portfolio will be increased or reduced accordingly.

In addition, Toronto Hydro considers it vital to maintain operations centers dispersed across the city in order to permit reduced travel times to worksites that are themselves widely dispersed across the city. Toronto Hydro strives to maximize the time spent by crews working directly on the distribution system ("wrench time") and minimize the time spent by crews travelling to the work sites across the City. Because Toronto Hydro's service area is a highly congested urban area,

travel times to work sites become a significant factor in Toronto Hydro's ability to respond to system and customer needs in a necessary and efficient manner.

However, the OCCP does not involve an increase in the number of operating centers (the opposite, in fact), and the locations of future operating centers in the southern, eastern, and western areas of the City will be the same or very close to those of the existing centers.

The existing OCCP facilities, which are the subject of this program, are briefly described below:

5800 Yonge Street

The facility at 5800 Yonge Street (north of Finch Avenue) is owned by Toronto Hydro and currently houses the primary system Control Center and Data Center. Until very recently it also housed the Call Center. The system Control Center is the facility through which Toronto Hydro centrally manages the electricity distribution system and responds to changing system conditions caused by operations and maintenance programs as well as unpredicted outages.

The (internal) Call Center houses Call Center staff and equipment to provide customer care for those customer calls which are not handled through external Call Centers. Generally the internally handled calls relate to more complex issues or larger customers and require a higher level of skill than the outsourced calls.

The Data Center at 5800 Yonge is one of two purposefully redundant Data Centers which house critical information technology equipment vital to the functioning of distribution operations, customer care and billing, and business support functions.

The Call Center, the Control Center, and the Data Center at 5800 Yonge are integral, indispensable parts of Toronto Hydro's operations.

The 5800 Yonge facility also accommodates ancillary requirements such as office space and parking for staff, meeting rooms, and common area facilities. Approximately 300 employees (i.e., Toronto Hydro employees and contract staff) work in or out of 5800 Yonge.

500 Commissioners Street

The facility at 500 Commissioners Street (south of Lakeshore Boulevard at Carlaw Avenue) is Toronto Hydro's largest operations center, comprised of four buildings and associated facilities on 16.8 acres of land. Toronto Hydro owns the buildings and occupies the land under a long-term (99 year) lease signed in February of 1995. It accommodates operations and maintenance staff

and equipment, a materials warehouse, yard, fleet and garage space, the Apprenticeship Training Program, internal staff in Engineering, Field Operations and other departments, and ancillary requirements such as parking and common area facilities. Over 700 employees work at or out of Commissioners.

In emergency or unusual conditions, staff may be dispatched from any operating center to any part of the City of Toronto. Normally, however, the 500 Commissioners facility serves the downtown and southern areas of the city.

601 Milner

The facility at 601 Milner Avenue (between Sheppard Avenue East and the 401, east of Markham Road) is an operations center serving the northeast quadrant of the city. It accommodates operations and maintenance staff and equipment, as well as garage, warehouse and office space, and parking for system and employee vehicles. The property and building are leased by Toronto Hydro, with a lease expiry date of July 2017. Approximately 276 employees work in or out of 601 Milner.

6 Monogram Place

The facility at 6 Monogram Place (at Islington Avenue, south of the 401) is an operations center serving the northwest quadrant of the city. It accommodates operations and maintenance staff and equipment as well as garage, warehouse and office space, and parking for system and employee vehicles. The property and building are leased by Toronto Hydro, with a lease expiry date of November 2016. Approximately 307 employees work in or out of 6 Monogram.

28 Underwriters Road

The facility at 28 Underwriters Road (south of Lawrence Avenue, east of Warden Avenue) is an operations center presently accommodating the centralized System Response function as well as the Investment Recovery (i.e., scrap materials recycling) operation. "System Response" is the collection of activities through which Toronto Hydro responds to and corrects unpredicted faults, outages, and other disruptions to its electricity distribution system.

This facility is owned by Toronto Hydro and consists of two buildings of different vintages (1989 and 1945) situated on 12 acres of land. The System Response operation runs all day, every day and is accommodated with vehicle parking, and material, tool and equipment storage space in the newer building. Investment Recovery operations are conducted in the older building, which has

been partly decommissioned. This site is currently being remediated for the presence of lead and other metals, asbestos, PCBs, and various hydrocarbons.

Approximately 63 employees work in or out of 28 Underwriters. This includes 57 System Response staff and 6 Investment Recovery staff.

E8.3.3 Why the Program is Needed

The purpose of the OCCP is to achieve three primary outcomes:

1) Ensure security of tenure at major crew-supporting operating centers;

2) Ensure the uninterrupted continuation of critical functions (i.e., Data, Control, and Call Centers) by transferring these functions to a location where vital fibre-optic communication facilities and an uninterruptible power supply are certain to be available or can be installed; and,

3) Achieve permanent and significant cost savings for customers through:

    a. Allocating net after-tax gains and related tax savings on sale of properties to ratepayers;

    b. Shedding otherwise ongoing property-related costs associated with the properties to be disposed of; and,

    c. Increasing the utilization of remaining properties.

The OCCP will help ensure Toronto Hydro's security of tenure at its major northwest and northeast operating centers. Toronto Hydro's leases at those two locations are set to expire between 2015 and 2019. By relocating to owned facilities, Toronto Hydro can avoid exposure to unnecessary costs and risks arising from having to relocate its operations in the event that a lease cannot be renewed in the future. For example, standard commercial leases are "free-hold", which require the lessee to return the property back to "ready to lease" state, which can be costly. These costs must be incurred whenever a lease comes up for renewal because there is no guarantee that it will be renewed. Toronto Hydro has protection against such risks and costs at 500 Commissioners due to the unusually long term of lease at that property. The OCCP will extend that protection to its two other crew-supporting centers through ownership.

The crew-supporting operations centers have specialized facility and property requirements compared to centralized administrative operating centers, since they require substantial land for warehouses, zoning for outside storage, and very good access to roads and highways, among other factors. Toronto Hydro expects these attributes to become increasingly scarce in the future.

In addition, the OCCP helps ensure the uninterrupted availability of critical communications facilities and uninterruptible power supply which are vital to the Control Center, Data Center, and Call Center. These functions are essential to Toronto Hydro's continued ability to operate its distribution system safely and effectively, to carry out the billing function and numerous other corporate functions such as payroll and financial reporting, and to provide responsive customer care. It is also expected to resolve existing requirements and constraints related to expiring leases on existing facilities, and the cessation of critical fibre-optic services at the 5800 Yonge Data Center. In addition, it is expected to better match existing and new facilities to system requirements and operations, and enable the relocation and upgrading of Data Center facilities.

By selling properties that become surplus through the execution of the OCCP, Toronto Hydro expects to realize significant net, after-tax gains and related tax savings. Toronto Hydro forecasts that these gains, through the sale of the 5800 Yonge and 28 Underwriters properties, will be approximately [redacted] million dollars. Toronto Hydro proposes that these net, after-tax gains on sale be credited to ratepayers, as described in evidence at Exhibit 8, Tab 1, Schedule 1. This proposal substantially reduces rate impacts associated with Toronto Hydro's overall capital plan.

The execution of the OCCP would result in a net decrease of two operating centers (5800 Yonge and 28 Underwriters). The property-related costs of these operating centers are significant, and disposing of these properties means that Toronto Hydro can permanently shed ongoing operating and capital costs. The substantial cost savings resulting from the disposition of the properties are certain, since the costs are directly tied to the operation of those specific properties, which Toronto Hydro will no longer operate.

The OCCP aims to substantially decrease the total square footage of Toronto Hydro's portfolio of operating centers and will improve space utilization in the remaining facilities. At present, Toronto Hydro's major facilities total 4.2 million square feet inclusive of all indoor and outdoor space. Under the OCCP, square footage is planned to be reduced to approximately 2.6 million square feet, a reduction of 1.6 million square feet or approximately 43%. Total space utilization per person (i.e., total square footage inclusive of all indoor and outdoor space divided by the total number of occupants) is expected to decrease from approximately 2,670 square feet in 2012 to

1,650 square feet in 2017. Existing facilities would be used more intensively and interior office configurations will be updated and standardized to accommodate transferred employees.

The reduction in total square footage is not expected to have adverse effects on Toronto Hydro's performance or cost structure otherwise, since the existing operating centres in the northwest and northeast portions of the City would be replaced by centres that are very nearby and equally advantageous in terms of the efficiency of crew deployment.

The result of these outcomes is expected to deliver a number of benefits, summaries of which are shown in Table 1.

TABLE 1: SUMMARY PROGRAM BENEFITS

Customer Value	ƒ Significant reduction in revenue requirement over the CIR period and for the useful lives of the facilities involved ƒ No expected consequential reduction in operating efficiency or increase in capital and maintenance costs
Reliability	ƒ Maintenance of dispersed operating centres throughout the City enabling more rapid response
Efficiency	ƒ 'Inputs' in the form of support facilities square footage reduced while 'outputs' unaffected ƒ Operational and administrative aspects of facility management streamlined
Other	ƒ Ensures security of tenure at critical crew-supporting operating centres ƒ Improved robustness of critical support facilities enhances readiness to serve customers and respond to system needs in emergency situations

The customer value of the OCCP's proposed approach warrants further detail. The principal aspect of customer value is the significant and enduring reduction in revenue requirements that will result from execution of the program. As set out in detail in the Evaluation of Alternatives section in this schedule, the execution of the OCCP is expected to create a savings of $145.3 million in net present value terms over 50 years relative to a base case. Even over the CIR period, which represents a small fraction of the useful life of the facilities involved, the OCCP creates a reduction in revenue requirements of $23.9 million in NPV terms. /C /C

This benefit is achieved without compromising the ability of Toronto Hydro's operating centres to support its core operations, and without indirectly increasing the costs of those operations.

As noted previously, the actions required to execute the OCCP are as follows:

- The sale of the facilities at 5800 Yonge and 28 Underwriters;
- The termination of existing leases for the 601 Milner and 6 Monogram properties; and,

- Investment in new and existing facilities at 500 Commissioners, 715 Milner Avenue, and 71 Rexdale Boulevard, followed by the transfer of staff and equipment to those properties.

These activities will be executed in four distinct phases. The remainder of this section provides a description and corresponding rationale for each of the four phases.

E8.3.3.1 Phase 1 – Transfer of Staff and Functions From 5800 Yonge to 500 Commissioners

Phase 1 of the OCCP involves the transfer of staff, functions, and assets from 5800 Yonge to 500 Commissioners. 5800 Yonge has historically housed the Call Center, Control Center, and Data Center. All of these are integral and indispensable to Toronto Hydro. The Call Center provides Customer Care. The Control Center centrally manages the distribution system, enabling planned maintenance and construction activities and responding to unplanned outages and other events on the system. The Data Center provides critical IT support to all of Toronto Hydro's functions. In total, approximately 300 employees will be transferred to the Commissioners facility; to date, approximately 170 Call Center employees have been transferred to 500 Commissioners.

At the Commissioners location, the facilities-related infrastructure supporting these functions will be reinforced and enhanced to better facilitate Toronto Hydro's functions under extreme or emergency conditions. These investments include: new electrical power connections, uninterruptible back-up generation, communication links, and security features associated with the Data Center; set-up of the relocated Call Center and Control Center together with associated equipment; and reconfigure office space and provide additional parking for transferred employees. The transfer will also allow critical fibre-optic communications service to continue uninterrupted despite the impending cessation of those services at 5800 Yonge.

This process is complex and many elements overlap; however, a high-level timeline for the project is given below in Figure 2. Toronto Hydro intends to vacate and sell the property by the end of 2015.

Phase 1 Project Time Line											
	2013			2014				2015			
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Design											
Tender/Permits											
Construction											
Staff Relocations to 500 Commissioners											
Prep of 5800 Yonge For Sale											
Sale of 5800 Yonge											

FIGURE 2: PHASE 1 HIGH-LEVEL TIMELINE

Rationale for Vacating 5800 Yonge

There are three major factors that support the vacating and disposing of the 5800 Yonge facility. First, this will create enduring and significant OPEX savings arising from avoided property-related costs, including property taxes, utilities, maintenance, security, and other items. These are expected to be approximately $1.6 million per year on average over the CIR period. In addition, significant capital costs are avoided which are expected to total $16.6 million across the CIR period.

Second, the provision of critical fibre-optic communication facilities, which is necessary to support all three vital functions currently housed at 5800 Yonge, will terminate as of November 2014, pursuant to the contract between Toronto Hydro and the provider.

Third, the opportunity cost to Toronto Hydro of maintaining an owned facility in the intensely developed Yonge Street corridor has significantly increased, due to surrounding development of high-rise condominium and commercial buildings, and the fact that the 5800 Yonge property is the last relatively undeveloped, large property in the area. The 5800 Yonge property consists of the building, but more importantly in the long term, a contiguous parcel of 8.1 acres of land suitable for high-rise development. Toronto Hydro has an opportunity to sell this land for a significant premium over net book value to produce a net, after-tax gain on sale and related tax savings of approximately [redacted] million.

As discussed in detail at Exhibit 8, Tab 1, Schedule 1, Toronto Hydro proposes that the net, after-tax gain on sale of the 5800 Yonge property be allocated to the benefit of ratepayers by means of rate riders.

Preparation of 500 Commissioners to Receive Transferred Staff and Functions

The readying of 500 Commissioners to accept the transferred staff and functions from 5800 Yonge began in 2013 and involves an extensive process of design, procurement and construction to install the various required facilities. The Call Centre was transferred to Commissioners earlier in 2014. The remaining staff and functions are expected to be transferred by the end of 2014.

As set out in further detail below, the capital budget for the modifications at Commissioners is $63.8 million, of which $1.3 million is proposed for the 2015 to 2019 period. The total investment covers diverse items including the reconfiguration of space, provision of facilities and equipment to support the relocated Call, Control, and Data Centres, incremental Data Centre investment and consequential costs such as expanding the employee parking lot. The budget for these expenditures is set out below in Table 2:

/C

/C

TABLE 2: BUDGETED PHASE 1 CAPITAL COSTS FOR 500 COMMISSIONERS

OCCP Budgetr Phase 1		Budget ($000s)		
Data Centre Facilities			$	18,661.0
	3rd Floor Power Upgrade (DC)	2,600		
	Data Centre Construction	4,000		
	FACr IT Conduit	161		
	Generationr Redundant Power	6,850		
	IT Space	850		
	Security (DC)	350		
	Structural Steel (roof) (DC)	600		
	Substation (DC)	2,600		
	Upgraded Sprinkler/Early Detection (DC)	650		
3rd Floor Offices			$	3,188.3
	3rd Floor Reconfiguration	3,000		
	3rd Fl Conference Rooms	113		
	3rd Floor Manager Offices	75		
2nd Floor Education Centre and Apprentice Program Offices/Classrooms			$	3,822.0
	Education Centre	1,700		
	EHS & trades Training	1,500		
	Mezz In fill	622		
Data Centrer IT			$	25,601.4
	ITr Call Centre	901		
	ITr Ctrl Rm	1,251		
	Data Centrer IT	17,500		
	IT Fibre CostsrCtrl Rm Move	3,450		
	IT Fibre CostsrData Centre Move	2,500		
Control Centre/System Operations Centre			$	5,000.0
	Control Room Construction	3,800		
	Glove Lab	700		
	System Operations Centre	500		
Distribution & Operation Support Offices			$	2,019.7
	Facilities Space	170		
	Clerks Space	632		
	Marshalling Space	752		
	Supply Chain Space	466		
Call Centre			$	3,000.0
500 C Revitalization			$	1,000.0
Parking Lot			$	1,500.0
		Total Budget	$	63,792.4

/C

Operating costs for Phase 1 related to the work at Commissioners are immaterial.

Table 3 below sets out the construction status of the projects at Commissioners.

TABLE 3: 500 COMMISSIONERS SUB-PROJECT STATUS

Consolidation BudgetrPhase 1		Status
Data Centre Facilities		
	3rd Floor Power Upgrade (DC)	in construction
	Data Centre Construction	in construction
	FACrIT Conduit	in construction
	GenerationrBackup Power	in construction
	IT Space	in construction
	Security (DC)	in construction
	Structural Steel (roof) (DC)	in construction
	Substation (DC)	in construction
	Upgraded Sprinkler/Early Detection (DC)	in construction
3rd Floor Offices		
	3rd Floor Reconfiguration	in construction
	3rd Fl Conference Rooms	complete
	3rd Floor Manager Offices	complete
2nd Floor Education Centre and Apprentice Program Offices/Classrooms		
	Education Centre	in design
	EHS & trades Training	in design
	Mezzanine In fill	in design
Data Centrer IT		
	ITrCall Centre	in construction
	ITrCtrl Rm	in construction
	Data CentrerIT	in construction
	IT Fibre CostsrCtrl Rm Move	in construction
	IT Fibre CostsrData Centre Move	in construction
Control Centre/System Operations Centre		
	Control Room Construction	in construction
	Glove Lab	in construction
	System Operations Centre	in construction
Distribution & Operation Support Offices		
	Facilities Space	complete
	Clerks Space	in construction
	Marshalling Space	complete
	Supply Chain Space	complete
Call Centre		complete
500 C Revitalization		complete
Parking Lot		in design

/C

As noted, Toronto Hydro began the process of preparing 500 Commissioners for the transfer of staff and functions in 2013. Table 4 below isolates the items completed to date, and provides the budgeted and actual costs, and variances.

TABLE 4: 500 COMMISSIONERS COMPLETED WORK TO DATE

Name of Project	Status	Budget	Actual Cost	Variance
			$000s	
3rd Fl Conference Rooms	complete	$113.3	$270.4	
3rd Floor Manager Offices	complete	$75.0	$66.6	$8.4
Facilities Space	complete	$169.7	$296.9	
Marshalling Space	complete	$752.0	$869.6	
Supply Chain Space	complete	$466.0	$538.8	
Call Centre	complete	$3,000.0	$2,780.1	$219.9
500C Revitalization	complete	$1,000.0	$408.4	$591.6
Total		$5,576.0	$5,230.7	$345.3

Toronto Hydro has presented the budget for the capital work at 500 Commissioners, but because this project has begun, some amounts will be reflected in 2014 year-end Property, Plant, and Equipment, and some amounts will be reflected in CWIP.

5800 Yonge Decommissioning and Preparation for Sale

After the transfer of staff, functions, and assets from 5800 Yonge to 500 Commissioners, 5800 Yonge would be prepared for sale and marketed. Toronto Hydro anticipates that prospective buyers would wish to purchase the property with the building in a condition appropriate for a short term lease in order to provide cash flow while preparations are made for subsequent development. As such, Toronto Hydro expects to include much of the existing fixtures, furniture, and equipment in the transaction. Toronto Hydro expects to place the 5800 Yonge property on the market by Q2 of 2015 and for the transaction to close by Q4 of 2015.

There are no requirements for significant remediation at 5800 Yonge. However, until the real estate transaction closes, Toronto Hydro will continue to incur costs (which will subsequently be shed) for items including baseline utilities, property taxes, security, and similar items. Toronto Hydro will also incur costs directly related to the marketing and sale of the property, such as real estate commissions. Toronto Hydro estimates the real estate and disposition costs for Phase 1 of the OCCP to be approximately $1.3 million.

Stream of Future Avoided Costs

Table 5 below sets out the categories and amounts of avoided costs Toronto Hydro expects to realize over the CIR period as a result of disposing of the 5800 Yonge property. Over $9.1 million of the $16.7 million capital saving in 2015 is related to capital expenditures on upgrading the Data Centre if Toronto Hydro were to remain at 5800 Yonge. The majority of the remaining capital savings are also IT-related.

/C

TABLE 5: COSTS AVOIDED BY THE DISPOSAL OF 5800 YONGE

Avoided Costsr5800 Yonge Street					
	2015	2016	2017	2018	2019
			$000s		
Operational Savings	$ 843	$ 1,722	$ 1,758	$ 1,795	$ 1,833
Avg 2015r2019	$ 1,590				
Capital Savings	$ 16,722	$ 7,616	$ 7,646	$ 1,517	$ 1,549
Avg 2015r2019	$ 7,010				

E8.3.3.2 Phase 2 – Transfer of Staff and Operations from 601 Milner to 715 Milner

Phase 2 of the OCCP principally involves the transfer of existing staff and functions from the operations centre at 601 Milner to the facility Toronto Hydro owns at 715 Milner. In addition, some staff currently located at 601 Milner would be transferred to 500 Commissioners. No further capital expenditures, apart from those shown for Phase 1, are required for this reason at 500 Commissioners. Some staff from 5800 Yonge will also be transferred to 715 Milner.

A high-level timeline for Phase 2 is presented below in Figure 3.

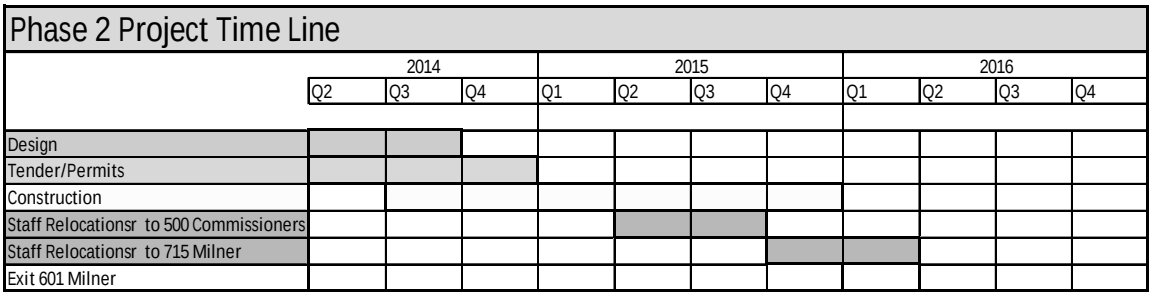


FIGURE 3: PHASE 2 HIGH-LEVEL TIMELINE

Toronto Hydro purchased the 715 Milner property in 2011, with the intention of developing it into an operations center. However, capital constraints have required that development to be postponed until 2014. At present, the building is vacant but it is capable of housing the staff and functions presently accommodated at 601 Milner.

Rationale for Vacating 601 Milner

The principal reasons to vacate 601 Milner and to develop and occupy 715 Milner are to achieve security of tenure for a major operations center and to produce permanent and significant cost reductions.

As noted, by moving to an ownership model for these facilities, Toronto Hydro can avoid unnecessary costs and risks arising from having to relocate its operations in the event that a lease cannot be renewed in the future. Compared to centralized administrative operating centers, the crew-supporting operations centers have specialized facility and property requirements, since they require substantial land for warehouses, zoning for outside storage, and very good access to roads and highways, among other factors.

The lease at 601 Milner expires as of July 2017. Vacating that property is expected to shed significant costs associated with leasing and maintaining that property. Toronto Hydro also plans to terminate the lease at 601 Milner in advance of its expiry. By vacating 601 Milner as of the end of Q1, 2016, Toronto Hydro expects lease savings to cover the cost of early termination of the lease.

The initial capital expenditures necessary to ready 715 Milner are not entirely offset by costs avoided over the CIR period to 2019. However, this is typical for long-term investments in facilities, due to the need to make up-front capital expenditures in order to secure a long-term stream of cost savings. Over the 50 year horizon, the NPV of the reduction in revenue requirement for Phase 2 is [redacted] million.

Preparation of 715 Milner to Receive Transferred Staff and Functions

The building at 715 Milner is essentially vacant at present. Assessment of the building is currently underway to determine exactly what work has to be done to the building envelope to ensure water-tightness, the absence of any contaminants such as mold, and to be energy efficient. It will also determine the need (if any) for structural reinforcement. Several elements of

the building have reached end-of-life and require replacement, including the roof, HVAC units, windows, doors, and seals, and the electrical substation.

Upon completion of the building envelope, the process of fitting the interior space to provide office space and other work facilities will begin. The office space constructed will conform to new standards and configurations also applicable to 500 Commissioners and other operations centers.

Toronto Hydro will renovate the warehouse to provide covered truck parking and upgrade the loading docks. A portion of the existing parking lot will also be converted to outdoor storage.

The budget for the work at this location is $26.8 million, of which $17.8 million is proposed for the 2015 to 2019 period. Further details are set out below in Table 6. Toronto Hydro is expected to complete the readying of 715 Milner to accept the transferred staff and functions by Q4 of 2015.

TABLE 6: BUDGETED PHASE 2 CAPITAL COSTS FOR 715 MILNER

OCCP Budget - Phase 2		Budget ($000s)		
Office Space - Interior Fit-out			$	12,600.0
	Soft Cost for Building Office Fit-out - Incl Furniture	2,700.0		
	Office ground Floor renovated	3,700.0		
	Future IT Space - warehouse unrenovated	250.0		
	Office Ground Floor Warehouse Conversion	2,700.0		
	Swing Space, Second Floor - Renovated	3,250.0		
Warehouse - Interior Fit-out			$	2,750.0
	Soft Cost for Warehouse and Vehicle Storage	300.0		
	Warehouse 1	500.0		
	Warehouse 1	150.0		
	Vehicle Storage	1,800.0		
Parking			$	2,250.0
	Soft Cost for Exterior Parking	200.0		
	LD/MD Parking Exterior	800.0		
	Staff Parking	1,250.0		
Base Building - Building Envelope			$	2,000.0
Ancillary Work - WH Demo			$	400.0
IT			$	3,656.4
Capitalized maintenance during construction			$	3,100.0
		Total Budget	$	26,756.4

Decommissioning of 601 Milner

The costs of exiting the lease at 601 Milner are low. Toronto Hydro will remove its own equipment and fixtures, and perform any other actions pursuant to the requirements of the lease. Most equipment and other chattels, excluding office furniture, will be transferred the short distance to 715 Milner and be reused at that location.

Stream of Future Avoided Costs

Table 7 below sets out the categories and amounts of avoided costs Toronto Hydro expects to realize over the CIR period as a result of disposing the 601 Milner property. The average OPEX cost saving over the 2015 to 2019 period is $2.3 million per year; capital maintenance costs are also avoided. The avoided capital expenditure of approximately $8.8 million relates to the initial capital expenditures on leasehold improvements that are assumed to be necessary when newly occupying a leased facility. Thereafter, capital expenditures resume a normal pattern. The amount was based on historical averages for both the 601 Milner and 6 Monogram facilities.

TABLE 7: COSTS AVOIDED BY EXITING 601 MILNER

Avoided Costs - 601 Milner					
	2015	2016	2017	2018	2019
	$000s				
Operational Savings	$ -	$ 2,057	$ 2,780	$ 3,291	$ 3,360
Avg 2015-2019	$ 2,298				
Capital Savings	$ -	$ 8,850	$ 74	$ 76	$ 78
Avg 2015-2019	$ 1,816				

E8.3.3.3 Phase 3 – Transfer of Staff and Operations from 6 Monogram to 71 Rexdale

Phase 3 involves the transfer of staff and operations from the leased facility at 6 Monogram to the Toronto Hydro-owned facility at 71 Rexdale, which was purchased in June 2014. The reasons for the move from leased facilities to owned facilities in the northwest quadrant of the City are the same as those of Phase 2; the objectives are to achieve security of tenure and long-term cost savings. A high-level timeline for Phase 3 is presented in Figure 4 below.

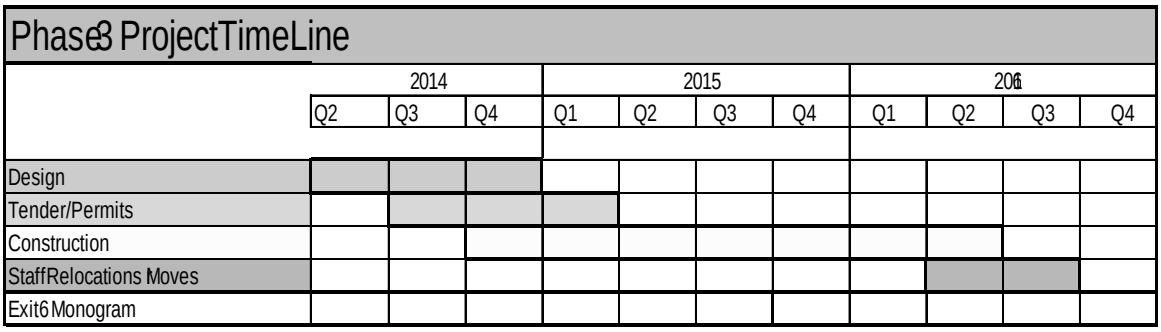


FIGURE 4: PHASE 3 HIGH-LEVEL TIMELINE

Rationale for Vacating 6 Monogram

Toronto Hydro has become aware that the current owners of the property at 6 Monogram intend to sell it. As a result, there is a reasonable likelihood that Toronto Hydro will not be able to renew its lease at the property, which expires in November 2016. Due to the long lead times involved in securing another property, making necessary modifications to it, and transferring staff and functions, Toronto Hydro could not risk waiting until notice is given to it under the terms of the lease for 6 Monogram. As such, it was necessary for Toronto Hydro to acquire a substitute property in the same general location to accommodate staff and functions currently housed at 6 Monogram.

Toronto Hydro needs to maintain a base of operations in the west sector of the city in order to optimize its construction and maintenance programs in that area (for example, by reducing travel time and thereby increasing wrench time). For reasons of tenure security, Toronto Hydro sought to purchase rather than lease a property.

After engaging a firm specializing in commercial real estate, Toronto Hydro was able to purchase the property at 71 Rexdale Boulevard, very nearby the 6 Monogram facility. In May of 2014, Toronto Hydro offered $12.8 million for the property at 71 Rexdale, and after clearing inspection and due diligence, the transaction closed June 13, 2014.

The Rexdale property is a highly suitable replacement for the Monogram facility. It offers excellent access to major roads and is zoned to permit outside storage. The Rexdale property occupies a total of 11.59 acres and is zoned E1, which permits outside storage. Outside storage

is a more economical way to meet Toronto Hydro's storage requirements than having to provide inside storage. Toronto Hydro intends to fully or partially demolish the existing structure and erect a new building designed to meet its needs.

FIGURE 5: 71 REXDALE – DETAILED MAP OF LOCATION

Due to the very recent acquisition of the property, Toronto Hydro has not been able to develop detailed budgets for its development. However, based on initial estimates to construct and fit out office space, warehouse space, and parking, as well as demolition, and the acquisition of the property, Toronto Hydro estimates the Phase 3 capital budget to be approximately $52.1 million,

of which $33.2 million is proposed for the 2015 to 2019 period. The preliminary budget for the construction necessary at Rexdale is set out below in Table 8.

TABLE 8: PRELIMINARY BUDGET FOR COMPLETION OF REXDALE PROPERTY

OCCP Budget - Phase 3	Budget ($000s)
Office Space - Constuction and Fit-out	$ 15,500.0
Warehouse - Constuction and Fit-out	$ 10,500.0
Parking	$ 3,500.0
Ancillary Work - WH Demo	$ 500.0
Land and Building	$ 13,600.0
IT	$ 4,136.4
Capitalized maintenance during construction	$ 4,400.0
Total Budget	$ 52,136.4

Stream of Future Avoided Costs

Table 9 below sets out the categories and amounts of avoided costs Toronto Hydro expects to realize over the CIR period as a result of disposing of the 6 Monogram property.

The avoided capital expenditure totals $9.1 million over the 2015 to 2019 period. The majority of this ($8.9 million) relates to the initial capital expenditures on leasehold improvements that are assumed to be necessary when newly occupying a leased facility; thereafter, capital expenditures resume a normal pattern. The amount was based on historical averages for both the 601 Milner and 6 Monogram facilities.

[redacted]

TABLE 9: COSTS AVOIDED BY EXITING 6 MONOGRAM

Avoided Costs - 6 Monogram						
	2015	2016	2017	2018	2019	
	$000s					
Operational Savings	$ r	$ 321	$ 4,521	$ 4,616	$ 4,713	
Avg 2015-2019	$ 2,834					
Capital Savings	$ r	$ 8,850	$ 74	$ 76	$ 78	
Avg 2015-2019	$ 1,816					

E8.3.3.3 Phase 4 – Disposal of Surplus Property at 28 Underwriters Road

Phase 4 of the OCCP involves vacating and selling the facility at 28 Underwriters Road. This location has historically housed the System Response and Investment Recovery functions.

System Response is the collection of activities through which Toronto Hydro responds to unplanned outages and other trouble events on its system. Independent of the OCCP, Toronto Hydro has begun the process of de-centralizing the System Response function to dispersed System Response sites throughout the City to improve response times to those calls, reduce outage times (i.e., SAIDI) and improve customer service.

Investment Recovery is the activity through which Toronto Hydro recycles metals and other materials from its operations. Toronto Hydro also plans to outsource the Investment Recovery operation thereby eliminating the need to provide space within Toronto Hydro facilities for that function.

These two processes are expected to be complete by the end of 2014. As a result, the Underwriters facility will become surplus to Toronto Hydro's operating requirements. Toronto Hydro proposes to dispose of the property and return the estimated net, after-tax gains on sale of approximately [redacted] million to ratepayers. Toronto Hydro expects the transaction to close by 2014 year end or Q1 of 2015.

Rationale for Disposing of 28 Underwriters

As noted, 28 Underwriters is no longer required to support the System Response and Investment Recovery functions it has housed. Selling the property would realize permanent and significant cost savings from shedding the costs of holding and maintaining the property, and to make net after-tax gains on sale from the sale of Underwriters available to ratepayers. The cost savings over the CIR period are approximately $0.8 million per year, and the net, after-tax gain on sale for distribution to ratepayers is forecast to be approximately [redacted] million.

Decommissioning of 28 Underwriters

28 Underwriters has historically been used as an industrial site. It is currently undergoing environmental assessment and remediation for the presence of lead and other metals, asbestos, PCBs, and various hydrocarbons.

Upon completion of the remediation process, and the transfer of System Response equipment and staff, 28 Underwriters will be prepared for marketing. Toronto Hydro intends to market the property in clean, vacant, but otherwise "as is" condition, and does not anticipate any modifications to or demolition of either of the buildings on the site by Toronto Hydro.

Toronto Hydro anticipates that the work to prepare 28 Underwriters for sale (including transfer of the System Response function) will be complete by the end of Q3 2014, and that closing of the sale transaction could occur by the end of 2014 or Q1 of 2015. During the interim period between the vacating of 28 Underwriters and closure of the sale transaction, Toronto Hydro will continue to bear property-related costs, although at a reduced level reflecting vacant, baseline maintenance of the facility.

Stream of Future Avoided Costs

By disposing of the Underwriters property, Toronto Hydro expects to save approximately $800,000 per year in operating costs, as well as a further $100,000 per year in capitalized maintenance costs.

Table 10 below sets out the categories and amounts of avoided costs Toronto Hydro expects to realize over the CIR period as a result of disposing of the Underwriters property.

TABLE 10: COSTS AVOIDED BY DISPOSING OF 28 UNDERWRITERS

Avoided Costs – 28 Underwriters						
	2015	2016	2017	2018	2019	
	$000s					
Operational Savings	$ 750	$ 766	$ 782	$ 798	$ 815	
Avg 2015-2019	$ 782					
Capital Savings	$ 100	$ 102	$ 104	$ 106	$ 109	
Avg 2015-2019	$ 104					

E8.3.4 Timing & Pacing of the Program

Timing and Pacing of the OCCP

The expected timelines for the OCCP are detailed on a phase-by-phase basis in Section 8.3.3.

E8.3.5 Program Execution

E8.3.5.1 Program Management

Toronto Hydro has assembled a team composed of internal staff and external, contracted resources to manage the execution of the OCCP from initial stages of requirements identification through to completion of construction and occupation of the re-developed facilities.

Toronto Hydro has significant internal expertise in managing its own facilities and has relied on internal staff in Customer Care, Information Technology, and Operations and Maintenance, to identify requirements. Toronto Hydro's internal team consists of representatives from these areas as well as staff and executives specifically charged with overseeing each aspect of the project and the overall project itself.

In three principal areas Toronto Hydro does not maintain internal expertise since needs are transient and are not core to distribution activities. These are real estate evaluation, acquisition, and disposition; facilities design; and facilities construction management. In these areas Toronto Hydro has secured responsible contractors through competitive tendering practices conducted in accordance with Toronto Hydro's procurement policy.

Toronto Hydro has established an Integrated Project Team (IPT) consisting of internal staff and representatives of the contractors to manage the overall project. The structure of the IPT is shown in Figure 6.

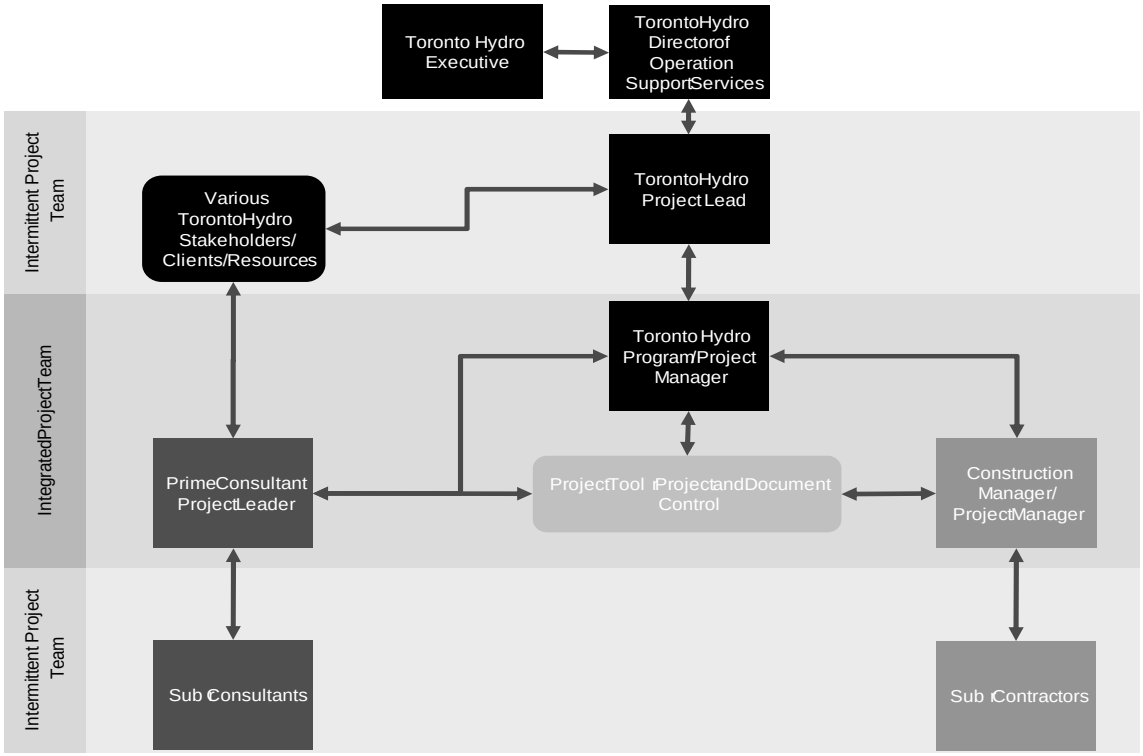


FIGURE 6: INTEGRATED OCCP TEAM

Toronto Hydro Oversight

The Toronto Hydro OCCP team consists of the Integrated Project Team (IPT) dedicated to the project as well as various internal resources including members of the Executive, client groups, and staff with special expertise in areas such as information technology, and environment, health, and safety. The IPT will serve as the single point of contact for external contractors and will ensure that schedule, cost, and quality requirements are met throughout the project.

External resources are also engaged, with a summary of their roles below:

- Real Estate
  - DTZ Canada Inc. has been engaged through a competitive procurement process to provide services related to the disposition of the 5800 Yonge and 28 Underwriters properties, and the sourcing of the Rexdale property.

- Prime Consultant
  - Bennett Design Associates has been engaged through a competitive procurement process to provide the comprehensive design components of the program delivery.
- Sub-Consultants
  - Engaged by the Prime Consultant to support and provide specialized expertise on an as required basis through the life cycle of the program.
- Construction Manager
  - Govan Brown Construction Managers has been engaged through a competitive procurement process to deliver the comprehensive construction and physical implementation components of the program delivery
- Sub-Contractors
  - Competitively procured and contracted by the Construction Manager to supply and install the physical construction on a per trade or discipline basis through the lifecycle of the program.

E8.3.5.2 Program Risks

Toronto Hydro's OCCP is exposed to risks that are commonplace in construction projects. No unusual or elevated risks have been identified. Nevertheless, Toronto Hydro is acting to mitigate existing risks to the degree reasonably possible, by, for example, applying for permits and required approvals as early as possible and on a phased basis where possible.

Phase 1

There is a risk that some required materials and equipment may not be available on a timely basis. Some aspects of Phase 1 construction and equipment installation involve complex equipment such as generators and electrical substations. Manufacturers of this equipment are operating at or close to capacity to meet growing global demand, and long lead times are required for certain types of equipment and materials. Toronto Hydro has pre-ordered material where it has been possible and prudent to do so.

Phase 2

There is a risk that final construction could be delayed due to the discovery of conditions requiring remediation at the site. As noted above, Toronto Hydro is conducting testing and analysis of current building conditions at 715 Milner to obtain early information on any conditions (for example, the presence of mold or other toxic substances) that would have to be remediated prior to final construction. Toronto Hydro is also pre-arranging the installation of the required fibre-optic cable to ensure its availability at the time of occupation.

Phase 3

There is a risk that Toronto Hydro may have to vacate 6 Monogram before the 71 Rexdale property is ready to be occupied. The 71 Rexdale property will be extensively re-developed and as such requires site plan approval from the City, which can take between 5 and 11 months for the entire site. Toronto Hydro will re-use as much of the existing building as possible to minimize the scope of the required construction and will apply for permits on a phased basis to allow the work to proceed in stages.

E8.3.6 Evaluation of Alternatives

Development and Definition of Alternatives

Toronto Hydro developed the four phases of the integrated OCCP in response to requirements and opportunities it faced concerning its portfolio of operating centers. For each Phase, Toronto Hydro examined its existing assets in conjunction with requirements, constraints, and opportunities, and developed what it considers to be the optimal response in each case.

The main facility-related requirements for Toronto Hydro were to ensure the uninterrupted ability to accommodate all of its staff (including contractors), equipment and other assets, and operations in facilities that were adequate and appropriate to the purpose, and to maintain the same basic distributed geographic configuration for its operating centers supporting its planned construction and maintenance activities.

For its northwest and northeast operating centers, Toronto Hydro faced constraints due to expiring leases on the properties involved. However, Toronto Hydro also had opportunities in the form of being able to dispose of potentially surplus properties at 5800 Yonge and 28 Underwriters, and utilizing the property it already owned at 715 Milner.

While in theory there are an indefinite number of alternatives that Toronto Hydro might have been able to pursue, the existence of these requirements, constraints, and opportunities substantially narrowed the range of consideration.

Toronto Hydro proposes the OCCP because it believes that it is the optimal response to the conditions that Toronto Hydro faces. However, for purposes of analysis, Toronto Hydro has also defined two alternative scenarios: a "Base Case" scenario and a "Do Nothing" scenario.

The Base Case essentially represents a continuation of the status quo, subject to the requirement that Toronto Hydro continue to respond to changing circumstances (e.g., the expiry of existing leases) as well as meeting evolving requirements, such upgrading and expanding its Data Centre. The Base Case does not involve the disposition of 5800 Yonge and assumes that the northwest and northeast operating centres continue to be leased. The Base Case assumes moves to new leased facilities for the northern operating centres would be required every ten years. Under the Base Case, significant capital expenditures would be required at 5800 Yonge to compensate for deferred capital maintenance over the past several years in anticipation of disposition, to provide expanded and upgraded facilities required for the Data Centre and for other IT-related investments. /C

Toronto Hydro also defined a "Do Nothing" alternative strictly for the purpose of providing a point of reference. The Do Nothing alternative is untenable because it exposes Toronto Hydro to unacceptable risks of being displaced from its northwest and northeast operating centres, and fails to meet evolving requirements around its technology infrastructure. Under the Do Nothing scenario, Toronto Hydro would passively rely on being able to renew existing leases on its northwest and northeast operating centres indefinitely into the future. Under commercially available terms of lease, Toronto Hydro would be subject to the unacceptable risk that either or both of those leases would not be renewed, with insufficient notice to enable Toronto Hydro to arrange even temporary alternative accommodation.

In addition, the Do Nothing scenario does not provide for required expansion and upgrading of Toronto Hydro's Data Centre at 5800 Yonge. Toronto Hydro's ability to provide basic IT infrastructure support to its core operations would decline over time to unacceptable levels in the face of growing requirements for that infrastructure.

Because the Do Nothing alternative is untenable, Toronto Hydro has not developed detailed financial forecasts based on it. However, Toronto Hydro has conducted detailed analysis of the OCCP in comparison to the Base Case. The results of this analysis are presented below.

E8.3.6.1 Quantification/Evaluation of Options

Introduction

Toronto Hydro has conducted a detailed financial analysis of the incremental costs of the OCCP and of the Base Case. The term "incremental costs" means costs that would be incurred or avoided relative to the level of costs currently embedded in Toronto Hydro's rates, inclusive of all elements of capital-related costs (return, taxes, depreciation) as well as all elements of OPEX, which when combined constitute the incremental base revenue requirement that would be created by either the OCCP or the Base Case, in isolation from all other elements of the total base revenue requirement.

The capital-related costs of the incremental investment in the improvements and expansions at 500 Commissioners are treated as a virtual facility, since the pre-OCCP Commissioners facility will continue to exist in any case. Otherwise, the incremental cost analysis includes the incremental capital-related costs of keeping 5800 Yonge, 71 Rexdale, and 715 Milner in ratebase, inclusive of any further investments that need to be made to those facilities (depending on the scenario involved).

Definition of Base Case

Phase 1

Under the Base Case, the facility at 5800 Yonge would be retained and continue to house the functions historically situated there. In addition to the normal OPEX associated with running that facility, incremental maintenance capital would be invested to compensate for maintenance that has been deferred in anticipation of selling the property. In addition, capital expansions and upgrades related to the Data and Control Centers would be made.

The 500 Commissioners facility would remain unchanged from its pre-OCCP state and would attract no incremental costs.

Phase 2

The facility at 601 Milner would continue to be leased until 2016, at which time an alternate facility would be leased for ten years, then replaced by a further alternate facility, with the 10-year cycle continuing for 50 years until 2064. Upon the initial leasing of each successive facility, capital

investments in leasehold improvements are assumed. The last change of facility within the horizon occurs in 2056. Incremental operating costs for the facility are included.

The facility at 715 Milner is assumed to be excluded from ratebase and attracts no capital-related or operating costs.

Phase 3

The treatment of the northwest operating center is parallel with that of the northeast facility.

The facility at 71 Rexdale is assumed to be excluded from ratebase and attracts no capital-related or operating costs.

Phase 4

The facility at 28 Underwriters is assumed to be retained to house the Investment Recovery function, which would be transferred to the north building. The south building would be demolished as it is not cost-effective to undertake the significant repairs that would otherwise be required. The property would continue to attract moderate incremental OPEX and CAPEX costs.

Common Assumptions

Toronto Hydro applied common parameter assumptions and methodology to both the OCCP and Base Case scenarios throughout the analysis. Major assumptions and parameters are listed below:

- Basic Analysis Horizon: 50 years, set to match the expected useful lives of the facilities involved
- Short Analysis Horizon: 5 years, set to cover the CIR period and isolate effects occurring within that horizon
- Capital structure: equal to current (60 debt: 40 equity)
- ROE: equal to current (9.55%)
- Discount Rate: the discount rate used for calculating the NPVs of the cost streams is 6.06%, equal to Toronto Hydro's current weighted average cost of capital

- OPEX Cost and Escalation Rate: OPEX costs are based on historical rates per square foot and escalated at the forecast rate of inflation
- CAPEX Cost and Escalation Rate: CAPEX costs are based on historical expenditures and escalated at the forecast rate of inflation
- Statutory Tax Rate: 26.5% throughout

RESULTS OF THE FINANCIAL ANALYSIS OF OPTIONS

The financial analyses (i.e., benefit cost analysis, or BCA) are set out in Appendix A for the OCCP and Appendix B for the Base Case. Each case is reviewed over two horizons: the five-year period of 2015 to 2019, the CIR term; and the 50-year period of 2015 to 2064 period), which is the expected useful life of the facilities. The tabs break out the summed costs and benefits by building and by phase.

BCA RESULTS

In net present value terms, the OCCP offers significant reductions in Base Revenue Requirements (BRRs) over both analysis horizons (i.e., to 2019 and 2064). In contrast, the Base Case scenario produces increases in BRRs over both horizons. Table 11 below summarizes these differences.

TABLE 12: SUMMARY OF BCA NPV RESULTS FOR OCCP AND BASE CASE SCENARIOS

[redacted]

In most instances, business cases involving front-end capital expenditures, made to produce cost savings that follow, exhibit weaker or even negative results as the horizon is shortened. This is because shortening the horizon has the effect of excluding future benefits that, while being generated by the initial investment, occur beyond the horizon. It is notable in the case of the

OCCP that a net reduction in the NPV of the BRR occurs even over the short horizon (to 2019), due to the sale of the property.

SUMMARY

The OCCP is expected to yield significant benefits to ratepayers and to Toronto Hydro. For ratepayers, substantial ongoing cost reductions is expected to occur without causing the costs of Toronto Hydro's capital renewal and maintenance programs to increase. In addition, ratepayers would enjoy the benefit of rate riders estimated to exceed [redacted] million dollars.

Both ratepayers and Toronto Hydro will benefit by the security of tenure at major crew-supporting operating centers, and the improved robustness of infrastructure supporting critical Toronto Hydro functions. This is especially important during emergency conditions.

E8.4 IT Hardware Refresh

E8.4.1 Summary

Program Description

Toronto Hydro uses numerous information technology ("IT") systems that support and in many cases, are critical to the execution of various business processes. These IT systems enable Toronto Hydro employees to execute tasks and perform activities that are essential to the proper functioning of the utility, including accounting, customer care and distribution grid management. In addition, these IT systems increase the efficiency of business processes and streamline reporting for both internal and external purposes.

Toronto Hydro employees interact with technology on a daily basis through: (1) endpoint hardware such as desktop computers, laptops, telephones, and printers; and (2) back-end hardware such as servers, local area networks and data storage. Through the IT Hardware Refresh Program, Toronto Hydro plans to replace, maintain and manage its IT hardware over the 2015 to 2019 period in accordance with best practices and standards. In executing the program, Toronto Hydro will efficiently maintain existing IT hardware where possible and will replace IT hardware as it approaches end-of-life.

Toronto Hydro needs to undertake this program in order to maintain the reliability of its IT hardware. Reliable IT hardware enables Toronto Hydro to efficiently and effectively plan and execute capital and operational programs and to fulfill its obligations to customers and applicable regulatory bodies. In addition to providing reliability benefits, this program is expected to mitigate risks to the utility's operations and cyber security and to facilitate the development of technological solutions to address emerging business needs and requirements.

Hardware components addressed in the program can be split into two categories:

(i) Endpoint assets

a. Responsible for computing and printing

b. Desktop computers, laptops, telephones, and printers

(ii) Core Backend Infrastructure assets

a. Rresponsible for computing, storage and communication

b. Servers, local area networks and data storage

The following table summarizes the anticipated benefits of the IT Hardware Refresh program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Updated hardware assets help maintain accurate customer billing. ƒ The hardware refresh will provide additional data storage and processing capabilities to respond to customer growth demands. ƒ Newer hardware has a lower risk of failure, supporting faster restoration times and shorter outages. ƒ The risk of compromise to sensitive customer data is lowered by updated IT hardware assets. ƒ Customer interfaces such as online billing and online customer account information are better supported by updated hardware assets.
Reliability	ƒ Updated hardware assets enable core business activities that are necessary to maintain a reliable distribution system for customers.
Efficiency	ƒ IT hardware supports the automation of business processes, which results in more efficient use of employee time. ƒ New hardware assets are less prone to fail and require less maintenance; this reduces the employee time is managing new hardware assets

Safety	ƒ Updated hardware helps ensure the cyber security of Toronto Hydro's distribution system, and guard against unauthorized access to distribution systems and assets. ƒ Updated hardware assets support environmental health and safety systems and processes in the work place and at the job site, such as the completion of the job site conditions and safety forms and safety audits.
Other Benefits	ƒ Updating hardware assets ensures that support services are available, which reduces the costs associated with specialized technical resources. ƒ Updated hardware systems enables Toronto Hydro to comply with the regulatory requirements of bodies such as Measurement Canada, the OEB and the IESO.

Program Drivers

The trigger and secondary drivers for this program are outlined in Table A below.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
System Maintenance and Capital Investment Support	ƒ IT hardware must be periodically refreshed to ensure the high availability of the systems that support Toronto Hydro's core operations and to minimize risk of failure impact to the business. ƒ Toronto Hydro relies on this technology to satisfy its obligations to customers and to comply with existing and emerging requirements of the various regulatory bodies that govern the utility's operations.
Secondary Drivers	**Reasoning**
Cyber Security Risks	ƒ IT Hardware must be kept current to mitigate the risk of malicious cyber attacks that can compromise sensitive customer data, operational and employee information, as well as the integrity of the distribution system.
Business Operations Efficiency	ƒ IT Hardware supports the automation of core processes and functions, such as customer billing and outage management. It also enables the utility to manage new business objectives and requirements, such as the need for additional data storage and processing capabilities to respond to customer growth demands.

Preferred Alternative

In developing the program, Toronto Hydro evaluated a number of alternatives with respect to both endpoint assets and core backend infrastructure assets.

Alternatives for endpoint assets:

(1) Run the assets to failure and react as needed; or

(2) Install new hardware based on asset lifecycle management methodology.

Alternatives for core backend infrastructure assets:

(1) Run the assets to failure and react as needed;

(2) Implement an externally hosted and managed solution; or

(3) Adopt an internally hosted and managed solution based on asset lifecycle management methodology.

Toronto Hydro determined that the preferred alternatives are to replace the endpoint assets through the "New Hardware" approach and replace the core backend infrastructure through the "Internally Hosted and Managed" approach. Toronto Hydro expects that this course of action will minimize the risk of interruptions to operations and core processes caused by IT hardware failure, in addition to mitigating cyber security risks and increasing the overall security of the utility's IT system.

Timing and Pacing

The forecasted total cost of the IT Hardware Refresh program over the 2015 - 2019 year period is $36.7 million. The program is comprised of multiple projects and the cost breakdown by asset category is as follows:

- Endpoint Assets: $ 9.06 million; and
- Back-end Hardware: $ 27.62 million.

The estimated future cost of the IT Hardware Refresh program is between $5.6 million and $9.8 million per year over the 2015 to 2019 time period. These figures are based on Toronto Hydro's asset lifecycle manager policies for IT hardware. For additional discussion of timing and pacing, refer to section E8.4.4 below. The historical and estimated costs of the IT Hardware Refresh program are provided in Table B below.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Forecasted Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Annual Spend ($M)	-	6.62	6.39	5.4	6.03	5.87	7.99	7.41	9.79	5.63

E8.4.2 Program Description

IT systems, comprising of both software and hardware components, support most of Toronto Hydro's operations. Software components are intangible assets such as Microsoft ("MS") Word and Adobe Acrobat applications that enable users to perform specific functions. Toronto Hydro utilizes many software applications to automate processes and efficiently execute required tasks such as preparing customers' bills and dispatching crews to respond to outages. These applications run on core backend infrastructure assets such servers, storage disks and computers, and are operated by employees via end-point assets such as desktops, laptops and tablets. The IT Hardware Refresh Program addresses the renewal and maintenance of these hardware assets. Software upgrades and enhancement are addressed by the IT Software Upgrades, Enhancements and Analytics Program, filed at Exhibit 2B, E8.5. The relationships and dependencies between software and hardware assets are illustrated in Figure 1 below:

FIGURE 1: IT HARDWARE MAPPING WITH UTILITY APPLICATIONS AND PROCESSES

IT hardware components are the building blocks of the overall IT System. IT hardware investments must be planned and implemented with regard to both current and future utility needs and operational requirements in order to enable Toronto Hydro to execute its plans and programs securely and efficiently, and to pursue its short and long-term objectives. IT hardware standards must be continually reviewed, assessed and implemented based on the utility

requirements from an operational, regulatory and customer service perspective. This requires Toronto Hydro to continuously invest in its IT hardware assets.

IT hardware assets are classified either as Endpoint Assets or Core Backend Infrastructure Assets. Endpoint Assets are the assets that the end-user interfaces with to execute, process, complete and review business tasks and operations, while Core Backend Infrastructure Assets are responsible for the computation, storage and communication necessary to support IT systems. Based on their functionality, these assets in this program can be further categorized as follows:

- Endpoint Assets:
  - Computing assets support the execution of business processes, data transactions and analysis - desktops, laptops and tablets used by employees.
  - Printing assets allows the representation of electronic documents such as engineering drawings, standards and contracts on paper and photocopying, scanning and faxing capabilities - printers and plotters.
- Core Backend Infrastructure:
  - Servers manage access to centralized resources and services in the network and security appliances secure the network from unwanted traffic.
  - Storage assets enable the secure retention of digital data such as customer information. Disk and flash arrays store records for access by servers.
  - Communication assets facilitate the exchange of data within and between the core backend assets and the endpoint assets, so that can user can access information in a central IT system. Network and telephony assets enable computers, services and storage devices to exchange data and manage communication services.

To illustrate the relationship between core backend infrastructure assets and endpoint assets, consider an employee in a call centre accessing the Customer Information System (CIS) while interacting with a customer. The employee uses his or her endpoint (i.e. desktop or laptop) to access the CIS application that runs on a server. The application retrieves the necessary data from the storage assets. The network assets facilitate the connection between all the

components of the system. This diagram below depicts the typical structure and dependency of the system:

FIGURE 2: TYPICAL ENDPOINT ASSET TO CORE INFRASTRUCTURE RELATIONSHIPS

Toronto Hydro has over 2,000 endpoint assets and over 1,500 core backend infrastructure assets. To effectively manage its IT hardware infrastructure, the utility has implemented a structured asset management approach that is aligned with industry best practices, vendor lifecycle recommendations and Toronto Hydro empirical data. To learn more about Toronto Hydro's IT asset management methodology, refer to Exhibit 2B, D4.

The lifespan of the assets targeted by this program is in the four to seven year range which is considered within industry norms. After four to seven years, the hardware assets risk of failure increases significantly and could impact core business processes. To determine the refresh cycle of existing hardware, Toronto Hydro maintains an inventory of its hardware assets that includes technical details and lifecycle information such as date of implementation and end of vendor support. This approach ensures that IT hardware assets are available to support the effective and efficient execution of utility's operations.

Furthermore, Toronto Hydro has a cautious approach to implementing any new technology hardware. Toronto Hydro requires reviewing the hardware specifications and testing hardware performance prior to approval for implementation. As a result, the hardware implemented in

Toronto Hydro is typically not the latest vendor released version. This ensures the systems have an acceptable performance and there is minimal impact to operational processes.

The high level scope of the different initiatives in the program is presented below:

- Identify the specific assets in the scope of the planned hardware refresh;
- Verify the technical requirements and compatibility of the proposed hardware;
- Provision for the assets per the published IT Technical Standards;
- Install and test the new hardware using Standard Operating Procedures;
- Test compatibility, redundancy, and integration as per the IT Testing Standard;
- Upgrade Operating Systems of virtual systems on legacy hardware if required to move to the new Hardware; and
- Migrate virtual systems to the newly deployed Hardware.

The table below presents the approximate breakdown of programs costs by asset type. The total estimated program cost for the 2015 to 2019 period is $ 36.69 million.

TABLE 1: ESTIMATED COST BREAKDOWN BY ASSET TYPE

No.	Asset Class	Hardware Function and Assets	Total ($ M)
1	End point Assets	Compute Desktops laptops, tablets Print Printers and plotters	$ 9.06
2	Core Back-end Infrastructure Assets	Compute Servers	$ 9.37
3		Storage Disk arrays and flash arrays	$ 6.69
4		Communication Network and telephony assets	$ 9.75
5		Miscellaneous Items	$ 1.81

No.	Asset Class	Hardware Function and Assets	Total ($ M)
		Ancillary items needed for the functioning of the above hardware components	
		TOTAL	$ 36.69

The following table summarizes the anticipated benefits of the Hardware Refresh Program.

TABLE 2: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Updated hardware assets help maintain accurate customer billing. ƒ The hardware refresh will provide additional data storage and processing capabilities to respond to customer growth demands. ƒ Newer hardware has a lower risk of failure, supporting faster restoration times and shorter outages. ƒ The risk of compromise to sensitive customer data is lowered by updated IT hardware assets. ƒ Customer interfaces such as online billing and online customer account information are better supported by updated hardware assets.
Reliability	ƒ Updated hardware assets enable core business activities that are necessary to maintain a reliable distribution system for customers.
Efficiency	ƒ IT hardware supports the automation of business processes, which results in more efficient use of employee time. ƒ New hardware assets are less prone to fail and require less maintenance; this reduces the employee time is managing new hardware assets
Safety	ƒ Updated hardware helps ensure the cyber security of Toronto Hydro's distribution system, and guard against unauthorized access to distribution systems and assets. ƒ Updated hardware assets support environmental health and safety systems and processes in the work place and at the job site, such as the completion of the job site conditions and safety forms and safety audits.
Other Benefits	ƒ Updating hardware assets ensures that support services are available, which reduces the costs associated with specialized technical resources. ƒ Updated hardware systems enables Toronto Hydro to comply with the regulatory requirements of bodies such as Measurement Canada, the OEB and the IESO.

E8.4.3 Why the Program is Needed

The IT Hardware Refresh Program is needed to maintain the reliability of the IT hardware systems that enable Toronto Hydro to efficiently and effectively plan and execute capital and operational programs and to fulfill its obligations to customers and regulatory bodies.

The IT Hardware Refresh Program plans the refresh of IT Hardware within the 4 to 7 year timeline. This duration is determined based on the asset type, asset sub-type and the acceptable performance of the hardware asset in terms of the expected hardware failure rate and the resulting impact to business operations. Based on the asset type and asset sub-type, beyond the 4 to 7 year timeline, it is expected that the hardware failure rate will significantly impact core business processes and will need a higher overhead to maintain and manage the hardware. This concept is explained in terms of the Bathtub Curve in the E8.4.4 Timing & Pacing of the Program section of this narrative. In the absence of the rigour in maintaining assets by a defined lifecycle, there is a significant risk to interruption of core business operations. There is a support risk from management of hardware assets by exception and increased overhead costs in the management of the hardware assets.

E8.4.3.1 Purpose

The table below summarizes the trigger and secondary drivers of the IT Hardware Refresh Program:

TABLE 3: PROGRAM DRIVERS

	Drivers	Reasoning
Trigger Driver	System Maintenance and Capital Investment Support	› IT hardware must be periodically refreshed to ensure the high availability of the systems that support Toronto Hydro's core operations and to minimize risk of failure impact to the business. x Toronto Hydro relies on this technology to satisfy its obligations to customers and to comply with existing and emerging requirements of the various regulatory bodies that govern the utility's operations.

	Drivers	Reasoning
Secondary Drivers	Cyber Security Risks	› IT Hardware must be kept current to mitigate the risk of malicious cyber attacks that can compromise sensitive customer data, operational and employee information, as well as the integrity of the distribution system.
	Business Operations Efficiency	› IT Hardware supports the automation of core processes and functions, such as customer billing and outage management. It also enables the utility to manage new business objectives and requirements, such as the need for additional data storage and processing capabilities to respond to customer growth demands.

This program directly impacts customer experience because Toronto Hydro's IT hardware infrastructure assets support a number of customer service functions. Currently, approximately 93,000 customers use the online electronic billing function and approximately 72,000 customers have accounts through which they can complete key self-serve functions, such as management of account details, customer moves, payment options and landlord information. Hardware assets also support a number of customer interfacing applications and processes delivered via telephony through the Toronto Hydro Call Centre. If the hardware assets supporting these functions were to fail, customers would be unable to access these systems, and could experience a significant delay in completing routine transactions. This would impact customer service satisfaction and would likely lead to increased volume of calls and complaints to Toronto Hydro's call center.

Hardware assets support systems that are used to manage the field crews and respond to outages. By providing distribution grid management employees real-time access to crew availability, geographic outage location and crew location, these systems enable Toronto Hydro to efficiently and effectively deploy crews to restore power to customers in a timely fashion. In the event of core backend infrastructure failure, the functionality of these applications would be impaired, and as a result, Toronto Hydro's outage response time would be negatively affected. This program therefore has direct impact on the duration of outages and the reliability of the distribution system.

The hardware assets in this program also support environmental health and safety systems and processes in the work place and at the job site. The processes range from completion of the job

site conditions and safety forms, review of the Material Safety Data Sheets (MSDS), safety and environmental audits and incident and claims investigation. In the event of an IT Hardware failure, employees may not have access to the information required to make informed decisions about environmental and health and safety issues that may arise, potentially leading to unsafe work conditions and/or resulting in inadvertent breaches of key obligations and requirements.

IT hardware assets contribute to operational efficiency by reducing manual processing times and ensuring consistency in the execution of operational task and processes. In the event of a hardware asset failure, business processes could be significantly affected. For example, Toronto Hydro uses a Customer Information and Billing system to process and generate customer bills. If the hardware supporting this system were to fail, Toronto Hydro could lose important data and experience notable delays in processing billing. In the worst case scenario, employees would need to revert back to manually processing billing data for thousands of customers, which would increase the time and cost associated with the billing process, as well as the likelihood of errors.

This program is needed to mitigate the following risks associated with aging IT Hardware Assets:

- Business Continuity: Use of obsolete IT hardware exposes users to unreliable system and application performance resulting, and increases the likelihood of interruptions to core processes that the utility relies on to effectively and efficiently execute its capital plans and operational programs.

- Cyber Security Risks: Obsolete IT hardware exposes Toronto Hydro to cyber security threats because it impairs the ability of system administrators to apply necessary service packs, security patches and upgrades to the operating system and the applications that are critical to maintaining a robust security posture. If this risk materializes, sensitive customer, operational and employee information could be compromised.

- Inability to Support Business Needs and Pursue Operational Efficiency: Business needs and operational efficiency drive the implementation of software solutions to enhance and automate processes. Due to compatibility issues, obsolete hardware assets could limit Toronto Hydro from implementing new solutions to achieve its business goals and objectives. If this risk materializes, Toronto Hydro would have to respond to emerging business needs on a case-by-case basis. This could result in poor response times for implementing new initiatives, and could create a fragmented hardware infrastructure that will become increasingly difficult and expensive to maintain and support as time passes.

- Lost Opportunity Cost: If Toronto Hydro does not effectively and efficiently manage its assets in a structured way, it will add new IT hardware assets in an ad hoc fashion based on immediate short term requirements. There will be lost opportunity cost to consolidate the infrastructure in a "Pooled or Farm" based concept. A "Pooled or Farm" based concept is a collection of hardware resources to complete desired computing operations that exceed the requirements of a single hardware machine. The pooled farm based concept simplifies applying services packs, patches and bug fixes from a gain in economies of scale. In the absence of the pooled farm based concept, the burden of managing hardware assets increases significantly as does the risk of IT hardware not being effective to support new business requirements.

E8.4.4 Timing & Pacing of the Program

The timing and pacing of the program for each asset sub-type is driven by the asset lifecycle defined in the respective standards. The standards are designed to extract maximum value of hardware asset and minimize negative impact of potential asset failures. This is explained through the concept of the "Bathtub Curve".

FIGURE 3: IT HARDWARE ASSET LIFECYCLE FAILURE RATE OVER TIME

As illustrated above, the bathtub curve breaks life-cycle of an asset into three distinct areas:

- Decreasing Failure Rate: This is the region of the curve associated with the reducing failure rate over time. This is typical of new IT hardware. The vendor quickly releases service packs, patches and bug fixes that reduce the IT hardware failure rate.

- Constant Failure Rate: As the failure rate decreases it comes to a stage when it stabilizes and it is almost constant. The cost of ownership in this area of the bathtub curve is steady and the considered financially optimal.

- Increasing Failure Rate: As the IT hardware ages beyond useful life, the failure rate starts to increase again. This is attributed to the general operational wear and tear of the asset as well as vendor focus on development of new products, in essence, lack of investment in obsolete products. The system failures and associated maintenance costs start to rise steeply in this portion of the bathtub curve.

Toronto Hydro's IT standards attempt to define asset lifecycles so that assets operate within the "Constant Failure Rate" region of the bathtub curb where they enjoy the lowest failure rate. This approach minimizes the strain on Toronto Hydro's operational support resources and leads to a reduction in hardware support costs.

Toronto Hydro also considers forecasted capacity requirements to ensure it has the necessary IT hardware to support general business growth and associated increased data storage and data processing requirements. The forecasts are based on the analysis of the following factors:

- Historic trends of current assets capacity versus utilization by existing information technology systems;

- Asset resource requirements to support system enhancements and new initiatives; and

- New operational requirements that necessitate increased hardware resources. An example of this is the estimated increase in storage resources required to account for an increase defined by the retention policy of electronic records.

Toronto Hydro maintains a centralized registry of all hardware. This includes dates the hardware assets were implemented in Toronto Hydro. This information is used in conjunction with the applicable IT standard(s) and the forecast capacity requirements to determine the replacement quantities and schedules over the 2015 to 2019 period.

The approximate breakdown of the annual costs of the program by the IT Hardware Sub-Type is presented in the table below . Details of the 2015 replacement are presented at the end of this document in Table 7.

TABLE 4: ESTIMATED COSTS BY IT HARDWARE SUB-TYPE

No.	Hardware	Hardware Sub-Type	Approximate Annual Spend ($,M)			TOTAL ($,M)		
			2015	2016	2017	2018	2019	
1	End-point Assets	Desktop, Laptops, Tablet, Printer and Plotter assets	1.78	1.77	1.84	1.82	1.84	9.06
2	Core Back-end Infrastructure Assets	Servers and Security Appliances	1.33	3.32	2.20	1.71	0.82	9.37
3		Disk and Flash Storage Assets	0.34	0.71	1.67	3.14	0.83	6.69
4		Network and Telephony Assets	1.68	2.05	1.57	2.71	1.74	9.75
5		Miscellaneous Items (Accessories, Power etc.)	0.74	0.13	0.14	0.40	0.40	1.81
TOTAL			5.87	7.99	7.41	9.79	5.63	36.69

Endpoint Assets

It is expected that all endpoint assets would reach end of life within the 2015 to 2019 period. Toronto Hydro estimates that it will replace approximately an equal number of endpoint assets each year. The annual of forecasted cost associated with replacing these assets is therefore consistent over the 2015 to 2019 period.

Servers and Security Appliances

Per the server asset lifecycle, no major server and appliance replacements are needed in 2019, this results in a smaller estimated spend in 2019. The increase in spend in 2016 and 2017 is attributed to the lifecycle replacement of security appliances.

Disk and Flash Storage Assets

Toronto Hydro's forecast expenditures relating to storage assets are highest in year 2017 and 2018 since these investments are timed and paced in accordance with a four to six year replacement schedule.

Network and Telephony Assets

Expenditures relating to the renewal of specific network assets are forecast to be the highest in the year 2018, consistent with their asset lifecycle management of five years.

Miscellaneous Items

The estimated expenditure towards miscellaneous items is higher in 2015 in comparison to other years due to the planned lifecycle of hardware accessories such as racks, cables and tools.

Summary

There is a difference in forecasted spend between years 2018 and 2019 of approximately $4.16 million. This difference is largely attributed to the higher spend in 2018 in storage assets and network and telephony assets. To reduce this difference, Toronto Hydro would need to defer some of the investments relating to the refreshment of storage and network and telephony assets beyond their planned lifecycle. This would significantly increase the likelihood of storage and network and telephony asset failure, which is a risk that Toronto Hydro is unprepared to take because these assets are critical to the proper functioning of the IT systems that the utility relies upon.

Historical Spend

As provided in the figure below historic spend from 2010 to 2014 varied between $5.19 million and $10.6 million averaging $7.72 million annually. The estimated future cost of this program over the 2015 - 2019 period range between $5.63 million and $9.79 million per year, with an average of $7.34 million. Some of the highlights of the proposed spend are presented below:

- The planned refresh of IT storage assets and network and telephony assets coincide in 2018. This results in a high estimated spend in 2018.
- The planned network and telephony asset replacement coincides with the planned security appliance refresh in 2016 that results in a high estimated spend of $7.99 million in 2016.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Forecasted Future Spending				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	10.60	9.39	7.41	6.00	5.19	5.87	7.99	7.41	9.79	5.63

E8.4.4.1 Ranking & Prioritization

In determining the priority of the investments in this program, failure impact is the main consideration that Toronto Hydro takes into account. If endpoint assets such as laptops, desktops or printers fail, the impact would be localized to a specific user(s), and in most cases, it would be possible to provide the affected users with a corresponding replacement asset in a timely fashion. Although it is likely that some re-work would be required to configure the corresponding assets for the user, the impact would likely be manageable and minimal. As the likelihood of failure of the endpoint assets would increase with the increase in asset age, Toronto Hydro would need to keep more assets as "standby" to minimize impact to the business users.

In contrast, the failure of core backend infrastructure could lead to the failure of entire IT systems, and could have a profound impact on core operations and business processes or could affect a large number of users. Such a failure could lead to a loss of productivity and/or the unavailability of core system(s) while the workarounds and fixes are being developed and implemented. Because the impact to the utility is likely more profound in event a core backend infrastructure failure, these assets are given a higher priority than endpoint assets.

Within the endpoint assets, there are two asset sub-types, computers, and printers and plotters. The impact of failure to Toronto Hydro from printer and plotter failure is smaller than that from computer failure. In the event of printer and plotter failure, business users would have the opportunity to use alternative endpoint printers and plotters within the utility premises to complete the print function. While this could potentially delay completion of business processes, this failure does not cause employee downtime. In case of computer failure, there is some employee downtime before the employee can commence execution of duties. Therefore, at the endpoint asset layer, the compute assets are more critical than print assets.

Within the core backend infrastructure assets, there are three sub-types of assets: servers, storage and network assets. Restoration of servers, while tedious, can be completed with some

employee downtime. In case of network and telephony asset failure, the immediate impact is to users in a specific location. Restoration of service typically involves replacement of the faulty asset with a corresponding new asset. Employees would be unable to access IT systems running on servers and storage assets. This will cause considerable employee downtime. Finally, in case of failure of storage assets, the impact is very serious and significant as a large number of users, would be affected. There would likely be data corruption issues and data loss. There would also be a considerable delay in the restoration of IT systems to resume regular business operations and processes.

Given the above considerations, the hardware assets to be addressed by this program are provided below, in order of highest to lowest priority.

1. Core Backend Infrastructure Assets
    1.1. Servers
    1.2. Network and telephony assets
    1.3. Storage assets
2. Endpoint Assets
    2.1. Printers and plotters
    2.2. Compute devices - Desktops, laptops and tablets

E8.4.5 Program Execution

The program will be executed through multiple projects. The high level steps in executing the projects within this program are presented below:

- Identify the specific assets in the scope of the planned hardware refresh project - Determine the IT hardware assets that need to be replaced based on the defined IT hardware asset standard lifecycle. This step will define the project scope in terms of the required IT hardware specifications and quantity of IT hardware assets that need to be managed.
- Verify the technical requirements and compatibility of the proposed hardware with other interdependent components - In this step, Toronto Hydro will review the hardware technical specifications of new hardware that would replace the existing IT hardware. This will ensure the ongoing optimal performance of the assets. Toronto Hydro will also ensure the hardware compatibility with dependent components. As an example,

in case of new servers, the Toronto Hydro would ensure compatibility with the applications, databases and storage assets.

- Provision the assets per the published IT Technical Standards - Toronto Hydro will initiate the process to procure the required IT hardware assets. Toronto Hydro will issue tenders to invite competitive bids from vendors. On the successful selection of the vendor, Toronto Hydro will purchase and provision the assets needed.
- Install and test the new hardware using the Standard Operating Procedures - In this step, Toronto Hydro would implement the new hardware and validate the hardware installation steps per the established Standard Operating Procedures.
- Test compatibility, redundancy, and integrat ion as per the IT Testing Standard - In this step, Toronto Hydro would test the new hardware in the IT system for security, performance and architectural compliance. Through security testing, it is determined that the applicable security controls are in place and the security posture is validated; in performance testing, the hardware performance criteria is validated with load and stress tests; and architectural compliance testing ensures the solution is appropriately designed and validates the design with appropriate simulation of failure scenarios for Disaster Recovery purposes.
- Upgrade Operating Systems of virtual systems running on legacy hardware if required to move to the new Hardware - This additional step is completed in case of legacy hardware. This step requires to upgrade the operating system to a new version to allow the virtual system to be reassigned to the enables the upgrade
- Migrate virtual systems to the newly deployed Hardware - In this step the infrastructure teams will complete the deployment of the new IT hardware in the IT system. The applications, databases and middleware are migrated to the newly deployed hardware.

(i) Program Risks

The program faces several risks that could impact the program in terms of scheduling and sequencing of work, program costs and quality of work. The potential impact of program risks is presented below:

TABLE 6: RISKS AND CONSEQUENCES

Risk	Potential Consequences	Mitigation Measures
Internal Resource Availability: insufficient resources to complete the planned program tasks and activities	Schedule Risk of delay to interdependent and downstream program/ project activities Cost: project costs could increase due to the need to procure temporary skilled resources at a premium.	› Adopt a long term resource plan based on project tasks and activities that Toronto Hydro plans to undertake over the next five years x Ensure appropriate responsibility overlaps between labour resources to minimize impact from attrition
Vendor Management: vendor does not meet its program delivery obligations, or changes the product cost structure	Schedule vendor is unable to provide the product according to the project schedule Quality: the vendor does not deliver per the product specifications. Cost: program costs could vary significantly from the program budget.	› Clearly state expected timelines and have resolution clauses to address delays x Delineate an escalation path to quickly resolve conflicts and discrepancies x Enforce short interval control through vendor project status updates and reports x Complete comprehensive due diligence of scope and requirements prior to undertaking projects and incorporate findings in the tender documentation x Enter into long term

Risk	Potential Consequences	Mitigation Measures
		contracts, where appropriate, with vendors and suppliers to ensure costs are fixed over a long period of time x Solicit vendor responses to competitive bids
Overall Program Schedule r Toronto Hydro is at risk of missing the program timelines from the volume of work in the program	This risk might impact the defined project and program timelines, deliverables and costs.	› Closely monitor the project progress and project deliverables through monthly Project Status Reviews with senior management and executives

(ii) External Constraints

The planned IT Hardware Refresh program faces a number of external constraints that could impact program schedule, budget and/or the quality of work.

- Vendor Strategy: Changes to the vendor planned hardware release dates or product strategy could impact the project schedules. The changes to the release schedule of a specific hardware component will impact other interdependent hardware component activities and projects in scope of this program. This will risk delays to the planned program schedule. Likewise, if a vendor decides to terminate a product line, Toronto Hydro would have to review the planned project scope and it will impact program quality. Similarly, should the vendor change its product strategy it would likely have an impact on the planned hardware asset management. For example, the vendor might terminate a product line that would require a review of the planned project scope and impact program quality. Toronto Hydro continually monitors changes to the technology landscape that might impact its program plans. Toronto Hydro will adhere to its internal architecture framework for standards and associated specifications which would redefine the program scope and timelines.

- Technical Compatibility: Each hardware component needs to be compatible with the underlying interdependent hardware components. Should the technical requirements of the hardware components in this program change, there could be potential impact to the interdependent hardware components needed to successfully complete the IT hardware refresh program. For example, servers need to be compatible with storage hardware and, to a lesser extent, the underlying network components. Should the technical compatibility requirements of the server assets change, it will force a review of the architecture. This might result in the unplanned procurement of a new suite of flash and disk array storage assets. This will affect the overall program costs.

Technology evolves at a fast pace with new products frequently entering the technology market space. It is likely that new technologies will become available to Toronto Hydro in the 2015 to 2019 period. Toronto Hydro will evaluate these new technologies with respect to product stability, benefit to business units, and alignment with Toronto Hydro's technology standards and long term technology strategy. Should the evaluation deem that the new technologies would be beneficial to Toronto Hydro, it would impact the planned scope and quality of this program. Toronto Hydro will adhere to the internal governance framework in the implementation of changes to the planned hardware refresh.

(iii) Standard & Regulation Adherence

The program is broadly governed by the following regulations and standards:

External Regulations and Standards:

This refers to the legislation and directives provided by bodies such as the Ontario Energy Board and Measurement Canada.

Toronto Hydro will also adhere to the following standards and legislation:

- National Institute of Standards and Technology (NIST) SP800-82 - This standard provides the guidance for establishing industrial control systems. This standard applies to the Supervisory Control and Data Acquisition (SCADA) systems used in Toronto Hydro to complete remote switching operations on assets in the distribution grid network. Toronto Hydro must ensure that the products purchased as part of this program comply with the NIST SP800-82 requirements.

- North America Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) 002-009 - The NERC CIP 002-009 provides the guidance to ensure the protection of the critical cyber assets which control or affect the reliability of North America's bulk electricity systems. This standard applies to the SCADA systems used in Toronto Hydro to complete remote switching operations on assets in the distribution grid network. This standard requires the identification of critical assets; the protection and classification of the assets, the appropriate personnel training, the appropriate access controls and vulnerability assessments, the implementation of a broad range of measures to secure critical and non-critical assets, the maintenance of a response plan and retention policy of the documentation, and the review of recovery plans that includes backup and recovery of cyber assets. Toronto Hydro must ensure that the NERC CIP requirements can be appropriately applied to the hardware in scope of this program.
- NIST Interagency or Internal Reports (NISTIR) 7628 - This standard presents the analytical framework to develop effective cyber security strategies to mitigate Smart Grid risks and vulnerabilities. Toronto Hydro uses this standard in the metering process that measures, gathers and analyzes energy consumption. Toronto Hydro must ensure that the hardware in this program supports the applicable security frameworks.
- NIST SP800-53 - This standard stipulates the security controls for IT systems to protect the confidentiality, integrity and availability of the overall system and the information contained within it. This standard applies to the hardware of IT systems that support business operations such as finance, billing and accounts receivable.
- The Personal Information Protection and Electronic Documents Act [1] - This Act was enacted by the Government of Canada to regulate the collection, use, disclosure, retention, access and security of personal information in conducting commercial activities. This pertains to the management of personal customer and employee information as part of billing and payroll processes, respectively. Toronto must ensure that the hardware in this program support the systems that comply PIPEDA.

Internal Standards:

Toronto Hydro develops technical standards for computers, servers, storage devices and network devices govern and simplify hardware management and to gain economies of scale in hardware management. Collectively, these standards and regulations will provide the technology framework for the proposed hardware management.

[1] S.C. 2000, c. 5. ["PIPEDA"].

The following standards are the foundation of the Hardware Refresh program:

- Toronto Hydro Desktop and Laptop Standards:

  This standard provides requirements on the types of desktops and laptop hardware to provision, the base software that should be deployed to the desktops and laptops, the general management practices to use the hardware and the asset replacement lifecycle.

- Toronto Hydro IT Infrastructure Provisioning Standards:

  This standard provides the requirements to provision IT infrastructure components to provide a highly available, scalable and manageable platform for business applications deployed. The standard also documents the lifecycle for the assets, patches and capacity of the different components within the infrastructure such as server and storage assets.

- Toronto Hydro Core Backend Network Architecture and Provisioning Standard :

  This standard stipulates the hardware and feature specifications that must be deployed to deliver consistent and predictable levels of performance, capacity and availability from the Core Backend Network Assets and the associated Architecture.

- Toronto Hydro Testing Standard :

  This standard establishes the scope and methodology of non-functional or System Acceptance Testing for IT system in Toronto Hydro. The standard enumerates the categories of tests to be used to prepare detailed test plans during the implementation of IT projects.

E8.4.6 Evaluation of Alternatives

Toronto Hydro evaluated its alternatives based on asset type.

Endpoint Assets:

In case of endpoint assets, Toronto Hydro considered the following alternatives to refresh its desktops, laptops, tablets, printers and plotters:

(1) Do Nothing - Run Assets to Failure

(2) Install New Hardware - Standards Based Asset Lifecycle Replacement

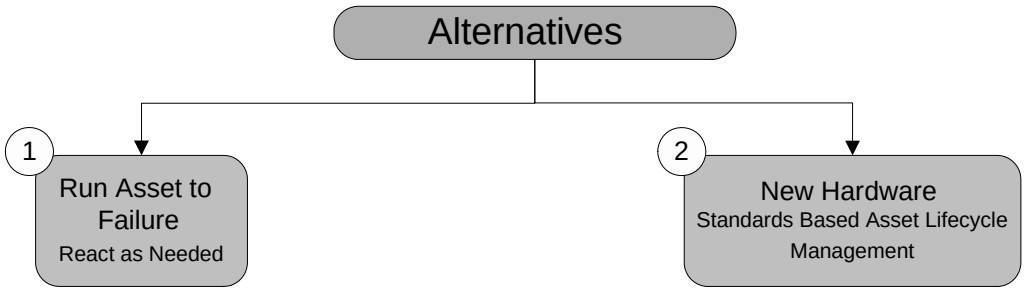


FIGURE 4: CONCEPTUAL REPRESENTATION OF ALTERNATIVES TO EXECUTE THE ENDPOINT ASSET REFRESH

Core Backend Infrastructure Assets:

In case of core backend infrastructure, Toronto Hydro considered the following alternatives to refresh its servers, security appliances, disk arrays, flash arrays, network and telephony assets:

(1) Run Asset to Failure - React as Needed

(2) Externally Hosted and Managed - Outsourced IT Hardware

(3) Internally Hosted and Managed - Asset Management Methodology

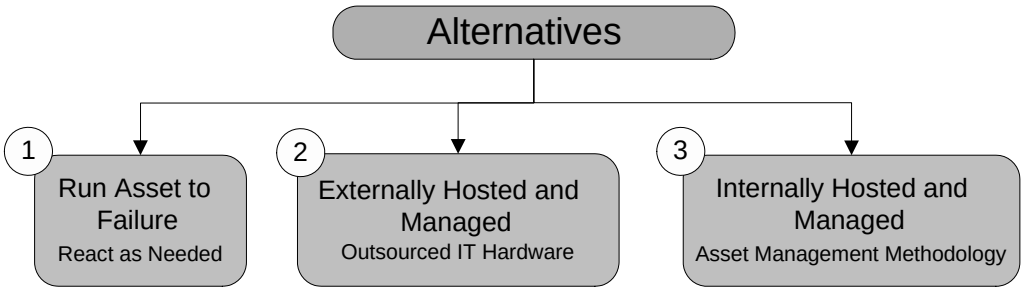


FIGURE 5: CONCEPTUAL REPRESENTATION OF ALTERNATIVES TO REFRESH CORE BACKEND INFRASTRUCTURE ASSET

E8.4.6.1 Quantification/Evaluation of Options - Endpoint Assets

Presented below is the analysis of the options with respect to Endpoint Assets:

1 Run Assets to Failure - React as Needed

In this alternative, Toronto Hydro would not upgrade and/or refresh the existing IT hardware endpoint assets in the 2015 to 2019 period. Within this period, all hardware will reach and pass its respective useful life. As such, Toronto Hydro would run outdated hardware and associated operating systems. Given the typical usage of the IT endpoint hardware, equipment suffers wear and tear with age. This will increase the probability of hardware failure. Any hardware refresh would be completed in a reactive and ad hoc fashion based on hardware asset failure. This could also lead to budgetary issues.

Running assets to failure and reacting as needed is not a preferred solution for the following reasons:

- Toronto Hydro would need to procure and stock assets at high costs to complete asset management activities on an expedited basis.
- There is high risk exposure to core business operations and processes and user experience from endpoint asset failure. The user will experience poor system response times to the commands and functions executed. There is a significant cost of failure from impacted business processes and employee downtime. There is a risk that the users would lose data that would need re-work that would further impede employee productivity.
- While this option entails the lowest upfront capital expenditure, it is offset by high operational expenditures related to maintenance/support and employee downtime. There is also a risk of unexpected increase in future capital expenditure to replace hardware on an expedited schedule.

2 New Hardware - Standards Based Asset Lifecycle Replacement

In this alternative, Toronto Hydro would refresh its computer endpoint assets per the lifecycle requirements stated in the desktop and laptop standard and refresh the printer endpoint assets per the vendor lifecycle recommendations. Each year, Toronto Hydro would procure a designated number of endpoint assets and deploy them to the business users and to designated Toronto Hydro locations, as required. Based on the typical computer hardware lifecycle, it is expected that all user endpoint devices will be replaced in the 2015 to 2019 period.

Toronto Hydro prefers this option for the following reasons:

- Reduced employee downtime from isolated incidents of endpoint failure. The endpoint assets would be replaced before asset performance is affected from wear and tear, age and general usage. This mitigates the risk of employee downtime and mitigates the risk of re-work and data loss from failure of endpoint assets.

- Reduced need to procure new endpoint assets on an expedited basis from vendors, or to maintain a large number of standby devices to address potential failure.

E8.4.6.2 Quantification/Evaluation of Options - Core Backend Infrastructure Assets

Presented below is the analysis of the options with respect to the core backend infrastructure assets:

1 Run Assets to Failure - React as Needed

In this alternative, Toronto Hydro would not upgrade and/or refresh the existing IT hardware in the 2015 to 2019 period. Within this period, most hardware would reach or pass its respective useful life. Toronto Hydro would run outdated hardware and associated operating systems. After a certain date, vendors would not provide any further service packs and patches, increasing the risk of hardware failure. Vendors typically offer support on a best effort basis with no assurances of turnaround times to fix hardware failure. Internally Toronto Hydro would need to develop workarounds to respond to hardware failure. As well, Toronto Hydro would need to procure specialists to support the archaic hardware. Any hardware refresh will be completed in a reactive and ad hoc fashion based on hardware asset failure.

This alternative is not preferable for the following reasons:

- Toronto Hydro would need to procure assets and labour resources at high costs to complete asset management activities on an expedited basis.

- IT systems are susceptible to malicious cyber attacks that could compromise sensitive customer, operational and employee information, or the integrity of the distribution system.

- The risk exposure to core business operations and processes is very high. There is a significant cost of failure from impacted business processes and employee downtime.

- While, this option entails the lowest upfront capital expenditure, it is offset by high operational expenditures related to maintenance/support and employee downtime.

Toronto Hydro will need to stock a larger quantity of replacements parts. In the worst case, Toronto Hydro will need to expedite the purchase of new equipment that will cause unexpected increases in the planned capital expenditure.

2 Externally Hosted and Managed - Outsourced IT Hardware

In this option, the core backend infrastructure assets would be housed in an environment that is outside Toronto Hydro. In this model, Toronto Hydro would stipulate the desired level of hardware availability and level of service. While the service provider is responsible for the provisioning, maintenance and support of the hardware, Toronto Hydro is responsible for network connectivity to the vendor infrastructure.

Toronto Hydro would stipulate the applicable security standards, desired service quantity and quality via specifications of infrastructure required to provide a business solution. Under this approach, Toronto Hydro has limited control and role in project implementation of hardware assets in the vendor infrastructure. The project must provision for high network availability and secure high volume connections between Toronto Hydro's network and the vendor infrastructure. System integration in this model will tremendously increase costs and complexity.

The hardware would be supported by two distinct groups. Toronto Hydro would provide the first level of support to address business queries and to verify the root cause as hardware issues. The vendor would then offer detailed technical support such as setting up a server, increasing storage and compute resources and addressing technical issues. The desired service levels and system availability would be detailed in the contract at differing price points.

The service provider would be responsible for the management of the core backend infrastructure assets. The service provider would also determine maintenance windows to apply service packs, patches, upgrade assets and increase compute resources as needed. The service provider would provide appropriate notices of the planned infrastructure outages.

This is not a preferred option for the following reasons:

- There is a risk to end user experience in performance issues from increased latency and lag in response time. This risk stems from the traffic load on the connection between the hosted environment and Toronto Hydro, and from the increased distance between hardware and the user than in the current internally hosted environment.

- The onus of data security is entirely on the service provider. Toronto Hydro runs the risk of misuse of data, data loss and cyber security in this option. Toronto Hydro will not have the details of the service provider security vulnerabilities and the mitigation strategies and activities.

- Toronto Hydro will not have the desired support and flexibility in managing maintenance windows with the service provider planned window. During system maintenance, the system is typically unavailable to business users, while it is patched, upgraded and applications System / application unavailability would severely hamper the distribution grid restoration effort In case the maintenance window coincides with a time of widespread distribution grid outages from ice storms and flooding.

- The service provider would not be in a position to offer an integrated IT strategy that aligns both hardware and software components. The vendor may decide to upgrade the core backend infrastructure without consideration of the applications running on it. This creates an interoperability risk between vendor hardware and Toronto Hydro systems running on them.

- Should Toronto Hydro decide to terminate the contract with the service provider, Toronto Hydro will need to provision and setup the hardware assets in a short period of time prior to the date of contract termination. This will result in inordinate costs in the IT hardware asset procurement and the labour needed to standup the new hardware asset environment and associated penalties from contract termination and migration delays.

- This option has the highest overall costs. Toronto Hydro will incur operational expenditures with respect to the vendor hosting the infrastructure assets in contrast to the current capital expenditures to refresh and maintain its hardware assets. Further to this, Toronto Hydro will incur huge operational expenditures related to network costs from Internet Service Providers (ISPs), who will provide the connectivity and bandwidth required between Toronto Hydro and the vendor infrastructure. This model would increase Toronto Hydro's annual operational expenditures.

- In the implementation of this approach, there is a risk of disruption of business operations from system outages. There would be considerable change in the management of infrastructure assets and their ongoing support. The adoption associated with this option will delay realization of any benefits from this option.

3 Internally Hosted and Managed - Asset Managed Methodology

In this option, Toronto Hydro would refresh hardware assets that will be hosted internally in Toronto Hydro premises. The core backend infrastructure assets are refreshed based on an asset management methodology; the applicable asset lifecycles are defined in Toronto Hydro's IT technical standards..

Toronto Hydro would be responsible for IT hardware asset management that includes upgrades, adding compute resources, replacement of hardware assets as they approach the end of useful life and leveraging the appropriate technology to gain operational efficiencies. Toronto Hydro would utilize internal resources to complete project tasks and activities.

The technical standards and age of existing hardware determine the hardware assets to be replaced and upgraded. Each year Toronto Hydro would draw near term IT hardware asset management plans in alignment with the long term plan and execute applicable projects to the plan.

Toronto Hydro would gain the necessary expertise to support the hardware in project implementation.

Toronto Hydro prefers this alternative for the following reasons:

- Toronto Hydro will have a granular view of project tasks and activities. This is critical to manage the project and program level schedules with the ability to remediate and mitigate shortfalls and risks that might impact the program.
- This option obviates the need of a secure connection between Toronto Hydro's network and externally hosted infrastructure to allow users to interact with different systems. This mitigates cyber security risks and exorbitant network connectivity costs.
- There system response time to the end user would be unchanged. Unlike the externally hosted and managed – outsourced IT hardware option, there will be no risk from system latency and lag in system response times.
- This option has the least risk of all alternatives. Toronto Hydro has the flexibility to modify hardware asset maintenance windows on an as needed basis. As well, Toronto Hydro will have the ability to quickly respond to hardware outages and to quickly internally escalate hardware asset issues for resolution, thereby efficiently supporting business

needs. This option will also mitigate risks and potential delays resulting from communicating with an external vendor in an emergency situation.

- This option offers least disruption to business operations. Furthermore, there is minimal change to internal support processes within IT.

2015 ASSET REPLACEMENT DETAILS

TABLE 7: 2015 ASSET REPLACEMENT DETAILS AND FORECASTED COSTS

No.	Asset Type	Asset Sub-Type	Project/Task	Total ($ M)
1	Core Backend Infrastructure	Server and Security Appliances	Threat, Risk, Control Infrastructure Lifecycle	$0.326
			Identify Access Management Infrastructure Lifecycle	$0.2
			Threat, Risk, Control Infrastructure Growth (Netmotion, SSL VPN)	$ 0.015
			VMware Additional CPU Licenses	$0.12
			x86 Blade and Rack server refresh	$0.393
			IBM million TPC Licenses	$0.15
			Citrix Licenses	$0.1
2	Core Backend Infrastructure	Disk and Flash Storage Assets	Brocade DCX SAN switch blade refresh	$0.085
			EMC VNX organic capacity growth	$0.08
			IBM million TEST/DEV Storage organic capacity growth	$0.016
			IBM million SVC Licence capacity upgrades	$0.05
			Backup Infrastructure Licenses	$0.1
3	Core Backend Infrastructure	Network and Telephony Assets	Data Network Environment Lifecycle	$0.5
			Upgrade from Layer 2 to Layer 3 networking	$0.25
			Voice (IPT/Call Center) Environment Lifecycle	$0.3
			Radio Network Environment Lifecycle	$0.092
			Telecom Environment Lifecycle	$0.204
			Data Network Environment Growth	$0.06
			Voice (IPT/Call Center) Environment Growth	$0.045

No.	Asset Type	Asset Sub-Type	Project/Task	Total ($ M)
			Radio Network Environment Growth	$0.06
			Telecom Environment Growth	$0.045
			Additional Voice Radio Mobiles & Portables	$0.063
			Telecom (Fiber/Optic) Repair supplies	$0.03
4	Core Backend Infrastructure	Miscellaneous Items	UPS Batteries Lifecycle	$0.03
			UPS Lifecycle (Does not include facilities work)	$0.26
			Data Centre UPS Capacity & Availability growth	$0.15
			Racks/Cables/PDUs/Tools/Patch Panels/Floor Tiles	$0.04
			Electrical works related to growth	$0.02
			DCI million Tool	$0.22

E8.5 IT Software

E8.5.1 Summary

Program Description

Toronto Hydro relies on various Information Technology ('IT') software systems to efficiently manage core operations and business processes and to execute planned programs relating to Distribution Grid Infrastructure Design and Construction, Distribution Grid Operations, Customer Billing and Service and Corporate Services. By automating and streamlining operations, IT software systems enable safe and efficient execution of numerous activities across the organization. Without these systems, a utility of Toronto Hydro's size and complexity would encounter significant challenges in operating its electricity distribution system, delivering its capital programs and satisfying its obligations to customers and other parties that it interacts with.

The IT Software program is composed of two sub-programs:

(i) Software Upgrades; and

(ii) Software Enhancements and Regulatory Compliance.

As software vendors release new product versions, they also terminate support for older products, which means that a vendor no longer provides any periodic software system upgrades, security upgrades and fixes for known issues. Software vendors do not guarantee any service

levels as time goes on, and the risk of running out of technically-qualified support personnel increases. In the event of a system's failure, there is a high risk that Toronto Hydro may experience prolonged restoration time and pay premium costs to procure specialized labour resources. Moreover, in the course of day-to-day operations, there is a high level of security risk when Toronto Hydro's software system may get exposed to an increased level of cyber attacks due to the lack of timely security upgrades. Thus, Toronto Hydro must upgrade its IT systems to ensure their availability to meet operational needs, and to protect itself against cyber threats that could jeopardize the security of the distribution system and the privacy of sensitive operational, customer and employee information. In addition, Toronto Hydro must explore IT software solutions and enhancements to existing applications to address evolving business needs and external requirements.

The following table summarizes the anticipated benefits associated with this program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ Updated software maintains accurate customer billing. ƒ Increased cyber security better protects customer information from unauthorized access. ƒ Newer software enables streamlined and simpler integration, which prevents delays in restoring outages and completing necessary maintenance for customers and enables new services.
Reliability	ƒ By automating and streamlining operations, IT software systems enable safe and efficient execution of numerous activities across the organization that are necessary to maintain a reliable distribution system for customers. ƒ Increased cyber security protects against threats to the distribution system, helping ensure reliability.
Efficiency	ƒ Automation of business processes improves employee efficiency. ƒ Consolidation of multiple application interfaces into fewer applications improves employee efficiency. ƒ Allow the seamless migration of business applications as Toronto Hydro migrates Operating Systems from Windows XP to Windows 7, reducing employee time spent troubleshooting migration issues. ƒ Analytics in relation to these new applications can provide Toronto Hydro with critical information about managing resources and restoring power to customers in emergency events such as the recent July flood and December ice storm in 2013
Safety	ƒ Updated software helps ensure cyber security of Toronto Hydro's distribution system. ƒ Increased cyber security mitigates the risk of unauthorized access to distribution systems and assets.

Other Benefits	ƒ Updating software ensures that support services are available from the vendor, which reduces the costs of specialized technical resources ƒ Updated software enables Toronto Hydro to comply with the regulatory requirements of bodies such as Measurement Canada, the OEB and the IESO.

Program Drivers

The trigger and secondary drivers for this program are outlined in Table A below.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
System Maintenance and Capital Investment Support	ƒ IT systems support core business operations and planned work programs. These systems must be maintained and upgraded in order to mitigate failure risk, which could jeopardizes the utility's operations, and its ability to execute planned work programs. Applications must be periodically enhanced and modified to provide additional functionalities and support evolving requirements and operational needs.
Secondary Drivers	**Reasoning**
Cyber Security	ƒ Ensure IT systems are upgraded, patched and secure from cyber attacks and that any vulnerabilities are addressed
IT Systems Compatibility	ƒ Software applications and the underlying components (e.g. servers and operating systems) must be compatible to ensure uninterrupted IT system operations and deliver the desired end user experience and functionality.
Regulatory Compliance	ƒ IT systems enable adherence to the requirements of regulatory bodies such as Measurement Canada, the OEB and the IESO.

Preferred Alternative

The Software Upgrades sub-program includes the regular upgrades of more than 70 software applications that support Toronto Hydro's core functions and processes. The following alternatives were analyzed and evaluated for the Software Upgrades sub-program:

(1) Do Nothing - Run Asset to failure and react accordingly

(2) Managed Services - Outsourced Management of IT Applications

(3) Standards based asset lifecycle management - Asset Management Methodology

Option 3, "Like for Like Upgrades" of the software asset systems, is the preferred alternative because:

- It has the lowest cost and shortest implementation time
- It poses the lowest risk to ongoing core business operations
- It offers the most straightforward change management process
- It is the most secure option from a cyber security perspective

The Software Enhancements and Regulatory Compliance sub-program includes work that is required to optimize or enhance business operations, or to comply with external requirements provided by entities such as Measurement Canada and Ontario Energy Board (OEB). Given the diverse and reactive nature of these investments, Toronto Hydro does not have a pre-defined options analysis. In planning and executing these initiatives, Toronto Hydro intends to rely on its internal governance processes to ensure that appropriate options are considered and evaluated for each specific initiative.

Timing and Pacing

The total estimated cost of the IT Software program over the 2015-2019 period is $81 million, consisting of $51.87 million for the Software Upgrades sub-program and $29.13 million for the Software Enhancement and Regulatory Compliance sub-program.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending ($M)					Forecasted Future Spending ($M)				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Software Upgrades	12.48	2.66	1.49	3.13	5.55	9.68	10.50	9.91	10.93	10.85
Software Enhancements	7.65	18.35	11.34	4.46	3.50	4.22	4.16	4.31	4.28	4.32
Regulatory Compliance	2.06	0.15	1.60	2.01	1.05	1.55	1.52	1.57	1.56	1.58
TOTAL	22.20	21.17	14.45	9.61	10.11	15.46	16.19	15.81	16.78	16.76

The program covers planned IT systems upgrades, enhancements and analytics, as well as modifications to existing IT systems or new IT systems which are required to comply with regulatory obligations. The estimated annual cost of the program is in line with historical trends. For Software Upgrades, the forecasted costs are based on detailed asset level information that Toronto Hydro maintains in its IT Inventory system (for more information, refer to IT Asset Management Strategy at E8-4). Due to funding limitations in 2013-2014, Toronto Hydro had to defer certain software upgrades, resulting in a forecasted increase in these types of investments over the 2015 to 2019 period.

E8.5.2 Program Description

The utility plans to undertake numerous IT software projects over the 2015-2019 period, all of which will involve intricate planning, testing, and execution. Toronto Hydro plans to execute these projects under the following sub-programs: 1) Software Upgrades, and 2) Software Enhancements and Regulatory Compliance.

1) Software Upgrades

This Software Upgrades sub-program includes the planned lifecycle upgrades of applications that support core functions and processes relating to Distribution Grid Infrastructure Design and Construction, Distribution Grid Operations, Customer Service and Billing, and Corporate Services. As illustrated in the Figure 1 below, multiple software systems are embedded in each of these core processes and functions.

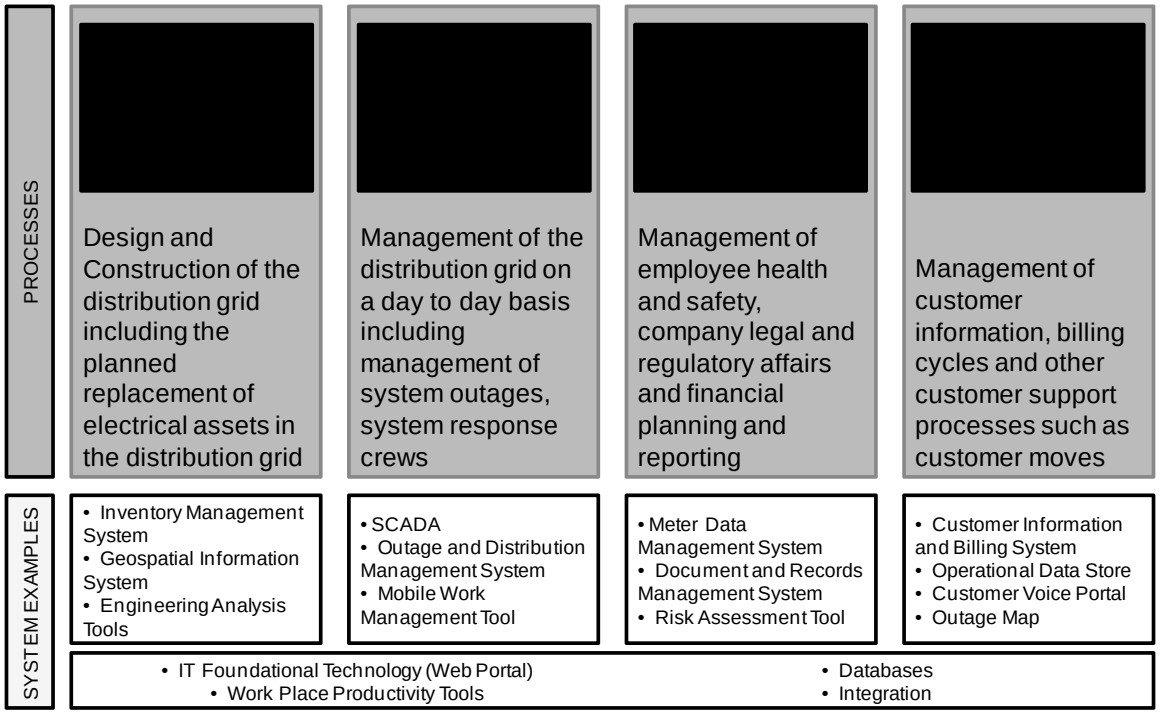


FIGURE 1: CORE PROCESSES AND FUNCTIONS

To execute its capital plans and programs and adequately serve its customers in an uninterrupted manner, Toronto Hydro must upgrade all of its software applications (approximately 70) during the 2015 to 2019 period. These investments will be made in accordance with the asset lifecycle

and other key information that Toronto Hydro maintains as part of it IT Inventory system (refer to IT Asset Management Strategy at Exhibit 2B, Tab 4, Section D, Schedule 4).

The projects in this sub-program typically include the following activities:

- Engage vendor(s) to provide upgrade assistance
- Upgrade the underlying infrastructure
- Configure the application to ensure compatibility with underlying components
- Configure the application to meet Toronto Hydro business requirements
- Integrate with other utility IT systems, as needed
- Complete regression testing to ensure the upgrade is successful
- Train the business users of the new features and functionality
- Change Management activities to minimize impact to the business users
- Deploy the new systems and release it to the business users

2) Software Enhancements and Regulatory Compliance

As the name suggests, this sub-program consists of two categories of projects: Software Enhancements, and Regulatory Compliance projects. Software Enhancement projects are designed to improve existing systems and processes, develop new reports and functionalities, provide business analytics, and integrate IT systems and software applications. Regulatory compliance projects enable the utility to adhere to the requirements of regulatory bodies such as Measurement Canada, the OEB and the IESO.

Over the 2015-2019 period, Toronto Hydro plans to undertake software enhancements and regulatory compliance projects pursuant to the four-step process described below (see Figure 2). The utility intends to evaluate each project through a rigorous exercise, whereby it will identify operational requirements, define the scope, assess options and validate benefits before it proceeds with the project.



FIGURE 2: COMPLIANCE PROJECTS PROCESS

Evaluate:

The IT group validates the proposed project, and works with the designated business subject matter experts to determine the project scope, business requirements, current state business processes, future state business processes, the options to achieve the future state and the preferred approach. The relevant business units commit to tangible and measurable benefits and intangible benefits from the implementation of the new initiative.

Align:

Toronto Hydro reviews the proposed project to ensure the following:

- Governance, due-diligence, rationale and accuracy of the project costs and benefits
- Strategic alignment with utility objectives (e.g. value for money)
- Effect of newly-deployed software system on Toronto Hydro's risk profile (e.g. cyber security)

Prioritize:

Toronto Hydro prioritizes the project based on project dependencies, costs, benefits, strategic alignment and risk assessment.

Execute:

Project execution typically consists of the following steps:

- Engaging the vendor to provide application enhancement and analytics
- Gathering more detailed user and technical requirements
- Developing and/or procuring the application as needed

- Provisioning the infrastructure to host the application
- Configuring the application(s) to meet the business requirements
- Testing the application for compatibility with Toronto Hydro's infrastructure
- Engaging users to test that the application meets their business and functional requirements
- Training the users about the features and functionality of the application; Implementing the application across the appropriate utility departments

The following table summarizes the anticipated benefits of the Software Upgrade Program.

TABLE 1: SUMMARY OF PROGRAM BENEFITS

Customer Value	• Updated software maintains accurate customer billing. • Increased cyber security better protects customer information from unauthorized access. • Newer software enables streamlined and simpler integration, which prevents delays in restoring outages and completing necessary maintenance for customers and enables new services.
Reliability	• By automating and streamlining operations, IT software systems enable safe and efficient execution of numerous activities across the organization that are necessary to maintain a reliable distribution system for customers. • Increased cyber security protects against threats to the distribution system, helping ensure reliability.
Efficiency	• Automation of business processes improves employee efficiency. • Consolidation of multiple application interfaces into fewer applications improves employee efficiency. • Allow the seamless migration of business applications as Toronto Hydro migrates Operating Systems from Windows XP to Windows 7, reducing employee time spent troubleshooting migration issues. • Analytics in relation to these new applications can provide Toronto Hydro with critical information about managing resources and restoring power to customers in emergency events such as the recent July flood and December ice storm in 2013
Safety	• Updated software helps ensure cyber security of Toronto Hydro's distribution system. • Increased cyber security mitigates the risk of unauthorized access to distribution systems and assets.
Other Benefits	• Updating software ensures that support services are available from the vendor, which reduces the costs of specialized technical resources • Updated software enables Toronto Hydro to comply with the regulatory requirements of bodies such as Measurement Canada, the OEB and the IESO.

E8.5.3 Why the Program is Needed

This program is needed to support Toronto Hydro's operations and processes. In addition, periodically upgrading applications minimizes the risk of system integration challenges, cyber security risk and reduces maintenance costs by keeping applications current with the supporting infrastructure and aligned with vendor support cycles.

The applications in this program are important in the execution of utility processes. Application failure must be avoided in order to mitigate the following impacts:

- Employee downtime and loss of productivity;
- Potential delays in completion of core business processes such as customer billing; and
- Operational risks such as the inability to respond to outages in a safe, timely and effective manner.

This program is also needed to minimize the financial risks associated with running application past the expiry of the vendor support cycle. If an application is not upgraded before the vendor support cycle expires, Toronto Hydro may have to procure specialized technical resources to maintain and support the application (i.e. resolve incidents, address issues, or customize/enhance the application to suit the utility's needs).

Furthermore, Toronto Hydro may have to put in place additional contingencies to accommodate the outdated application and supporting infrastructure. These contingencies include standalone environments of legacy applications. In stand alone environments, the applications are run on server infrastructure that hosts the desired applications in a separate environment with compatible technology. To allow the seamless migration of business applications as Toronto Hydro migrates Operating Systems from Windows XP to Windows 7, a number of applications are hosted in standalone environments. Toronto Hydro needs to gradually reduce the footprint of standalone environments to reduce the burden of maintaining parallel infrastructure.

E8.5.3.1 Purpose

The purpose of the program is to upgrade the IT systems that support Toronto Hydro's core business operations and enable the utility to execute planned work programs. This program also mitigates risks relating to cyber security, ensures the compatibility of IT systems, facilitates regulatory compliance and enables process improvements and operational efficiencies.

The chart below outlines the trigger and secondary drivers of the program:

TABLE 2: PROGRAM DRIVERS

Trigger Driver	Reasoning
System Maintenance and Capital Investment Support	• IT systems support core business operations and planned work programs. These systems must be upgraded in order to mitigate failure risk, which could jeopardizes the utility's operations, and its ability to execute planned work programs. • Applications must be periodically enhanced and modified to provide additional functionalities and support evolving requirements and operational needs.
Secondary Drivers	**Reasoning**
Cyber Security	• Ensure IT systems are upgraded and secure from cyber attacks and that any vulnerabilities are addressed
IT Systems Compatibility	• Software applications and the underlying components (e.g. servers and operating systems) must be compatible to ensure uninterrupted IT system operations and deliver the desired end user experience and functionality.
Regulatory Compliance	• IT systems enable adherence to the requirements of regulatory bodies such as Measurement Canada, the OEB and the IESO.

System Maintenance and Capital Investment Support

To ensure the safe and efficient execution of its capital plans and operational programs, Toronto Hydro must maintain and enhance the software systems that support its core processes and operations. When IT systems are beyond the period of extended vendor support, the vendor and the market place do not guarantee availability of qualified resources and expertise needed to resolve any potential issues. As a result, if these systems fail, it typically take a longer time to restore, which can have a significant effect on the utility's operations and its ability to execute planned work programs and deliver service to its customers.

For example, control room operators and dispatchers rely extensively on the Outage and Distribution Management System and Mobile Network Management System to access to real time outage data and to view the location and status of field crews. Upgrading these systems ensures Toronto Hydro's continued ability to respond to outages in a safe, timely and efficient manner. In addition, system enhancements and analytics in relation to these applications can

provide Toronto Hydro with critical information about managing resources and restoring power to customers in emergency events such as the recent July flood and December ice storm in 2013.

Engineers, designers, and field crews depend on IT systems such as the Geospatial Information system and the Distribution Network Analytical Tool to access important information about assets across the distribution system, and to develop asset replacement plans, determine project detail estimates and review the conditions of assets prior to physical intervention.

Likewise, to execute planned work programs and to respond to outages in a timely fashion, Toronto Hydro's construction project teams and outage response teams must have access to various materials. The inventory management system facilities this by managing asset inventory levels across multiple warehouse locations, and enabling the delivery of materials at job sites and key locations across the system. A failure of this system could lead to potential errors in entering material information that could affect asset costing information, or even worse, may jeopardize the safety of employees using these materials. Delays in the delivery of materials to project sites could also hamper the utility's ability to respond to outages and to execute planned work in a timely and efficient manner.

Toronto Hydro's customer service teams also rely on IT software systems, such as Customer Care and Billing system, to access important customer information (e.g. customer addresses, billing information, and account history) in providing efficient and effective service to customers. The older versions of the systems present Toronto Hydro with increased security risks as they require the more frequent installation of security patches. This is an especially serious issue as security breaches can potentially compromise confidential customer information, e.g. customer bank accounts, SIN's, etc. As the customer care systems are aging, the probability of their failure is increasing. The potential failure of the Customer Care and Billing system presents a financial risk to Toronto Hydro as the utility will not be able to bill customers and can lose its revenue for the duration of these systems failure. Toronto Hydro expects that upgrades to this system will provide call center employees better functionality to effectively manage customer queries and relations, and associated IT systems enhancements and analytics are expected to provide the management with operational insights to better manage customer service.

There are many other IT software systems that are embedded into Toronto Hydro's operational processes and the majority of these systems are interconnected. The failure of any of these systems can potentially disrupt the supported process and negatively impact Toronto Hydro's overall operations.

Cyber Security Risks

When applications are used beyond the extended vendor support, the vendor no longer provides security upgrades or patches and performance upgrades or fixes for the software, which makes the application more vulnerable to cyber security risks. Each month, Toronto Hydro's IT security team successfully blocks, on average, over 50,000 "Exploit" type attacks and over 2,000 "Denial of Service" type attacks. "Exploit" type attacks seek to compromise IT systems, gain unauthorized access to confidential information and services, or tamper with normal IT system operations by exploiting known or potential system vulnerabilities. The "Denial of Service" attacks attempt to make a machine or network resource unavailable to its intended users. For example, a successful "Exploit" type cyber attack on the Customer Information and Billing System would compromise customer usage and billing data, and customer information. Any stolen data can be used in fraud and identity theft. Similarly, a leak of Toronto Hydro operational information could lead to malicious attempts to jeopardize day–to-day operations and, in extreme cases, a system vulnerability could lead to mass outages across the grid.

IT System Compatibility

Software applications and the underlying components (e.g. servers and operating systems) must be compatible to ensure uninterrupted IT system operations and deliver the desired end user experience and functionality. In many cases, the IT systems and their underlying components are on different lifecycles because the applications hosted in-house are purchased from the software product vendors and the underlying components are purchased from the hardware product vendors.

The ongoing use of applications past end of useful life leads to retention and maintenance of standalone underlying components that lag vendor support lifecycles. This exposes the IT systems to security and failure risks from the underlying components. Toronto Hydro must address these risks by upgrading its applications to maintain compatibility with underlying with infrastructure. The utility plans to do so in accordance with its IT Asset Management Strategy. To learn more about this strategy please refer to Exhibit 2B, Section D4.

Regulatory Compliance

Each year, Toronto Hydro must make changes to its business processes in order to comply with emerging regulatory requirements imposed by various regulatory bodies such as the OEB and

Measurement Canada. These changes must be reflected in the IT systems that support the relevant business processes. Examples of major past projects include the following:

- Creation of a new rate class for 30,000 customers who were billed using specialized suite meters, reflecting an OEB decision.
- Development of operational capability and reporting for Low-Income Energy Assistance Program (LEAP) customers.
- Development of operational processes and system functionality to implement the Ontario Clean Energy Benefit.
- Modification of operational process and systems functionality to support a 3000 kWh cap on the Ontario Clean Energy Benefit.
- Enhancements to Regulated Price Plan functionality to true up customer accounts based on updated OEB regulation.
- Redesign of the Non Billed Budget customer letters to match updated OEB regulations.

E8.5.3.2 Development of systems, self-service capabilities and internal control to manage operations in accordance with Canadian Anti Spam Legislation

All the IT software applications that Toronto Hydro owns and maintains (approximately 70 applications) are in the scope of this program.

Enterprise Applications describes a collection of computer programs built with the aim to display, process and store the large amounts of complex data to support enterprise-wide business processes.

Enterprise application software performs business functions such as procurement, scheduling, customer information management, energy management and accounting. It is typically hosted on servers and provides simultaneous services to a large number of users, typically over a computer network. This is in contrast to a desktop single-user application that is executed on a user's personal computer and serves only one user at a time.

Toronto Hydro's classifies its enterprise applications in two categories: Tier 1 and Tier 2.

The "Tier" nomenclature denotes the application importance or operational criticality.

- Tier 1 applications enable Toronto Hydro's operations and support utility-wide processes. They are functionally integrated with other applications, and are supported by complex underlying infrastructure such as databases, middleware, storage and network. As a result, Tier 1 applications generally have higher maintenance costs and a large user base. In a disaster scenario, the recovery point objective is less than 4 hours. Examples of Tier 1 applications include the ERP (Enterprise Resource Planning) System and Geospatial Information System.

The table below demonstrates that all the major IT systems (Tier 1 applications) in scope of this program and their underlying infrastructure will reach their end of life in the 2015 to 2019 period and must be upgraded:

TABLE 3: TIER 1 IT SYSTEMS DETAILS

System Name	System Age in 2015	Vendor End of Extended Support	Infrastructure End of Life
Financial Planning and Forecasting Tool	14 years	2012	2014
Inventory Management System	3 years	2013	2015
Geospatial Information System	12 years	2010	2012
Supervisory Control and Data Acquisition System (SCADA)	7 years	2015	2015
Distribution Network Management System	10 years	2011	2012
Mobile Work Management Tool	5 years	Not Applicable[1]	2015
Customer Information and Billing System	4 years	2015	2012
IT Foundational Technology	4 years	2013	2012

The IT systems and underlying infrastructure are on different end-of-life and vendor support cycles. This is a well understood reality in the IT industry because the systems hosted in-house are purchased from the software product vendors and all the underlying hardware infrastructure those systems are running on (e.g. servers, network devices, etc.) are purchased independently from the hardware product vendors. This practice explains the fact that, for example, the Customer Information and Billing System will be past of vendor support in 2015, whereas its underlying infrastructure reached its end of life in 2012.

[1] Mobile Work Management Tool is a system developed in house

- Tier 2 applications enable specific divisional and departmental processes. These applications have little to no integration with other enterprise applications, and are typically supported by simple infrastructure. In a disaster scenario, the recovery point objective is less than 24 hours. Tier 2 applications generally have lower maintenance costs, and cater to a smaller user base than Tier 1 applications.

The table below provides examples of Tier 2 applications and explains how these application support business processes:

TABLE 4: TIER 2 APPLICATIONS

Business Area	Examples of Business Processes	Examples of Tier 2 Applications
Customer Service	1. Processes supporting customer self-services	1. TorontoHydro.com – used to enable various web services to customers including access to their accounts and ability to complete transactions
Operations	1. Processes supporting engineering design of Toronto Hydro electric distribution infrastructure	1. Computer Aided Design (CAD) Software – used to design and create work prints for electrical distribution system
Corporate Services	1. Process to manage payroll of Toronto Hydro employees 2. Process to manage workplace accidents	1. Payroll Application – used to extract employee pay data from Enterprise Resource Planning system and transmit the data to ADP (the payroll services company) to process payroll and transfer funds to various employee bank accounts 2. Workplace Incident Management Program –used to keep track of incidents, claims, and investigations relating to workplace accidents
Information Technology	1. Processes to manage IT user requests 2. IT Incident and Problem Management	1. Service Request Management Tool – used to track corporate-wide requests to IT 2. IT Central Data Repository – used to maintain information about IT assets and their relationships to each other

The typical lifecycle of a Tier 2 enterprise application is 2-5 years. This means that software vendors release the new versions of their systems once every 2-5 years. As the current

Distribution System Plan covers the period of 5 years, Toronto Hydro plans to upgrade all Tier 2 applications during the 2015-2019 period.

The table below (Table 5) presents the approximate number and percentage of the number of the Tier 2 applications that Toronto Hydro intends to upgrade each year:

TABLE 5: PLANEED TIER 2 APPLICATION UPGRADES

Tier 2 Enterprise Applications to be Upgraded	Year				
	2015	2016	2017	2018	2019
Approximate percentage	25%	20%	20%	14%	21%
Approximate number	15	12	12	9	13

Although Toronto Hydro makes its best efforts to distribute the upgrades and associated investments evenly during the 5-year period, the historical evolution of the IT landscape overtime and the uneven deployment of new systems in the past few years explains the increase in the number of assets to be upgraded in 2015 and explains the drop in the number of assets to be upgraded in 2018.

IT Software Enhancement

When any enterprise application is initially deployed, the pre-built functionality of this application is typically limited and does not provide sufficient analytics and reporting. To overcome the above-mentioned limitation, Toronto Hydro utilizes in-house and external IT developers to enhance application functionality and create customized reports to:

- Meet growing business needs
- Supply Toronto Hydro's leadership with the data to help them make informed business decisions
- Provide services to customers
- Provide management with short-interval process measurements and controls to achieve strategic and tactical goals

For example, the enhancements to the reporting functionality in the Attendance Management System in Toronto Hydro gave middle and senior management visibility in employee attendance records. The analytics were effectively used to improve Toronto Hydro's employee engagement.

This functionality enabled Toronto Hydro to achieve above average industry results with respect to absenteeism. For more information, refer to the Human Resources and Safety Program at Exhibit 4A, Tab 2, Schedule 18.

E8.5.4 Timing & Pacing of the Program

The total estimated cost of the IT Software Program is $81.0 million. The annual project costs over the 2015 – 2019 period is between $15.46 million and $16.78 million, and the average annual cost is $16.20 million. The table below (Table 6) provides the estimated cost breakdown by year from 2010 to 2019:

TABLE 6: HISTORICAL AND FUTURE SPENDING

CAPEX / ACTIVITY	Historical Spending ($M)					Forecasted Future Spending ($M)				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Software Upgrades	12.48	2.66	1.49	3.13	5.55	9.68	10.50	9.91	10.93	10.85
Software Enhancements	7.65	18.35	11.34	4.46	3.50	4.22	4.16	4.31	4.28	4.32
Regulatory Compliance	2.06	0.15	1.60	2.01	1.05	1.55	1.52	1.57	1.56	1.58
TOTAL	22.20	21.17	14.45	9.61	10.11	15.46	16.19	15.81	16.78	16.76

The program covers planned IT systems upgrades, software enhancements and analytics, as well as IT investments which are required to comply with regulatory obligations. The total forecasted program costs are consistent with historical trends. For software upgrades, the forecasts are also based on the asset lifecycle and other key information that Toronto Hydro maintains with respect to its IT assets in the IT Inventory System (refer to Exhibit 2B, D4). Due to funding limitation, Toronto Hydro had to defer certain upgrades in 2013 and 2014, and as a result, there is a forecasted increase in software upgrades investments in 2015-2019 period.

The timing and pacing of the software upgrade program is also influenced by a number of factors, including co-ordination with the proposed Enterprise Resource Planning (ERP) program, application complexity, and resource balancing.

Integration with the ERP Program:

Some of the applications in this program, such as the Mobile Work Force Management Tool and the Customer Information and Billing System must be integrated with Toronto Hydro's ERP system. As a result, the utility plans to defer upgrading certain applications until the ERP Program is completed in order to reduce duplicative efforts of integrating these applications with the existing ERP, and subsequently with the new ERP. All the IT application upgrades that are dependent on the ERP Program have been scheduled accordingly.

Application Complexity:

The IT software systems differ by the level of criticality and complexity.

Toronto Hydro classifies its enterprise applications in two categories: Tier 1 and Tier 2. The "Tier" nomenclature denotes the application importance or business criticality.

- Tier 1 applications enable Toronto Hydro's operations and support utility-wide processes. They are functionally integrated with other applications, and are supported by complex underlying infrastructure such as databases, middleware, storage and network. As a result, Tier 1 applications generally have higher maintenance costs and a large user base. In a disaster scenario, the recovery point objective is less than 4 hours. Examples of Tier 1 applications include the ERP System and the E-Mail System.

- Tier 2 applications enable specific divisional and departmental processes. These applications have little to no integration with other enterprise applications, and are typically supported by simple infrastructure. In a disaster scenario, the recovery point objective is less than 24 hours. Tier 2 applications generally have lower maintenance costs, and cater to a smaller user base than Tier 1 applications.

As a common IT industry practice, the most critical Tier 1 applications take priority while scheduling the IT software upgrades. For example, several applications at Toronto Hydro integrate with the IT Foundational Technology. The IT Foundational Technology provides the necessary software layer to run enterprise applications and cross-platform solutions. Toronto Hydro must upgrade the IT Foundation Technology first, prior to upgrading other applications that integrate to it. This sequence is important because if the integrated to IT Foundational Technology applications were to be upgraded first, Toronto Hydro would duplicate the amount of integration work: first, to integrate the less complicated applications after they are upgraded to IT

Foundational Technology, and then, to integrate them again after the IT Foundational Technology is upgraded.

Similarly, dependencies exist between different projects within this program. For example, a Finish to Start dependency exists between the Outage and Distribution Management System Upgrade and the Geospatial Information System Upgrade. This means, the Geospatial Information System Upgrade can commence only after the Outage and Distribution Network Management System Upgrade project completes.

Resource Balancing:

The projects are timed to ensure Toronto Hydro engages a steady level of available resources throughout the 2015 to 2019 period. This approach allows the utility to achieve a relatively stable annual capital expenditure plan over the 2015 to 2019 period, and reduces the cost pressures associated with the need to procure temporary resources to meet peak resource demands from projects.

E8.5.4.1 Ranking & Prioritization

As detailed in the IT Asset Management Strategy filed at Exhibit 2B, D4, Toronto Hydro employs a robust process in making decisions about which IT initiatives to pursue in a given time period. In accordance with this strategy, the utility plans to rank and prioritize the initiatives in this program by weighing the following considerations, and their effect on the utility's operations.

- Compliance with regulatory requirements: Regulatory bodies such as Measurement Canada and the OEB periodically review and amend regulations, standards and policies that govern Toronto Hydro operations. Toronto Hydro must take necessary steps to comply with the revised requirements to mitigate the risks of regulatory non-compliance which could result in financial penalties and legal repercussions.

- Core business operations and planned work programs: Toronto Hydro relies on IT systems to run its core business operations and to execute its capital plans and operational program. In case of an IT system failure, the affected business processes can become completely impaired, which could have a significant effect on Toronto Hydro's operations, its ability to serve customers and employee productivity. The utility must ensure that IT systems are available to support key business processes.

- Data security from cyber attacks: IT systems house important and highly sensitive information about utility's operations, and its customers and employees. This data must be secure against external cyber threats. The systems and underlying components must be upgraded and kept current to receive the latest security upgrades and service packs that ensure a strong cyber security posture.

- Impact to customer service: To sustain and improve the current levels of customer service, Toronto Hydro must ensure that its IT systems are available to support core customer service processes and functions. In some cases, Toronto Hydro must upgrade its applications to provide customers with new functionality, to maintain the security of these systems and to protect customer personal information.

E8.5.5 Program Execution

(i) Program Risks

The program risks can be categorized as follows:

Costs:

The program cost is based on estimates of internal labour, external labour and software costs over the 2015 to 2019 period. While Toronto Hydro can make confident estimates for the 2015 period this program is subject to greater price fluctuations over the 2016-2019 period. For example, there is a risk that vendors may increase software costs over the 2016 to 2019 period. This risk is mitigated by building the long term relationships with software vendors and including the appropriate clauses into the contractual agreements.

In addition, the absence of appropriate resources could be a risk to the cost of this program. In the event of resource shortages, Toronto Hydro will need to procure temporary skilled labour. Temporary skilled resources for projects needed at short notice cost a premium. To mitigate this risk, Toronto Hydro intends to procure resources for the 2015 to 2019 period based on long term program requirements.

Schedule:

Resource availability is critical to this program as the absence of appropriate resources could significantly impact the program schedule. This risk is mitigated through the development of

resource requirement plans for each year based on planned project load, and by spacing the initiatives over the 2015 to 2019 period to ensure there is a steady annual resource requirement.

Quality:

The two major risks to project quality stem from the following:

- IT System Integration: The IT systems in this program are tightly integrated with other IT systems across the utility, and the current levels of integration must be maintained in order to sustain existing processes. If the program fails to deliver the existing level of integration, business processes could be impeded and process inefficiencies could be introduced from manual data updates to and from other utility IT systems. The risk is mitigated by careful consideration and analysis of the new underlying component configurations in defining project scopes.

- Project Delivery: IT systems support core business processes, and as such, the delivery of a new IT system version to business units poses a risk to these processes. To mitigate these risks, the project plans include extensive regression testing and user testing, prior to rolling out the final upgrade to the business units. In addition, risks are mitigated through appropriate user engagement and communication, and project governance including contingencies to minimize the impact to the business users in the final implementation.

(ii) External Constraints

The planned scope of this program may be limited by the external constraints summarized below. Toronto Hydro intends to monitor these potential external constraints to ensure that sufficient time is available to plan and react in a way that minimizes the impact to this program.

Changes in the Technology Landscape

Toronto Hydro will monitor the technology landscape to ensure the most appropriate application meeting Toronto Hydro's business requirements is selected and implemented. Prior to each upgrade, Toronto Hydro will scan the product category to validate that the planned software upgrade is the most appropriate choice for Toronto Hydro. Should a superior alternative emerge, Toronto Hydro may consider implementing the better alternative software. The costs associated with the new software could impact the overall project costs.

Software Release Dates

Any changes to the application version release dates will impact the project schedule and potentially impact downstream projects in the program. For example, there exists a Start to Finish dependency between the Outage and Distribution Management System and Geospatial Information System; the latter cannot be upgraded until the former system is successfully upgraded. In this case, a delay in the release of the new version of the Outage and Distribution Management System Upgrade will delay the planned upgrade of the Geospatial Information System.

Standard & Regulation Adherence

All projects that form part of this program are governed by the external or internal standards and regulations. Collectively, these standards and regulations provide the technology framework for the proposed Software Program.

External standards and regulations include technology and information standards and regulations issued by bodies such as the OEB and Measurement Canada. For example, some Measurement of Canada recent regulations have led to Toronto Hydro's IT system changes:

- Modification of data collection, billing processes and core systems to bill customers based on register reads
- Customization of residential customer bills to display line loss and related units of measure

Internal standards include standards developed by Toronto Hydro for its servers, databases, middleware and network to effectively govern their selection, simplify the maintenance of solution components, and reduce the burden of managing unique stand-alone IT systems. To learn more about IT standards, refer to the IT Asset Management Strategy at Exhibit 2B, D4

E8.5.6 Evaluation of Alternatives

Toronto Hydro considered the following alternatives in relation to the Software Upgrades sub-program:

(1) Do Nothing - Run assets to failure and react accordingly.

(2) Managed Services - Outsource management of IT applications

(3) Standards based asset lifecycle maintenance - Asset Management Methodology

E8.5.6.1 Quantification/ Evaluation of Options

1. Do Nothing - Run assets to failure and react accordingly

Under this alternative, Toronto Hydro would not undertake any planned projects to upgrade its applications, but rather would run the applications to failure. After a certain period of time (typically after 2-5 years after the application is released), the software vendor would issue a new version of the application and would no longer provide support for the old version. When a software application is out of vendor support, it does not receive any security upgrades or service packs from vendors. As a result, Toronto Hydro would not be able to upgrade any underlying components, would become exposed to operational risks associated with application failure, and would be vulnerable to cyber security threats.

Project Implementation:

No projects are planned under this option. However, it is expected that Toronto Hydro would need to execute ad hoc projects to upgrade existing solutions on a reactive basis. The project budgets, timelines and scope will be determined on an as needed basis.

Change Management:

In theory, the Change Management requirement of this option is the lowest because Toronto Hydro would continue to use the same applications in the 2015 to 2019 period. However, it is likely that Toronto Hydro would need to upgrade existing IT systems or implement new IT systems in a reactive manner when an existing IT system fails. This would create change management issues in user adoption of the new or upgraded IT system and in users fully utilizing the features and functionalities in the new version or IT system. The reactive nature of this implementation would create additional change management challenges, i.e. limited time for testing, training, contingencies, etc.

Customizations:

It would become increasingly difficult to customize IT systems under this option due to compatibility issues related to the obsolescence of the IT system. For the same reason, it would be expensive to procure the necessary resources and skill sets to implement future customizations.

Ongoing Maintenance:

In this option, once the application is past its useful life, and out of guaranteed vendor support, Toronto Hydro would be responsible for maintaining the application and dealing with all the application issues. This would necessitate developing workarounds to known problems rather than long term solutions.

Risk:

This option has the highest risk exposure, as business processes and operations could be severely affected by the failure of the IT systems which support them. In addition, this option poses a significant cyber security risk because outdated systems are more vulnerable to cyber attacks and compromises. There is also a financial risk from the labour and vendor charges in undertaking unplanned and ad hoc projects to upgrade IT system(s) when they fail.

2. Managed Service

In this alternative, Toronto Hydro would enter into contractual agreements with a number of vendors to manage its software applications. Toronto Hydro would provide the requisite underlying components, but an external vendor would administer and maintain the applications that the utility requires to carry out its business processes and executed its plans and programs. The external vendor would also apply the necessary service packs, security upgrades and bug fixes, and upgrade the software as needed.

Project Implementation:

The vendor and Toronto Hydro would collaborate to determine the appropriate product upgrade schedule to be undertaken in the 2015 to 2019 period. The vendor would complete the software upgrade activities, in collaboration with the relevant Toronto Hydro teams responsible for the underlying components. Toronto Hydro would be responsible for providing necessary customization requirements and completing user acceptance testing of the new software version, but could not directly control delivery timelines.

Change Management:

The change management impact of this option would be the highest out of all alternatives. First of all, the whole interaction process between the IT division and the business users of the systems would need to be re-designed as the IT division would no longer be responsible for the systems'

performance and on-going maintenance. Second, the managed service model will affect the structure, roles and responsibilities of the IT division. In dealing with IT systems failures, as opposed to completing detailed investigations and fixing the issues at the time of incidents, the business users will need to report of incidents to vendors and manage communication with them.

Customizations:

In this model, Toronto Hydro would need to engage the vendor to customize the software, as the vendor would have the required expertise with respect to the configuration of the IT system, its features and functionalities, as well as the database structure. This approach can potentially complicate the coordination of all involved stakeholders and prolong the execution timelines.

Ongoing Maintenance:

This option presents Toronto Hydro with the least control over the maintenance of its IT software applications. Over time, Toronto Hydro would lose the knowledge and expertise in maintaining its IT systems. Should there be a need to quickly resolve a number of IT systems incidents simultaneously, as is usually the case during emergency events (e.g. storms, flooding, etc.), there is a significant risk that the third-party vendors would not be able to accommodate the demand in a timely manner. As a result, Toronto Hydro could experience prolonged IT systems outages and, by necessary implication, customers could experience prolonged electricity outages. Since the vendor would be responsible for the overall management of the application, the Operational Expenditure in this option would be very high.

Risks:

Vendor management is a key risk that the utility has to consider under this option. If Toronto Hydro terminates the contract with a vendor or vice versa, there is a risk that the IT system would be unsupported until a suitable support alternative is found. This situation could prolong the duration of IT system failures and jeopardize the continuity of Toronto Hydro's business operations. There are increased risks to data security from vendor data accessibility and vendor cyber security risks.

3. Like-for-Like Upgrades - Asset Management Methodology

In this alternative, Toronto Hydro will upgrade the software and the underlying components to more recent and stable vendor supported versions. Toronto Hydro policy is to stay one version behind the latest release, but not to exceed two versions behind the latest release. This allows a

sufficient stabilization period for the IT system prior to an upgrade by Toronto Hydro and allows for the development of any necessary performance and security fixes to minimize interruptions to the utility's operations and planned work programs.

Project Implementation:

From a project implementation perspective, this option will deliver the projects relatively quickly. This option reduces the time and effort needed to evaluate different IT system options and negotiate new contracts. Toronto Hydro has considerable knowledge in understanding the project effort, duration, and complexity involved in upgrading existing IT systems.

Change Management:

A Like-for-Like upgrade ensures minimal impact to processes and incremental changes to business user experience. Toronto Hydro will implement new features that would provide incremental benefits to existing processes. Upgrading existing IT systems minimizes the effort required to overcome challenges from change management and re-training of business users on new IT systems. This ensures a higher rate of user adoption and a more successful upgrade. This option also minimizes the re-training needed for IT staff to support the new IT systems.

Customizations:

The existing system integration and configurations will be migrated to the next version. Since the integration and configurations are within the same product, the effort needed to duplicate this effort for a new version is less than that required for a new IT system. Extensive regression testing will be needed to ensure no bugs are introduced in the upgrade.

Ongoing Maintenance:

This option gives Toronto Hydro control over the maintenance of the software and its underlying components. By retaining and building upon the detailed knowledge of its IT systems, this option enables Toronto to quickly resolve incidents and known errors, and to manage and respond to emergencies and other urgent situations more effectively and efficiently than a third party vendor could. Under this option, Toronto Hydro will control the IT system maintenance windows, which allows the utility to address underlying component needs and compatibility considerations, and better manage data security issues.

Risk:

This option offers the lowest risk of all options. Toronto Hydro will mitigate to the risk of IT system outages that could impact core operations and business processes by carefully planning and scheduling applications' upgrades. This option ensures the overall IT system is up to date, and secure from malicious cyber security threats.

The table below (Table 7) summarizes the analysis of the alternatives and presents Toronto Hydro's recommendation:

TABLE 7: OPTIONS EVALUATION

Criteria	Option 1 Do Nothing - Run assets to failure and react accordingly	Option 2 Managed Services - Outsource management of IT applications	Option 3 Standards based asset lifecycle maintenance - Asset Management Methodology
Ease of Project/ Upgrade Implementation	N/A	high	high
Change Management	medium	high	low
Ease of Customizations	low	low	high
Ease of Ongoing Maintenance	medium	high	low
Risk	high	medium	low
Recommendation			X

For the investments in the Software Enhancements and Regulatory Compliance sub-program, which are more diverse and reactive in nature, Toronto Hydro will leverage the governance process described above in section E8.5.2 and the IT Asset Management Strategy filed at Exhibit 2B, D4, to assess the scope and evaluate the technical alternatives for each proposed initiative. This process will help ensure that Toronto Hydro considers relevant options, and makes the most prudent decision with respect to these types of investments.

E8.5.7 2015 Projects

Software Upgrades

1) OMS / DMS Upgrade
2) Web Portal Foundation
3) JBOSS Interface Migration
4) ODS Upgrade
5) ARIS Upgrade
6) AP Link (RBC Express)
7) Iteraplan Upgrade
8) Microsoft SharePoint 2013 Migration
9) Websphere (WAS)
10) SPI SPOKE interface upgrade
11) Data Package Reporting System (DPRS) Upgrade
12) Mercury / HPQC Upgrade
13) Microstation Design Tools Upgrade
14) SRR (eSRR) – System Response Report Upgrade
15) Admin Studio Upgrade
16) Visual Studio Upgrade

E8.6 Enterprise Resource Planning Program

E8.6.1 Summary

Program Description

Enterprise Resource Planning (ERP) systems are Information Technology (IT) tools that perform critical "back-office" processes, such as finance, human resource and supply chain activities, to support Toronto Hydro's core utility operations. Toronto Hydro's end-of-life ERP, Ellipse, was introduced in 2002 and will soon no longer be supported by its vendor. The cessation of this support will introduce a number of technical risks that severely restrict the ongoing sustainability of Ellipse.

To meet evolving statutory, regulatory and operational demands, Toronto Hydro implemented additional applications to complement Ellipse where its functionality was insufficient. While this approach extended the life of Ellipse, it created an IT framework that is challenging and expensive to support and inhibits Toronto Hydro's ability to add new functional requirements in a cost-effective manner. Moreover, many of those applications face sustainability issues of their own.

Toronto Hydro's preferred approach is to replace Ellipse and 30 other applications ("Legacy Systems") with a new, fully-supported ERP. The new ERP would incorporate new functional requirements that deliver incremental benefits such as cost savings and process improvements. This approach would also allow Toronto Hydro to remove Ellipse and the Legacy Systems from its operations, avoiding the need to make technical upgrades to address its sustainability issues.

Program Drivers

The trigger and secondary drivers for this program are summarized below.

TABLE A: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	ƒ Between 2015 and 2019, Ellipse and many of Toronto Hydro's Legacy Systems, will no longer be supported by vendors. ƒ Cessation of vendor support raises a number of critical risks, including cybersecurity.

Secondary Driver	Reasoning
Business Operations and Efficiency	ƒ Toronto Hydro has identified a number of key processes that could be made more efficient if supported by an IT solution.

Preferred Alternative

Toronto Hydro considered four approaches to this program:

(1) Technical Upgrade (Base Case): Executing technical upgrades of Ellipse and the Legacy Systems.

(2) Ellipse and Legacy System Renewal: Executing technical upgrades of Ellipse and the Legacy Systems and further customizing these applications to deliver the new functional requirements.

(3) ERP Implementation (Proposed): Replace Ellipse and the Legacy Systems with a new ERP that delivers the new functional requirements.

(4) Extended ERP Implementation: Replace Ellipse, the Legacy Systems and three additional applications with a new ERP that delivers the new functional requirements.

Option 3, "ERP Implementation", delivers the highest net present value of the four options considered. On this basis it is Toronto Hydro's preferred option.

Timing and Pacing

Toronto Hydro's proposed ERP Program consists of a single project culminating in the implementation of a new ERP during the 2015 to 2019 period. This project is scheduled to be completed by end of 2016. A four-phase implementation approach will be adopted that emphasizes an integrated design process and requirements definition prior to the selection of a system. These phases are:

(1) Initiation: During the Initiation Phase, Toronto Hydro developed the program's high-level implementation approach and timeline to give structure and direction to the remaining phases of the project. Resources required to execute the subsequent stages were also defined.

(2) Strategize & Architect: The purpose of the Strategize & Architect phase is to identify, define and verify the functional requirements of the program. Once the functional requirements are determined, the benefits associated with each improved process will be estimated.

(3) Design, Realize & Deploy: This phase encompasses the standard phases of an ERP Implementation, including detailed design, configuration, testing, training, data cleansing and conversion and all associated change management activities.

(4) Support & Optimize: The objectives of this phase are to stabilize the ERP System, to embed the new processes into day-to-day operations, and to capture unanticipated system or process inefficiencies for subsequent resolution.

As shown in Table B, Toronto Hydro plans to spend $51.3 million to implement this program during the DSP period.

TABLE B: HISTORIC AND FUTURE SPENDING

	Historical Spending					Forecasted Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	1.8	0.9	17.7	33.6	0	0	0

E8.6.2 Program Description

The Enterprise Resource Planning Program (the "ERP Program") proposes to replace Ellipse, Toronto Hydro's current end-of-life ERP system, and 30 other "back-office" information technology systems (together the "Legacy Systems") with a single ERP application.

An ERP System is an integrated suite of applications covering broad operational end-to-end utility processes, such as those found in finance, human resources, distribution, project systems, maintenance service and the supply chain. ERP tools share a common process and data model which allow operational transactions to be linked to financial transactions, specifically general ledger transactions, in real time.

Toronto Hydro's current ERP system, Ellipse, was implemented in 2002 and is a legacy from the period of IT system renewal undertaken following the amalgamation of Toronto Hydro's predecessor utilities. That period of system renewal was focused on replacing the predecessor utilities' outdated information technology applications, and synthesizing their back-office systems. At the time of purchase, Ellipse was classified as an ERP system, however the industry has developed significantly since then to the point where Ellipse is no longer considered an ERP.[1]

Since 2002, Toronto Hydro's operating environment has undergone considerable change due to evolving legislative, regulatory and operational requirements. Moreover, Toronto Hydro has undertaken an increasingly complex and demanding capital renewal program and is constantly working to meet evolving customer needs. This evolving utility landscape has demanded new or different functionality from what Ellipse was capable of providing. For example, Toronto Hydro must publish financial reports using multiple accounting rules, including the simultaneous production of USGAAP, IFRS and regulatory accounts, a function that Ellipse is unable to execute.

To fulfill these incremental requirements in a cost-effective manner, Toronto Hydro opted to extend the lifespan of its existing system by implementing new applications networked with Ellipse as they were needed. To modernize its accounting practices in response to the new financial requirements, SAP was introduced to meet those needs.

[1] In a 2013 review of ERP systems by Gartner, a leading IT research and advisory firm, for companies like Toronto Hydro, Ellipse was omitted from that list.

Consequently, Ellipse and the Legacy Systems form a substantial part of an integrated application topology that performs crucial back-office tasks that support the core financial, human resource, work execution and safety processes that are essential to Toronto Hydro's operations.

Figure 1 illustrates the current topology of Toronto Hydro's back-office systems, including Ellipse and the Legacy Systems which are proposed for replacement under this program. A brief description of each of the 30 Legacy Systems can be found in Appendix A.

FIGURE 1: A VISUALIZATION OF THE TOPOLOGY OF ELLIPSE AND OTHER IT SYSTEMS

Like all information technology applications, as Ellipse and the Legacy Systems age, they must be maintained on an ongoing basis to ensure that they continue to operate efficiently and

securely. For example, in 2006 Toronto Hydro undertook a mid-lifecycle technology upgrade of Ellipse. Among other things, this step ensured Toronto Hydro could obtain security patches and other kinds of technical support, extending the functional life of Ellipse.

However, the version of Ellipse currently used by Toronto Hydro is once again functionally obsolete, exposing the utility to a number of technical risks that must be addressed. These risks, discussed in greater detail in the Needs section of this case, are:

- Operation on uncertified hardware
- Application capability limitations
- Technology limitations that impede operational efficiency
- Cybersecurity

The functional gaps between Ellipse and Toronto Hydro's operational requirements create further issues for the ongoing sustainability of Ellipse and the Legacy Systems. As shown in Figure 1, Toronto Hydro now uses a suite of applications to complement the functionality of Ellipse. Toronto Hydro must maintain 31 software interfaces to ensure that existing back-office utility operations are supported. However, securing and maintaining seamless processes across these applications becomes increasingly complex and resource-intensive with each additional application.

The constraints imposed by Ellipse and the Legacy Systems are problematic because Toronto Hydro has identified a number of operational processes that require the back-office IT support. These processes, discussed in further detail in the Needs section of this case, are:

- Planning;
- Record-to-Report;
- Human Capital Management;
- Asset Plan, Build, Maintain
- Source to Pay; and,
- Customer Connection.

Replacing Ellipse and the Legacy Systems with a new ERP is an effective means of addressing functional obsolescence. Under this program, Toronto Hydro would remove Ellipse and the Legacy Systems from its operations and replace them with a single ERP system that is equipped to meet the utility's operational needs for serving its customers. The incremental functionality required by these processes would be incorporated at the design phase of the ERP development process.

Toronto Hydro expects its selected ERP approach to provide it with the opportunity to achieve benefits that fall into three primary categories:

- cost savings;
- cost avoidance; and,
- process improvements.

Cost savings can be obtained in moving away from Ellipse and the Legacy Systems to a new ERP by eliminating the need to do certain tasks or activities. This includes the savings expected to materialize through no longer needing to support Ellipse, the Legacy Systems and many existing software interfaces. By comparison, the topology centred around the new ERP would be far simpler, as shown in Figure 2. The number of interfaces that require ongoing support and maintenance would be reduced by more than half, from 31 to 14. As a result, Toronto Hydro would require fewer resources to provide the necessary support to the new ERP, and would require fewer specialized skills that are otherwise necessary to maintain Ellipse and the Legacy Systems. Table 1 lists the applications that would be retired with Ellipse upon implementation of the new ERP.

FIGURE 2: NEW IT TOPOLOGY UPON IMPLEMENTATION OF THE NEW ERP.

TABLE 1: LEGACY SYSTEMS PROPOSED FOR REPLACEMENT IN ADDITION TO ELLIPSE

1. Asset Management Portal	16. New Location Request Application
2. Attendance Management System	17. On-Line Hold Off Request Form
3. Cable Failure Web Application	18. Picking Slip Application
4. Confined Space System	19. Reclaim Equipment Application
5. Employee Moves	20. Resource Requisition (RRAP)
6. Ellipse Management Reporting System (EMRT)	21. Return Slip Application
7. Equipment Without Maintenance Scheduled Tasks	22. SAP
8. Feeder Information System	23. Scope Planning
9. Feeder Operating Conditions	24. Support Point Paniva
10. Hyperion	25. TeamMate Audit Management
11. IT Time Sheet	26. Timelink
12. Labour/Vehichle Costing Application	27. Treasury Manager
13. Maintenance Schedule Task Application	28. Unit Price Contract Management System
14. Material Reference Book	29. Work Activity Log
15. Material Requirements Planning and Forecasting	30. Work Request System

Implicit in implementing a new ERP is the avoided cost of the otherwise necessary remedial action need to address the functional obsolescence of Ellipse and the Legacy Systems. This work, discussed in further detail under in the Evaluation of Alternatives section, constitutes the basis for comparing the various options considered under this case.

It is also expected that the new ERP would deliver process improvements by reducing the amount of time required to undertake tasks in the new ERP environment. Process improvements are expected in each of the six functions identified above. This includes the benefit of the projected increase in the reliability of Toronto Hydro's IT systems.

The ERP Program is forecast to require capital expenditures of approximately $51.3 million in the 2015 to 2019 period, as outlined in Table 2. The total cost of the program, inclusive of pre-2015 capital expenditures, includes Software and User Licenses of approximately $5.1 million, computer hardware and other required technical infrastructure of approximately $3.4 million and system implementation resources and services of approximately $45.4 million. A description of how Toronto Hydro intends to execute the program is included in the Program Execution section.

Appendix B contains a summary of the projected costs and benefits of implementing the proposed ERP Program over its expected ten-year life.

TABLE 2: EXPECTED CAPITAL EXPENDITURES – ERP IMPLEMENTATION

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	1.8	0.9	17.7	33.6	0	0	0

E8.6.3 Why the Program is Needed

Toronto Hydro implemented its current ERP system, Ellipse, in 2002. Since then, Toronto Hydro has taken steps to maintain Ellipse as a cost-effective, secure, reliable and relevant component of its back-office IT infrastructure. These steps included performing a mid-lifecycle technology upgrade on Ellipse in 2006 and adding applications to leverage or to supplant Ellipse's capabilities when Ellipse on its own could not deliver the required functional improvements.

While Toronto Hydro's investments in Ellipse and the Legacy Systems provided value to the utility and ratepayers, they can no longer prudently satisfy the utility's operational, statutory, or regulatory requirements, nor is there any prudent means of further extending their useful lives. Material risks of continuing to operate Ellipse and the Legacy Systems in their current state include inadequate availability of support resources, performance and cybersecurity risks. In order to mitigate these risks and achieve additional operational efficiencies, Toronto Hydro proposes to replace Ellipse and the Legacy Systems within the 2015 to 2019 period.

E8.6.3.1 Program Drivers

TABLE 3: PROGRAM DRIVERS

Primary Driver	Reasoning
Functional Obsolescence	ƒ Between 2015 and 2019, Ellipse and many of Toronto Hydro's Legacy Systems, will no longer be supported by vendors. ƒ Cessation of vendor support raises a number of critical risks, including cybersecurity.
Secondary Drivers	**Reasoning**
Business Operations and Efficiency	ƒ Toronto Hydro has identified a number of key processes that could be made more efficient if supported by an IT solution.

E8.6.3.2 Functional Obsolescence

Vendor support for Toronto Hydro's version of Ellipse is coming to an end which, if unaddressed, would render it functionally obsolete.

Ellipse is a "Commercial Off-the-Shelf" (or "COTS") software application. A major advantage of purchasing a COTS application, as opposed to developing an application in-house, is the availability of vendor support for the application and its underlying database and operating system for the duration of the General Support period.

Ellipse's General Support, provided by its vendor, Ventyx, was crucial to the system's ongoing usefulness to Toronto Hydro. While Ellipse was in General Support, Ventyx developed some of the functionality required to comply with new legislative, regulatory and operational requirements in a timely fashion.[2] They quickly identified and resolved system issues and security vulnerabilities in the application's source code. Periodically, they also certified new database, operating system and hardware configurations to ensure system performance.

Similarly, Toronto Hydro had a General Support Agreement in place with Oracle to support Ellipse's Oracle database. This helped ensure that newly discovered database bugs and security vulnerabilities were resolved in a timely manner through patches.

While General Support provides significant benefits to application users, these agreements are only available for a limited time, as application vendors do not offer indefinite support arrangements.[3]

As Table 4 illustrates, Ellipse's Oracle 9i database has been out of General Support since July 2007, while General Support for the application itself expired in March 2008.

TABLE 4: ELLIPSE SOFTWARE COMPONENTS –SUPPORT STATUS

	Software	End Of General Support	End Of Sustaining Support
Application	Ellipse 5.2.3.7	Q1 2008	Q2 2015
Database	Oracle 9i	Q2 2007	Indefinite

Once the General Support period for a software product ends, vendors typically offer Sustaining Support. However, Sustaining Support is subject to time and scope limitations and other exclusions and limitations. These departures from the General Support terms reduce the value of vendor support, but not its cost. Over time, continued reliance on Sustaining Support means that

[2] As detailed above, this functionality was not delivered to the extent required by Toronto Hydro.
[3] While arrangements vary from vendor to vendor, the typical or "industry standard" General Support period is 5 years, followed by an additional 3 to 5 year period of Sustaining Support (also sometimes called Extended Support).

the value-for-money of the investment consistently diminishes.[4] Given these considerations, it is not prudent for Toronto Hydro to continue operating current versions of Ellipse or the Oracle database beyond the actual or effective expiration of their respective Sustaining Support periods.

One alternative to vendor Sustaining Support is to provide those critical services either by a suitably qualified third-party or from within Toronto Hydro's Information Technology department. However, Toronto Hydro expects that obtaining replacement services will be increasingly challenging and costly. Moreover, the efficacy of this increased effort and expenditure would also likely be limited, particularly with respect to the certification of hardware and the maintenance application and database security as these sorts of activities are highly specialized and therefore not feasible to maintain "in-house".

The functional obsolescence of Ellipse introduces the following technical risks:

- Operation on uncertified hardware;
- Application capability limitations;
- Technology limitations that impede operational efficiency; and
- Cybersecurity.

Operation on Uncertified Hardware

Retaining General Support for an information technology application is valuable because the vendor will certify that their applications will operate properly on certain hardware. Certification is essential because applications require processors, disk drives and other physical internal systems to reliably and accurately gather, process or transmit information properly. Vendors' support contracts specify that support will not be provided for technical issues that occur on unsupported hardware. Information technology vendors will also cease to certify a version of their software to operate on any new hardware once that version's General Support period ends.

No hardware released in the last five years is certified by Ventyx to run the version of the Ellipse application currently used by Toronto Hydro. The lack of certification for new equipment would not be an issue if the physical hardware required to operate Ellipse had an indefinite life. However, information technology equipment eventually degrades and requires replacement. Ellipse's

[4] Oracle's Software Technical Support Policies are indicative of the kinds of restrictions that take effect upon the expiry of General Support. See the following link for more information: http://www.oracle.com/us/support/library/057419.pdf. Accessed June, 2014.

original server became less reliable over its 12 years of service, with its disk drives and readers wearing out and its power supplies degrading. Because the hardware was no longer manufactured, replacement parts for these critical components also became difficult to obtain.

To mitigate the risk of a physical server failure, Toronto Hydro migrated Ellipse to unsupported servers in November 2013. While necessary and carefully planned, tested and executed, Ellipse's migration onto these unsupported servers raised the risk that Ellipse may not function properly in certain situations due to incompatibility between the application and its uncertified physical hardware.

There is already some evidence that the new server components supporting Ellipse are unable to efficiently execute the instructions sent by Ellipse in certain circumstances. For instance, since the migration onto the new hardware took place, the nightly update processes required to ensure that Ellipse and the other Legacy Systems that receive data from it are ready for the start of the next business day take approximately one hour longer to complete. Given that those nightly processes must be complete before the next day's processing can begin, Toronto Hydro's ability to use Ellipse at the start of the next business day could be compromised if performance deteriorates further. This could result in a significant loss of operational efficiency.

Moreover, in the absence of vendor support for new hardware certification in the future, Toronto Hydro cannot eliminate the possibility that additional and more serious software or hardware compatibility issues will emerge when the next server change is required to address the risk of hardware failure.

Application Capability Limitations

Today, Ellipse's software platform presence in North America generally, and within the utility industry more specifically, is very limited. This reduced industry footprint raises two important sustainability issues for Toronto Hydro.

First, the release of new application functionality for Ellipse is lagging when compared to its competitors, diminishing the breadth of Ellipse's solution-offering over time. As a result, Toronto Hydro has been forced to look to other providers for cost-effective, back-office information technology solutions to fulfill operational requirements. For example, in 2009 Toronto Hydro implemented SAP's Finance module because Ellipse was unable to support the simultaneous use of USGAAP and IFRS accounting rules in a timely manner. Toronto Hydro also implemented Timelink's timekeeping solution in 2012 because Ellipse's functionality was inadequate. It is likely

that Toronto Hydro will be forced to continue to develop or purchase additional software in the future to meet new operational requirements, which is not prudent given the level and specialized nature of resources required to maintain this topology.

The second sustainability issue that arises from Ellipse's reduced industry footprint concerns the timely availability of application support. Since implementing Ellipse in 2002, it has been difficult to locate qualified Ellipse support staff, especially those capable of supporting and integrating the utility's aging version of the application. This situation continues to worsen with time.

The application support risk stemming from the very small number of resources with sufficient skills in Ellipse is significant to Toronto Hydro because it requires specialized skills to repair the Ellipse system. These skills are not always available and can be expensive when they are. Without access to that talent, Toronto Hydro will be far less likely to be able to effectively support Ellipse over time.

Finally, it is reasonable to expect that the utility may experience challenges with the provision of Oracle database resources in the future, since Oracle's Sustaining Support service does not guarantee that necessary information and skills will be available. Future resourcing issues are likely to emerge as the Oracle database version used by Toronto Hydro ages.

Technology Limitations that Impede Operational Efficiency

The version of Ellipse used by Toronto Hydro has four other technical limitations that prevent or impede the development of more efficient and secure processes.

- Absence of a Standard Application Programming Interface: Toronto Hydro integrates Ellipse with the Legacy Systems to fulfill its operational process needs. Integrating applications improves the accuracy and security of the data contained within it. However, while necessary to ensure operational efficiency, the integration between Ellipse and the Legacy Systems is often complex and costly to undertake because the older version of Ellipse used by Toronto Hydro, unlike many other ERP systems, does not have a standard Application Programming Interface (API) to facilitate the technical work required. Consequently, all integration to and from Ellipse must be custom-developed, tested and implemented. This is a more costly and time-consuming approach than would be the case if an API was available in the application. Moreover, interface support costs are further increased because of the need to retain relevant skill sets and to monitor of number of complex, interdependent

interfaces. The lack of integration capability within Ellipse is a significant barrier to integrating new applications that are necessary for Toronto Hydro to operate efficiently and effectively.

- No Lightweight Directory Access Protocol Support: One of the measures Toronto Hydro uses to maintain the effectiveness of its information security administration is a centralized user account/privilege repository known as the Lightweight Directory Access Protocol (LDAP). LDAP was implemented to help Toronto Hydro information technology staff better manage user access across all systems. However, the version of Ellipse currently used by Toronto Hydro cannot be integrated with LDAP and so additional manual effort to manage users and permissions in Ellipse is required. These extra measures substantially increase the required security management oversight, necessitating frequent audits to ensure that application access privileges are not granted in error to users that are not entitled to receive them. This extra effort raises the cost of sustaining Ellipse.

- "All or Nothing" Access to Operational Functions and Data: The ability of Ellipse to segregate access to operational data and functions on a sufficiently granular level is limited, making it difficult to restrict user access in certain areas, modules and situations. This "all or nothing" access to data and operational functions creates a number of issues including the inability to limit access to human resource or financial data to a single department of the organization or to only certain users. This technical limitation means that the utility has to decide between not fully leveraging Ellipse's capabilities, or losing internal control over the use of data.

- No Cross-functional workflow: Cross-functional workflow capability would allow the utility to define, sequence and monitor tasks performed by different actors across operational functions. Ellipse has only primitive workflow management capabilities and, as a result, instead of implementing automated workflows to orchestrate efficient processes, Toronto Hydro must rely on manual systems to facilitate the integration of tasks that cross utility functions. For example, within the purchasing area, manager approvals are required when purchase orders exceed prescribed thresholds, but there is no way to automatically route these approval requests to the relevant manager from within the version of Ellipse used by the utility. As a result, Toronto Hydro employs a manual system using e-mail to perform this function. This approach increases the effort required to monitor the process, raises the likelihood of errors

and introduces delays that would not occur if a fully-automated and fully integrated workflow management solution was available.

Cyber Security

During the course of its operations Toronto Hydro gathers, processes and stores large amounts of confidential financial, asset and human resources data within Ellipse. Protecting this information from unauthorized disclosure or use is a key priority for Toronto Hydro, especially given the rising threat posed by increasingly sophisticated malicious parties. As the Independent Electricity System Operator (IESO) notes in its "Cyber Security Threat Overview" the number and complexity of cyber attacks by individual, sub- or pan-national interest groups and rogue states grew by 42% in 2012, with the Energy/Utilities sector being the 5th most targeted industry.[5]

Toronto Hydro recognizes that an information technology security breach could have material adverse effects on the utility and its ability to deliver essential services. It mitigates this risk by using layers of technical and management controls to prevent or to detect and limit the extent of any breach. These efforts include:

- Using security event management tools ("firewall") to assess network activity and to detect and prevent intrusion;
- Applying security patches provided by vendors to applications and databases;
- Performing regular vulnerability assessments on critical IT assets;
- Implementing corrective measures where vulnerability assessments indicate a weakness;
- Conducting periodic system scans for known cyber threats and signatures of malicious traffic; and
- Training staff in information security awareness.

The protection measures applied to the Ellipse application and its database are not keeping pace with new threats. Ellipse's application and database software have received Sustaining Support since Q1 2008 and Q2 2007 respectively, which does not require the vendors (Ventyx and Oracle respectively) to search for undiscovered vulnerabilities or provide the patches to fix them. This lack of regular security support by the vendor leaves Ellipse more vulnerable to potentially significant information security breaches than it would be if such support was provided. While

[5] Hammerschmidt , Jason D. "Cyber Security Threat Overview" IESO PowerPoint Presentation ., p. 7, 10,& 12.

developing in-house application and database security capacity is technically an option, doing so would likely be prohibitively expensive and, given the large number of threats to identify and remedy, likely less effective than vendor-led efforts.

For these reasons, Toronto Hydro is becoming increasingly dependent upon its corporate firewall and other compensating controls to ensure Ellipse's security. If these measures are circumvented, both the application and its database would be more susceptible to virus, malware and other hacking exploits than if vendor support for information security patching was provided. Consequently, there is a heightened risk that Ellipse may experience database damage, information leakage or externally caused system failure in the future.

E8.6.3.3 Legacy Systems – Sustainability Issues

Since Ellipse's implementation, Toronto Hydro has had to implement many COTS and custom-developed information technology applications to address the utility's evolving operational needs. While these applications enabled Toronto Hydro to leverage and prolong the life of Ellipse, many of these solutions now have sustainability issues of their own.

Table 5 briefly describes the applicable sustainability issues and indicates which custom-developed Legacy Systems are impacted:[6]

TABLE 5: CUSTOMIZED LEGACY SYSTEM SUSTAINABILITY ISSUES

Issue	Description	Legacy Systems Impacted
End of Extended Support for Oracle Databases	Oracle's support for the databases that now support most of the Legacy Systems is now in the Sustaining Support Phase. While this support is "indefinite", it does not include security patch updates to close newly discovered security vulnerabilities. Unpatched security gaps make the system increasingly vulnerable to a cyber intruder. In addition, if database	ƒ Asset Management Portal ƒ Attendance Management System ƒ Cable Failure Web Application ƒ Confined Space System ƒ Employee Move Form ƒ EMRT ƒ Equipment without Maintenance Schedule Tasks ƒ Feeder Information System ƒ Feeder Operating

[6] Note that one system may be impacted by multiple issues.

Issue	Description	Legacy Systems Impacted
	programming is required to maintain the system. Acquiring and maintaining resources with the requisite technical skills to maintain these programs is expected to be challenging moving forward. Delays in acquiring these resources may impact Toronto Hydro's ability to fulfill its core mandate in a timely and efficient manner in the future.	Conditions ƒ IT Timesheet ƒ Labour Vehicle Costing Application ƒ Maintenance Schedule Task Application ƒ Material Reference Book ƒ Material Requirements Planning & Forecasting ƒ New Location Request Application ƒ Picking Slip Application ƒ Reclaim Equipment Application ƒ Resource Requisition Application ƒ Return Slip Application ƒ Unit Price Contract Management System ƒ Work Activity Log ƒ Work Request System
End of Extended Support for Visual Basic 6	Microsoft's support for Visual Basic 6 has ended, causing two sustainability issues. First, Microsoft no longer provides security patch updates to close newly discovered security vulnerabilities. Unpatched security gaps make the system increasingly vulnerable to an intruder. Second, all of the Visual Basic 6 applications are now more than 15 years old. Acquiring	ƒ Confined Space System ƒ Unit Price Contract Management System ƒ Work Activity Log ƒ Work Request System

Issue	Description	Legacy Systems Impacted
	and maintaining resources with the requisite technical skills to maintain these programs is expected to be challenging moving forward. Delays in acquiring these resources may impact Toronto Hydro's ability to fulfill its core mandate in a timely and efficient manner in the future.	
End of Extended Support for Windows Server 2003	Microsoft's support for Windows Server 2003 will end in July 2015, causing two sustainability issues. First, Microsoft no longer provides security patch updates to close newly discovered security vulnerabilities. Unpatched security gaps make the system increasingly vulnerable to a cyber intruder. Second, as all of the Windows Server 2003 applications are now based on an environment that is now 11 years old. Acquiring and maintaining resources with the requisite technical skills to maintain these programs is expected to be challenging moving forward. Delays in acquiring these resources may impact Toronto Hydro's ability to fulfill its core mandate in a timely and efficient manner in the future.	ƒ Feeder Information System ƒ Feeder Operating Conditions
End of Extended Support For Websphere Application Server 5	IBM's support for the version of the Websphere Application Server operated by Toronto Hydro has also now ended,	ƒ Maintenance Schedule Task Application

Issue	Description	Legacy Systems Impacted
	causing two sustainability issues. First, IBM no longer provides security patch updates to close newly discovered security vulnerabilities. Unpatched security gaps make the system increasingly vulnerable to a cyber intruder. Second, the Maintenance Schedule Task Application is now ageing. Acquiring and maintaining resources with the requisite technical skills to maintain these programs is expected to be challenging moving forward. Delays in acquiring these resources may impact Toronto Hydro's ability to fulfill its core mandate in a timely and efficient manner in the future.	
End of Support for Access 2003	Microsoft's support for Access 2003 has also now ended, causing to two sustainability issues. First, Microsoft no longer provides security patch updates to close newly discovered security vulnerabilities. Unpatched security gaps make the system increasingly vulnerable to a cyber intruder. Second, the Scope Planning System is now ageing. Acquiring and maintaining resources with the requisite technical skills to maintain	ƒ Scope Planning System

Issue	Description	Legacy Systems Impacted
	these programs is expected to be challenging moving forward. Delays in acquiring these resources may impact Toronto Hydro's ability to fulfill its core mandate in a timely and efficient manner in the future.	

In addition to the issues described above, four of Toronto Hydro's COTS Legacy Systems are experiencing sustainability issues today or will experience them in the 2015 to 2019 period. These issues are briefly described in Table 6.

TABLE 6: COTS LEGACY SYSTEM SUSTAINABILITY ISSUES

System	Status
Hyperion	Hyperion 9.3.1 is in sustaining support, and Oracle no longer provides security patch updates to close newly discovered security vulnerabilities in the application or the database. Absent implementing a new ERP, this application would require an upgrade.
Panviva	The version of Panviva used by Toronto Hydro is no longer supported by the vendor. Absent implementing a new ERP, this application would require an upgrade.
Team-Mate	Support for this application is set to expire in May 2016. Absent implementing a new ERP, this application would require an upgrade at that time.
Timelink	Timelink was acquired by a competitor in July 2013 and its new owner has not committed to developing or supporting the application after the end of the existing support period.

E8.6.3.4 Business Operations and Efficiency

Toronto Hydro identified eight primary operational needs that could be made more effective or efficient through improved IT capability. At present, Ellipse and the Legacy Systems perform most or all information processing requirements for six core back-office functions:

- Planning;
- Record-to-Report;

- Human Capital Management;
- Asset Plan, Build, Maintain
- Source to Pay; and
- Customer Connection.

Ellipse and the Legacy Systems also perform tasks related to Toronto Hydro's Meter-to-Cash and Event Management processes.

These functions enable Toronto Hydro to support the core financial, human resource, work execution and safety processes that are essential to its operations. However, the complex topology of Ellipse and the Legacy Systems limit Toronto Hydro's ability to add new functionality in response to changing operational, statutory and regulation requirements in a prudent fashion. With such an array of applications, providing the necessary support and administrative oversight is resource intensive both in terms of the level and specialized nature of those resources. Technical expertise in COTS applications and development technologies such as Cold Fusion, Visual Basic and Access 2000 would need to be retained in the absence implementing a new ERP.

By implementing a new ERP, there are opportunities to improve each of these operational processes by removing these general limitations in addition to those specific to each function. These are described in greater detail below.

Planning

The Planning function allows Toronto Hydro to perform and maintain governance over a number of planning-related tasks across the utility's operations, including:

- Integrating planning activities with Human Capital management (HCM) and Asset Management Systems;
- Performing long term planning based on historical trends;
- Preparing Operational and Capital Expenditure Forecasts;
- Creating Planned Projects;
- Planning for asset decommissioning and de-recognition;

- Planning for property disposition, pre-capitalized inventory, and Asset Retirement Obligation; and
- Controlling and monitoring planning changes.

Executing these tasks often relies on data contained within other systems. To date, it was not cost effective to develop a common planning user interface for these disparate systems. This gap significantly complicates data transfers and process tracking and necessitates the use of extensive manual processes in order to meet the utility's regulatory and reporting requirements.

By integrating these functions into a common platform, the new ERP system is expected to mitigate those issues and deliver new planning capabilities, including:

- Improving centralized planning governance and processing and incorporating change controls;
- Integrating Finance, HCM and Asset Management organizational planning activities in one system;
- Improving project type and delivery traceability across multiple plans;
- Generating multiple plans based on different accounting standards; and
- Implementing real-time reporting with flexibility to meet regulatory and operational requirements.

Record-to-Report

The Record-to-Report function provides centralized governance over the collection, analysis, distribution and publication of Toronto Hydro's financial filings and management reports. Since Ellipse was implemented in 2002, Toronto Hydro's financial and regulatory reporting requirements have increased considerably, but Ellipse's native financial and regulatory reporting capabilities did not. As a result, Ellipse's inherent reporting capabilities are no longer sufficient to meet the utility's basic financial and regulatory reporting obligations.

Tasks currently being performed that are expected to be retained by the new ERP include:

- Producing statutory, regulatory, management and operational financial reporting (including US GAAP and IFRS report requirements);

- Managing on-going and periodical financial postings and accruals (including fiscal period opening and closing);
- Managing cash flow and other Treasury functions;
- Calculating Payments in Lieu of Corporate Taxation, Property Taxes and other taxes; and,
- Managing the Fixed Assets Sub-ledger, asset accounting and costing.

The new ERP system is expected to add new Record-to-Report capabilities, such as:

- Establishing a centralized repository of all financial data, with real-time, automated updates to the General Ledger;
- Improving controls over versioning and accounting ledgers;
- Automating fixed asset sub-ledger activities (including project traceability, energization, costing, de-recognition, reporting and regulatory compliance); and,
- Implementing real-time reporting with flexibility to meet new regulatory and operational requirements.

Human Capital Management (HCM)

HCM encompasses strategic human capital planning functions and the processing of day-to-day human resource transactions. Ellipse currently contains employee demographic data and information storage capabilities, allowing it and the Legacy Systems to provide many HCM tasks, including:

- Planning retirement projections and roll-out retirement details;
- Developing headcount and succession plans as well as associated budgets;
- Managing timesheets and process payroll, expenses, compensations and benefits;
- Storing and updating employee information (union and non-union); and,
- Coordinating employee on-boarding, cross-boarding and off-boarding.

However, the limitations of Ellipse and the Legacy systems require a number of manual tasks to be complete, introducing inefficiencies and data quality risks. The new ERP would address these limitations by incorporating new functionality, including:

- Performing organizational structure management across the utility, including the ability to assign and reassign employees, in a more timely and accurate manner;
- Improving workforce planning functionality, including: retirement projections, headcount planning and budgeting, succession planning and career development, skills and training, and job design;
- Implementing workflow management for resource requisition, on-boarding, cross-boarding, off-boarding, leave request and approval, timesheet follow-up and job changes;
- Establishing a single point-of-entry for time and attendance with integration to payroll/finance and ADP for payments;
- Enhancing Human Capital Management process audit capabilities to ensure adherence to policies and procedures; and
- Implementing real-time reporting with flexibility to meet new regulatory and operational requirements.

Asset Plan, Build and Maintain

The Asset Plan, Build and Maintain function encompasses long-range distribution asset planning capabilities and the ongoing management of asset renewal programs and projects for which Ellipse and the Legacy Systems are used to:

- Make long term asset plans;
- Perform Program scoping and project design as well as create packaged estimates;
- Initiate, manage and track asset construction;
- Establish asset maintenance plans/schemas and perform asset maintenance;
- Prioritize work, planning and scheduling to support asset life cycle operations;

- Capture planned and actual labour effort and resource utilization and associated internal and external costs; and
- Enhance employee and public safety.

Currently, these functions require the significant use of other work management application such as Microsoft Project, Microsoft Access, Excel and other software to overcome the shortcomings of Ellipse. The new ERP system is expected to add significantly to the work that could be undertaken through the ERP, including:

- Improving project management capabilities with the ability to:
  - compare Quoted Pricing between contractors
  - categorize projects and programs
  - track task completion, progress and actuals versus planned in real-time
  - identify risks, delays, and resource availability
  - generate notifications when project timelines are at risk
  - publish updated project schedules
  - automatically close a project for capitalization for ISAs
- Adding new Workflow Management capabilities including the ability to:
  - automate workflow in design
  - assign scopes and projects to supervisors and construction electronically
  - track scope and design performance
  - generate reports on scope status in the work queue
  - provide notifications for milestones in design and construction
- Improving productivity management functionality, including the ability to create work schedule and measure productivity based on labour rates.

- Providing a central repository for project documentation and data, enabling planning, design, and construction documentation to be shared amongst different groups more easily.

Event Management

The Event Management function encompasses long-range forecasting and program development as well as the day-to-day intake, resolution and management of system events.

The new ERP system is expected to enable the Event Management function to:

- Improve Event Management work tracking capabilities including the ability to:
  - create a Service Notifications or a Work Order based on a triggering event in OMS
  - link work orders to a master event to capture time, cost and materials when multiple resources are required to complete work or where work is referred to another work group for follow up
  - upload digital files (e.g., pictures) into Event Management Work Orders
- Optimize communication for all field personnel using laptops and tablets to enable real-time work order execution functionality;
- Extract and interface available crew and skill set information to the OMS.

Source to Pay

The Source-to-Pay function supports Toronto Hydro's material and service purchasing capabilities at the strategic and day-to-day level. Ellipse and the Legacy Systems are used to:

- Perform sourcing, vendor management, contract management and procurement operations;
- Manage material inventory (including receiving, shipping and stock transfer operations);
- Manage repairs, returns and warranties;
- Perform vehicle maintenance operations;

- Track crew, fleet and tools/equipments assignments; and
- Manage PO and GR based accounts payables and standalone accounts payables.

However, many of these tasks are not fully automated and require manual processes for execution. The new ERP system is expected to integrate new functionality into the Source-to-Pay function, allowing Toronto Hydro to:

- Link product failures back to their original purchase and warranty terms;
- Implement electronic request functionality, including storing request templates, tracking request gates, and managing request-related vendor correspondence;
- Roll out self-serve procurement for non-inventory items with automatic Purchase Order creation;
- Group approvals of non-order invoice payments;
- Manage Consignment Inventory;
- Integrate Contract Management functionality with Purchase Orders;
- Approve RFP and sole source documentation with automated workflows; and
- Enhance Vendor Master search functionality.

Customer Connection

Ellipse and the Legacy Systems support Customer Connections processes, including billing and account management functions that are required to connect new customers and to provide additional supply to existing customers. These functions are essential to fulfilling Toronto Hydro's mandate to connect and serve its customers.

However, Ellipse is not able to manage the full end-to-end Customer Connection process. Instead, Toronto Hydro uses separate systems for specific tasks, such as logging certain technical requirements. This is another example how the limitations of Ellipse introduce inefficiencies and the potential for data issues to current processes. The new ERP system is expected to improve the Customer Connection function by:

- Automating the customer design deposit and Offer to Connect (OTC) processes;

- Automating the Net Present Value calculation for customer work;
- Tracking charges by all departments to a customer connection;
- Implementing Work Flow Management for OTC processes; and,
- Time Stamping all system based handoffs between Toronto Hydro and Customers.

Meter to Cash

While the majority of Meter-to-Cash processes are supported by Toronto Hydro's Customer Care and Billing System (CC&B), Ellipse is used to initiate, process and track non-electricity customer accounts receivable related to the payment of customer-initiated capital work and other ancillary services. However, its functionality in this regard is limited. For example, Ellipse is unable to accept interim or staged payments that are otherwise permitted or automatically calculate and charge the interest on unpaid balances. Instead, manual processes are relied upon.

The new ERP system would remedy the limitation of the Meter to Cash function by:

- Improving non-electricity billing functionality including the ability to:
  - track information such as labour, material, fleet, contracts against a work order or invoice calculation
  - capture customer bill format preference
  - automatically apply late payment charges
- Automating the collection process;
- Automating the deposit interest calculation process;
- Including an on-demand deposit interest calculation capability;
- Automating the trigger to review the customer's commitment for capital contribution;
- Accepting general ledger account entry adjustments from the CC&B system; and,
- Accepting accounts payable entries at the sub-ledger level, including appropriate taxes.

E8.6.4 Timing & Pacing of the Program

The timeline in Figure 3 reflects Toronto Hydro's current expectations for the timing and pacing of the four phases of this program. The four phases of the program are described in the Program Execution section below.

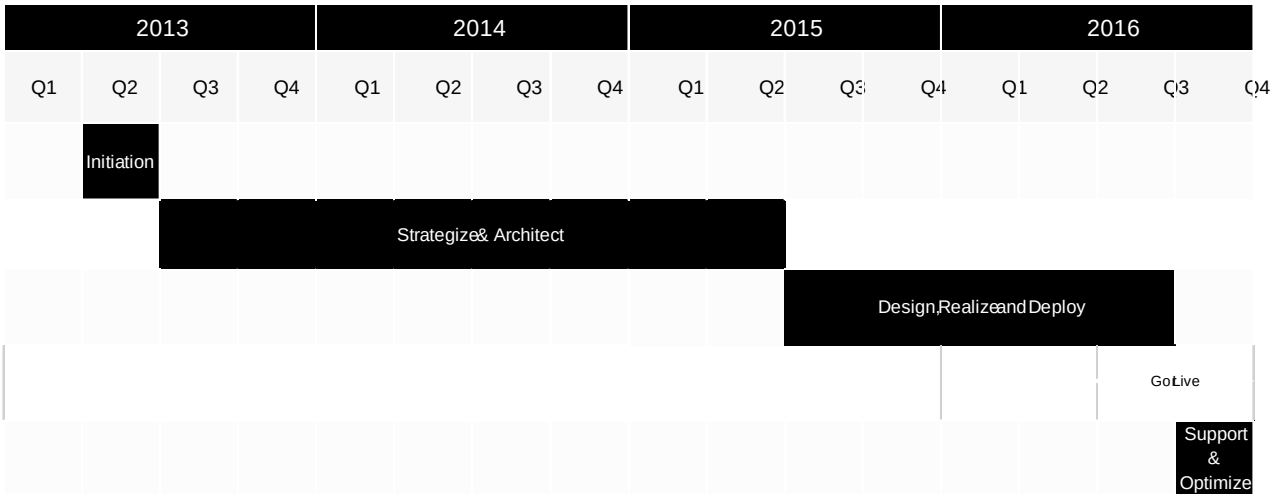


FIGURE 3: EXPECTED TIMELINE FOR NEW ERP IMPLEMENTATION.

E8.6.5 Program Execution

Toronto Hydro's proposed ERP Program consists of a single project culminating it the implementation of a new ERP during the 2015 to 2019 period. Toronto Hydro has adopted a four-phase implementation approach that emphasizes an integrated design process and requirements definition prior to the selection of a system.

This approach is represented at a high level in Figure 4 and explained in more detail below.

FIGURE 4: FOUR PHASES OF THE PROPOSED PROGRAM EXECUTION APPROACH.

Initiation

During the Initiation Phase, Toronto Hydro developed the program's high-level implementation approach and timeline to give structure and direction to the remaining phases of the project. Resources required to execute the subsequent stages were also defined.

Strategize & Architect

The purpose of the Strategize & Architect phase is to identify, define and verify the functional requirements of the program prior to the Design stage when making changes to the requirements is far more costly. Consequently this phase was entirely "paper-based".

Once the functional requirements were determined, the benefits associated with each improved process were estimated. At this stage of the program, estimates were made without reference to any particular information technology approach or system, recognizing the fact that various approaches or vendor technologies could be used to fulfill operational requirements.

The next step was to identify the preferred technical approach to deliver the required functionality. Here, the technical and operational merits of each approach were considered and costs were thoroughly compared. At the conclusion of this process, the recommendation to implement an ERP with the necessary incremental functionality was made.

The process of selecting an ERP system and a system integrator to assist Toronto Hydro with the Program's subsequent phases would be undertaken subsequent to regulatory approval.

Design, Realize and Deploy

The Design, Realize and Deploy Phase encompasses the standard phases of an ERP Implementation, including detailed design, configuration, testing, training, data cleansing and conversion and all associated change management activities.

During this phase, Toronto Hydro will be supported by System Integrator and Vendor resources to ensure that the functional requirements identified in the previous phase are seamlessly implemented in the ERP solution. Using a System Integrator and Vendor resources provide valuable experience from other ERP projects during this phase of the program, which can help to minimize implementation costs.

This phase ends at the time the ERP system goes live.

Support and Optimize

The Support and Optimize phase commences immediately after the ERP System becomes functional and continues for approximately three months.

The objectives of this phase are to stabilize the ERP System, to embed the new processes into day-to-day operations, and to capture unanticipated system or process inefficiencies for subsequent resolution.

During this phase support will be provided to end-users through an "ERP Help Desk" staffed during business hours, in-department "super-users" and proactive and reactive post-"Go-Live" user training and follow-up sessions.

It is at this point that Ellipse and the Legacy Systems would no longer be used to support Toronto Hydro's operations.

E8.6.5.1 Program Risks

Toronto Hydro identified a number of risks to the successful completion of the new ERP and is taking a proactive approach to mitigating them.

Solution Fit to Utility Requirements

The processes proposed for incorporation into the new ERP must be able to deliver the functionality Toronto Hydro requires to meet its operational, legislative, regulatory and customer obligations. A design approach that considers functionality as silos is particularly risky.

Toronto Hydro made efforts to fully consider all areas of its operations before any configuration or coding has taken place. All processes and system requirements are defined and documented by Toronto Hydro prior to system selection and integration. End-to-end operational process scenarios will be used in the testing phase of the new ERP.

Functional Obsolescence

The new ERP system selected by Toronto Hydro must be able to deliver the functionality Toronto Hydro requires while the system is in use, including requirements that are not known or anticipated at this time.

Toronto Hydro is mitigating the risk that the new ERP will not be able to fulfill unforeseen future needs by selecting its solution from those offered by top-tier ERP Vendors with a large presence in the utilities industry. The selection of a financially strong vendor with robust application capabilities and a commitment to meeting its utility sector customers' future needs will mitigate the risk the new ERP would be unable to meet functional requirements that are not known at this time.

E8.6.7 Evaluation of Alternatives

E8.6.7.1 Quantification/Evaluation of Options

Option Identification

Toronto Hydro developed four options that consider different approaches to addressing the program drivers identified in the Needs section.

To address the primary driver, functional obsolescence, Toronto Hydro could:

(1) Execute a Technical Upgrade of Ellipse and the Legacy Systems to a version or release fully supported by its vendor.

(2) Replace Ellipse and the Legacy Systems with a new ERP system, thereby avoiding the need to perform the Technical Upgrade.

To address the secondary driver, business operations and efficiency, Toronto Hydro could:

(1) Customize Ellipse further by developing or purchasing new applications that deliver the required functional improvements.

(2) Implement a new ERP that integrates the required functionalities into the system at the design phase.

Toronto Hydro considered four options, as summarized in Table 7 and described in further detail below. Option 3 is the preferred option, as described extensively in the Program Description section.

TABLE 7: SUMMARY OF THE FOUR OPTIONS CONSIDERED IN THIS PROGRAM.

	1. Technical Upgrade (BASE CASE)	2. Ellipse & Legacy System Renewal	3. ERP Implementation (PROPOSED)	4. Extended ERP Implementation
Is Technical Upgrade Required?	Yes	Yes	No	No

	1. Technical Upgrade (BASE CASE)	2. Ellipse & Legacy System Renewal	3. ERP Implementation (PROPOSED)	4. Extended ERP Implementation
Delivers new required functionality? If so, how?	No	Yes, Appended	Yes, Integrated	Yes, Integrated
Which IT systems are retired?	None	None	Ellipse, Legacy Systems	Ellipse, Legacy Systems + 3 applications

The costs and benefits of each of these options were estimated over a 10-year period, the expected life of the proposed new ERP, and are summarized in Appendix B.

(i) Option 1 (Base Case): Technical Upgrade

To address the functional obsolescence of Ellipse and the Legacy Systems, Toronto Hydro must at a minimum upgrade those systems to a version or release fully supported by their vendors. Upgrading these systems to a supported version would allow Toronto Hydro to continue to apply security patches to maintain the application and database security and ensure that vendor support for current hardware is maintained.

The Technical Upgrade option is projected to require a capital investment of $13.2 million in the 2015 to 2019 period.

This option would not deliver incremental value for ratepayers and the utility, as it would not satisfy Toronto Hydro's operational needs and would leave material risks and challenges unaddressed. Specifically, this option would not address the technical issues with respect to interfaces, the implementation of LDAP support or data access and segregation concerns present in Ellipse today.

In addition, this option would not deliver any incremental functional capabilities needed to improve the operational efficiency of the utility. Toronto Hydro's corporate processes would remain unchanged if this option was adopted, and existing inefficiencies and data quality risks would go unabated. All applications as well as the interfaces between Ellipse and the Legacy Systems would be maintained "as is."

Under this approach, Toronto Hydro would still have a complex application environment to administer and support after the successful completion of this initiative. At a minimum, patches for each unique application, technology or database in the current IT topology would need to be checked for and applied. Similarly, Toronto Hydro would remain responsible for maintaining the 31 interfaces. Together, these undertakings would be complex and time consuming and, as a result, gaps in the timely application of security patches and the timely development of interface changes are likely.

Toronto Hydro would also remain responsible for designing, developing, testing, implementing and supporting any additional tax, legal or regulatory requirements that pertain to the 24 custom applications retained in this scenario. This would require additional incremental expenditures over time. Finally, a high degree of Vendor Relationship Management will be required to establish the boundaries and the accountabilities of the application, technology and database vendors contributing to this solution.

(ii) Option 2: Ellipse & Legacy System Renewal

Like the Technical Upgrade, this option would upgrade Ellipse and each of the Legacy Systems to a version or release fully supported by its vendor, allowing Toronto Hydro to continue to issue security patches and to obtain vendor support. In addition to undertaking these technical upgrades, the new functional requirements would be incorporated through additional configuration within Ellipse, further custom development of the Legacy Systems and new integration improvements.

Toronto Hydro estimates that implementing this option would require capital expenditures of $71.6 million in the 2015 to 2019 period.

Implementing this option would deliver the same incremental efficiency benefits (i.e., cost savings, cost avoidance and process improvements) of the preferred option, but with one exception. Because Ellipse and the Legacy Systems would continue to be used for Toronto Hydro operations, the improvements made to those systems would not improve the reliability of Toronto Hydro's IT infrastructure to the same extent as a new ERP. Accordingly, only a share of that benefit would be obtained through this approach.

There are other, cost-related drawbacks with this option. The resulting application topology would be a far more complex system to operate, administer and support than the system that exists today or that would be implemented through a new ERP. For example, System Security staff

would still have to, at a minimum, check for and apply patches for each unique application, technology or database. This is a complex and time consuming undertaking and gaps in the timely implementation of security patches are likely to arise as a result.

Interface support requirements would also increase if this option is adopted as additional integration will be required to incorporate the new functionality discussed in the proposed option. For example, eliminating the use of excel-based data transfers in the Planning, Record to Report and Human Capital Management functions would require the building of additional interfaces to securely transmit information between Ellipse, SAP and Hyperion.

If this option was implemented, Toronto Hydro would remain responsible for designing, developing, testing, implementing and supporting any additional tax, legal or regulatory requirements that pertain to the 24 custom applications retained in this scenario. Development work in excess of what is currently necessary would be required.

(iii) Option 3 (Preferred): ERP Implementation

The implementation of a new ERP is the option described in this exhibit and is Toronto Hydro's preferred option. As noted, Toronto Hydro estimates that implementing this option would require capital expenditures of $51.3 million in the 2015 to 2019 period. The total cost of this option is estimated to be $54.0, inclusive of pre-2015 capital expenditures.

(iv) Option 4: Extended ERP Implementation

Like the proposed Option 3, in this scenario Toronto Hydro would replace Ellipse and the Legacy Systems with a single ERP system. This would address all of the sustainability, security and efficiency issues identified earlier.

This initiative would also replace all other applications within the current ERP that could be replaced with an ERP. These functions provided by these applications, including Toronto Hydro's Current Warehouse Management System (Red Prairie), its Safety Incident Recording System (Intelex) and its Performance Management System (Halogen), would be integrated into with the new ERP as standard functionality.

Toronto Hydro estimates that implementing this option would require capital expenditures of $65.5 million in the 2015 to 2019 period.

It is unlikely that that this option would provide any incremental benefits when compared to the proposed option. In Toronto Hydro's view, these additional systems are operating as required and no material functional improvements associated with incorporating these systems into the ERP were identified.

Options Analysis

To compare each of the options on a consistent basis, Toronto Hydro estimated the prospective costs and benefits of each of the four options over the expected 10-year period, corresponding to the expected life of a new ERP.

The basis of comparison is the Technical Upgrade, Option 1, which represents the work that Toronto Hydro must at a minimum execute to address the serious risks posed by the functional obsolescence of Ellipse and the Legacy Systems. For options that do not require the Technical Upgrade there is an associated cost avoidance benefit equal to the amount of that upgrade.

Table 8 summarizes the net present value (NPV) calculation associated with each of the four options. In Option 2, the cost of incorporating the new functional capabilities by further customizing Ellipse and Legacy Systems does not outweigh the benefits of doing so. In Option 4, the cost of expanding the scope of the ERP beyond what is required does not deliver incremental value.

By delivering the incremental monetary benefits and process improvements in a cost-effective fashion, Option 3 is optimal approach to addressing the functional obsolescence and inefficiencies of Ellipse and the Legacy Systems. On this basis, Option 3, implementing a new ERP with the new required functionality, is the proposed option.

TABLE 8: NPV COMPARISON OF THE FOUR OPTIONS CONSIDERED FOR THIS PROGRAM.

	1. Technical Upgrade (BASE CASE)	2. Ellipse & Legacy System Renewal	3. ERP Implementation (PROPOSED)	4. Extended ERP Implementation
Net Capital Investment	This option used as basis for comparison	$71.6M	$54.0M	$65.5M
Expected 10 yr NPV: Monetary benefits only		($31.2M)	($15.3M)	($25.4M)
Expected 10 yr NPV: Monetary and Process benefits		($16.5M)	$4.9M	($5.3M)

APPENDIX A

Table 1 lists and describes the Legacy Systems which would no longer be required for Toronto Hydro's operations upon implementing the new ERP.

TABLE 1: A SUMMARY OF THE 30 APPLICATIONS THAT MAKE UP THE LEGACY SYSTEMS.

Legacy System	Function
Asset Management Portal	ƒ Provides access to a number of applications and forms used to manage the inspection process for approximately Toronto Hydro distribution system assets.
Attendance Management System	ƒ Enables supervisory staff to monitor the frequency and severity of employee absences and to analyze the associated trends.
Cable Failure Web Application	ƒ Retrieves cable failure data stored in the EMRT and provides multiple parameters to enable standard analysis or to export into Excel for custom analysis.
Confined Space System	ƒ Tracks hazards in confined spaces in the old City of Toronto.
Employee Moves	ƒ Facilitates a variety of Human Resource processes (e.g., employee changes, transfers, salary changes, and terminations).
Ellipse Management Reporting System (EMRT)	ƒ Provides users with pre-defined analytical, operational, financial reports as well as an ad-hoc reporting tool that can be used to query the database.
Equipment Without Maintenance Scheduled Tasks	ƒ Reports all assets that do not have a Maintenance Schedule Tasks and provides multiple parameters to enable standard analysis or to export into Excel for custom analysis. Works with EMRT.
Feeder Information System	ƒ Manages requests from designers when new loads are to be added on feeders.
Feeder Operating Conditions	ƒ Analyzes current loading on the Toronto Hydro's feeders for planning purposes.
Hyperion	ƒ Produces annual budgets and monthly, quarterly and year-end financial reports.
IT Timesheet	ƒ Captures and approves time and attendance data for Toronto Hydro Information Technology employees and contractors.
Labour/Vehicle Costing Application	ƒ Tracks labour and vehicle costing, crew overtime and other data against Work Orders.

Legacy System	Function
Maintenance Schedule Task Application	ƒ Produces paper-based inspection form unique to a specific equipment type.
Material Reference Book	ƒ Combines description of an item from the Ellipse catalogue with a corresponding photo of the item to allow staff to select the correct material for every task.
Material Requirements Planning and Forecasting	ƒ Provides Inventory Analysts with visibility into the material requirements for planned work.
New Location Request Application	ƒ Allows users to reserve a location number and create locations for assets in Ellipse.
On-Line Hold Off Request Form	ƒ Enables crews to request in advance non-switching planned work based Hold-Offs.
Picking Slip Application	ƒ Provides an interface to select materials for planned work and to generate an Issue Requisition (IREQ) in a fashion that ensures defined operational processes are followed.
Reclaim Equipment Application	ƒ Creates a new asset for reclaimed equipment that can be refurbished.
Resource Requisition (RRAP)	ƒ Used to deploy forms and workflows to support the on-boarding process for new employees.
Return Slip Application	ƒ Used to manage the return of inventory to the warehouse.
SAP	ƒ Toronto Hydro fulfills its Ontario Securities Commission, Accounting Standards Board, and Ontario Energy Board financial reporting requirements using a combination of Ellipse and SAP's Finance Module.
Scope Planning	ƒ Creates and tracks future project information for regulatory filings.
Support Point- Paniva	ƒ Delivers role-specific user documentation for the Ellipse application.

Legacy System	Function
TeamMate Audit Management	ƒ Provides a streamlined application for managing internal audits.
Timelink	ƒ Performs Time and Attendance, Workforce Scheduling, Absence Management, and Labour Planning functions.
Treasury Manager	ƒ Manages and reports cash inflows and outflows, including bill payments, payroll withdrawals, vendor payments and customer bill payments.
Unit Price Contract Management System	ƒ Manages and administers civil and electrical work assigned to external contractors.
Work Activity Log	ƒ Manages the Street Lights Trouble Call Center.
Work Request System	ƒ Schedules and coordinates primary feeder work.

APPENDIX B

On the following pages, Tables 1 through 4 enumerate the costs and benefits of Options 1 through 4 respectively.

As noted in the Evaluation of Alternatives section, Options 2 through 4 consider not having to undertake Option 1, the Technical Upgrade, as a cost avoidance benefit. The NPVs of Options 2 through 4 are therefore relative to Option 1. As it serves as the baseline for comparison, the NPV of Option 1 is axiomatically zero.

TABLE 1: EXPECTED COSTS AND BENEFITS OF OPTION 1 – TECHNICAL UPGRADE.

	Expected Spending ($M)										
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CAPEX	13.2	-	-	-	-	9.0	-	-	-	-	9.0
Hardware	1.5	-	-	-	-	1.5	-	-	-	-	1.5
Software & Implementation	11.7	-	-	-	-	7.5	-	-	-	-	7.5
OPEX	-	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
TOTAL EXPENDITURE	13.2	1.6	1.6	1.6	1.6	10.6	1.6	1.6	1.6	1.6	10.6
	Expected Benefits ($M)										
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Monetary	-	-	-	-	-	-	-	-	-	-	-
Cost Savings	-	-	-	-	-	-	-	-	-	-	-
Cost Avoidance	-	-	-	-	-	-	-	-	-	-	-
Process Improvements	-	-	-	-	-	-	-	-	-	-	-
TOTAL BENEFIT	-	-	-	-	-	-	-	-	-	-	-

TABLE 1: EXPECTED COSTS AND BENEFITS OF OPTION 2 – ELLIPSE AND LEGACY SYSTEM RENEWAL. [7]

	Expected Spending ($M)										
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CAPEX	71.6	-	-	-	-	9.5	-	-	-	-	-
Hardware	2.1	-	-	-	-	1.5	-	-	-	-	-
Software & Implementation	69.6	-	-	-	-	8.0	-	-	-	-	-
OPEX	0.2	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
TOTAL EXPENDITURE	71.8	2.6	2.6	2.6	2.6	12.1	2.6	2.6	2.6	2.6	2.6
	Expected Benefits ($M)										
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Monetary	-	17.9	4.2	4.2	4.2	13.2	4.2	4.2	4.2	4.2	13.2
Cost Savings	-	3.4	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Cost Avoidance	-	14.5	0.1	0.1	0.1	9.1	0.1	0.1	0.1	0.1	9.1
Process Improvements	-	1.4	1.8	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
TOTAL BENEFIT	-	19.3	5.9	6.2	6.2	15.2	6.2	6.2	6.2	6.2	15.2
	Net Present Value (NPV)										
10-yr: Monetary only	-31.2										
10-yr: Monetary and Process	-16.5										

[7] Option 2 entails a renewal of Ellipse and the Legacy Systems which includes the work required to perform technical upgrades those systems. The cost of doing this upgrade work is incorporated in the Expenditures lines, but to ensure that the NPV calculation reflects only the incremental work relative to the Technical Upgrade option, those costs are offset by the Cost Avoidance line. Further, as discussed in the Evaluation of Options section, it is estimated that process improvements delivered by increased IT infrastructure reliability is 55% of what is likely to be achieved by a replacement ERP system.

TABLE 2: EXPECTED COSTS AND BENEFITS OF OPTION 3 – ERP IMPLEMENTATION

	Expected Spending ($M)										
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CAPEX	54.0	-	-	-	-	5.5	-	-	-	-	-
Hardware	3.4	-	-	-	-	1.5	-	-	-	-	-
Software & Implementation	50.5	-	-	-	-	4.0	-	-	-	-	-
OPEX	0.2	2.8	2.4	2.4	2.4	2.4	2.4	2.4	2.2	2.2	2.2
TOTAL EXPENDITURE	54.1	2.8	2.4	2.4	2.4	7.9	2.4	2.4	2.2	2.2	2.2
	Expected Benefits ($M)										
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Monetary	-	17.9	4.2	4.2	4.2	13.2	4.2	4.2	4.2	4.2	13.2
Cost Savings	-	3.5	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Cost Avoidance	-	14.5	0.1	0.1	0.1	9.1	0.1	0.1	0.1	0.1	9.1
Process Improvements	-	1.9	2.4	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
TOTAL BENEFIT	-	19.8	6.6	7.0	7.0	16.1	7.0	7.0	7.0	7.0	16.0
	Net Present Value (NPV)										
10-yr: Monetary only	-15.3										
10-yr: Monetary and Process	4.9										

TABLE 3: EXPECTED COST AND BENEFITS OF OPTION 4 – EXTENDED ERP IMPLEMENTATION

	Expected Spending ($M)										
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CAPEX	65.5	-	-	-	-	6.8	-	-	-	-	-
Hardware	3.8	-	-	-	-	1.5	-	-	-	-	-
Software & Implementation	61.8	-	-	-	-	5.3	-	-	-	-	-
OPEX	0.4	3.0	2.6	2.6	2.6	2.6	2.6	2.6	2.5	2.5	2.5
TOTAL EXPENDITURE	65.9	3.0	2.6	2.6	2.6	9.4	2.6	2.6	2.5	2.5	2.5
	Expected Benefits ($M)										
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Monetary	-	17.9	4.2	4.2	4.2	13.2	4.2	4.2	4.2	4.2	13.2
Cost Savings	-	3.5	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Cost Avoidance	-	14.5	0.1	0.1	0.1	9.1	0.1	0.1	0.1	0.1	9.1
Process Improvements	-	1.9	2.4	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
TOTAL BENEFIT	-	19.8	6.6	7.0	7.0	16.1	7.0	7.0	7.0	7.0	16.0
	Net Present Value (NPV)										
10-yr: Monetary only	-25.4										
10-yr: Monetary and Process	-5.3										

Toronto Hydro ERP Submission Review

Prepared on: July 21, 2014

Prepared for: 7RURQWR +\GUR LQ FDUH RI 7RU\¶V //3

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A. EXECUTIVE SUMMARY

SUMMARY

Toronto Hydro has prepared a submission to the Ontario Energy Board for the implementation of an ERP solution to replace their legacy Ventyx Ellipse system due to significant operational, security and functional gaps in that system.

InfoTech was asked to review the submission to provide an opinion on the feasibility of the approach, the recommendation, and the options for the Ellipse replacement. InfoTech is an independent IT research and advisory firm operating globally in support of its members, and focusing on the practical and pragmatic operations of IT within complex environments. InfoTech is not associated with any software or hardware firms, and does not implement any systems, including ERP systems.

InfoTech reviewed the replacement of the Ellipse system in the context of the large utilities and determined that the approach was consistent with the rest of the utility industry. InfoTech also notes that SAP and Oracle are the dominant ERPs in that segment of the utility industry and, as such, should be the primary -considered solutions to take advantage of industry ERP supported capabilities.

InfoTech reviewed the four options presented by Toronto Hydro and recommends, in concurrence with Toronto Hydro, that Option 3, with the replacement of base or core functionality with either SAP or Oracle, is preferred. Option 1, which includes the continued use of the Ellipse system, does not address concerns with the security capability of Ellipse or the creation of needed business functionality. Option 2 has some security advantages over Option 1 but increases the complexity of the technology environment for both the implementation and the ongoing operation. Option 4, which extends the use of the ERP to include three other areas of functionality, does not include strong business value creation at this time and should be deferred until and unless a new business case is presented.

InfoTech has also reviewed the cost models for the four options and found the methodology, completeness, and quality to be reasonable.

As a result, InfoTech is in agreement with 7 R U R Q W R + \ G U R ¶ V U H F R P P H Q G D W L R Q for Option 3 of this submission: the purchase and implementation of an enterprise ERP, at a cost of $54 million over four years.

B. INTRODUCTION

APPROACH OVERVIEW

This review of the Toronto Hydro ERP submission encompassed three main areas of investigation:

1. Does the preferred approach align with the utility industry IT strategies and actions?
2. Does the preferred option meet reasonable implementation, sustainment, and business requirements?
3. Does the pricing methodology and analysis of all four options meet a reasonable and supportable level of quality?

This document aligns with the investigation approach laid out above and discusses at a high level each of the topics above. The materials used to support that investigation are noted with footnotes at each of the sections, although all topics required a level of experience and expertise to put facts into context.

C. INDUSTRY BACKGROUND

ERP SYSTEMS IN UTILITIES

Companies that generate, transmit, distribute, and sell energy are encountering two primary challenges: the need to manage and reduce costs and the management of large amounts of essential data in terms of both governance and quality. As the needs of the industry evolve, ERP has become a top priority for utility investment. Mature utilities are looking to enhance existing ERP systems to support broader business goals and support organizational excellence. In emerging or small markets, utilities are building ERP systems for the first time in order to enhance corporate services and develop competencies.

Of the systems used by utilities to achieve these goals, operational systems are playing less of a central role with further emphasis being placed on business processes outside of the WUDGLWLRQDO DVVHW GULYHQ ³FRUH´ RI WKH XWLOLWLHV LQGXVWU\ 6 analytics, maintenance budgeting, corporate governance, human capital management, and procurement have become part of the overall integrated information technology solutions. In the past, these functions and others have been owned by a number of separate systems with varying degrees of integration. Much of the drive behind the adoption or expansion of ERP is the ability to have each of these processes as part of a single system. Utilities are moving towards having a single, unified view of the organization to better identify opportunities for achieving more demanding goals in a more complex technology world.

There is a growing concern within the utility industry, and rightfully so, about the potential for cyber attacks and malicious hacking. The difference between these two is that a cyber attack is an external attack while malicious hacking is usually internal. While the first is about breaching the firewall that surrounds the systems, the second can be an attack inside the firewall, targeting systems that do not maintain adequate internal security or access segregation.

The value of resources and data maintained by electric utilities means that cyber attacks from outside parties present a significant operational risk. In 2012, cyber attacks were the sixth highest cause of incidents affecting user connections ±up 81% from 2010 [1]. Utilities were also the fifth most attacked industry in the same year. Underscoring this threat is the IDFW WKDW RI DOO GDWD EUHDFKHV LQ ZHUH GXH WR KDFNHU DF SXEOLF´ DQG ³WKHIW RU ORVV´ DFFRXQW [2]. Utilities are increasingly efforts to guard against cyber attacks in order to avoid loss of data and control over crucial systems.

[1] Jason D. Hammerschmidt, Cyber Security Threat Overview (Independent Electricity System Operator, 2013) slide 5. http://ieso-public.sharepoint.com/Documents/consult/cybersecurity/cyber20131128-IESO%20Cyber%20Security%20Forum,%20Cyber%20Threat%20Overview-Hammerschmidt.pdf

[2] Ibid., slide 11.

ERP LANDSCAPE

Toronto Hydro is currently using the Ellipse system, with significant customizations and integrated point solut ions, as their ERP. Initially classed as an Enterprise Resource Planning solution focusing on asset -centric industries, Ellipse is no longer considered a full ERP system by the IT industry and the owners of Ellipse.

Since the acquisition of parent compa ny Mincom by ABB, the renamed Ventyx Ellipse has been marketed as an Enterprise Asset Management point solution. While Ellipse has a strong utility record in its home country of Australia and has seen some success in South Africa and the U.K., it has had a limited presence in North America [3]. This means that there is a small resource pool, especially in Canada, that is qualified to implement and support Ellipse. The acquisition by ABB has resolved the financial issues faced by Ellipse, but the number of new sales to utilities has been in decline.

As the industry evolved, the capabilities of Ellipse eroded to the point where it could no longer compete in the ERP market. In the case of Mincom and other smaller players, their products were purchased and used t o reinforce the existing solution capabilities of larger companies. While some legacy solutions have remained as independent systems, many have been merged into existing ERP capabilities. This shrinking of the number of ERP market players has created more robust single solutions supporting a greater range of processes. The overall shrinking of the ERP industry has also led to a skills commoditization in the North American market, benefiting utilities with an available and lower cost, technology workforce.

The primary ERP systems in use in large utilities in North America, similar in size to Toronto Hydro, are Oracle and SAP. These two ERP systems dominate the large enterprise space beyond just utilities and have become the standard options for large enterprises looking for a new ERP. In utilities SAP has a large presence in Canada with utilities such as Hydro One, Hydro Quebec and BC Hydro and a global presence of over 20% in the utilities industry [4]. Oracle is similarly present in the US with many l arge utilities but a somewhat smaller global presence. These two systems dominate the large enterprise space in almost every industry and both systems maintain utility specific industry support, industry enhancements and industry user groups.

This type o f large scale support and investment for industry development and industry support is essential for the utility industry that is going through complex changes toward utilizing Smart Meter/Smart Grid capabilities.

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[3] Kristian Steenstrup, Magic Quadrant for Delivery Utility Enterprise Managem ent (Gartner, 18 September 2013) p. 14. http://www.ifsworld.com/en/~/media/pdf/pr/reports/gartner%20mq%20on%20eam%20for%20delivery%20utilities.ashx

[4] SAP for Utilities ± Executive Overview (SAP AG, 2013) p. 43.

FUTURE CONSIDERATION

Many electric ut ilities have , or are in the process of , implementing smart grid and smart meter infrastructure. Utilities are faced with the task of collecting and analyzing up to 3,000 times more data than ever before [5]. With this reality comes a host of data management concerns. While ERP systems are not the primary systems that support this new capability, the underlying data bases, infrastructures and capabilities need to adapt to this new environmental reality [6].

The need for integration between smart grid systems, operational systems, planning systems, and financial systems to support t hese developing requirements , continue s to put pressure on older and less able legacy systems and infrastructures. ERP system implementations are often used to eliminate a large number of older and less capable systems to improve the flexibility and adap tability of the technology platforms , as well as to formalize data governance rules and methods within the new environment [7]. These seemingly unconnected modernizations also improve the overall ability of the utility to implement these new systems .

An emerging trend in the utility technology market is that of Mobile ERP enabled by a highly capable ERP system. Especially in an organization with a highly mobile workforce such as the utility maintenance crews, Mobile ERP can lead to improvements in productivity and efficiency. This technology can further streamline business processes by providing real time access to information for those who previously did not have it [8]. These capabilities have been expensive to develop independently but utilities are now using standard ERP functionality that is shared by the entire industry. These capabilities are supported by SAP and Oracle ERP systems.

Ultimately, utilities are recognizing the need to develop cohesive and industry aligned strategies for managing their IT assets. Unlike assets used in energy distribution, it is no longer a GHTXDWH WR PDQDJH ,7 DVVHWVDZQLQWKD PE3XLXQG WLWW IDVL0RX QHHG LW mentality . Unlike other assets in the utility industry, the asset life in the IT Infrastructure world is defined by the outside environment instead of the asset itself. As the security attacks become more sophisticated, the hardware assets become obsolete, not because parts fail, but because the asset can no longer function securely . Similarly as the need for complex integration arises, the software assets become obsolete, not b ecause the software can no longer be changed, but it can no longer communicate to other software at a reasonable cost or with reasonable performance.

The impact of a single asset failing, be it hardware or software, is too significant to the organiza tion with automated systems fundamental to the operations of the utility business . The loss of any one system can impact processes from customer billing to power distribution itself. While some assets could be used indefinitely, their effective life is oft en much shorter

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[5] - H V V H % H Thev Wa ter data management pitfall utilities are overlooking ´Smart Grid News 31 May, 2011.

[6] ³(I I H F W L Y H O \ 0 D Q D J H ' D W D InfoR Tech UResearch Group (31 October 2012).

[7] ³2 S W L P L] H % X V L Q H V V 3 U R F H V V H V W R / L InfoL-Tech 5Research &XVWRP L (12 W L R Q ´ March 2014).

[8] ³0 R E L O L] H W K H : R U N I R U F H E \ InfoR-Tech Research Group ´ (4 April 2014).

as the environment that they operate in changes . Hardware and software become unsupported by their respective vendors, increasing the overall risk of operation.

The typical life spans of IT assets are shrinking as the complex utility technology world evolves from stand alone systems run by engineers and accountants with paper, to that of a fully integrated, data driven, technology managed utility. This has changed the typical lifespan of infrastructure from 10 years to 3 to 5 years, ERP systems from 20 years to 10 years, and system portfolio lifecycle reviews from 5 years to yearly. Storage is another area that has not reached any stable or predictable lifespan with storage reviews and storage operational enhancements occurring monthly as data capture and data analysis has become the new norm for utilities and businesses around the world.

C. REVIEW OF THE NEED FOR INVESTMENT

CRITICAL CONCERNS WITH THE CURRENT OPERATION

The current Ventyx Ellipse system has some critical areas of concern, based on our analysis of the ERP submission supporting documents, that require immediate action to sustain a reasonable risk profile for the Toronto Hydro operation. These areas are:

- The lack of vendor support for the current Ellipse system and the Oracle database with security patches not being provided, opening the systems up to both penetration hacking and malicious hacking
- The operation of the current Ellipse system on uncertified hardware which could cause significant operational downtime or prevent a timely restart in the event of a system failure or shutdown
- The inability of the current Ellipse system to connect with LDAP (Lightweight Directory Access Protocols) for access control which increases the potential failure points in granting, but more importantly, denying access for departing employees or contractors
- The inability of the current Ellipse implementation to practically segregate access to operational data and functions, increasing the risk severity of malicious hacking or inappropriate access to data.

Toronto Hydro represents these as major issues that drive the need for investment and we agree. In particular, the negative implication to the security profile of Toronto Hydro is substantial and is not considered prudent practice in any industry.

The lack of security patching in these systems means that the Toronto Hydro technology environment is highly dependent on the reliability of the external firewall and supporting manual processes to keep external attackers out of the systems. Once inside the firewall, the vulnerabilities of the Ellipse system can be exploited, and because there is no segregation of data and functionality access, the ability of a hacker to cause maximum damage is enhanced. The ability of sophisticated hackers to breach firewalls is well documented with an average of over 20 major data breaches occurring per month over the last year.

In addition, the combination of the use of manual processes to manage the system access on-boarding and off-boarding of employees, with a lack of segregation of access to data and functionality within Ellipse, means that malicious hacking by current or future employees or contractors, with the intent to damage Toronto Hydro, is a significant risk. Lack of segregation of data access also means that malicious hackers could release private or confidential data to unauthorized parties or gain a competitive advantage in contract or procurement negotiations with the use of insider knowledge.

While productivity improvements are an important element of any IT operating strategy, and 7RURQWR +\GUR LV DOVR IDFLQJ LQFUHDVHG RSHUDWLRQV FRPSOH[LW\ QRWKLQJ´ LQ WKH IDFH RI VXFK PDMRU VHFXULW\ ULVNV VXFK DV WKHVH LV QRW DQ DSSURSULDWH UHDVRQ IRU LQYHVWPHQW. InfoTech agrees that at minimum the systems need to be updated and brought to industry standards of regular patching, LDAP compatibility and segregation of data access.

C. REVIEW OF THE FOUR OPTIONS

RISK DISCUSSION

InfoTech uses a COBIT 5 framework as the basis for all of its research and for the creation of operational methodologies for its 34,000 client members. The COBIT 5 framework is an IT industry supported open standard that is used globally to enable users to establish complete, risk governance processes for the effective management of Information Technology in the Enterprise.

As a result, the discussions below are framed within a risk context. While InfoTech maintains extensive risk tools to assess the detailed plans for implementation and sustainment, the business risks noted below represent the assessment of options within the industry context. In the interest of clarity, the summaries of the risk assessments are presented below in the options review. The definitions used of the risk levels are in the table below:

Definition			
Risk Element	Low	Medium	High
Implementation	x Minimal development x Stabilization of existing application footprint	x Configured Commercial Off The Shelf (COTS) applications or ERP x Integration through adaptors or Service Oriented Architecture (SOA) and Enterprise Service Bus (ESB)	x Extensive custom development x Complex point-to-point integration
Sustainment	x Large ERP footprint x Minimal integration points x Stable, well-supported solutions	x Multiple point solutions x Multiple integration points x Stable solutions	x Multiple point solutions x Complex integration x New / non-stable solutions requiring specialized and rare skill sets
Business	x Meets all identified future business needs	x Meets some future business needs	x Does not meet future business needs

OPTION 1

Option 1 is th e upgrade of the Ventyx Ellipse, its Oracle Database and the associated legacy systems.

This option is expensive , without any functionality enhancements , and does not address two of the critical areas of concern that were noted in the earlier sections. This option will not address the lack of integration to an LDAP system and will not improve the lack of segregation of functionality or data access. While this option mitigates the risk of external hacking it does not address any of the concerns of potential malicious hacking.

In addition, from a strategic point of view, Ellipse remains a system with little to no future in the utilities industry in North A merica, without sufficient functionality to market their Ellipse system as an ERP. Investing significantly more money into this system without a near term exit strategy being prepared is not prudent. The momentum in the large utility industry is toward S AP and Oracle, and this will likely push this system, like so many others before it, into extinction.

The technical risk of the implementation of Option 1 is relatively low. The upgrade path with few enhancements will be a standard process supported by the Ventyx Ellipse software company. These standard upgrades are usually well tested and, although slow to implement and requir ing extensive testing, will generally be completed on time and on budget. There is a lack of implementation resources with Ellipse experience so this may increase the risk of the price of the resources and require scarce experienced resources to be obtained globally (Australia) instead of locally as is common practice. This h as been adequately reflected in the pricing model.

The technical risk of the sustaining operation of Option 1 would be considered medium. The collection of systems used to operate the back office of Toronto Hydro will remain a patchwork of point solution s with Ellipse in the middle. The number of integration points will remain the same and the sophistication of the integration will remain low (point to point integrations always act as individual programs that need ongoing monitoring, testing and upgradin g).

The business risk of Option 1 would be considere d high. This approach will not deliver the identified functionality needed for Toronto Hydro and there is no path forward that provides the functionality without significant cost or significant time. In addition, the Ellipse system remains in the portfolio, managing the operations of Toronto Hydro, without a plan to replace as it approaches functional obsolescence.

InfoTech does not recommended this option as a viable solution for Toronto Hydro and does not view this option as prudent investment considering that critical security concerns will still remain within the IT portfolio.

OPTION 2

Option 2 is t he upgrade of the Ventyx Ellipse, its Oracle Database and associated legacy systems plus the custom development of additional external functionality.

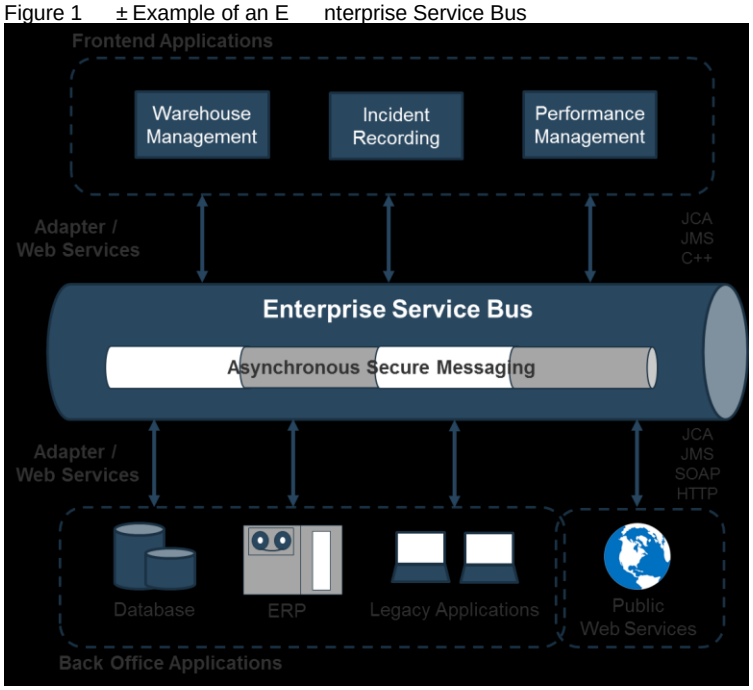
This option will take the application environment and extend the back office system landscape with additional point systems to achieve the enhanced functionality that Toronto Hydro is look ing to build. While my comments on the future desirability of the Ellipse system still stand, there are additional concerns with this approach.

The IT industry, as a whole, is moving away from custom developed software for many good reasons. The costs t o build, maintain and operate these systems have been extensive and often underestimated. The legacy portfolio of systems and their multiple point to point integrations have become barriers to build ing new functi onality or extending functionality in busin esses. As a result, many IT groups have become expensive barriers to progress instead of enablers of progress .

One of the key considerations in building business capabilities is the need to test all of the systems and integrations within the interconne cted system portfolio. This is the point where costs of implementations become prohibitive and sometimes IT groups take risks to push systems into production instead of incur or recognize these costs. Unforeseen issues arise during these types of operations that create either failure to achieve on -time and on -budget results or downtime due to quality issues that were moved into production before technical readiness.

There is a potential technical solution to help mak e these legacy systems more manageable and more adaptable. , 7 D U F K L W H F W V K D Y H E H H Q X V L Q J D V W D Q G D U G V \ V W H P Enterprise Service Bus or ESB (see Figure 1) . This additional off -the -shelf system creates a standardized means of connecting a nd monitoring all of the integrations needed between the legacy portfolio of systems. During any changes, builds or upgrades, the testing only includes the new functionality itself and the connection to the Enterprise Service Bus. This simplifies and red uces the risks of both implementation and testing of a large portfolio of legacy systems. This has not been included in the proposal for Option 2.

Figure 1 ± Example of an E nterprise Service Bus



The technical risk of the implementation of Option 2 is high. While the necessary upgrade is of low complexity, the build out and integration of point solutions to integrate with Ellipse is complex, uncertain and involves the creation of many additional systems. This would all be custom development undertaken by Toronto Hydro at a time when the industry is moving solidly away from that approach. The proposed Option 2 does not include an ESB within the architecture and seems to be treated as equivalent in implementation risk to the other options.

The techni cal risk of the sustaining operation of Option 2 is high. The collection of systems used to operate the back office of Toronto Hydro will increase the patchwork of point solutions with Ellipse in the middle. The number of integration points will increase greatly and the sophistication of the integration will remain low (point to point integrations always act as individual programs that need ongoing monitoring, testing and upgrading).

The business risk of Option 2 is als o high. While Toronto Hydro will achieve the functionality it needs today, it will be building a large barrier to progress for future enhancements and business functionality as it adapts to Smart Grids and other industry changes. The cost of future enhan cements will continue to escalate based on the investments made toward this type of IT system architecture.

As a result of this risk profile, we recommend the addition of between $10 million and $15 million in project costs to either manage the risk of the implementation through extension of testing resources, timing and ongoing support, or through the addition of an ESB purchase and implementation into the system architecture for this solution. InfoTech would highly recommend the addition of an Enterp rise Service Bus if this option is selected.

InfoTech does not recommend Option 2 for Toronto Hydro. The creation of an increasing portfolio of disconnected systems runs counter to the architectural recommendations in the

IT industry and even though the expense is very high, the resultant system will likely require replacement well ahead of a more conventional ERP approach.

OPTION 3

Option 3 is the elimination of Ellipse, elimination of the current legacy portfolio and the replacement with an integrated ERP.

This reduction of the number of systems and the number of integrations is standard good practice within the IT industry as it reduces operating costs and complexities, and increases the ability and flexibility of the organization to respond to changes if the replacement systems are chosen with care and diligence. It is also common practice that all IT investments are challenged to not only deliver functionality but to reduce the IT system portfolio size, complexity, manag eability and average age.

The implementation of a leading ERP system will be supported with extensive experienced industry implementation teams and well tested suppo rting processes. In addition, if an ERP system is chosen that has a significant footprint in the utility industry in North America (usually SAP or Oracle) then future functional improvements are shared across the industry and the burden would not solely f all on the need for custom development at Toronto Hydro.

The technical risk of the implementation of Option 3 is medium. The implementation of an ERP system is complex and requires both experienced and disciplined teams. The governance structure should be in place from the inception of the project and that needs to continue unabated throughout the life of the system. The practices in the industry have varied throughout ERP implementations and the results have not always been successful. A conservative and thoughtful approach without arbitrary timelines has provided the most success in implementation. These costs have been reasonably represented in the pricing model for Option 3.

The technical risk of the sustaining operation of Option 3 is low. The reduction of the integration points, the support of a leading ERP provider and the availability of standard support processes and systems are all positive enhancements for Toronto Hydro compared to the current state or Options 1 or 2 . The use of a main s tream ERP also increases the options for Toronto Hydro with infrastructure, employees, contractors and consultants allowing future cost containment.

The business risk of Option 3 is also low. Toronto Hydro will achieve the functionality it needs today an d will benefit from the utility base of the chosen system to achieve future functionality as part of standard upgrades. In addition the system portfolio landscape will be simplified and costs of future enhancements will be delivered with lower risk and, p otentially, lower cost.

Option 3 represents the best use of funds for investment with a managed transition to a more robust IT portfolio, enhanced functionality and a strong alignment to the utility industry IT leading practices.

OPTION 4

Option 4 includes the replacement of the current legacy portfolio with SAP as well as extending the implementation to cover other areas of Warehouse, Safety and Performance Management.

This option would extend the functionality of the SAP system to eliminate three additional legacy systems that would have major operational affects across the employee user base in Toronto Hydro.

This option increases the risk of implementation by touching many more users than the Option 3 functionality which remains essentially a back office capability. In addition to expected professional users in Option 3, this option will have a wide spread impact on front line workers. As a result the need for enhanced training and organizational change management is important for Option 4.

Since these targeted-for-replacement systems are also relatively new to the Toronto Hydro system portfolio and appear to be working at this time, the value of including them at this time with the increased churn that will occur during this major project appears low.

The technical risk of the implementation of Option 4 is high. The inclusion of significant numbers of front line workers to the training and organizational process change will increase the likelihood of increased costs without being able to establish a clear message to the workforce for the need of a change, when these current systems are functioning reasonably well.

The technical risk of the sustaining operation of Option 4 remains low. The reduction of the integration points, the support of a leading ERP provider and the availability of standard support processes and systems are all positive enhancements for Toronto Hydro compared to the current state or the Option 1 or Option 2. The use of a main stream ERP also increases the options for Toronto Hydro with infrastructure, employees, contractors and consultants allowing future cost containment.

The business risk of Option 4 remains low. Toronto Hydro will achieve the functionality it needs today and will benefit from the utility base of the chosen system to achieve future functionality as part of standard upgrades. In addition the system portfolio landscape will be simplified and costs of future enhancements will be delivered with lower risk and, potentially, lower cost.

As a result of the risks of implementation, InfoTech recommends an increase of training and organization change management costs to the cost of the Option 4. It would be prudent to expect that a dedicated change management team would be added to the project team to deal with the implementations in the warehouse, safety, and operational management functionality. InfoTech expects that this would require an additional $1 million to $2 million in costs.

InfoTech does not recommend Option 4, as the increase in investment does not appear to support business value creation and appears to minimally reduce the cost of IT sustainment. The increased value in the replacement of those three other systems can be reviewed at a

future time when the IT portfolio is being reviewed for either functionality improvements or cost reduction requirements.

RISK SUMMARY

RISK ELEMENTS			
Option	Implementation	Sustainment	Business
1	Low	Medium	High
2	High	High	High
3	Medium	Low	Low
4	High	Low	Low

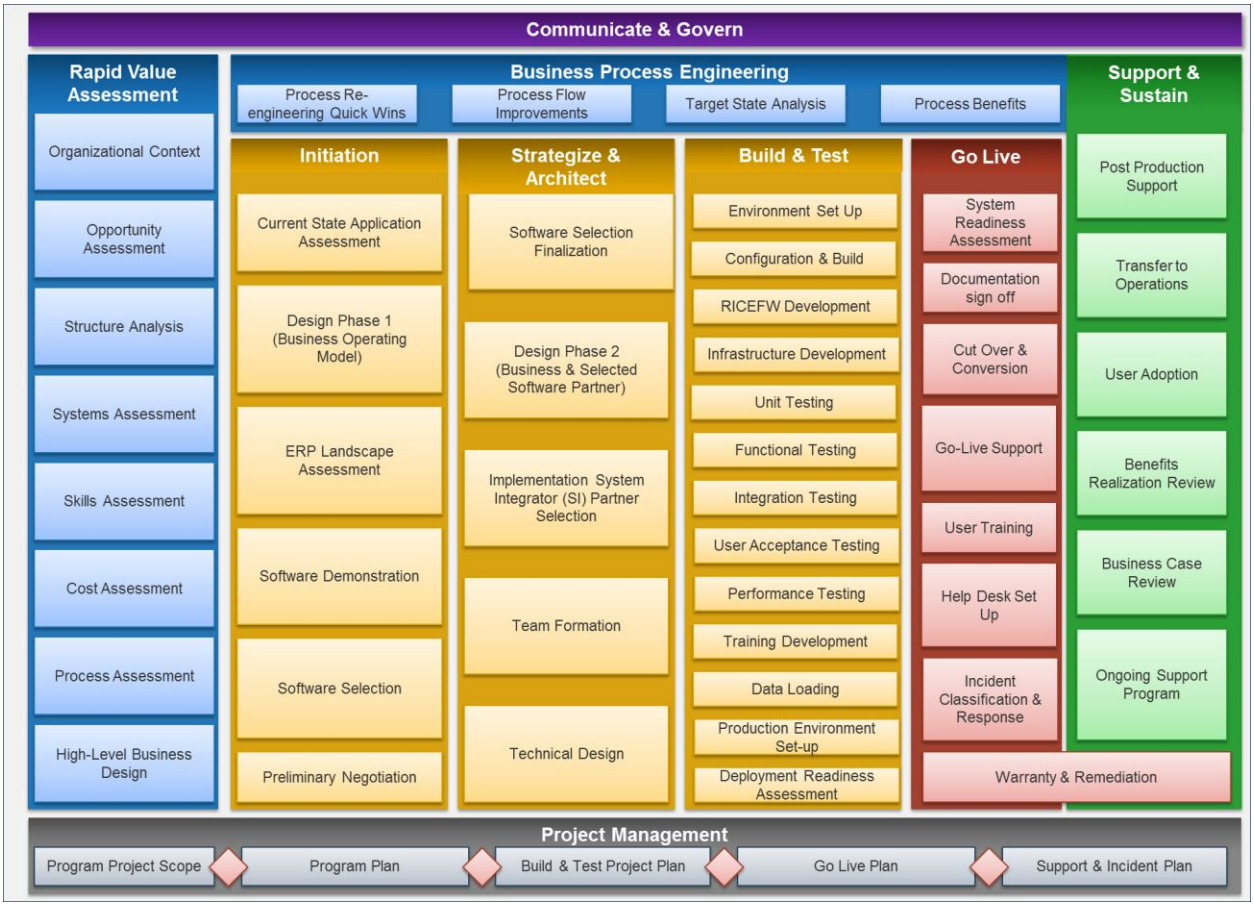
Definition			
Risk Element	Low	Medium	High
Implementation	x Minimal development x Stabilization of existing application footprint	x Configured Commercial Off The Shelf (COTS) applications or ERP x Integration through adaptors or Service Oriented Architecture (SOA) and Enterprise Service Bus (ESB)	x Extensive custom development x Complex point-to-point integration
Sustainment	x Large ERP footprint x Minimal integration points x Stable, well-supported solutions	x Multiple point solutions x Multiple integration points x Stable solutions	x Multiple point solutions x Complex integration x New / non-stable solutions requiring specialized and rare skill sets
Business	x Meets all identified future business needs	x Meets some future business needs	x Does not meet future business needs

C. PRICING REVIEW

PRICING METHODOLOGY

The pricing templates provided were reviewed for completeness against the standard ERP implementation framework that InfoTech uses to support and advise its members. The items included in the pricing model used by Toronto Hydro are complete and sufficient to provide an adequate and responsible project budget for all options.

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LICENSING COSTS

The licensing costs for the ERP systems were compared to published materials from the key ERP providers in the utility industry (SAP and Oracle) . These costs were compared on average to those included in the proposal and InfoTech views the submission costs as adequate and responsible for the purposes of the ERP submission .

There are many factors that will go into the completion of the contracted licensing costs including the potential that these costs can be reduced with professional negotiation. These costs may provide a small upside depending on the commercial environment at the time of negotiations.

SERVICES COSTS

The costs to implement the projects through the use of service providers was reviewed by three competent and experienced ERP strategic, planning and implementation advisors, includi ng the author of this review. All the advisors have experience in utilities and ERP within the Toronto and North American market.

The costs of the services appear to be reasonable and prudent. The costs of the services for Option 3 and 4 are more predictable as they will draw on a large and well established pool of talent for a major ERP in a major market.

In all four cases the size of the projects and the variability of resources required will require prudent and comprehensive project management which has been included in the pricing of all four Options.

D. CONCLUSION

InfoTech can support the following conclusions:

1. The selection of a major ERP (either Oracle or SAP) will support the functional needs for Toronto Hydro as stated in the submission and will resolve the major security concerns that are inherent in the current state systems.

2. Neither the upgrade of the Ellipse and legacy systems (Option 1) nor the replacement and enhancement of the Ellipse and legacy systems (Option 2) are recommended for reasons that include security profile, cost, lack of functionality , and increased complexity of system sustainment.

3. The pricing model for Option 2 should include an additional $10 million to $15 m illion in costs to either include an Enterprise Service Bus or additional costs in testing and sustainment because of the comp lexity of the integration environment being created.

4. The pricing model for Option 4 should include an additional $1 million to $2 m illion in support for training and change management for the front line workforce who will be experiencing significant proce ss changes on three additional systems.

5. Other than those additions, the pricing methodology is complete and reasonable based on the information presented on the scope and complexity of the projects.

6. InfoTech concurs with Toronto Hydro that Option 3 repre sents the best use of investment funds that meets the necessary security requirements and aligns best to the needs of the large utility industry.

E8.7 Voice Radio System Upgrade Program

E8.7.1 Summary

Program Description

The objective of this program is to upgrade Toronto Hydro's existing voice radio system. Toronto Hydro needs to upgrade the existing system in a timely manner because the key infrastructure components will not be supported or maintainable beyond 2016.

The two way radio is used to:

- establish and ensure protection of exposed workers,
- establish hold-offs; in addition to protecting the plant from possible damage, establishing a hold-off informs the control authority of the presence of workers in a specific location which is critical should an emergency occur,
- ensure orders to operate (OTO) are followed correctly and both the control authority and workers are in continual contact during the execution of an OTO, and
- summon help in an emergency through the mayday protocol.

The following table summarizes the anticipated benefits associated with this program.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ This technology enables Toronto Hydro to safely and effectively respond to trouble calls, resulting in shorter restoration times in the event of an outage. ƒ The new system is expected to have lower maintenance costs than the current aging system.
Reliability	ƒ Facilitates faster restoration times, thus increasing system reliability. ƒ Protects the integrity of the distribution system by keeping the Control Centre up to date on conditions that pose a reliability threat ƒ Radio communication is required for field work operations, which support overall system reliability. ƒ Cell phone service is often unavailable during an emergency due to overloads on telecommunications networks, while radio communications remain operational.
Efficiency	ƒ This technology enables Toronto Hydro to better coordinate responses to trouble calls. ƒ Upgrading the radio system will increase efficiency by reducing the time it takes for field crews to receive instructions from the Control Centre and begin work – work that must be stopped if the radio system is down. ƒ The new equipment will facilitate multiple calls from the field at one time, unlike the existing Control Centre radio equipment. ƒ Enables communication between workers in below grade situations, which enables the efficient completion of field work.
Safety	ƒ Reliable communications with the Control Centre will help create safer working conditions for Toronto Hydro employees by keeping crews updated about changing conditions in an emergency situation. ƒ Real-time information communicated through the radio system about the energization status of equipment helps reduce the risk of injury to field workers. ƒ Enables communication in below grade situations, which is essential to worker safety. ƒ The radio system is relied upon to contact emergency response crews in the event of an incident.
Other Benefits	ƒ The new system has readily available technical support. The specialized labour required to the maintain old system is in short supply, which causes delays to field work when the radio system requires maintenance but support is unavailable. ƒ The availability of spare parts for the old system is diminishing, which will result in longer and more frequent radio outages. Spare parts are readily available for the new system.

Program Drivers

As the voice radio system serves a number of critical safety-related functions, Toronto Hydro requires all field operations to be stopped when the system is down, and requires that field work

only resume after the system has been completely restored. This an important precaution in mitigating a multitude of potential safety risks associated with field work, including:

- inadvertently operating equipment that is energized,
- not being readily informed of changing conditions on the system that could pose a threat,
- not being able to contact the Control Centre or emergency services for help when needed, and
- other precarious circumstances that may arise while working on the overhead or underground distribution plant.

The trigger and secondary drivers for this program are outlined in Table B below.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Safety	Maintain the high reliability and availability of critical voice communications to Toronto Hydro field crews to protect them from injury or harm, and to provide them priority access to emergency services
Secondary Drivers	**Reasoning**
Capital and Maintenance Program Support	The voice radio system is essential to Toronto Hydro's core distribution operations as it enables the utility to safely and effectively deliver its planned capital and maintenance programs in the ordinary course and to respond to trouble calls in a safe, timely and efficient manner
Obsolescence	The radio system infrastructure cannot be supported or maintained beyond mid-2016

Preferred Alternative

Toronto Hydro considered the following options to address the risks associated with the aging voice radio system infrastructure:

(1) maintain the existing system beyond 2016 on a "best effort" basis;

(2) migrate to a contracted radio service;

(3) replace the existing analog system with new digital radio system TETRA ; or

(4) upgrade the existing analog system to new digital radio system P25 .

Toronto Hydro evaluated the alternatives and determined that option 4 - "Upgrade the existing analog system to digital radio system P25" is preferred because Toronto Hydro expects it to be the most cost-effective solution for addressing the risks of the current system and is designed to optimize the continuity of Toronto Hydro's core operations by:

- allowing Toronto Hydro to leverage the existing radio infrastructure and re-use some of its components, and, thereby, it helps minimize program execution costs and timelines, and
- enabling Toronto Hydro to execute upgrades in phases, which is expected to minimize the interruption of Toronto Hydro's operations.

Timing and Pacing

Due to the majority of the voice radio system infrastructure components aging by 2016, Toronto Hydro must upgrade the system. The implementation cannot be delayed as it creates potential safety risks to Toronto Hydro crews. The historical and estimated costs of the Voice Radio System program are provided in Table C below.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Forecasted Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Annual Spend ($M)	0.02	0.1	0.1	0.25	0.12	6.68	13.73	0.0	0.0	0.0

E8.7.2 Program Description

The objective of this program is to upgrade Toronto Hydro's existing voice radio system. Toronto Hydro needs to upgrade the existing system in a timely manner because the key infrastructure components will not be supported or maintainable beyond 2016. Toronto Hydro estimates that this program will cost approximately $20.41 million and that the work will be completed in 2015 and 2016.

The two way radio is used to:

- establish and ensure protection of exposed workers,
- establish hold-offs; in addition to protecting the plant from possible damage, establishing a hold-off informs the control authority of the presence of workers in a specific location which is critical should an emergency occur,
- ensure orders to operate (OTO) are followed correctly and both the control authority and workers are in continual contact during the execution of an OTO, and
- summon help in an emergency through the mayday protocol.

Toronto Hydro has set following requirements to the voice radio system to enable its employees to successfully and safely perform their job functions:

TABLE 1: VOICE RADIO REQUIREMENTS

Business Requirement/ System Feature	Toronto Hydro Employees who Require the Feature	Why it is important for Toronto Hydro's operations	Current State Challenges	Mitigation due to the Voice Radio System Upgrade
1. Provides a reliable city wide wireless voice communication that field crews can access readily.	All Toronto Hydro crews and contractors working in the field: x Emergency response overhead and underground crews, x Construction and maintenance	Whenever Toronto Hydro's field crews enter or access distribution system plants, they need to notify the Control Centre. The voice radio system is a dedicated system that allows this type of	The presence of "dead zones" in some parts of Toronto where the radio signal is weak or absent.	Yes: The program provisions for additional radio sites to address the weak radio signal issues and improve the city wide coverage.

Business Requirement/ System Feature	Toronto Hydro Employees who Require the Feature	Why it is important for Toronto Hydro's operations	Current State Challenges	Mitigation due to the Voice Radio System Upgrade
	overhead and underground crews, and x Stations crews	communication.		
2. Supports emergency communication and signaling procedures, which are required to satisfy 'mayday' contingency protocols.	All Toronto Hydro crews and contractors working in the field: x Emergency response overhead and underground crews, x Construction and maintenance overhead and underground crews, and x Stations crews	› This feature enables the quickest priority access to the Control Centre with the press of an Emergency Button x No other known technology, except for the voice radio system, is capable of providing this benefit.	No challenges	Yes: This feature is available in the upgraded system.
3. Enables below grade communications in confined spaces such as ground vaults, cable chambers and other underground structures.	Toronto Hydro underground crews and contractors working in the field: x Emergency response underground crews, and x Construction and maintenance underground crews	This is one of the most essential features, as the underground distribution system assets covers approximately 57% of the total distribution system within the City of Toronto and any work on these assets require the use of below ground radio communication.	During the implementation of the voice radio system in 2001, Toronto Hydro selected the best available technology at that time and enabled below grade communication through installation of vehicular repeaters on utility trucks. As a result, the operating procedure required to enable the below grade radio communication is	Yes: x The upgraded system is expected to provide seamless below grade voice radio communication, which will simplify its use by field employees.

Business Requirement/ System Feature	Toronto Hydro Employees who Require the Feature	Why it is important for Toronto Hydro's operations	Current State Challenges	Mitigation due to the Voice Radio System Upgrade
			manual and tedious.	
4. Provides sufficient call r management tools that enable Toronto Hydro personnel to effectively manage voice radio communications with Toronto Hydro field operatives and external contractors.	Power System Controllers and Dispatch Operators.	This feature allows the Control Centre Operators to respond to the radio call of the field crews to issue instructions, hold o-offs and emergency calls.	Radio calls to the Control Centre are often queued. This occurs because up to six Power System Controllers service the same area, yet only one call can be active at any time as a result of the fact that all users of the area share a single radio talk group. This situation leads to a call processing time of 30 -60 minutes.	Yes: Existing desktop radios in the Control Centre are expected to be replaced with proper dispatch consoles, which, unlike the desk top radios, offer features such as call management tools and user r friendly interfaces.

The existing system was installed in 2001 and will not be maintained and supported by the vendor beyond 2016. Due to its age and the lack of vendor support, Toronto Hydro expects that the existing system will not be able to satisfactorily support its operations beyond 2016. To address this issue, Toronto Hydro plans to upgrade the voice radio system infrastructure over the course of the next two years. The chart below summarizes the work that Toronto Hydro proposes to complete as part of this program, and the estimated costs of completing the work.

TABLE 2: 2015 -2019 COST SUMMARY

		Estimated Costs for 2015-2019, $M					
Infrastructure Type	Asset Type	2015	2016	2017	2018	2019	Total
Data Network and Facilities At high site locations (Non-Toronto Hydro premises)	• Facilities Assets (UPS, Generator, A/C) • High-speed IP Network (Fiber Optic)	3.6					3.60
Backend Infrastructure and Labour	• Core Equipment • Antenna Site Base Stations • Gateway Devices		8.64				8.64
Below-Grade Infrastructure and Labour (old city of Toronto only)	• Antennae/ Base Stations for additional sites		2.03				2.03
Front-end Infrastructure and Labour	• Dispatch Consoles • Radios	3.08	3.05				6.13
TOTAL		6.68	13.73				20.41

The following table summarizes the anticipated benefits of the Voice Radio System Upgrade Program.

TABLE 3: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ This technology enables Toronto Hydro to safely and effectively respond to trouble calls, resulting in shorter restoration times in the event of an outage. ƒ The new system will have lower maintenance costs than the current aging system.
Reliability	ƒ Facilitates faster restoration times, thus increasing system reliability. ƒ Protects the integrity of the distribution system by keeping the Control Centre up to date on conditions that pose a reliability threat ƒ Radio communication is required for field work operations, which support overall system reliability. ƒ Cell phone service is often unavailable during an emergency due to overloads on telecommunications networks, while radio communications remain operational.
Efficiency	ƒ This technology enables Toronto Hydro to better coordinate responses to trouble calls. ƒ Upgrading the radio system will increase efficiency by reducing the time it takes for field crews to receive instructions from the Control Centre and begin work – work that must be stopped if the radio system is down. ƒ The new equipment will facilitate multiple calls from the field at one time, unlike the existing Control Centre radio equipment. ƒ Enables communication between workers in below grade situations, which enables the efficient completion of field work.
Safety	ƒ Reliable communications with the Control Centre will help create safer working conditions for Toronto Hydro employees by keeping crews updated about changing conditions in an emergency situation. ƒ Real-time information communicated through the radio system about the energization status of equipment helps reduce the risk of injury to field workers. ƒ Enables communication in below grade situations, which is essential to worker safety. ƒ The radio system is relied upon to contact emergency response crews in the event of an incident.

Other Benefits	ƒ The new system has readily available technical support. The specialized labour required to the maintain old system is in short supply, which causes delays to field work when the radio system requires maintenance but support is unavailable. ƒ The availability of spare parts for the old system is diminishing, which will result in longer and more frequent radio outages. Spare parts are readily available for the new system.

E8.7.3 Why the Program is Needed

The voice radio system is essential element in Toronto Hydro's ability to execute its core distribution operations because it helps facilitate the safety of employees, contractors, third party workers entering Toronto Hydro's plant, and protects the integrity of the distribution system. Field crews rely on the voice radio system to communicate with the Control Centre prior to initiating and completing work, to receive instructions and clarifications from their supervisors, and to contact emergency response services in the event of an incident. Since the voice radio system serves these critical functions, Toronto Hydro requires all field operations to be stopped when the system is down, and requires that field work may only resume after the system has been completely restored. This an important precaution in mitigating a multitude of potential safety risks associated with field work, including:

- ƒ inadvertently operating equipment that is energized,
- ƒ not being readily informed of changing conditions on the system that could pose a threat,
- ƒ not being able to contact the Control Centre or emergency services for help when needed, and
- ƒ other precarious circumstances that may arise while working on the overhead or underground distribution plant.

As previously mentioned, Toronto Hydro plans to upgrade the existing system as soon as possible because the vendor will not support the system beyond 2016. Spare parts are no longer being manufactured for this system, and the inventory of available parts is rapidly depleting. If the key components of the voice radio system cannot be maintained, the risk of system failure increases significantly. Given the critical function of this technology in Toronto Hydro's core distribution activities, such a failure could result in a prolonged interruption of the utility's

operations and potentially create safety concerns for field crews who rely on this infrastructure. To mitigate this risk, Toronto Hydro proposes to promptly undertake the work under this program.

The diagrams below illustrate that over the past few years, the performance of the aging voice radio system is steadily degrading and associated maintenance costs have increased significantly. Costs have increased because the vendor's technical specialists are no longer trained to provide technical support on this technology. As a result, specialized labour needs to be procured to support this system. Such labour comes at a higher cost, and more importantly, cannot be guaranteed by the vendor. As such, Toronto Hydro bears the increasing risk of not being able to obtain the desired support when needed.

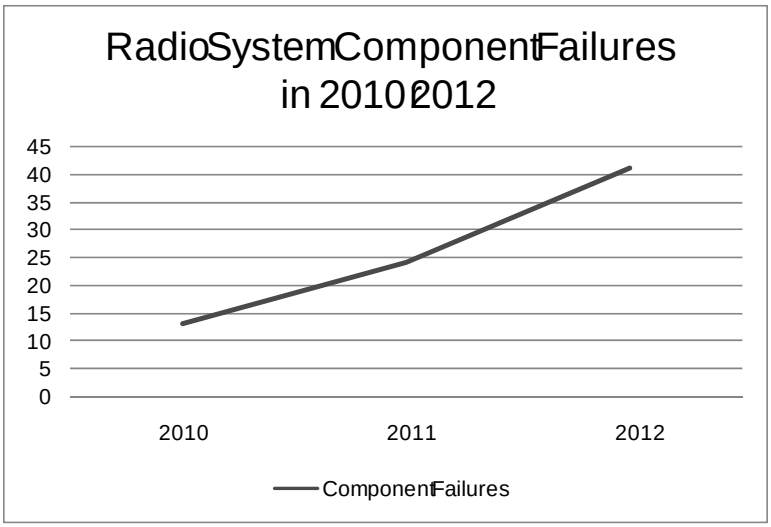


FIGURE 1: VOICE RADIO SYSTEM COMPONENT FAILURES IN 2010-2012

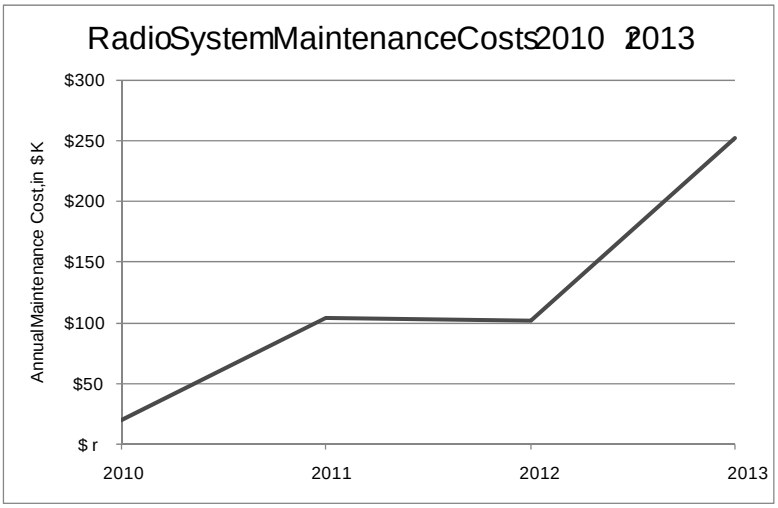


FIGURE 2: VOICE RADIO SYSTEM MAINTENANCE COSTS IN 2010-2012

In addition to the deteriorating system's performance and increasing maintenance costs, there are a number of technical issues related to the aging voice radio system that can be resolved through this program:

(1) Due to the growing number of high-rises under construction in the city, there are several radio frequency dead zones with poor or no radio signal;

(2) The underground radio coverage is unreliable because it connects two radio systems that are not designed to work together through vehicular repeaters. The more elements any system contains, the higher the probability of system failure;

(3) 81% of the radio units are past their end of useful life and should be replaced;

(4) The Control Centre operators do not possess the technical ability to inform field crews where they are in the call queue in the current system;

(5) All conversations between the field crews and the Control Centre are taped. However, the existing technology does not enable Toronto Hydro to tag or identify recordings in any way that allows for categorizations of conversations or for it to be able to find a particular conversation sometime in the future. Where an accident occurs, it is very difficult and laborious to locate the conversations related to the event in questions, information that is necessary for safety investigations and labour disputes;

(6) The Control Centre radio equipment lacks proper call management functionality and capacity to take more than one call at a time.

Due to the recent developments and innovations in the radio industry and based on the preliminary research of the standard capabilities of the upgraded radio system offered by the vendors in Canada, Toronto Hydro plans to resolve all of the above-mentioned issues with the proposed upgrade solution.

Toronto Hydro expects that the upgraded voice radio system will enable the Control Centre to manage voice radio communications with Toronto Hydro field crews and external contractors more efficiently. A particular challenge with the existing system is that calls are often queued. This occurs because up to six Power System Controllers service the same area, yet only one call can be active at any time because all users of the area share a single radio talk group. This configuration leads to a call processing time of 30-60 minutes. The system that Toronto Hydro plans to install addresses this problem by upgrading the existing desk top radios in the Control Centre with proper dispatch consoles, which, unlike the desk top radios, offer features such call management tools and user-friendly interfaces that provide the controller and dispatchers increased flexibility and functionality.

E8.7.3.1 Purpose

The purpose of the program is to ensure that Toronto Hydro has access to reliable voice radio communications, to better protect the safety of Toronto Hydro's field workers and to ensure the continuity of the Toronto Hydro's core operations.

The chart below outlines the trigger and secondary drivers of the program:

TABLE 4: DRIVERS

Drivers		Reasoning
Trigger	Safety	Maintain the high reliability and availability of critical voice communications for Toronto Hydro field crews in order to protect them from potential injury or harm, and to provide them priority access to emergency services.
Secondary	Capital and Maintenance Program Support	The voice radio system is essential to Toronto Hydro's core distribution operations as it enables the utility to safely and effectively deliver its planned capital and maintenance programs in the ordinary course and to respond to trouble calls in a safe, timely and efficient manner.

Drivers		Reasoning
	Obsolescence	The radio system infrastructure cannot be supported or maintained beyond mid-2016.

E8.7.3.2 Asset Details

TABLE 5: ASSETS TO BE REPLACED BY ASSET CLASS

Asset Class	Infrastructure Type	Asset Type	Costs for 2015-2019, $M					
			2015	2016	2017	2018	2019	Total
Radio Hardware: SAP Activity Code 1760; SAP Asset Class Code 3360	Data Network and Facilities	• Facilities Assets (UPS, Generator, A/C) • High-speed IP Network (Fiber Optic)	3.60	-	-	-	-	3.60
	Backend Infrastructure and Labour	• Core Equipment • Antenna Site Base Stations • Gateway Devices	-	8.64		-		8.64
	Below-Grade Infrastructure and Labour (old city of Toronto only)	• Antennae/ Base Stations for additional sites	-	2.03		-		2.03
	Front-end Infrastructure and Labour (Dispatch Consoles only)	• Dispatch Consoles • Radios	3.08	3.05		-		6.13
	TOTAL		6.68	13.73		-	-	20.41

(i) Asset Lifecycle

The two major technical components of the system are the infrastructure equipment and subscriber gear (radio units). The vendor has indicated that these components will not be

supported and maintained beyond 2016. The radio system component lifecycle is presented in the table below:

TABLE 6: LIFE CYCLE

Product	Year of Deployment by TH	Product Lifecycle in Years	Support Details
2-way Fixed Network Equipment (Infrastructure)	2001	15 Years	End of support in 2016
Mobile/ Portable 2-way Radios	Various years	10 Years	81% of radios are out of support

(ii) Asset Failure Impacts

Voice radio communications are critical for Toronto Hydro because a failure of the system can potentially result in the failure of business operations and increased safety risks for Toronto Hydro employees.

If the voice radio system fails, emergency response crews have to use cellular phones as a back-up option. This is a very unreliable means of communications, especially during large power outages, for several reasons:

- The cellular phone system can be overloaded with customer calls and can become inaccessible, particularly during major events such as storms and floods;
- The cellular phone system can be inaccessible if is affected by a power outage;
- In case of an emergency call made from a cell phone, there is no way for a Power System Controller in the Control Centre to identify the urgency and criticality of the call, which potentially creates additional safety concerns for Toronto Hydro field employees.

The two way radio system has proven to be the only reliable means of communicating between the field crews and the Control Centre. Without a functional two way radio system, the safety issues associated with restoring power can worsen.

E8.7.4 Timing & Pacing of the Program

Toronto Hydro has a window of approximately 36 months to upgrade the voice radio system before the system's major components will longer be supported and maintained by the vendor. Toronto Hydro should not defer or delay this work beyond 2016 because a failure of the voice

radio system creates potential safety risks for Toronto Hydro's crews and compromises the utility's ability to sustain its core operations.

Toronto Hydro plans to implement this Program in the following stages:

Project Phase	2015				2016	
	Q1	Q2	Q3	Q4	Q1	Q2
Network & Facilities Infrastructure						
Backend Infrastructure						
Deploy Below Grade Infrastructure						
Purchase Radio HW (Handsets and Dispatch Consoles)						

FIGURE 3: PROGRAM IMPLEMENTATION

As a reference, historical CAPEX spending incurred and the forecasted future CAPEX spending is presented in the table below:

TABLE 7: HISTORICAL AND FUTURE SPENDING

	Historical CAPEX Spending, $M					Future CAPEX Spending, $M				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Annual Spend ($M)	0.02	0.1	0.1	0.25	0.12	6.68	13.73	0.0	0.0	-

E8.7.5 Program Execution

Toronto Hydro considered and evaluated the following program execution options:

- "Big bang" implementation which refers to the simultaneous upgrade of all radio system components; and
- Phased implementation, which refers to a gradually sequenced upgrade of the radio system components.

A "big bang" approach is not a viable or prudent option for Toronto Hydro for the following reasons:

- It would require the installation of a new radio system in parallel with the present radio system. This option is not desirable because it does not allow for the re-use of any existing equipment, requires significant capital investments into the new radio system and adds maintenance costs to support the old radio system during the transition period;

- Since there is not enough space to install the new radio sites and other equipment without de-commissioning the old infrastructure, additional sites would have to be secured and validated. This is not desirable because it could impose both schedule risks and substantial costs on Toronto Hydro;

- There is a higher level of potential safety risk associated with this option, as handheld radio devices and dispatch consoles in the Control Centre also would have to be duplicated and used in parallel during the time of system replacement (for several months), which necessitates considerable training efforts, physical inconvenience and increases the risk that the devices will be mixed and used erroneously.

Toronto Hydro plans to upgrade the existing radio system in phases. This approach is optimal for the following reasons:

- it minimizes the potential safety risks because a large portion of the equipment can be re-used and the employees are familiar with this equipment and of how to operate it;

- it minimizes the effect of the upgrade process on business continuity because the radio system components can be upgraded gradually, likely causing minimal to no interruption to business operations, and

- it minimizes the deployment costs as some radio system infrastructure components may be re-used.

The proposed phases of the program are:

- Phase 1: Connect the existing Smartnet 3.Z system to a P25 Core via a SmartX gateway, which will allow the Smartnet infrastructure to operate as a component of the new P25 infrastructure. Toronto Hydro does not expect this transition to affect the operation of the system. From a business continuity perspective, Toronto Hydro expects that this phase will only require a short downtime of approximately 2-4 hours.

- Phase 2a: Replace the existing dispatch radios with proper dispatch consoles and gradually replace the radio units used by crews in the field. Toronto Hydro expects that

the implementation of this phase will not exceed 12-18 months, and that it will not affect business continuity.

- Phase 2b: Implement additional radio sites to improve the radio coverage. Toronto Hydro expects to complete this phase in approximately 16-18 months.
- Phase 3a: Complete the gradual replacement of the radio units. This phase can occur in parallel with phases 1 and 2 above.
- Phase 3b: Install the new P25 radio sites at the same locations as the existing Smartnet sites and switch over each site from Smartnet to P25, thereby completing the system upgrade.

(i) Program Risks

Toronto Hydro does not foresee any major risks to the execution of this Program. Minor risks that Toronto Hydro plans on addressing include:

(1) Provisioning of the backhaul infrastructure (e.g. fibre optics), and

(2) Receiving Construction Permits from the City of Toronto.

To mitigate these risks, Toronto Hydro plans to proactively engage the City of Toronto and put the necessary contractual provisions in its agreements with the selected vendor.

E8.7.6 Evaluation of Alternatives

E8.7.6.1 Quantification/ Evaluation of Options

Toronto Hydro considered a number of alternatives for addressing the safety and operational risks associated with the aged voice radio system infrastructure:

(1) maintain the existing system beyond 2016 on a “best effort” basis;

(2) migrate to a contracted radio service;

(3) replace the existing analog system with new digital radio system TETRA; or

(4) upgrade the existing analog system to digital radio system P25.

Option 1: Maintain the existing system beyond 2016 on a "best effort" basis

Toronto Hydro considers this option infeasible for the following reasons:

- Maximum Safety Risk: In this option, Toronto Hydro would not upgrade or replace the existing voice radio system from 2015-2019. Within this period, all voice radio system components will reach the end of their useful lives, increasing the risk of failure. Any failure of voice radio system generates potential safety issues because they can potentially affect the emergency communication between the field crews and the Control Centre

- Maximum Vendor Risk: The vendor may offer support on a "best effort" basis without any service levels guarantees. There is a high risk that in the near future, the spare parts for the antiquated radio system will not be available.

- Medium Operational Risk: With the foreseen scarcity of technical and labour resources to resolve the voice radio system component failure due to the lack of vendor guaranteed support, the time required to resolve the program could be substantial, which may threaten the continuity of Toronto Hydro's operations whenever employees need to contact the Control Centre via the radio system.

- Medium Amount of Investments: Toronto Hydro would likely incur additional costs to procure obsolete radio system components as well as technical specialists to support the voice radio system on a "best effort" basis.

Option 2: Migrate to a contracted radio service

Under this option, Toronto Hydro would migrate to managed or contracted services, including outsourcing critical voice radio communication activities to the external supplier, which will own the radio system and would be accountable for the functionality and performance of this system.

Toronto Hydro considers this option infeasible for the following reasons:

- Maximum Potential Safety Risk: No known external vendors' radio system provides below-grade capability. The lack of below-grade coverage by the two-way voice radio system provided by the external vendor could expose Toronto Hydro to an unacceptable level of potential safety risk. Below-grade communication capability is one of the most essential features of Toronto Hydro's voice radio system as underground distribution

system assets covers approximately 57% of the total distribution system within the City of Toronto.

- Maximum Vendor Risk: The concept of managed service is based on the pre-requisite of attracting the sufficient number of customers to guarantee the availability of radio system to the organizations lacking in-house radio expertise at a reasonable cost. A number of organizations in Ontario have contemplated this option as their radio communications systems reached their "end of life" cycle. Currently, Bell Mobility Radio is the only service provider of managed radio services. Bell Mobility Radio serves six governmental stakeholders: Ontario Provincial Police (OPP), Ministry of Health (MOH), Ministry of Transportation (MTO), Ministry of Natural Resources (MNR), Ministry of Correctional Services (MCS), and Guelph Police and Fire. Bell Mobility's current contract with the Ontario Government expires in 2016, and their efforts to secure customers for a future shared vendor-managed solution have not produced any commitments to date. If Bell Mobility is not be able to subscribe new customers or renew the contract with the Ontario Government, their offering of the managed radio services is at risk.

- Maximum Operational Risk: In the absence of a below-grade communication feature, Toronto Hydro cannot use the contracted radio system to manage its field operations, which presents a high operational risk.

- Medium Amount of Investments: The switch to the contracted radio services is costly and, should Toronto Hydro decide to move to the in-house radio system at a later time, would likely require substantial additional investments.

Option 3: Replace the existing analog system with new digital radio system TETRA

Terrestrial Trunked Radio (TETRA) (formerly known as Trans-European Trunked Radio) is a professional mobile radio and two-way transceiver specification and a European Telecommunications Standards Institute (ETSI) standard published in 1995. TETRA was specifically designed for the use by government agencies, emergency services (police forces, fire departments, ambulance), by public safety networks, rail transportation, transport services and the military in Europe. The development of TETRA standard was driven by the need to standardize radio communication across the European Union and across various industry groups. TETRA is a new standard; the only way to transition to it is by replacing the existing radio system completely in one stage (http://www.tandcca.com).

Toronto Hydro considers this option infeasible for the following reasons:

- Maximum Potential Safety Risk: During the deployment phase, for example, field employees must carry two radio units, which can be confusing and can result in mistakes being made, while using a new system entirely presents an unacceptable level of potential safety risk in case of emergency radio communication.

- Maximum Vendor Risk: As the TETRA standard was developed in Europe, there are no vendors in North America which supply radio systems based on this standard.

- Maximum Operational Risk: There is an unacceptable level of operational risk associated with this option as all the existing radio system infrastructure components, as well as radio units, have to be scrapped and re-installed from scratch. This cannot be accomplished without significant interruptions to Toronto Hydro's field operations.

- Maximum Amount of Investments: During the deployment period, the whole voice radio system must be duplicated, which likely requires substantial investments and additional system maintenance costs. Toronto Hydro expects that the replacement of the existing radio system with a completely new system would not allow for the re-use of the existing radio infrastructure, which makes its deployment prohibitively expensive.

Option 4: Upgrade the existing analog system to digital radio system P25

Toronto Hydro considers this is a preferred alternative for the following reasons:

- Minimum Potential Safety Risk: The upgrade of the existing analog system to digital radio system P25 presents a minimal safety risk because it allows using some existing equipment while upgrading certain other components. The radio system users are familiar with the equipment and know how to operate it.

- Minimum Vendor Risk: P25 is a suite of standards for radio communications for use by federal, state/ province and local public safety agencies in North America to enable them to communicate with other agencies and mutual aid response teams in emergencies. The P25 system fills the same role in North America that the European Terrestrial Trunked Radio (TETRA) standard fills in Europe (http://www.motorolasolutions.com). There are several well-established and reputable vendors in Canada that provide P25 voice radio systems. Toronto Hydro intends to go through a competitive bidding process to select the vendor who most satisfies the utility's requirements.

- Minimum Operational Risk: Toronto Hydro believes that upgrading the existing system to P25 technology is the options associated with the least interruption to Toronto Hydro's operations, as it offers a gradual transition from the present state to the future state radio system by upgrading certain radio system components one-by-one with the simultaneous re-use of other components that end users are familiar with. In addition, Toronto Hydro expects that it will be easier to implement because it optimizes the opportunity for training and minimizes the impact to end users, as it presents them with an opportunity to gradually adjust to the new operating environment.

- Minimum Amount of Investments: The ability to re-use existing radio infrastructure is important because Toronto Hydro will likely be able to leverage some of its existing assets throughout the upgrade process; for example, 19% of radio units may be re-used. Coupled with reduced training efforts in comparison with options two and three, the equipment re-usability opportunity makes this option most economically efficient.

Preferred Alternative

The assessment of four considered alternatives is summarized in the table below. Based on the analysis, Option 4 is Toronto Hydro's preferred alternative because of the minimal level of safety, vendor and business continuity risks it presents and because it is the most economically viable option:

TABLE 8: ALTERNATIVES EVALUATION

Criteria	Option 1: maintain the existing system beyond 2016 on a "best effort" basis	Option 2: migrate to a contracted radio service	Option 3: replace the existing analog system with new digital radio system TETRA	Option 4: upgrade the existing analog system to digital radio system P25
Potential Safety Risk	maximum	maximum	maximum	minimum
Vendor Risk	maximum	maximum	maximum	minimum
Operational Risk	medium	maximum	maximum	minimum
Amount of Investments	medium	medium	maximum	minimum
Recommendation				X

E8.8 Program Support

E8.8.1 Summary

Program Description

Toronto Hydro's Distribution System Plan (DSP) has been developed through a series of asset management processes, tools, systems and resources, as identified within Section D (Asset Management Process). Key outputs of the Asset Management Process include both long-term capital programs and discrete capital projects contained within those programs. The proposed Program Support expenditures will allow for continued refinement and improvements to the development of capital projects within the five-year period along with future development of capital programs from 2020 and beyond, through the execution of two key support studies: a climate adaptation study and a customer interruption cost (CIC) study. Table A provides a summary of this program's benefits.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ CIC study is expected to further enhance the Feeder Investment Model (FIM) with localized outage costs ƒ System improvements based on the studies will facilitate the reduction of customer impacts due to extreme weather events and climate change
Reliability	ƒ Proposed studies will support efforts towards reduction in the frequency and duration of adverse-weather related outages ƒ The development of localized customer interruption costs would further enhance Toronto Hydro's capability to manage system reliability in a

	customer-focused manner
Safety	ƒ Proactively targeting areas vulnerable to extreme weather and climate change impacts is expected to reduce crews' exposure to work on the system during severe weather events
Efficiency	ƒ Enhancements to localized outage costs are expected to further enhance Toronto Hydro's business case evaluation (BCE) process, facilitating an enhanced economic evaluation of capital investments. ƒ Storm hardening improvements to the distribution system will help mitigate the risks associated with extreme weather events, creating opportunities for cost reductions of weather-related service restoration.

Program Drivers

The trigger driver for this program is summarized in the following table.

TABLE B: PROGRAM DRIVER

Trigger Driver	Reasoning
System Maintenance and Capital Investment Support	ƒ Plans based on the climate adaptation study are planned to be executed in both Overhead and Underground Circuit Renewal Programs ƒ Update localized outage costs into the Feeder Investment Model

Preferred Alternative

In the absence of the proposed studies, adaptation to climate change within Toronto Hydro's distribution system can be derived solely from historical information and trends in weather-related events. Similarly, Toronto Hydro would continue to use existing customer interruption cost (CIC) inputs as part of their Feeder Investment Model (FIM) and business case evaluation (BCE) process. This option is not preferred as it does not address the expected impacts of climate change and would not allow for the continuous improvement of the FIM approach.

Timing and Pacing

Both studies comprising this program are planned to be conducted in the first two years of the DSP period. After the completion of the climate adaptation study, Toronto Hydro plans to review the plans completed through the FIM, as well as compare the climate change adaptation study results to the existing programs being executed, to benefit from any cross-program synergies or to build on existing programs that may already be investing in system resiliency. The CIC study is

planned for completion in 2015 because the localized outage costs calculated would have to be tested and gradually incorporated into the FIM to further enhance the model in preparation of prioritization of projects in the later years of the DSP period. Toronto Hydro proposes to spend $1.7 million for this program as shown in Table C.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	1.2	0.5	0	0	0

E8.8.2 Program Description

The objective of Program Support program is to enhance Toronto Hydro's long-term and short-term asset management planning processes, and ultimately enhance capital program and capital project development through the execution of the key planning studies. These studies include a climate adaptation study and a customer interruption cost (CIC) study. The climate adaptation study would permit Toronto Hydro to enhance its standards and design practices with storm-hardening capabilities, while also identifying specific areas within the distribution system that face an elevated amount of weather-related risks. The CIC study is expected to enhance a key input that is used as part of Toronto Hydro's Feeder Investment Model (FIM) decision-support system, such that the overall business case evaluation (BCE) process will be further improved.

E8.8.2.1 Climate Adaptation Study

Toronto Hydro plans to conduct climate adaptation study in 2015 and 2016 to assist with engineering analysis, informed decision-making and standards for overhead and underground capital programs. The study will focus specifically on identifying areas of the distribution system that are vulnerable to extreme weather and climate change. Figure 1 shows an example of reconfiguring the distribution system to move it outside of a flood plain, which is an example of the type of work that could be carried out as result of climate adaptation study. As recommendations from the climate study become available, pilot projects will be conducted as part of the studies to test the recommendations. The purposes of including the pilot projects as part of the studies is to finalize the climate adaptation solutions before programs are carried out at a system level.

FIGURE 1: RECONFIGURING DISTRIBUTION SYSTEM OUTSIDE OF FLOOD PLAINS

E8.8.2.2 Customer Interruption Costs (CIC) Study

The proposed Customer Interruption Costs (CIC) study is a survey-based interruption cost study to estimate outage costs specific to the City of Toronto context. This study would survey various customer classes, Toronto Community Councils, and Business Improvement Areas (BIAs). Surveying across different customer demographics ensures that Toronto Hydro's diverse customer base is captured in this study. In addition, the proposed study would also ask each survey participant about their expectations (i.e. the frequency and duration of outages that customers consider acceptable) and perceptions (i.e. how satisfied customers are with the level of reliability they currently experience) of service reliability.

The selected vendor for this study would recommend outage scenarios and their proposed cost estimation methodology based on the diversity of survey participants. The different outage scenarios would include a combination of seasonal (summer/winter), weekly (weekend/weekdays), and daily (morning/afternoon/night). As shown in Figure 1, based on historical data, there is no single hour that accounts for more than 7% of outages or less than 2% of outages. Accordingly, the study must be designed to capture information across all time

periods. Finally, each set of these scenarios will need to include durations of 5 minutes, 1 hour, 4 hours, 8 hours and 24 hours[1].

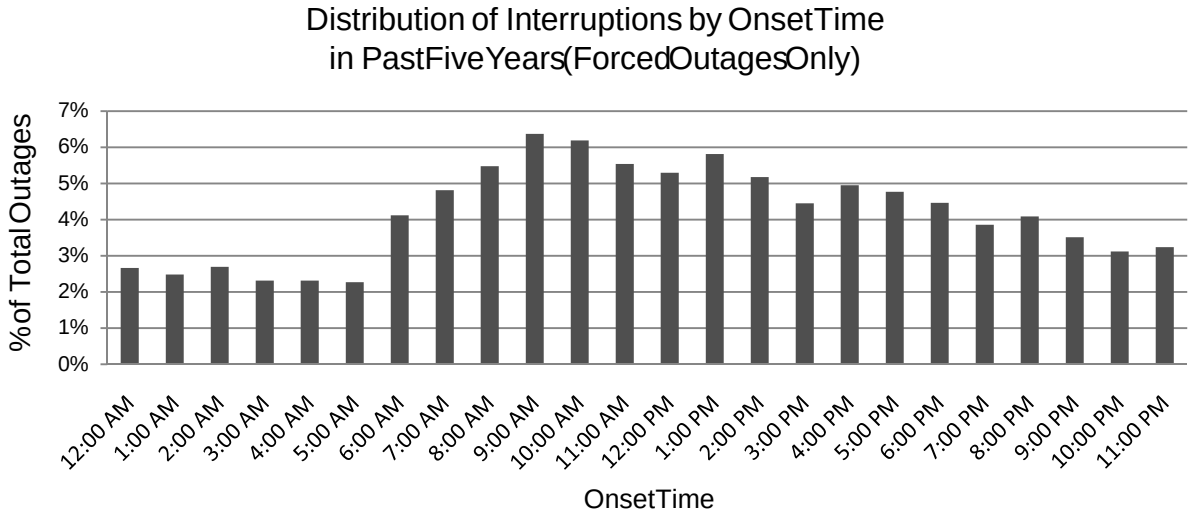


FIGURE 2: DISTRIBUTION OF INTERRUPTIONS BY ONSET TIME IN PAST FIVE YEARS

The different cost estimation methodologies are willingness-to-pay (WTP), willingness-to-accept (WTA), and direct-worth[2]. WTP cost estimations involve measuring the amount that customers would be willing to pay to avoid experiencing a service interruption; WTA involves measuring the level of compensation that customers would require to avoid a service interruption. Both of these approaches contribute to understanding how much customers would pay to avoid service interruptions. As costs for residential customers are mostly an inconvenience or hassle, they are often intangible and difficult to estimate using a direct-worth method. The combination of WTP and WTA approaches is a rigorous way of determining these implied costs. The direct-worth (DW) method involves asking customers to estimate the direct costs they would experience during a service interruption. These include outage related costs (e.g. labour and material costs incurred during an outage), lost production, cost to operate backup generation equipment,

[1] M.J. Sullivan and D.M. Keane, Outage Cost Estimation Guidebook (Electric Project Research Institute Research Project 2878-04 Final Report) (San Francisco Freeman, Sullivan and Company, 1995).
[2] Leona Lawton et al., A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys (Berkley: Population Research Systems, LLC and Lawrence Berkeley National Laboratory, 2003), online: Consortium for Electric Reliability Technology Solutions <http://certs.lbl.gov/pdf/54365.pdf>.

material costs to restart the production processes, etc. The DW approach is recommended for non-residential customers, i.e. small, medium, and large commercial and industrial (C&I) users.

This proposed study would survey customers across the Toronto Hydro service territory to determine system-wide values along with an analysis showing the confidence level of the values. Once these outage costs are calculated, they will be used in the FIM described in Section D3.

The anticipated benefits of this program are summarized in Table 1.

TABLE 1: SUMMARY OF PROGRAM BENEFITS

Customer Value	ƒ CIC study is expected to further enhance the FIM with localized outage costs ƒ System improvements based on the studies would help reduce customer impacts due to extreme weather events and climate change
Reliability	ƒ The studies would help achieve a reduction in the frequency and duration of adverse-weather related outages ƒ The development of localized customer interruption costs would further enhance Toronto Hydro's capability to manage system reliability in a customer-focused manner
Safety	ƒ Proactively targeting areas vulnerable to extreme weather and climate change impacts would help reduce crews' exposure to work on the system during these events
Efficiency	ƒ Enhancements to localized outage costs would allow Toronto Hydro to further enhance its business case evaluation (BCE) process, facilitating enhancements to the economic evaluation of capital investments. ƒ Storm hardening improvements to the distribution system would help mitigate the risks associated with extreme weather events, facilitating reductions in weather-related reactive work.

E8.8.3 Why the Program is Needed

The purpose of the two studies in this program is to assist Toronto Hydro in preparing for climate change and mitigate its impacts and to enhance the FIM by reflecting the localized interruption costs for Toronto Hydro's customers. The climate adaptation study would include detailed engineering analysis and development of climate adaptation plans as well as pilot project testing based on recommendations from the study's findings. Localized customer interruption costs would help Toronto Hydro enhance the FIM, which is used to prioritize future projects.

E8.8.3.1 Program Drivers

As shown in Table 2, the trigger driver for this program is System Maintenance and Capital Investment Support. This driver classifies the program in the General Plant category. These two key support studies would allow for the continued refinement and improvements of the development of the capital projects within the five-year period along with future development of capital programs beyond 2020.

TABLE 2: PROGRAM DRIVER

Trigger Driver	Reasoning
System Maintenance and Capital Investment Support	ƒ Plans based on the climate adaptation study ware planned to be executed in both Overhead and Underground Circuit Renewal Programs ƒ Update localized outage costs into the Feeder Investment Model

(i) Climate Adaptation

On July 8, 2013, and December 22, 2013, (shown in Figure 3), the City of Toronto was hit with two different types of extreme weather that adversely affected Toronto Hydro's distribution system.

FIGURE 3: FALLING BRANCH ON STREET ENTANGLED WITH CONDUCTOR [3]

[3] "Photos: Toronto coated in ice following destructive winter storm", Windsor Star (22 December 2013) online: Windsor Star <http://www.windsorstar.com/news/national/cms/binary/9318821.jpg?size=640x420>.

Based on the information outlined in the AECOM-Toronto Hydro report entitled Future Impacts of Climate Change on Toronto Hydro's Distribution System (filed at Appendix A to this schedule), extreme weather events of this nature adversely affect Toronto Hydro's distribution system and will continue to do so in the future. The proposed climate adaptation study and pilot project would analyze, develop and test plans to make Toronto Hydro's distribution system more resilient to weather induced failure by reducing the time for restoring service to customers.

Toronto Hydro uses two fundamental measures of outage durations and outage frequency, namely System Average Interruption Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). One of the sub-categories for both SAIDI and SAIFI tracks the impact of adverse weather specifically. In both metrics major event days (MEDs) (i.e. atypical events that are beyond the design or operational limits of the system) are put aside from historical tracking because they can distort perception of the utility's reliability performance. However, because of the nature of the climate adaptation study, it is relevant to look at how MEDs affect Toronto Hydro's distribution system.

Table 3 shows the total annual SAIDI for adverse weather excluding MEDs, and the average annual SAIDI from 2000-2013 for these values.

TABLE 3: AVERAGE ANNUAL SAIDI DUE TO ADVERSE WEATHER

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Annual SAIDI excluding MEDs (min)	40.5	33.3	35.6	35.0	18.4	19.8	26.9	26.5	26.6	28.9	32.8	38.2	16.8	30.5
Average Annual SAIDI from 2000 to 2013, excluding MEDs = 29.3 minutes														

By definition, MEDs can have a significantly higher than average impact on SAIDI. Toronto Hydro experienced two MEDs recently: the July 8, 2013, flood with a SAIDI total of 197.26 minutes, and the December 21 to the 26, 2013, ice storm with a preliminary SAIDI total of 990.7 minutes. Both MEDs far exceeded the average adverse weather SAIDI count for an entire year, demonstrating the extreme impacts adverse weather has on Toronto Hydro's distribution system. For further information on recent weather events affecting network performance refer to Future Impacts of Climate Change on Toronto Hydro-Electric System Limited (Appendix A)

The proposed climate adaptation study would assist Toronto Hydro in the implementation of the overhead and underground programs by focusing on the identification of areas of the system that are vulnerable to extreme weather. This will consist of a logical breakdown of the distribution system at a system level and a matrix comparison between different weather scenarios, highlighting areas affected by changing climate.

Other electrical utilities have also conducted studies on climate adaptation and have developed climate adaptation programs based on the findings to move underground equipment out of flood plains, or elevate equipment where possible to remove the hazard. Where removal of equipment is not possible, equipment upgrades could be implemented in flood zones to incorporate submersible equipment that would not be as vulnerable to the water. For more detail on what other electrical utilities are developing for climate adaptation please refer to (Future Impacts of Climate Change on Toronto Hydro-Electric System Limited in Appendix A). Overhead equipment, which endures the most pressure from extreme weather, would also be examined; in certain areas where power supply is critical, system reconfiguration may be used to increase reliability and the integrity of the overhead distribution system.

Future increases in temperature could have adverse effects on the Toronto Hydro distribution system as well. It is forecasted that in 100 years, increased temperatures could produce a 10 percent reduction in efficiency of the distribution system. Potential mitigation programs can look at changing the amount of energy consumed by customers through new technologies.

The proposed climate adaptation study would include pilot projects to test feasibility of the recommendations. The benefit of testing the study's recommendations before system level implementation is to ensure the most effective solutions go forward. These proposed pilot projects are included in the forecasted expenditures for the program.

At this point in time, there are many solutions Toronto Hydro could use to mitigate climate change impacts. However, in order to ensure the correct steps are taken, two years of studies and pilot projects will be used to identify the critical path for future climate adaptation programs.

(ii) Customer Interruption Costs

The proposed CIC study would help further enhance customer interruption cost inputs used within the Feeder Investment Model (FIM), which is further detailed in Section D3. Customer Interruption Costs are defined as a measure of the monetary losses for customers due to an interruption of

electric service. The inconvenience and damage encountered by customers involves three periods:

(1) The first period is immediately after power interruption. Customers need to take the necessary action to mitigate the immediate effects of the interruption risks to health and welfare of employees, tenants or the public, production impacts, and other business and non-business activities. This first period can be monetized as per the formula shown below:

(a) Event Cost = $(SAIFI_{EFFECT})$(Total Load)

Where:

- $SAIFI_{EFEECT}$ ($30) represents the cost associated with this first period of the interruption.
- Total Load represents the peak load that will be interrupted due to the outage event.

(2) The second period follows, with on-going disruption to production, sales, office work and entertainment. In this period the customer interruption cost is proportional to the duration of power failure. This second period can be monetized as per the formula shown below:

(a) Duration Cost = (SAIDIEFFECT)(Total Load)(Outage Duration)

Where:

- $SAIDI_{EFEECT}$ ($15) represents the cost associated with this second period of the interruption.
- Total Load represents the peak load that will be interrupted due to the outage event.
- Outage Duration represents the average duration of the outage event in hours.

(3) The third period is after the restoration of power when customers take action to resume normal production.

As noted above, Toronto Hydro has adopted the use of a $30/kVA (peak load) customer interruption cost value to represent the first period of the outage (the "Event") and a $15/kVA-hour (peak load) customer interruption cost value to represent the second period of the outage (the "Duration"). These costs were developed with input from consultants, who have worked with other

utilities in establishing similar parameters. Reliability valuation studies, such as those from Roy Billinton, were used to aid in the development of these parameters, which are applied consistently to quantify power interruptions to all types of customers. Due to the immediate termination of regular activities involving electricity during the first period of the outage, it is expected that the costs associated with this period will be larger in comparison to the second period, where the customer has now re-adjusted their activities to account for the loss of electricity. It is during the second period, however, that the inconvenience and disruption associated with the outage will continue to grow as the outage continues to linger. Therefore, the monetized value associated with this stage will be multiplied with the duration of the outage, in hours.

The customer interruption cost study proposed within Program Support will further enhance the $SAIFI_{EFFECT}$ and $SAIDI_{EFFECT}$ inputs through the development of a localized customer survey for the City of Toronto, which will better reflect the specific needs and preferences of Toronto-area customers. Furthermore, it should be noted that during the ICM interrogatories, both the interveners and the OEB Staff[4] recommended that Toronto Hydro look into the "use of surveys on the various customer classes to determine the units of [outage costs per customer class] as recommended by experts in that field". Toronto Hydro believes that conducting this study will help in the development of localized outage costs that address these concerns from various stakeholders.

E8.8.4 Timing & Pacing of the Program

Toronto Hydro plans to conduct these two studies to help mitigate the impact of the extreme weather and further enhance the FIM through localized outage costs. The spending forecast for the five-year period starting in 2015 is shown below in Table 4.

TABLE 4: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	1.2	0.5	0	0	0

Toronto Hydro plans to conduct the climate adaptation study in 2015 and 2016 while the CIC study is expected to be completed in 2015. The proposed total costs for climate adaptation study is $1.0 million over the two years with a budget of $0.5 million each year, while the CIC study is expected to cost $0.7 million.

[4] EB-2012-0064, Board Staff Submission (September 30, 2013), at page 13.

It is preferable to complete the climate adaptation study in the first two years of the DSP period. Upon completion of the climate adaptation study, Toronto Hydro would review its existing plans through the FIM, and compare the results to existing programs Toronto Hydro is currently executing, to benefit from any cross-program synergies or to build on exist existing programs that may already be building on system resiliency. The CIC study is planned for completion in 2015 because the localized outage costs calculated will have to be tested and gradually incorporated into the FIM to further enhance the model in preparation of prioritization of projects in the later years of the DSP period.

E8.8.5 Program Execution

Both of the studies in this program are planned for the first two years (2015-2016) of the DSP period as shown in Table 5. The climate adaptation and the CIC studies are expected to be completed in 2015-2016 and 2015 respectively. Toronto Hydro plans to contract out both studies on a competitive bid basis, while working closely with the vendors to provide the required data and direction.

TABLE 5: PROPOSED WORK PLAN

Year	Program Support
2015	CIC Study
2015	Climate Adaptation
2016	Climate Adaptation

The climate adaptation study in 2015 and 2016 would focus on identifying areas of vulnerable to extreme weather and climate change in the distribution system. The starting point of the studies would pick up where previous programs have left off. (Refer to Toronto Hydro's Actions to Date in Appendix A; Future Impacts of Climate Change on Toronto Hydro-Electric System Limited). Specifically, the study would start by looking at extreme weather event scenarios that are expected to increase in future climate change projections. These scenarios include but are not limited to flooding, freezing rain, increase in temperature, and ice-storm etc. In each scenario thresholds and boundaries would have to be created to identify what areas of the distribution system will be affected. In some cases where information is not readily available external parties will be engaged. Once thresholds and boundaries of each extreme weather scenario are known, a detailed engineering analysis of impacts from each event will be created.

For the CIC study, a vendor would be selected based on past experience conducting extensive outage costs surveys for different scenarios and across different customer demographics. Most

importantly, the preferred vendor should possess sufficient experience with the cost estimation methodologies described earlier in the narrative. Due to the survey nature of this study and Toronto Hydro's customer base, it is critical to ensure adequate customer representation and random sampling to mitigate sampling bias in the survey participants.

Following vendor selection, Toronto Hydro would work with the vendor to develop the questionnaire and expects to complete the survey by end of Q3 2015. The vendor would be expected to process the surveys and analyze the results and provide a final report. The goal is to complete the survey by end of Q4 2015.

E8.8.5.1 Program Risks

Both studies in this program would require external the involvement of external experts with proven experience in their fields. This is especially important for the CIC study. The CIC study requires a group with background in statistics (to ensure the right sample mix and no sampling bias exists), economics (quantify outage costs), survey design and execution. Toronto Hydro plans to reach out to authors of previous CIC studies, among other potential vendors.

E8.8.6 Evaluation of Alternatives

E8.8.6.1 Quantification/Evaluation of Options

(i) Status Quo

In the absence of these two proposed studies, plans to adapt to climate change within Toronto Hydro's distribution system would be derived solely from historical information and trends in weather-related events. Table 2 illustrates how customer interruptions associated with weather events would continue to increase due to the higher frequency of extreme weather. Similarly, Toronto Hydro would continue using existing customer interruption cost (CIC) inputs as part of their Feeder Investment Model (FIM) and business case evaluation (BCE) process.

This option is not preferred as it does not address the expected impacts of climate change and would not allow for the enhancement of CIC estimates.

(ii) Execution of Program Support

Through the execution of this program, Toronto Hydro would improve its Asset Management capabilities, including long-term and short-term planning processes, thereby allowing for improvements to capital programs and projects respectively.

AECOM

Future Impacts of Climate Change on Toronto Hydro•s Distribution System

Environment

Toronto Hydro
14 Carlton Street
Toronto, Ontario, M5B 1K5

Future Impacts of Climate Change on Toronto Hydro's Distribution System

AECOM 6031-8207

July 2014

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Executive Summary

This document provides an overview of how the impacts of climate change are likely to affect Toronto Hydro's electrical distribution network. It also outlines the need for, and process by which, Toronto Hydro can continue its efforts to better understand its risks, take proactive steps to manage the risks and enhance the resilience of its electrical distribution system to climate change.

Toronto Hydro and the City of Toronto

Toronto Hydro is a part of the electricity network that includes generators (supply-side), transmission and distribution companies and consumers (demand-side). Each element of the network is interdependent, and decisions by, or impacts to, any element will affect the others. Reliable electrical supply is a central element supporting the activities, economy and people of a resilient city.

Toronto Hydro serves the City of Toronto, Canada's largest city and home to over 2.5 million people. The city is the capital of the province of Ontario, a major North American financial centre, and an important air, road and rail transportation hub. The following factors present unique challenges for Toronto Hydro in the provision and maintenance of electricity, as well as the response to emergency events and outages:

- Dense inner city development;
- Significant transportation infrastructure (e.g. road, subway and rail); and,
- Complex networks of above and below ground utility systems (e.g. water, stormwater, sewer, gas and telecommunications).

The climate is changing

There is a significant body of evidence indicating that the weather affects the performance and reliability of the electricity network. There is also a significant body of evidence that global and regional climate has changed and will continue to change over the coming century.

Since the middle of the 20th century the weather has changed with recorded increases in daily temperature, heat waves, precipitation, droughts and frequency of tropical cyclones in the North Atlantic (Flato, et al., 2013). Specific to Toronto, the climate is projected to continue to change with:

- Continued increase in average temperatures;
- Increase in extreme maximum temperatures;
- Increase in the number days over 35°C per year;
- Increase in total annual rainfall;
- Decrease in the total annual snowfall; and,
- Increase in the intensity of rainfall events (SENES Consultants Limited, 2011).

Weather and climate change will impact the reliability of the electrical system

The weather (e.g. heat, precipitation and wind) has direct and significant impacts on the performance of all elements of the electricity network. The weather's influence on the system is not new and is actively managed by companies through design and operational activities. For example, components of the network (e.g. transformers and conductors) are designed to achieve a minimum standard of performance up to a particular wind or temperature threshold. However, in the face of projected changes in climate, electrical distribution companies like Toronto Hydro will be placed in the predicament of having to manage assets that were not designed for future climate conditions.

There have been numerous recent examples of how the weather has affected Toronto's network performance including:

- Severe Thunderstorms, August 2005;
- Hurricane Sandy, October 2012;
- Extreme Rainfall, July 2013; and,
- Ice Storm, December 2013.

Each event produced significantly greater than average outages to the network. In the case of the August 2005 and July 2013 events the weather surpassed previous records.

Without intervention, Toronto Hydro will continue to experience increased physical impacts to its network due to severe weather and a changing climate, generating significant operational and maintenance costs and disrupting the supply of electricity to communities and businesses.

Globally – Utilities are responding to changing climate

Many infrastructure utility owners and operators (including electrical utilities) around the world are experiencing significant damage and disruption to their infrastructure as a result of extreme weather events. In addition to recognizing current weather vulnerabilities, many utilities are also acknowledging that the climate will continue to change, and that they should take steps to better understand the likely impacts to their systems, assets and services, and plan to adapt to a changing climate.

The following examples demonstrate how some of these utilities, with a focus on the electrical sector, are addressing the issues presented by climate change around the world. While the projected changes in climate and the impacts to infrastructure differ across regions, in general, there is increasing action to better understand the impacts and invest in measures that will improve the resilience of networks. Case studies presented in this document illustrate the following:

- In Canada at the national level, there is acknowledgement that climate change presents potentially significant risks to critical public infrastructure and that there is a need to better understand the risks to enable proactive management. This is demonstrated by the Natural Resources Canada report From Impacts to Adaptation: Canada in a Changing Climate 2007 and the completion of 25 climate change risk assessment case studies across multiple sectors including one of which involved Toronto Hydro's electrical distribution assets;
- In Ontario, Horizon Utilities conducted an assessment in 2012 of climate change related risks to its business and developed a twenty-year adaptation strategy and action plan addressing assets, operations and procurement practices;
- In California, a study has quantified the impacts that climate change may have on electrical network performance. The study showed likely increases in outages and reduced performance as temperatures increase;
- Consolidated Edison of New York Inc. illustrates how stakeholder interest and pressure contributed to the adoption of regulatory requirements for considering climate risks and investment in resiliency projects and support from the regulatory authority with $1billion approved to support implementation;
- The UK case study illustrates how regulatory requirements have driven assessments of climate risk on electrical utilities and provides examples of the approach used to fulfill the requirements; and
- In Australia, significant disruptions to electrical networks in two regions stemming from extreme weather were documented. Approaches to building resilience (both direct and seeking regulatory support) were presented.

Toronto Hydro is already resp onding to a changing climate

Toronto Hydro recognizes that a changing climate will have an impact on its operations, assets, and system reliability. Toronto Hydro's efforts to understand and address climate change have included:

- Adopting an Environmental Policy outlining its commitment to environmental stewardship. The policy includes a principle to ensure that environmental considerations are integrated into its business processes. Toronto

Hydro's commitment to environmental stewardship is closely aligned with addressing the issue of climate change, as the latter has the potential to disrupt business operations and electrical supply, which may result in detrimental impacts to the environment;
- Collaborating with government, private and non-profit organisations through the WeatherWise Partnership and the Canadian Electricity Association (CEA) Roundtable Initiative on Climate Adaptation; and,
- Commencing the process of understanding the impacts of climate change on Toronto Hydro Distribution Assets by undertaking a climate change risk assessment in collaboration with Engineers Canada.

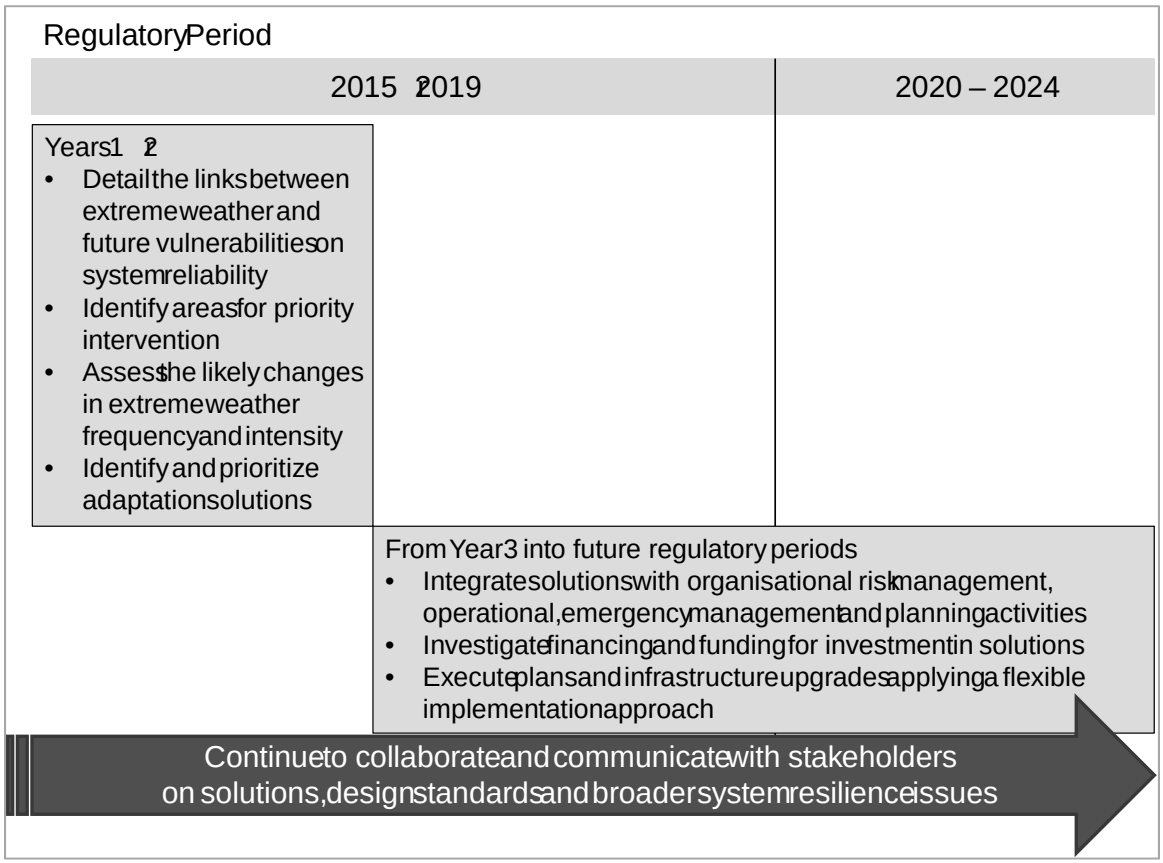
These efforts indicate that Toronto Hydro has taken initial steps in its journey towards building a resilient network for the City of Toronto. However, there are limitations in Toronto Hydro's current understanding of its potential network vulnerabilities in the face of climate change. Notably, much of the work to date remains at a preliminary phase and further detailed work is still required to understand the impacts of a changing climate including how the climate will evolve locally as well as developing, prioritizing, costing and financing the potential adaptation solutions to enhance the resilience of the electrical distribution system to climate change.

An Adaptation Plan to move forward

In order to address these limitations a logical, considered and flexible plan should be developed and implemented to guide Toronto Hydro's efforts in improving the resilience of its electrical network. The key elements of this plan are (refer to Figure 1):

- Enhancing understanding of the projected changes in extreme weather event frequencies and intensities (e.g. extreme heat, ice storms);
- Detailing the links between the climate (e.g. extreme weather events and longer term changes in climate) and future vulnerabilities on system reliability by undertaking detailed assessments of component and system vulnerabilities (e.g. interdependencies, redundancies, equipment condition and age, climate induced changes in energy demand profile);
- Projecting impacts of climate change on the number of customer service interruptions and quantifying through reliability measures (i.e. SAIDI, SAIFI) and the costs of outage events;
- Identifying areas for priority intervention in consultation with the City of Toronto based on electrical system vulnerabilities, vulnerable populations, and priority service areas (e.g. emergency response and health facilities, shelters etc.);
- Identifying adaptation solutions, which include engineering actions, maintenance and operations measures, procurement specifications, emergency response and recovery measures, and increased risk tolerance and insurance measures. These solutions must be identified in conjunction with community and stakeholder engagement and an assessment of organisational and community risk tolerances;
- Evaluating and prioritizing adaptation solutions based on evaluation of costs and benefits, system vulnerabilities, and priority geographic areas for intervention;
- Investigating financing and funding for investment in solutions;
- Developing implementation plans describing solutions, timelines and budgets for implementation. Incorporate flexibility into plans to allow the implementation process to integrate, in so far as possible, advancements in scientific understanding of climate change, ongoing evaluations of system performance, funding opportunities and scheduled upgrade opportunities on which to 'piggyback' integration of climate change resilience measures;
- Integrating solutions within organisational risk management, current operational and maintenance programs, and emergency response management and planning activities;
- Executing plans and infrastructure upgrades in accordance with the flexible implementation approach described above;
- Continuing to monitor system performance and reliability on an ongoing basis; and,
- Reviewing and updating design standards in collaboration with other utilities and the Canadian Standards Association.

Figure 1 Overview of the Proposed Next Steps for Toronto Hydro's Adaptation Planning



Adapting to Climate Change, an Ongoing Challenge

In summary, while the climate has and will continue to affect the reliability and performance of Toronto Hydro's network, with thoughtful planning, preparation and investment, Toronto Hydro can proactively address the issues presented by climate change and continue to support the reliability and resilience of Toronto's electrical system.

This document demonstrates Toronto Hydro's recognition of the importance of understanding, planning and acting to address climate change. Toronto Hydro should seek the support of the regulator in its efforts to systematically advance the resilience of the electricity network to increasing risks posed by climate change.

Having an Adaptation Plan that is logical, considered and flexible is the most sensible path to manage this new challenge. There are many actions that can be incorporated within business as usual operating constraints, but many others require new research, technologies, targeted investment and collaboration amongst agencies.

Toronto Hydro should fully develop its Adaptation Plan, carry out further detailed studies, and seek funding support for enhancing the resilience of its electrical network. Toronto Hydro should also seek longer term support for ongoing consideration of climate change in future operational and investment planning.

Flexibility in the development and execution of the Adaptation Plan is necessary to ensure that the results of further detailed studies (that are not known at this time) can direct investment towards identified high priority, and / or pilot projects to boost the reliability of its network to both gradual climate change related impacts as well as those stemming from increasingly severe weather events. Finally, the Adaptation Plan and measures developed and implemented by Toronto Hydro could be used as a template and guide to help other utilities across the electricity distribution sector to enhance the resilience of their systems to climate change.

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1.0 Introduction

The climate is changing and increasing the risks of damage to, and disruption of, critical infrastructure including the electricity network. This has significant implications for the resilience of communities and the economy.

The electricity network is made up of generators (supply-side), transmission and distribution companies and consumers (demand-side) (Figure 2). Each element of the network is interdependent, and decisions and actions made by one element will affect the others. For example, disruptions to the generation of electricity will affect the ability of transmission and distribution companies to provide electricity to consumers. Likewise, if consumers change their demand profile, it will place pressure on transmission and distribution infrastructure and may also influence operational and investment decisions made by generators.

Figure 2 Overview of the Electricity Network

Much of the activities of public and private sector organisations or individuals are dependent on reliable electricity supply, as illustrated by Figure 3. For example businesses and industry need electricity to produce goods or make transactions, while households need electricity for many recreational activities and heating and cooling. In addition, electricity supports food production and storage, water supply and treatment, and transportation systems (e.g. powering trains, providing lighting and signals on roads, and communications for air traffic control). During times of emergency the need for reliable electricity is even more apparent; it plays a critical role in:

- supporting communications in preparing for an event and during response and recovery activities;
- supporting mitigation efforts, for example flood control pumps;
- providing lighting for emergency management, repair and recovery activities; and,
- heating and cooling during extreme cold or warm periods.

Reliable electrical supply is central to the resilience of a city and community.

Toronto Hydro serves the City of Toronto, Canada's largest city and home to over 2.5 million people. The city is the capital of the province of Ontario, a major North American financial centre, and an important air, road and rail transportation hub. The following factors present unique challenges for Toronto Hydro in the provision and maintenance of electricity, as well as the response to emergency events and outages:

- Dense inner city development;
- Significant transportation infrastructure (e.g. road, subway and rail); and,
- Complex networks of above and below ground utility systems (e.g. water, stormwater, sewer, gas and telecommunications).

Figure 3 Importance of the Electricity Network in Supporting Community and Economic Activities and Resilience

Figure source: US Global Climate Change Research Program, 2009, US Department of Energy, p. 52, modified by AECOM.

The weather (e.g. heat, precipitation and wind) can have direct and significant impacts on the performance of the electricity system, from the efficiency of generators to the ability to distribute electricity to consumers and ultimately the level of consumer demand. The influence of the weather on the system is actively managed by companies through design and operational activities. For example, design standards are used for network components to achieve acceptable performance up to a particular wind or temperature threshold.

Generally, maintenance regimes are set to monitor the condition and performance of components over a given timeframe. Assets may be replaced based on their specified design life, but may also be repaired or refurbished to extend operational life beyond original design specifications. These types of maintenance, refurbishment and replacement decisions have traditionally been informed by standards and practices that are based on historical climate records.

Asset failure occurs when weather events exceed the design capacity / threshold of system components. The weather can also affect assets by directly, or indirectly damaging assets (e.g. flood waters inundating a substation, wind-blown debris bringing down power lines). There have been many recent examples of how extreme weather has affected the network in the Greater Toronto Area (GTA), including severe storm and flooding events in 2005, 2012 and 2013.

The climate has changed over the last 50 years and is projected to continue to change over the lifespan of assets that are critical to the electricity network. When combined with other circumstances such as changes in policy affecting demand and generation profiles, changes in the frequency and intensity of extreme weather events and longer term changes in the climate (e.g. average temperatures) will have significant, broad ranging impacts to all elements of the electricity network.

Changes in the projected average temperature and average precipitation can result in significant changes in the frequency or intensity of extreme events. As a result of the projected changes in climate, it is possible that the lifespan of assets will be shortened as they operate under greater stress, or may fail more frequently as their design thresholds are exceeded more often.

These changes have significant implications to operation, maintenance and capital costs, and the ability to meet performance standards, customer expectations and regulatory requirements. Increased occurrences of disruption to the electricity supply will also have broader implications to business continuity and community resilience, particularly the ability to respond to, and recover from extreme weather events and other disasters. Electricity is vital to support businesses in returning to normal operation, a key element of aiding recovery.

The issues presented by climate change have been recognised across the electrical utility sector globally by a variety of responses, some of which have been driven by regulators. Responses have included detailed investigations of vulnerability and risk, which have been used to inform changes in operational practices and system design to build the resilience of networks to withstand current extreme weather events and future changes in climate.

For Toronto Hydro, there is a real need to better understand the potential risks that changes in the climate may entail for its network and to develop proactive plans to actively manage these risks. This process must consider the likely costs associated with preparing for climate change. Furthermore, the timing for implementation must be evaluated based on an assessment of when risks are likely to occur in the future, as well as of the condition and lifespan of existing and planned future assets.

The objectives of this document are to:

- provide an overview of how the climate has changed and is projected to change at a global and local level;
- illustrate how recent weather has affected the performance of Toronto Hydro's network;
- provide examples of how other utilities in Canada and around the world are tackling the issue;
- document the initial steps Toronto Hydro has taken to date; and,
- outline the need for, and process by which, Toronto Hydro can continue its efforts to better understand its risks, and take proactive steps to manage the risks and enhance the resilience of its electrical system to climate change.

This document is presented in the following chapters:

- Chapter 1 Introduction: Provides an overview of the electricity network, its vulnerabilities to the weather and longer term changes in climate, and the objectives of the document;
- Chapter 2 Global Climate – Historic and Future: Provides a brief overview of the global climate system, how it has changed, the factors that influence these changes and how it is projected to change in the future;
- Chapter 3 Local Climate – Historic and Future: Provides information on present and future climate specific to the City of Toronto;
- Chapter 4 Weather Affects Network Performance: Outlines the impacts of the climate on network performance including examples of four recent events that affected Toronto Hydro's network;
- Chapter 5 Climate Adaptation in Other Jurisdictions: Provides examples of how utilities around the world are addressing the issues presented by climate change;
- Chapter 6 Toronto Hydro Actions to Date: Presents Toronto Hydro's efforts to understand and address climate changes and its impacts; and,
- Chapter 7 Next Steps and Conclusions: Summarizes the key points of the document and outlines a proposed approach for Toronto Hydro's adaptation planning.

2.0 Global Climate – Historic and Future

This chapter provides a brief overview of the global climate system, how it has changed, the factors that influence these changes and how it is projected to change in the future. Four climate variables are discussed: temperature, precipitation, wind and storms. For each variable, an overview of the globally observed and projected future changes is provided.

The main source of the global climate information presented in this chapter is the recent reports released by the Intergovernmental Panel on Climate Change (IPCC). The IPCC has members from 195 nations and is a leading scientific body established by the United Nations to assess the risks from climate change. The IPCC summarizes the state of knowledge on climate change, examining published and peer-reviewed literature to develop three working group reports covering the Physical Science Basis of Climate Change; Impacts, Adaptation and Vulnerability; and Mitigation of Climate Change. The latest set of reports, released in 2013 and 2014, are referred to as the Fifth Assessment Report (AR5).

Figure 4 illustrates some of the observed changes in climate extremes since the 1950's including increased hot days, heat waves, heavy precipitation, droughts and the frequency of tropical cyclones in the North Atlantic. These indicators represent climate variables that have seen the most robust global changes. Projections of the future climate indicate that these trends are likely to continue. The remainder of this chapter presents a discussion of these observed and projected future changes.

Figure 4 Climate Trends since the Middle of the 20th Century [1]

Note: Arrow direction denotes the direction of the change events (i.e. increase or decrease).
Figure source: (Hartmann, 2013, p. 219).

[1] Except for the North Atlantic storms where the period covered is from the 1970s.

2.1 Climate, Weather and Climate Modeling

Climate is the pattern of variation in temperature, humidity, wind, precipitation, pressure and other meteorological variables in a given region over an extended period of time. Weather is the present condition of these variables over shorter periods. In other words, climate is the average weather over a period of time ranging from months to thousands or even millions of years (Stocker T. D.-K., 2013a). The world's climate has changed in the past and will continue to do so. The indicators of climate change include physical changes in surface temperature, atmospheric water vapour content, precipitation, extreme events, glaciers, ocean and land ice, and sea level. The changing concentrations of the greenhouse gases[2] are another key indicator of global climate change (Stoker, 2013c).

Changes in the climate have been documented and measured using historical climate records (e.g. weather observations and ice core records) and global climate modeling. "A global climate model is a mathematical representation of the interactions between and within the ocean, land, ice and atmosphere" (Koshland Science Museum of the National Academy of Sciences, 2011). The models divide the earth into small boxes where energy, air and water are represented as horizontal and vertical exchanges between the boxes (Figure 5). The models seek to capture the complex interactions between the components. To test the accuracy of climate models, past climate conditions are modelled and compared with real historical climate data.

Many climate models have been developed in order to project future climate conditions. The different models vary in their ability to project different phenomena (e.g. temperature, precipitation) across different regions. Temperature and precipitation can be modelled with a high degree of accuracy over periods of 30 years. However, the modeling of smaller scale phenomena such as storms and seasonal events do not carry the same degree of precision (Koshland Science Museum of the National Academy of Sciences, 2011). The use of the outputs from multiple climate models is an acceptable scientific method of addressing the uncertainties in projecting future climate conditions (e.g. as demonstrated by IPCC's AR5). In this way, climate models are a useful tool to project future climate scenarios and inform assessments of vulnerability and adaptation planning.

Figure 5 Climate Modelling, an Overview

Figure source: (Koshland Science Museum of the National Academy of Sciences, 2011).

[2] Greenhouse gases (GHGs) are gases in the atmosphere that absorb and emit radiation within the thermal infrared range. This process is the fundamental cause of the greenhouse effect. While some of the solar radiation that passes through the atmosphere is reflected back into space, some amounts are absorbed by GHGs in the Earth's atmosphere. Common GHGs in the earth's atmosphere include water vapor, carbon dioxide (CO2), methane (CH4) and nitrous oxide (N2O). The greenhouse effect is the natural process that warms the earth to a habitable temperature. Human activity has significantly increased the rate at which greenhouse gasses are being released into the atmosphere causing an increase in the amount of heat trapped in the atmosphere, changing the earth's climate.

2.2 Temperature

Since the late 19th century, the Global Mean Surface Temperature ("GMST") has increased. Notably, the first decade of the 21st century has been the warmest decade on record and the three most recent decades have all of been warmer than any previous decade. Figure 6 shows multiple complementary temperature related indicators of a changing global climate. In summary they illustrate long term increases in temperature, humidity and sea levels and reductions in snow cover, sea ice and glacier mass.

Figure 6 Multiple Complementary Temperature Re lated Indicators of Global Climate Change

Note: Each colored line in the graphs represents a different dataset.
Figure source: (Stocker T. D.-K.-M., 2013b).

The global average surface temperature has increased approximately 0.6°C to 0.7°C between 1951 and 2010 (Stoker, 2013c). The IPCC indicates that global average surface temperature is likely to increase by between 0.4°C and 2.6°C by mid-century with the likely range given as 0.3°C to 0.7°C. By late century the increase is likely to be in the range of 0.3°C and 4.8°C. Both sets of projections are compared to a reference period of 1986-2005.

The rate of likely warming will be influenced by the level of future GHG emissions (which depend upon how population growth, economic development, technological dependence, and fossil fuel dependence, among other aspects, play out). In North America, climate warming is projected to result in increases in hot days and extended warm spells (i.e. heat waves), reductions in cold days, cold nights and frosts, and more rapid increases in minimum temperature extremes than maximum temperature extremes (Hartmann, 2013).

2.3 Precipitation

Precipitation (averaged over land areas) has increased since 1901 over the mid-latitude land areas in the Northern Hemisphere. For all other zones there is limited confidence in long term trends showing an increase or decrease in precipitation. Since the mid-20th century, the number of heavy precipitation events over land has increased in more regions than it has decreased. In North America, the frequency or intensity of heavy precipitation events has likely increased (Hartmann, 2013).

With increased global temperature, global-scale precipitation is expected to increase gradually in the 21st century (Stocker T. D.-K.-M., 2013b). As temperatures increase, short-duration precipitation events are likely to experience a shift to more intense individual storms and fewer weak storms. It is very likely that extreme precipitation events will become more intense and more frequent over most of the mid-latitude land masses by the end of this century (Stocker T. D.-K.-M., 2013b). In North America, the largest precipitation changes are projected to occur in winter.

The IPCC Fourth Assessment Report 2007 (AR4) drew no conclusion on historical changes in snowfall at a global scale. However, it did state that significant increases were found in most parts of Canada. According to the IPCC, studies since AR4 have continued to focus mainly on North America, showing that snowfall in Canada has increased mainly in the north, while a significant decrease has been observed in the southwestern part of the country between 1950 and 2009. According to IPCC's Fifth Assessment Report 2013 (AR5), most regions analyzed (including in North America and Europe) show that it is likely that there are decreasing numbers of snowfall events occurring where increased winter temperatures have been observed (Hartmann, 2013). At high latitudes of the Northern Hemisphere, projected precipitation increases may lead to increases of snowfall in colder regions and a decrease of snowfall in warmer regions due to a decrease in the number of freezing days (Collins, 2013).

2.4 Wind

There are uncertainties in the data sets and measurements used to analyze mean and maximum wind speeds over land (e.g. changing instrumentation and observing practices (Smits et al., 2005; Wan et al., 2010, in (Hartmann, 2013)) leading to low confidence in the assessment of these changes. However, recognizing these uncertainties, a weakening of seasonal and annual mean and maximum winds is reported for many regions from the 1960s and 1970s to the early 2000s, including much of the USA (Pryor et al., 2007 in (Hartmann, 2013)) and southern and western Canada (Wan et al., 2010 in (Hartmann, 2013)). Projections related to changes in maximum wind speed at a global level are focused on cyclones, which is addressed under the heading of Storms in the next section.

2.5 Storms

In the IPCC AR5 report, it was observed that the annual number of major storm events (which cover tropical storms, hurricanes/cyclones) have not increased over the past 100 years in the North Atlantic basin. However, the evidence indicates that since the 1970s the number of the most severe hurricanes/cyclones has most certainly increased in that same region, and that the intensity of these storms has also increased (Hartmann, 2013).

Projections for the 21st century indicate that the global frequency of hurricanes/cyclones will likely remain the same or decrease. However, it is likely that the maximum wind speed and precipitation amounts of these events will increase (Stocker T. D.-K.-M., 2013b). The confidence in region specific projections of hurricanes/cyclones is low. Furthermore, the frequency of the most intense storms will more likely than not increase in some basins including the North Atlantic and Western North Pacific. In addition, the extreme precipitation near the centres of hurricanes making landfall in North and Central America is projected to increase (Stocker T. D.-K.-M., 2013b).

In summary, although the annual number of major storm events has not increased over the last 100 years, the annual number of severe and intense hurricanes/cyclones has been increasing since the 1970s. In the future, while an overall increase in the number of hurricanes/cyclones may not be expected, those that do occur will continue the trend since the 1970s of being more intense and destructive.

3.0 Local Climate – Historic and Future

This chapter presents information on present and future climate specific to the City of Toronto. Based on information drawn from a climate study commissioned by the City of Toronto, the Toronto Climate Drivers Study (TCD Study), it was found that average annual temperature over the last 50 years has increased by 1°C and is projected to increase by up to 4°C by mid-century (i.e. 2050s). Increases in annual average temperatures will be accompanied by increases in the number of days of extreme maximum temperatures and extreme heat and humidity when compared with current climate patterns. Total annual precipitation is also projected to increase by mid-century with more of the precipitation falling in the form of rain than snow. It is projected that the magnitude of extreme rainfall events (i.e. the amount of precipitation dropped) may increase threefold. There is uncertainty in projecting the frequency and intensity of severe storm events like thunderstorms, ice storms, hail storms, etc. However, indications suggest that the frequency of storm events may be decreasing, and the intensity of storms and their accompanying precipitation and wind gusts are likely to increase.

3.1 The Toronto Climate Dr ivers Study Methodology

The climate information presented in the following chapter is drawn primarily from the Toronto Climate Drivers Study (TCD Study), commissioned by the City of Toronto in 2011. In commissioning the study, the City sought information that was more geographically specific than could be provided by larger scale global or regional climate modelling techniques. Lake Ontario has a significant influence on the climate experienced by the City of Toronto due to water's high heat specific heat capacity, and its relatively slower ability to warm up early in the spring and summer and cool off later in the fall. The influences of the lake on present and future local climate are inadequately captured by larger scale models (SENES Consultants Limited, 2011).

The TCD Study was used to model the climate for two ten-year time periods, from 2000–2009 (the current reference period) and 2040-2049. The modeling of the current reference period was used to check the accuracy and validity of the modelling method, which was then used to develop projections for 2040-2049. The modelling method applied in the study is based on a nested modeling technique where climate projections are developed at a coarser scale (300 x 300 km grids), downscaled using a regional climate model, and then fine-tuned to relatively minute 1x1 km grid scale using weather modelling tools for southern Ontario and the Greater Toronto Area (GTA). The climate information presented in the following sections are for the 2040-2049 period as compared to the 2000–2009 reference period.

The TCD Study produced data for 36 points across the GTA, 12 of which are located directly within the City of Toronto's municipal boundary. In the following discussion, only data for one point is provided, Toronto Pearson International Airport. While this location lies just to the west of the Toronto Hydro service area (e.g. the City of Toronto municipal boundary), it was chosen because its climate modeling information is based on a long term, high quality dataset maintained by the airport. The location is also sufficiently close to Toronto Hydro's service area that its climate modeling information can adequately illustrate how the climate is projected to change for the City of Toronto. Complete information of all data produced by the TCD Study can be found on the City of Toronto's website[3].

3.2 Toronto Climate Driv ers Study Limitations

As mentioned in the previous chapter, the process of projecting future climate using computer modelling is based on using mathematical equations to represent the complex physical processes that occur in the atmosphere, on land and in the oceans that shape and influence climate. There are several global and regional models that have been developed by scientific and research institutions around the world. While a discussion of the strengths and weaknesses of the different available modelling techniques is beyond the scope of this document, it should be

[3] www1.toronto.ca/wps/portal/contentonly?vgnextoid=b8170744ee0e1410VgnVCM10000071d60f89RCRD

noted that the TCD Study presents results based on one global and one regional climate model (the British Hadley HadCM3 GCM and the PRECIS RCM respectively). These models were considered state-of-the-art at the time the study was commissioned. Nonetheless, readers of the following chapter should be aware that the data presented contains some degree of uncertainty due to the complexities of modelling climate. Readers are invited to consult the original TCD Study for a full discussion of this uncertainty.

The use of only one model in the TCD Study does not encompass the full range of possible future climate values (e.g. averages, maximums, extremes) that may be produced by applying other climate models. However, the use of multiple modeling techniques at such a small local scale is impractical as it would be an extremely time and resource intensive undertaking.

It should also be noted that modelling techniques have continued to improve since the publication of the TCD Study (Flato, et al., 2013). These limitations however do not negate the discussion and utility of the TCD Study's results, which generally illustrate how the climate can be expected to change due to continued emissions of greenhouse gases.

Finally, the reader should keep in mind that future climate projections were developed based on plausible but hypothetical scenarios of future atmospheric GHG emissions rates and concentrations, the primary drivers of a changing climate. The TCD Study used one plausible future greenhouse gas emissions scenario, A1B, which predicts a future world that is characterized by rapid economic growth, global population increases to 9 billion people by 2050 (after which population stabilizes and gradually declines), as well as middle-of-the-way technological outlook and dependence on fossil fuels.

The A1B scenario was selected for the study as being representative of a moderate economic outlook that would also reveal clearly identifiable consequences from the continued emissions of greenhouse gasses for the 2040-2049 period in Southern Ontario. The data presented in the next section should be considered within this context, and its validity will depend on whether or not the conditions set out by the A1B scenario, including atmospheric greenhouse gas concentrations, are met.

3.3 Temperature

Annual average temperatures across Ontario have increased between 0^{o}C and 1.4^{o}C during the last half of the 20th century (1948-2006) (Chiotti & Lavender, 2007). Furthermore, the number of warm days and nights has increased throughout the province. Eight out of the ten warmest years on record in the region around the Great Lakes have occurred since 1990 (SENES Consultants Limited, 2011).

In the future, many indicators show that the City of Toronto will experience warmer years by 2040-2049 when compared to the 2000–2009 baseline period as determined for Toronto Pearson Airport. Average annual temperatures, as well as extreme high and low temperatures are all increasing. For example, average temperature is projected to increase by 4.4°C in the Toronto area compared to the global average of 0.4°C to 2.6°C (Stoker, 2013c) by mid-century. The humidex, an indicator of how hot the weather feels to the average person when both temperature and humidity factors are combined together, is generally increasing throughout the year and is most pronounced during the warm summer months of June to August. For example, extreme humidex is expected to reach 56.5 (°C equivalent) in the month of July by the 2040-2049 period, as compared to current level of 48 (°C equivalent). Table 1 summarizes the temperature related indicators between the reference and mid-century periods.

Table 1 Temperature Indicators, 2000–2009 and 2040–2049 Comparisons at Toronto Pearson Airport

Indicator	2000–2009 (Reference) Period	2040–2049 (Projected)	Difference[4]
Average Annual Temperature (°C)	8.7	13.1	+ 4.4
Extreme Maximum Temperature (°C)[5]	36.9 (August)	44.4 (August)	+ 7.6
Extreme Minimum Temperature (°C)[6]	-24.4 (December)	-11.4 (December)	+ 13.0
Extreme Humidex (feels like °C)[7]	47.9 (August)	56.5 (July)	~ +10

Table source: (SENES Consultants Limited, 2011).

An additional indicator of energy demand as related to temperature was also investigated in the TCD Study. It showed that the number of days per year where temperatures exceeded 20°C (the temperature generally above which air conditioning is used) will increase from 132 days per year during the reference period to 160 days per year during the 2040-2049 period.

The number of days where temperatures exceed 35°C is expected to increase from 0.8 to 14 days per year by mid-century. On the other hand, the number of days per year where temperatures drop below 10°C is expected to decrease from 151 to 110[8]. This indicates that a changing climate will increase demand for summertime cooling (i.e. air conditioning) while decreasing winter electrical demand for heating (see Table 2 for a summary).

Table 2 Number of Days at Select Temperature Thresholds, 2000–2009 and 2040–2049 Comparisons at Toronto Pearson Airport

Indicator	2000–2009 (Reference Period)	2040–2049 (Projected)	Difference
Number of days above 20°C per year	132	160	+28
Number of days above 35°C per year	0.8	14.1	+13.3
Number of days below above 20°C per year	151	110	- 41

Table source: (SENES Consultants Limited, 2011).

[4] Differences may not be exact due to the rounding of values.
[5] This is the highest expected maximum temperature reached in any given year within the time period.
[6] This is the highest expected minimum temperature reached in any given year within the time period.
[7] This is the highest expected humidex rating reached in any given year within the time period.
[8] Note that the temperature below which heating demand increases in Canada is generally 18 °C. However, data for this threshold was not available in the TCD Study, and 10 °C is next lowest value for which projections are available.

3.4 Precipitation

In general, total annual precipitation is expected to increase for the Toronto area as demonstrated by the estimate of a +15% increase at the Toronto Pearson Airport location. Warming temperatures, especially in wintertime, are expected to cause more of this precipitation to fall as rain rather than snow. Table 3 shows how annual rainfall, annual snowfall and the combined annual precipitation are expected to change between the two periods.

Table 3 Precipitation Indicators, 2000–2009 and 2040–2049 Comparisons at Toronto Pearson Airport

Indicator	2000–2009 (Reference Period)	2040–2049 (Projected)	Difference
Total Annual Rainfall (mm)	624.2	848.3	+ 224.1 (+36 %)
Total Annual Snowfall (cm)	153.8	48.1	- 105.7 (-69 %)
Total Annual Precipitation (mm)	778	896.4	+ 118.4 (+15 %)

Table source: (SENES Consultants Limited, 2011).

An analysis of the changes to precipitation patterns by season reveals that the total amount of precipitation received is expected to increase the most during the summertime followed by the fall. Total precipitation is expected to decrease during the winter and spring, especially precipitation that falls in the form of snow. (see Table 4 for summary).

Table 4 Changes in Seasonal Precipitation Patterns between the periods 2000–2009 and 2040–2049

Indicator	Winter	Spring	Summer	Fall
Total Rainfall (mm)	+58.5	+4.1	+134.6	+26.9
Total Snowfall (cm)	-73.9	-23.7	0	-8.1
Total Precipitation (mm)	-15.3	-19.7	+134.6	+18.8

Table source: (SENES Consultants Limited, 2011).

In addition to increasing annual rainfall, the TCD Study states that the intensity of rainfall events will increase. By mid-century, the rainfall intensity (mm / hour) of storms lasting two hours or more could double compared to similar storms in the 2000–2009 reference period (SENES Consultants Limited, 2011). As illustrated in Figure 7, there could be a threefold increase in the magnitude of extreme rainfall events during the month of July in the future as compared to the current reference period (SENES Consultants Limited, 2011).

Figure 7 Projected Magnitude of Extreme Rainfall Events by Month at Toronto Pearson International Airport, 2000–2009 and 2040–2049 periods

Figure source: (SENES Consultants Limited, 2011, pp. ES-11).

3.5 Wind

The risks posed by wind are generally expected to decrease as the climate warms, although they still pose a significant threat where they occur in conjunction with severe storm activity. According to the TCD Study, when compared to the current reference period, average wind speed, the speed of maximum wind, and the speed of wind gusts throughout the year all drop in the 2040–2049 period (by -7%, -48% and -42% respectively). According to the study's authors, "this finding can be explained by the fact that, with increased temperature, the differences between the air masses will decrease and the driving force for horizontal wind speed will decrease" (SENES Consultants Limited, 2011, pp. 5-14). However, it was noted that vertical wind speeds will likely increase as a result of increased convective storm activity. This will likely affect horizontal wind speeds, but insufficient information was available to quantitatively evaluate this phenomenon.

It is not unsurprising that wind chill events are also expected to decrease in the future due to increases in wintertime temperature. The number of days where wind chill values exceed -20 °C drops from 13.1 days per year in the current reference period to zero days in the 2040–2049 period.

3.6 Storms

The TCD Study emphasizes that predicting storm events (thunderstorms, hail storms, tornadoes, including events in the summer and winter) is an extremely difficult task due to the very small temporal and spatial scales on which they occur. Nonetheless, the study authors use a set of three indices to predict the occurrence of storms in the future.

Study authors find that the total number of storm events, based on the indices calculated for Toronto Pearson Airport, is decreasing throughout the year. This decrease is greatest in the winter. However, it was noted that potential for more intense and severe summer storms is increasing. This coincides with the finding that there will likely be fewer heavy precipitation events occurring in the future, but the amount of precipitation from these events is likely to be greater (SENES Consultants Limited, 2011). Furthermore, it is expected that more intense summer storms may be accompanied by stronger sustained winds and almost equally strong wind gusts than have been experienced in the reference period.

3.7 Other Climate Related Factors that Require Further Information

There is a range of other weather and weather related events that are relevant to assessing the likely risks to the electricity distribution network that require further study and investigation. Notably, these events include freezing rain and ice storms, flooding, fire and pests.

Freezing rain and ice storms are weather events where precipitation falls in liquid form and freezes upon contact with the ground or objects (e.g. trees). The amount of ice accumulation generally depends upon the duration of the event. More severe and longer duration (i.e. 6+ hours) events are often labelled as ice-storms.

Some work was completed on estimating the occurrence of these events for the City of Toronto as part of a risk assessment undertaken by Toronto Hydro in 2012 (AECOM, 2012). In that study, preliminary research suggested that climate change is expected to initially increase the risk of freezing rain events. As winter temperatures warm, mixed phase precipitation (e.g. wet snow, freezing precipitation) may become more frequent, leading to an increase in the frequency and intensity of freezing rain events.

Climate change is also likely to lead to longer duration ice storm events in the Toronto area due to climate change (Risk Sciences International, 2012). However, further work is necessary to establish potential timelines, frequencies and severities of such events, and to assess whether their intensity and frequency may taper off as temperatures continue to warm to mid-century.

The City of Toronto is a highly urbanized area, and the impacts of urban flooding can lead to significant damage, infrastructure service disruptions and economic costs. From 1985 to 2005, there were seven heavy rainfall events with a return frequency greater than 25 years that led to severe surface and basement flooding in the City of Toronto (D'Andrea, 2005).

At this time, further information is required to understand how the projected changing frequency and intensity of precipitation and storm events might contribute to riverine and urban flooding throughout the city, potentially putting infrastructure at risk of flooding that has not historically been at risk.

Fire risk may be enhanced by extreme drought conditions or increased ground strike lightning activity. Drought conditions increase the possibility of natural (e.g. lightning) and human-related fire risks (accidental fires, cigarettes, branch contacts with electrical wires causing sparks). While the City's urban areas are generally protected through a hydrant network, the city's ravines, parks and other greenbelt forests may be subject to increased fire risk in the future.

Furthermore, warmer year round temperatures are expected to prolong the growing season, potentially enhancing growth of tree foliage around electrical equipment increasing the risk of contact causing fires or damaging lines. Further work is required to better understand the potential changes in the risk profiles related to drought, lightning strikes, and increased vegetation growth rates.

Future warming of the climate could lead to more favourable conditions for the establishment of pests and vector and rodent borne diseases in Southern Ontario that may pose risks to certain types of infrastructure or field crews. For example, conditions may become favourable for the range of termites to expand (Peterson, 2010). In addition, diseases such as Lyme disease (tick-vector), West-Nile Virus and malaria (mosquito-vector), Hantavirus Pulmonary syndrome (rodent-vector) may become more prevalent as the warming climate favours the survival of disease vectors through the winter (Chiotti & Lavender, 2007). More information is still required to understand and project the spread and timelines for the migration of these pests and diseases in Southern Ontario.

4.0 Weather Affects Network Performance

Weather events impact all aspects of the electrical sector, from electricity generation, transmission and distribution infrastructure to consumers (i.e. demand). These impacts are already actively managed by infrastructure owners and operators. For example, electrical system components are designed to operate up to specific weather related thresholds, and equipment often continues to function to some extent beyond design thresholds due to built-in engineering safety margins. However, as explained in the previous chapter, climate change will bring about changes to temperature and precipitation patterns, averages and extremes.

A changing climate will impact the electrical system by exceeding the current system's design tolerances and operating characteristics, and may make current procedures and practices less effective in maintaining system reliability. This may result in impacts ranging from decreased capacity, shortened equipment life, equipment damage, to complete failure and power outages.

This chapter presents the range of impacts that climate change is expected to have across the electrical sector, the manner in which these impacts are tracked, and specific examples of recent weather events and their impacts on Toronto Hydro's network.

4.1 What are the Impacts?

The broad range of impacts across the entire electrical sector has been documented in numerous studies including those undertaken by Natural Resources Canada (Chiotti & Lavender, 2007) and the US Department of Energy (US Department of Energy, 2013). Impacts identified include increasing ambient air and water temperatures, decreasing generating efficiencies and power output, and increasing fuel consumption for thermoelectric power plants. Fuel supply transportation and infrastructure (i.e. pipelines, marine transportation) may be disrupted by extreme events.

Gradual changes to precipitation patterns will affect water availability, reducing hydro generation potential, stress ecosystems and consumptive water uses. Increased air temperatures are also expected to reduce transmission and distribution system efficiencies and power carrying capacity. Increased temperatures also contribute to conductor line sag, posing fire and safety risks if lines come in contract with trees or other on-ground objects.

Increased annual temperatures will increase the demand for summertime cooling while decreasing the demand for heating. However, while annual net energy demand may remain similar, peak load characteristics will change due to increased summertime cooling. Peak cooling demand due to high temperatures also tends to coincide with the greatest generation and transmission inefficiencies and losses, and may lead to greater wear on the system, increased fuel consumption, and potential outages due to component failures or demand exceeding supply.

Increased annual temperatures are likely to lengthen the growing season, and vegetation may experience greater than historical growth rates especially in the spring and fall. Increased vegetation growth can increase the likelihood of some risks such as tree contacts with wires during summer and winter storms. Risks of tree contacts may also increase during periods of high heat as a result of both line sag and increased vegetation growth.

Other intensifying weather events such as heavy rainfall and the occurrence of severe storms and high winds, will impact the reliability of the system. Unlike the gradual effects of temperature, precipitation and wind events tend to affect the system by directly damaging the system components or supports, or cause tree branches, trees or other wind-blown debris to come into contact with lines and supports.

Severe and intense rainstorms that exceed the capacity of existing drainage infrastructure can lead to flooding and washouts. Not only can equipment be damaged in the flood, but access to repair equipment is also hampered until flood waters clear and access can be reinstated. High winds and freezing rain can bring down power lines and poles themselves, or cause tree branches and other debris to contact and break lines and supports.

These primary physical impacts to system components and operations can lead to flow on impacts to the activities and systems that depend upon a reliable electrical supply. Outages directly affect the industrial, commercial and agricultural activities through the lack of power to production and storage facilities (e.g. refrigeration). Impacts can also be felt by companies and operations outside of the affected area as they can no longer supply affected businesses and industries, or depend on the outputs of affected businesses.

A reliable power supply is essential to the operations of key infrastructure services such as transportation (e.g. transit, signalling and lighting), drinking water and waste water services, as well as health and community services and facilities. Power disruptions also affect public safety (e.g. lighting, heating and cooling) and hinder emergency response and disaster recovery. Finally, the quality of life for residents (lighting, refrigeration, use and enjoyment) is affected by power disruptions.

Table 5 provides a summary of the impacts extreme weather events and the changing climate will have on the electrical sector as well as flow-on impacts to the community, economy and environment.

Table 5 High level Impacts across the Electrical Sector and Flow-on Impacts to the Broader Community

Impacts to the Electrical Sector		
Generation	Transmission and Distribution	Demand
x Changes in water levels affecting hydro plant generation capacity; x Increased cooling water temperatures impacting cooling efficiencies at thermal and nuclear facilities decreasing generation capacity x Increased storm intensity, frequency of flooding and risk of fire causing physical damage to assets and disruption of generation x Extreme events disrupting fuel transportation affecting generation capacity	x Increased temperatures reducing transmission efficiency and increasing transmission and distribution losses x Increased extreme temperatures causing damage to assets and risk of fires x Increased storm intensity, wind, lightning, frequency of flooding, vegetation growth and risk of fire causing physical damage to assets and disruption of services x Reduced asset life from change in ground movement and chemistry, corrosion rates, structural fatigue and change in distribution of pest species	x Increased temperatures causing increased demand for cooling x Increased wintertime temperatures resulting in decreased demand for heating by electricity or other fuel sources x Increased extreme temperatures causing increased peak electricity demand and blackouts x Note that policy responses such as improvements in energy efficiency and embedded generation will also affect demand profile
Flow-on impacts to the Broader Community		
x Disruption to commercial activities, loss of productivity and revenue x Disruption to industrial activities, potential loss of production capacity, delays and interruptions to supply chain x Disruption to agricultural activities, including storage (refrigeration) and processing x Losses leading to insurance cost increases x Disruption to transportation systems (e.g. trains, facilities, signaling) x Impacts to infrastructure services (e.g. water supply, sewer treatment) x Disruption of emergency services, disaster response and recovery x Public safety risks (e.g. loss of heating / cooling, loss of security / street lighting) x Impacts to essential services (e.g. health care, palliative care and at home care) x Disruptions to municipal and community services (e.g. indoor and outdoor facilities) x Reduction in quality of life from increased frequency and duration of outages (e.g. loss of refrigeration, lighting)		

4.1.1 Tracking System Reliability

Weather impacts to electrical systems can compromise system reliability. Two common metrics used by electrical utilities, including Toronto Hydro, to track system reliability are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI).

SAIDI is used to measure the average outage duration experienced by customers. It is calculated by summing up the total duration of all outages experienced by customers for a given time period (e.g. annually, a single storm event) and dividing by the number of customers in the system. SAIDI is measured in minutes. System design (e.g. system redundancy, segregation), restoration practices and response times all impact SAIDI values.

SAIFI measures the average number of outages experienced by customers for a given time period (e.g. annually, a single storm event). It is calculated by dividing the total number of customer interruptions by the total number of customers in the system.

Tracking of SAIDI and SAIFI year over year provides valuable information with which to judge an organization's efforts to maintain or improve reliability. Inversely, an increase in SAIDI and SAIFI values over time, given a fixed standard of system design or similar basis of operational management, may indicate how factors external to the organization, such as climate change influenced-weather, are impacting the reliability of the system.

4.1.2 Toronto Hydro's Recent Reliability

Table 6 reports annual SAIDI values (in minutes) from 2000 to 2013 for Toronto Hydro. These SAIDI values are drawn from Toronto Hydro's database, and encompass events where weather may have played a role in causing an outage. However, these values do not include SAIDI values reported for major event days (MEDs), for example when a major storm has occurred and caused significant outages. Excluding MEDs, the average annual value for SAIDI between 2000 and 2013 due to possible weather related outages is approximately 29.3 minutes.

MEDs are determined based on the applying the method set out in the Institute of Electrical and Electronics Engineers (IEEE) 1366 Standard in the analysis of Toronto Hydro's SAIDI database[9]. Since 2005, the average SAIDI value for a major adverse weather event (MED) is considered to be between 5 and 9 minutes for Toronto Hydro. Expressed another way, the SAIDI threshold indicating a major event day for Toronto Hydro is between 5 and 9 minutes.

Table 6 Tracking Toronto Hydro's System Reliability using SAIDI

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Annual SAIDI excluding MEDs (min)	40.5	33.3	35.6	35.0	18.4	19.8	26.9	26.5	26.6	28.9	32.8	38.2	16.8	30.5
Average Annual SAIDI 2000–2013 excluding MED	29.3 minutes													
Average SAIDI of a MED, or threshold when a MED is considered to have occurred, tracking since 2005	5–9 minutes													

The annual and MED values of SAIDI can be used as a point of comparison in the following section where examples of extreme weather events affecting Toronto's Hydro's network performance are presented. The impacts of extreme weather events on system reliability, reported as SAIDI values for storm events, are discussed.

[9] Days on which SAIDI values fall outside of 2.5 standard deviations of a five-year rolling average of SAIDI values are considered MEDs.

4.2 Recent Weather Events A ffecting Network Performance

This section presents an overview of four recent weather events that affected Toronto Hydro's network performance. The events chosen do not attempt to be an exhaustive list of recent extreme events. Rather, they were selected to provide an example of a range of events that have affected performance including extreme rainfall, thunderstorms, extreme wind and ice storms. The four events presented are:

- Severe Thunderstorms, August 2005;
- Hurricane Sandy, October 2012;
- Extreme Rainfall, July 2013; and,
- Ice Storm, December 2013.

4.2.1 Severe Thunderstorms, August 2005

On August 19, 2005, Ontario experienced its most expensive weather disaster. In Toronto, the event was characterised as being greater than one-in-100-year storm (SENES Consultants Limited, 2011), featuring torrential rains, quarter to golf-ball size hail, strong straight-line winds and flash flooding. At the height of the storm, wind gusts peaked at 72 km/ h and there were 1,400 lightning strikes per minute (SENES Consultants Limited, 2011).

The storm caused $671 million in damages, more than two and half times the losses of the next largest event, the 1998 ice storm (CBC News, 2013b; SENES Consultants Limited, 2011). The majority of the damage was caused by flooding, with many records broken including the national rainfall accumulation records for the 10, 15, 30 and 120 minute rainfall durations (Risk Sciences International, 2012). Within a three hour period, 153 mm of rain fell causing significant damage including washing out a 78 m stretch of Finch Avenue (Figure 8 and Figure 9), collapsing the Black Creek culvert, washing out a 48 m section of trunk sewer and unprecedented flooding of basements in private residences (Wells, 2012).

For Toronto Hydro, this storm caused mass outages across the city outside of the downtown area. The majority of impacts were felt on overhead systems, which were affected by winds, wind blow debris, lightning and tree contacts. Heavy precipitation also caused flooding of equipment located underground causing systems to fault. In the specific area around the Finch avenue washout, power lines and poles remained intact after the storm. However, Toronto Hydro forced an outage to the area as a protective measure in case the ground conditions around the creek deteriorated further.

During this major storm, on August 19, 2005, Toronto Hydro experienced a SAIDI count of 19.16 minutes (Toronto Hydro, 2013). This is almost equal to the total annual SAIDI value due to 'normal' (i.e. non-extreme) weather events of 19.8 minutes for the entire year of 2005. Furthermore, the SAIDI for this event was more than double the average SAIDI count for a major adverse weather event of 5 and 9 minutes for Toronto Hydro.

Figure 8 Finch Avenue in Toronto Being Washed Out During the August 19, 2005 Storm

Figure source: (Macleod, 2011).

Figure 9 Details of Affected Infrastructure Resulting from the Washout of Finch Avenue in Toronto by the August 19, 2005 Storm

Figure source: (Macleod, 2011).

4.2.2 Hurricane Sandy, October 2012

Hurricane Sandy was the deadliest and most destructive hurricane of the 2012 Atlantic hurricane season (Blake, 2013). It was measured to be the largest Atlantic hurricane on record with winds spanning 1,600 km as it reached the coast of the north-east United States (Toronto Hydro, 2012). On October 29th, 2012, Hurricane Sandy made landfall in New Jersey. Strong winds and flooding from rainfall and storm surge caused loss of life and significant damage to infrastructure including flooding streets, tunnels, subway lines, and power outages.

Even though the United States received the worst of Hurricane Sandy's impacts, Southern Ontario, Quebec and parts of the Maritimes were hit by the storm as well. In Canada, the estimated insured property damage from Hurricane Sandy was $100 million (Blake, 2013). Toronto received wind gusts of up to 100km/h (Mehta, 2012) and 25mm of rain (Toronto Hydro, 2012). There was significant infrastructure damage, some loss of life and interruptions to transport as a result of damaged traffic lights and cancellation of flights.

In Toronto, 218,000 customers lost power, of which 65,000 experienced sustained outages (Toronto Hydro, 2012). About 10,000 Toronto Hydro customers remained without power on the day following the event (O'Toole, 2012).

As per Toronto Hydro's records, the SAIDI count on October 29, 2012 was 9.37 minutes disrupting 77,099 customers and on October 30, 2012 was 18.78 minutes disrupting 61,043 customers for a total of 28.15 minutes over the two days (Toronto Hydro, 2013) The total SAIDI for both days far exceeds the total annual SAIDI value due to 'normal' (i.e. non-extreme) weather events of 16.8 minutes for the entire year of 2012. The two daily SAIDI values are also greater than the average SAIDI count for a major adverse weather event of 5 and 9 minutes for Toronto Hydro. Figure 10 shows an example of Toronto Hydro power lines that were downed by Hurricane Sandy.

Figure 10 Downed Toronto Hydro Power Lines as a Result of Hurricane Sandy, October 2012

Figure source: Toronto Hydro.

4.2.3 Extreme Rainfall, July 2013

Toronto recently experienced another extreme storm event on July 8, 2013. 126 mm of rain fell on Toronto in a two-hour period, more than the monthly average rainfall for July (68 mm, (SENES Consultants Limited, 2011)). The storm caused flooding in basements and underpasses (Figure 11), downed trees, disrupted train and airline services, and caused significant power outages.

The storm caused power outages that affected 324,672 Toronto Hydro customers (Toronto Hydro, 2013) as a result of flooding at Hydro One's Manby substation. By 10am on July 9, 35,000 customers were still without power, mainly in the west end of the city. By July 10, power was restored to all but 600 customers, most of which were affected by localized outages (e.g. caused by tree branches breaking lines).

This event is expected to be the most expensive natural disaster in Ontario history with preliminary estimates of insured property damage placed at more than $850 million (CBC News, 2013b). The previous most severe weather events in Ontario were the severe thunderstorms on August 19, 2005 which caused $671 million of damage, and a July 24–29, 2009 storm that caused $228 million of damage (CBC News, 2013b).

For Toronto Hydro, the SAIDI count for this event was 197.26 minutes (3 hours and 20 minutes) (Toronto Hydro, 2013). This value far exceeds the total annual SAIDI value due to 'normal' (i.e. non-extreme) weather events of 30.5 minutes for the entire year of 2013. It is also significantly greater than the average SAIDI count for a major adverse weather event of 5 and 9 minutes for Toronto Hydro.

Figure 11 Cars Stranded in Floodwater in Toronto July 8th, 2013

Figure source: (Anderson & Hicks, 2013).

4.2.4 Ice Storm, December 2013

On the morning of December 22, 2013, over 30 mm of freezing rain blanketed roads and trees, sending broken branches into power lines (Figure 12 and Figure 13) across Toronto and in Southern Ontario (Canadian Press, 2013).

Approximately 300,000 Toronto Hydro customers were affected by outages resulting from more than 120 primary feeders going out and more than 560 downed wires. Many customers remained without power for days after the ice storm. Overhead infrastructure was hit the hardest including primary and secondary conductors. More specifically, secondary conductors were affected by the extensive tree canopy in Toronto coming into contact with equipment. A preliminary count indicated that Toronto Hydro replaced 57,862 m of overhead secondary conductors, a figure that is equal to 20% of the amount of overhead cables that were replaced in 2012.

Secondary conductors are designed to withstand the combination of temperatures of - 20^{o}C, 12.7 mm of ice accumulation and 92 km/hr winds in a worst case scenario. The ice storm brought 10 mm to 30 mm of ice accumulation to parts of Toronto, exceeding the designed standard maximum for ice accumulation (CBC News, 2013c).

The preliminary totals for SAIDI for the period 21 December 2013 to 26 December 2013 was 990.70 minutes, significantly above the total annual SAIDI value of 30.5 minutes due to 'normal' (i.e. non-extreme) weather events for the entire year of 2013 as well as the average SAIDI count for a major adverse weather event of 5 and 9 minutes for Toronto Hydro.

Figure 12 Weight of Ice on Tree Branches Caused Them to Break and Fall on Power Lines

Figure source: Toronto Hydro.

Figure 13 Damage to Power Lines from the Ice Storm in a Residential Neighbourhood

Figure source: Toronto Hydro.

5.0 Climate Adaptation in Other Jurisdictions

Many infrastructure utility owners and operators (including electrical utilities) in Canada and around the world are seeing significant damage and disruption to their infrastructure as a result of extreme weather events. In addition to acknowledging these weather related-vulnerabilities, many utilities are recognizing that the climate will continue to change. They also see the need to take steps to better understand the likely climate change impacts to their systems, assets and services, and to plan accordingly.

The following examples demonstrate how some of these utilities, with focus on the electrical sector, are addressing the issues presented by climate change. While the projected changes in climate and the impacts to infrastructure differ across regions, in general there is increasing action on the part of utilities to better understand the impacts and invest in measures that build the resilience of networks. The case studies presented in this section illustrate the following:

- In Canada, at the national level, there is acknowledgement that climate change presents potentially significant risks to critical public infrastructure and that there is a need to better understand the risks to enable proactive management. This is demonstrated by the Natural Resources Canada (NRCan) report From Impacts to Adaptation: Canada in a Changing Climate 2007 and the completion of 25 climate change risk assessment case studies across multiple sectors, one of which involved Toronto Hydro's electrical distribution assets;
- In Ontario, Horizon Utilities conducted an assessment in 2012 of climate change related risks to its business and developed a twenty-year adaptation strategy and action plan addressing assets, operations and procurement practices;
- In California, a study has quantified the impacts that climate change may have on electrical network performance. Increases in outages and reduced performance will occur as temperatures increase;
- Consolidated Edison of New York Inc. illustrates how stakeholder interest and pressure contributed to a regulatory requirement for considering climate risks and investment in resiliency projects, with $1 billion approved by the regulator to support implementation;
- The UK case study illustrates how regulatory requirements have driven assessments of climate risk on electrical utilities and provides examples of the approach used to fulfill the requirements; and,
- Australia provides an example of the significant disruptions extreme weather caused to electrical networks in two regions and approaches to build resilience (both direct and seeking regulatory support).

5.1 Case Studies in Canada

The concern about climate change impacts in Canada has clearly been demonstrated by the efforts being made across different infrastructure sectors and by different municipal and provincial organizations. For example, in 2005, the Canadian Council of Professional Engineers (Engineers Canada) established the Public Infrastructure Engineering Vulnerability Committee (PIEVC) to lead efforts to systematically understand infrastructure engineering vulnerabilities to a changing climate. The PIEVC workgroup involves representatives of all three levels of government and spearheaded the development and application of screening level risk-assessment methodology to assist infrastructure owners and operators identify and understand the impacts of climate change on their assets.

To date, 25 individual PIEVC case studies applying the risk assessment methodology have been completed by infrastructure owners responsible for water resource systems (e.g. stormwater, waste water, drinking water, storage and control, coastal protection), transportation (e.g. roads, bridges, airports) and buildings[10]. One of the case studies involves Toronto Hydro, which completed the first phase of its study in 2012 focusing on its electrical distribution assets (discussed in further detail in Chapter 6).

[10] Consult www.pievc.ca/e/doc_list.cfm?dsid=3 for the full range of case studies.

All case studies completed to date have shown that, based on experiences with current climate, there are ongoing critical vulnerabilities that will be exacerbated by a changing climate, and that considered, ongoing and careful responses to a changing climate are required on the part of infrastructure owners and operators to ensure service reliability in the future (Engineers Canada, 2014).

There are also two further PIEVC case studies currently underway specific to the electrical sector. The first is being led by the Ontario Power Authority (OPA) in partnership with the Toronto Region Conservation Authority. This risk assessment is focussed on OPA's provincial electrical transmission infrastructure. The second study is being undertaken by Toronto Hydro in partnership with NRCan, Clean Air Partnership, and AECOM, and represents the second phase of the climate change risk assessment study completed in 2012. Both of these studies are due for completion in March 2015.

The outcomes of the PIEVC case studies were made possible by the joint recognition of the threats of climate change by the Canadian infrastructure owners and all tiers of government. The provision of financial and human resources from all parties was also critical to the successful evaluation and prioritization of risks and development of preliminary adaptation actions.

As another example of Canadian efforts regarding climate change, in 2012, Horizon Utilities[11] sought to understand the risks posed by climate change to its electrical distribution system by producing a report detailing climate change scenarios and potential impacts on the company's assets and operations. The report presented key issues and strategies to address these impacts over the next 20 years. Horizon Utilities also developed an adaptation strategy and action plan to minimize the risks of climate change to their infrastructure assets, notably through interventions on the infrastructure, operational and procurement elements of their business (Canadian Electricity Association, 2013; Horizon Holdings Inc., 2012).

Not only do the previous examples serve to inform individual infrastructure owners of the vulnerabilities of their assets, but the findings have informed ongoing discussions about the need to reconsider equipment design standards. All of the works have identified the need to develop better projections and understanding of climate change, and for ongoing monitoring, evaluation and handling of potential impacts through adaptation.

5.2 California Energy Commission, USA

The California Energy Commission recently worked with the Lawrence Berkeley National Laboratory to study the impacts of climate change on California's energy infrastructure including generation, transmission and distribution assets. The study focused on the vulnerability of California's energy infrastructure to warming temperatures, increased incidence of wildfire and sea level rise and storm surge.

The study found that increasing temperatures would have numerous impacts on the network including (Sathaye, 2012):

- Reducing substation efficiency (up to 2.7% by the end of the century);
- Reduction in transformer capacity (-0.7% for every degree over 30°C);
- Increase in transmission and distribution losses (between 1.5% and 2.5% by the end of the century);
- Decrease in capacity of fully loaded transmission lines (7.5% based on 5°C increase in the temperature on a hot day);
- Reduction in generation capacity of gas fired plants (10.3 GW on hot days);
- Increases in peak demand (21% on hot days);
- Need for increased generation capacity in some parts of the grid to maintain current performance (31.2%, excluding allowances for changes in population); and,
- Operation and maintenance activities may be affected during very hot temperatures.

The study also acknowledged that increasing temperatures increases the risk of fires. It noted that increased fire risk is likely to have the greatest impact on the network through increased maintenance costs and reduced efficiencies rather than directly causing outages. The assessment of sea level rise and storm surge impacts

[11] Horizon Utilities is an electrical service provider for residents and businesses in the cities of Hamilton and St. Catharines, Ontario.

identified 25 coastal power plants and numerous electricity substations and natural gas facilities at risk from flooding.

The study concluded that many of the impacts of climate change to the network may be avoided if they are anticipated and planned for. Examples of proactive measures included increasing generation capacity and protective measures to reduce flood risks.

5.3 Consolidated Edison of New York, Inc., USA

In New York City there has been significant interest in the response of Consolidated Edison Company of New York, Inc. (Con Edison) toward building the resilience of its network. This interest has centred on the most recent rate case. In December 2012, a coalition of concerned NGOs and academic centres, led by the Columbia Centre for Climate Change Law, filed a formal petition to the Public Service Commission (PSC) asking that it require all the utilities it regulates to develop climate adaptation plans.

The petition presented historical information indicating the impact of storms on utility service interruptions from 2007 to 2011 in support of its argument (Figure 14).

Figure 14 Total Customer Hours of Utility Service Interruption in New York City from 2007 to 2011 and Hours of Interruption due to Storms

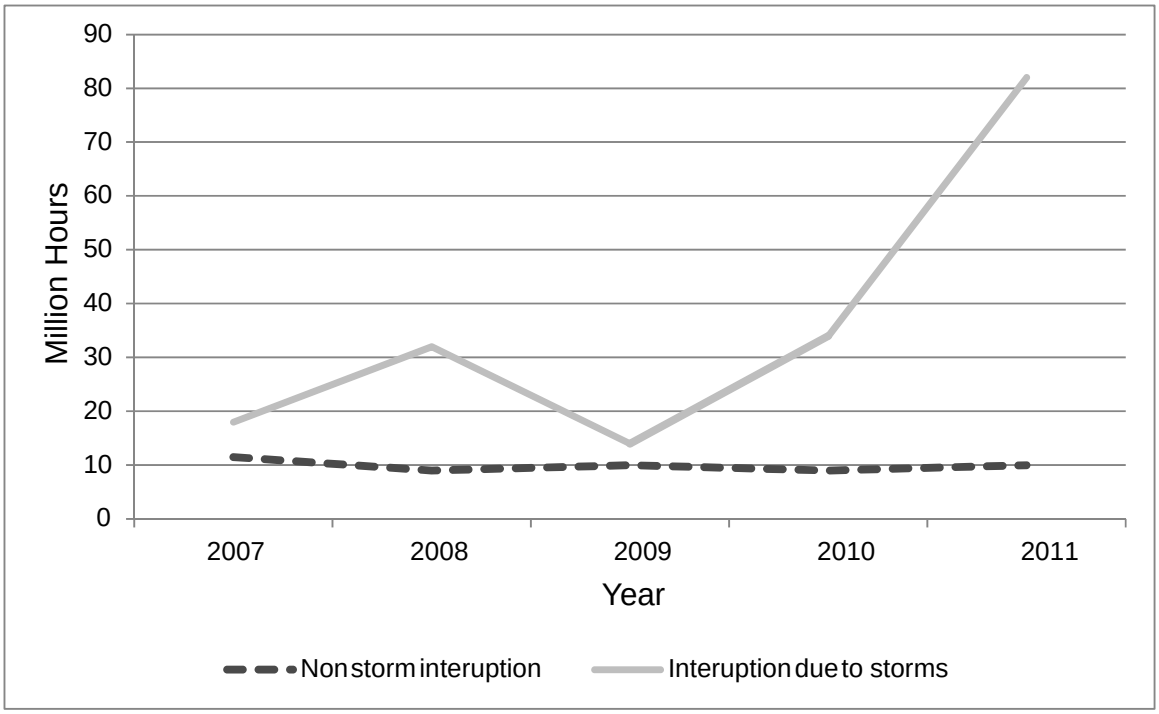


Figure source: (Source PSC 2011 in (Siders, 2012))

As well as the petition, the New York City Policy Panel put forward a testimony before the New York PSC Commission seeking harmonization of state and city energy policies to be implemented and advanced by Con Edison. In addition, it recommended that "the PSC place greater emphasis on the resiliency of the utility infrastructure in New York City, including a holistic shift in utility design, planning, construction, and operations to reflect the changing factors that can impact Con Edison's ability to provide safe and adequate service" (Mahnovski, 2013, p. 8). For example potential changes in the frequency, intensity, and duration of major storms and heat waves and other similar events can have catastrophic impacts on its ability to continuously provide utility services.

These submissions led to an order by the PSC for all New York utilities to integrate the potential impacts of climate change into their system planning, construction forecast and budgets. The order also approved Con Edison's plan to spend $1 billion over the next four years on storm hardening and resiliency projects.

The director of the Centre for Climate Change Law at Columbia Law School indicated that, to his knowledge, this is the first state to impose such a requirement and that it is likely to become a national precedent (Bloomberg BNA, 2014). The PSC ordered the Storm Hardening Resiliency Collaborative (established during the rate process) to continue the activity of its working groups that are focusing on:

- storm hardening design standards;
- alternative resiliency strategies;
- natural gas system resiliency; and,
- risk assessment/cost benefit analysis.

5.4 Western Power, UK

The UK Climate Change Act (2008) gave the government the power to direct certain bodies to report on their climate risks and adaptation plans (Western Power Distribution, 2011). As a result, Western Power Distribution (the distribution network operator for the East and West Midlands, South Wales and South West in England) was required to report on current and predicted impacts of climate change and the authority's proposals and policies for adapting to climate change.

Consideration of climate risk is embedded into Western Power Distribution's Asset Risk Management process. They acknowledge that, due to the long lifetime of their assets, there is a low marginal cost to adapting their network now for the impacts of climate change. They also acknowledge that, to ensure that sufficient financial provisions are included in their next planning cycle, discussions with their Regulator (Ofgem) are required.

To help them assess their vulnerabilities, Western Power Distribution collaborated with climate scientists from the Met Office Hadley Research Centre. The study found that the risk profile of transformers will be affected as design thresholds for temperature will be exceeded, and that changes in soil conditions (e.g. temperature and soil moisture) may also affect performance. However, in the UK, with few exceptions, including thermal rating of equipment and apparatus, there is no evidence to support adjusting network design standards (Western Power Distribution, 2011).

Four priority issues were identified for Western Power Distribution to address: extreme events; temperature increase impacts on overhead lines; major substations sites at risk from fluvial or sea breach flooding; and changes in vegetation growth. Areas of further research to better understand the level of risk or impacts included urban heat island effects on equipment ratings and predicting where significant changes in grounding resistance will occur.

In conclusion, the study acknowledged that impacts to the network are not limited to extreme weather events. Changes to demand patterns were also identified as a contributing factor to future impacts on their network. Other non-climate related issues that were identified include shifts from more carbon intensive fuels to electricity (e.g. for heating and transport) and developments of smart grid technology to help manage demand.

5.5 Victorian and Brisbane Elect ricity Distributors, Australia

Australian electricity networks have experienced significant impacts from extreme weather events. Melbourne, Victoria experienced heatwave induced blackouts in 2009 that shut down the city's rail and tram networks, forced thousands of businesses to close, affected nationwide internet services (The Age, 2009a) and led to an estimated 500,000 homes losing power (The Age, 2009b). Queensland saw wide spread damage to its electricity networks as a result of the 2010 and 2011 floods leading to 300,000 customers losing power across two major cities (Brisbane and Ipswich). Power outages were experienced in areas directly impacted by damaged assets as well as areas where precautionary disconnections were made for safety reasons (Lyster, 2013).

Consideration of climate issues among network service providers are in their early stages. Assessments of risk exposure have been undertaken by some providers including Queensland's Ergon Energy and Energex as well as Victorian state distribution companies (Powercor, Citipower, SPAusnet and United Energy).

In 2010, the Victorian companies incorporated climate risk management into their regulatory price submissions, the country's first attempt to do such a thing. This work looked at short term projections of climate and the likely impacts to network performance from more hot days, more extreme wind events, increased bushfire risk and vegetation management, increased termite damage and the need for reviews of climate risk. Associated disruptions to services and the impact on network performance were quantified by the companies, who then sought $47million from the Australian Energy Regulator (AER) for operating and maintenance expenditures related to the short term projections of climate change. This amount was part of a request of approximately $3 billion for operating and maintenance expenditures over the following 5-year period (Australian Productivity Commission, 2012).

While the regulator was unpersuaded that additional funds were required for climate proofing within the 5-year period, the AER did support jointly resolving the regulatory challenges posed by climate change with the industry ahead of the 2015-2020 round of determinations (Australian Energy Regulator, 2010; The Climate Institute, 2012).

As a result of the 2010 and 2011 floods in Queensland, Energex and Ergon Energy have taken voluntarily steps to minimise the impact of future events including revising documented flood levels, ensuring new developments occur above set flood elevations or include flood resilience measures, and undertaking flood mapping for new developments were it does not exist (Lyster, 2013).

6.0 Toronto Hydro Actions to Date

Toronto Hydro recognizes that a changing climate will impact its operations, assets and system reliability. In the next chapter, Toronto Hydro's current efforts to understand and address climate changes and its impacts are presented. Specifically, issues of governance, collaboration initiatives, and specific risk assessment projects are discussed, which demonstrate the corporation's recognition of the importance of understanding, planning and acting to address climate change.

6.1 Governance

The City of Toronto is the sole shareholder of Toronto Hydro and provides direction to the corporation on its fundamental principles of business through its "Shareholder Direction Document". One of the objectives set out by the Shareholder Direction Document is for Toronto Hydro to conduct its operations in a manner that is consistent with the City's objectives on climate change (City of Toronto, 2013). The City's commitments on climate change are outlined in its 2007 Climate Change, Clean Air and Sustainable Energy Action Plan (2007) and its 2008 Climate Adaptation Strategy titled "Ahead of the Storm: Preparing Toronto for Climate Change". These guiding documents commit the city to adapting to the impacts of climate change across all the sectors (e.g. public health, water supply and storm water, local transportation, parks and urban forestry, land use planning) (City of Toronto, 2014). Through the Shareholder Direction Document, the City of Toronto directs Toronto Hydro to adapt to climate change in order to help ensure consistent and reliable power supply. Toronto Hydro participates in monthly meetings with the City of Toronto's Executive Environment team to ensure that it aligns its own efforts with the City's Climate Change, Clean Air and Sustainable Energy Action Plan.

In 2011, Toronto Hydro adopted an Environmental Policy that reflects its commitment to environmental stewardship. The policy directs the corporation to conduct its business "in a manner that minimizes the impacts on the environment and embodies the principles of continual improvement" (Toronto Hydro, 2011, p. 1). One of the core environmental principles contained within this policy is to ensure that environmental considerations are integrated into its business processes. The notion of adapting to climate change aligns closely with this principle. Adapting infrastructure and assets to climate change can help minimize environmental impacts due asset damage or loss. Furthermore, a reliable electricity supply is critical to support other systems that mitigate environmental pollution (e.g. sewage pumping systems). The Environmental Policy applies to all Toronto Hydro staff and contractors.

6.2 Collaborations

Toronto Hydro is an active member of the WeatherWise Partnership, a group bringing together over 50 government, private and not for profit organizations to discuss the risks posed by severe weather events and develop plans to address the risks (Toronto Hydro, 2012).

In 2013, the City of Toronto and Toronto Hydro began working together on a program to develop and share a common Geographical Information Systems (GIS) database. The purpose of the program is to generate maps that can help decision makers, electrical system operators, and field response crews target areas of the city that are more vulnerable to the impacts of power outages in the context of severe events. The identification of vulnerable areas, as well as priority community facilities and shelters, will help to enhance emergency response capacity during major disruptive events, as well as forward system planning and strengthening of these priority areas.

In 2013, Toronto Hydro participated in a series of workshops facilitated by the Canadian Electricity Association (CEA) Roundtable Initiative on Climate Adaptation. Through these workshops Toronto Hydro worked with other utilities across Ontario to establish a common industry understanding and approach to climate change. Notably, participants worked to identify:

- the increasing number of impacts to electrical equipment caused by extreme weather events and a changing climate;
- key challenges to adaptation;
- opportunities to co-ordinate actions and avoid duplication of efforts;
- opportunities to provide input into the revision of equipment design standards; and,
- prioritized areas for further analysis.

Collaboration stemming from this Roundtable Initiative is ongoing as CEA members continue to work closely on understanding and addressing the impacts of climate change on their assets.

6.3 Risk Assessment

In 2012, as part of its ongoing efforts to understand the impacts of climate change on Toronto Hydro Distribution Assets, Toronto Hydro initiated a screening level risk assessment of its infrastructure using the methodology developed by the PIEVC and Engineers Canada. The project is taking place through a partnership with Natural Resources Canada (co-funding agency), Engineers Canada, Clean Air Partnership and AECOM.

The first phase of the risk assessment study (PIEVC Study, completed in 2012) was focused on identifying the risks posed by current climate to a select and representative set of its assets. The second phase of work examining future climate change risks is currently underway and due to be completed by March 2015. The first phase of work examined risks according to individual system components, but did not provide an adequate understanding of system level impacts.

The second phase of work will attempt to overcome this shortfall by examining risks at both a component and system level. Results from the first phase of work are presented below. While it is pre-emptive to conclude anything about the risks posed to the system by climate change in advance of the completion of the study's second phase, a preliminary overview of impacts and areas of future study are also presented below.

6.3.1 Current Climate Risks to Components

The first phase of the PIEVC study looked at current climate impacts on Toronto Hydro's distribution infrastructure at a component level. The major components examined included electrical conductors (i.e. wires), switches, transformers, poles, cable chambers and vaults. Toronto Hydro currently has over 15,000 km of overhead conductors and 10,800 km of underground conductors carrying electricity across the network (Toronto Hydro, 2012).

Switches allow the grid system to be sectioned off, either for maintenance purposes or in response to power outages. Transformers are voltage converting equipment that allows currents to be stepped down from the high voltages used in long distance transmission to lower voltages used by local distribution and household applications. Poles are used to carry overhead equipment while vaults and cable chambers house underground equipment. Both switches and transformers can be located on poles, at ground level, or underground.

Overhead components such as conductor wires, transformers, switches, and poles were found to be more vulnerable to weather events than equipment located at grade or underground due largely to the higher likelihood of direct interaction with external elements.

Equipment located underground such as underground cables, cable chambers, vaults, transformers and switches are more vulnerable to events such as heavy precipitation and flooding. Underground equipment built to current Canadian Standard Association (CSA) standards are generally stored in water tight housing (e.g. sheaths, corrosion resistant metal casings) which, with proper inspection and maintenance, should generally withstand the impacts of flooding. Equipment built to legacy standards still exist in the system and may not be adequately protected against water infiltration. Finally, it was noted that winter-time salting of roads and sidewalks can accelerate the corrosion of certain metal housing materials.

Challenges posed by heavy precipitation events of underground equipment relate more to the inability to access equipment for inspection, maintenance, or repair while the chambers and vaults containing them are flooded. Underground vaults built to current CSA standards are equipped with sump pumps and drains connected to the

storm sewer system (cable chambers are also connected to the storm sewer system) which generally work to keep these spaces from flooding. Adequate maintenance of pumps and drains is required to maintain flooding protection. However, not all vaults are equipped with sump pumps, and, as previously mentioned, legacy equipment in these vaults may not be adequately watertight. Despite the existence of pumping equipment and drainage, flooding may still occur during heavy storm events.

In addition to directly damaging assets, it was also noted that certain weather events such as high wind/tornadoes, freezing rain, heavy blowing snow/blizzard conditions, can present access challenges and safety risks to field crews, which can slow down and hamper restorative efforts during and after major weather events.

6.3.2 Future Climate Risks

The current standard for overhead conductors states that the maximum normal operating temperature is 30^{o}C ambient temperature. The standard also states that a conductor should not experience emergency temperatures for more than 24 hours four times in any consecutive 12-month period. The maximum normal and emergency temperatures under load depend on conductor type and size.

As both average and extreme temperatures are expected to increase by mid-century, overhead conductors are increasingly likely to operate above maximum normal and emergency temperatures. This would impact the current carrying capacity of conductors and result in lower transmission efficiencies. Furthermore, conductors operating above normal temperatures and under load could lead to conductor failure. Current overhead conductor standards will likely require fine tuning to compensate for expected temperature increases, while the gradual replacement of conductors across the system to accommodate higher ambient and extreme temperatures may be necessary.

Precipitation events such as freezing rain and accompanying high wind will continue to be an issue for conductors. Not only may conductors break under heavy ice loading, but ice loading and wind may cause tree branches to break and fall on and damage conductors. Further study is required to understand how these types of events may change in frequency or intensity before their likely impacts can be fully assessed.

The impacts of increased ambient and maximum temperatures are not expected to adversely affect switching equipment. Current CSA maximum temperature standard for switches is 55°C, and future climate by mid-century is not expected to reach such temperatures. However, 45°C is the current CSA transformer standards for maximum ambient operating temperature. Summer time temperature extremes are projected to approach this threshold and when combined with higher demand for cooling during these events, transformers may be subject to shortened lifespans, damage, or even failure.

Load forces by ice and wind are considered the greatest risks to poles. While it is generally predicted that maximum wind speeds are expected to decrease by mid-century, less is known about the potential frequency and intensity of freezing rain and ice storms events, as well as for severe summertime thunderstorms with strong vertical wind speeds and downbursts. The vulnerability of vaults and cable chambers is dependent on the presence of pumping systems that are sufficiently maintained and able to cope with the intensity of inundation events.

6.3.3 Further Work

The first phase of the PIEVC risk study helped Toronto Hydro to understand the impacts that current weather events have on its assets in order to provide a basis for investigating future climate impacts. However, to support adaptation planning further investigation and investment will be required across a range of topics as outlined below:

- Climate projections: It is understood that conductors and transformers are vulnerable to increased heat and that freezing rain, ice and wind storms cause significant impacts to above ground assets. However, better projections of the likely frequency and intensity of major storm events, freezing rain, and wind are required to better define the magnitude of the likely impacts on the distribution system;
- System level characteristics: The first phase of Toronto Hydro's PIEVC work did not address system level characteristics, and how future risks will be influenced by aspects such as system redundancy, local

geographical constraints and electrical system interdependencies with provincial generation and transmission infrastructure;

- Legacy equipment in the system: Much of the analysis conducted to date has focused on equipment designed to current standards. Legacy equipment designed to older standards exists in the system representing areas of greater vulnerability. Further investigation is necessary to identify where this equipment is located and the risks they pose to overall system reliability;
- Changes in efficiency and demand: Specific studies need to be undertaken to examine the extent operating in extreme temperatures will lead to increased distribution losses and shorten the lifespan of equipment. Consideration should also be given to how the changing climate may impact future increases in load on components as a result of customer demand, particularly during extreme events;
- Vegetation and other risks: Issues related to longer term gradual changes in climate (e.g. temperature and precipitation) and their effects on vegetation growth warrant investigation to understand how current vegetation trimming practices may or may not be sufficient to address the risks related to climate change enhanced vegetation growth. In addition, further study of the likely changes in distribution of pests and vector-borne diseases (e.g. termites, Lyme disease and West Nile) and the implications for infrastructure and health and safety is required; and,
- Identification, prioritization and investment in adaption options: With a better understanding of the scope and significance of climate change impacts, solutions ranging from system wide enhanced maintenance procedures, changes to design, and upgrading specific infrastructure can lead to improved system resilience. However, questions such as the nature, design, costing, prioritization and cost/benefit analysis of appropriate adaptation responses to climate change have not been carried out. Adaptation planning and investment will be most effective when integrated with other businesses decision making processes (e.g. organisational risk management, operation and maintenance programs etc.).

The second phase of the PIEVC study seeks to address some of the shortcomings and areas of future work just described. Notably, a component and system level risk screening assessment is underway. It is hoped that some of the questions regarding system redundancies and electrical system interdependencies will be addressed. However, the influences of demand and legacy equipment, or the full detailing and prioritization of adaptation solutions is beyond the scope of the planned second phase of the PIEVC study. Further work beyond the PIEVC case study is required.

7.0 Next Steps and Conclusions

There is a significant body of evidence indicating that the weather affects the performance and reliability of the electricity network. There is also a significant body of evidence that the global and local climate has changed over the past 50 years and will continue to change over the coming century. Combined, this means that electricity distribution companies like Toronto Hydro will be placed in the predicament of having to manage assets that are not designed for the climate conditions they will operate in. As a result, without intervention, electricity distribution companies will continue to experience physical impacts to their networks causing significant operational and maintenance costs and disrupting the supply of electricity to communities and businesses.

Many organisations in Canada, the United States and globally are taking steps to understand their risks to climate change and take informed actions to manage those risks. Toronto Hydro clearly recognizes the necessity to address climate change and to evaluate its impacts to its assets and operations. In Canada, wide recognition of this need is reflected by the 25 PIEVC case studies across various infrastructure sectors completed since 2005, two ongoing PIEVC case studies focused on the electrical sector in Ontario, the work of Horizon Utilities through their 2012 Climate Change Adaptation Report, Strategy and Action Plan, as well as the initiatives taken by the City of Toronto and the Canadian Electrical Association.

Toronto Hydro has taken a proactive role in addressing climate change as demonstrated by its initiatives to examine the risks of future climate on its assets and its collaboration with other stakeholders and infrastructure owners across the country.

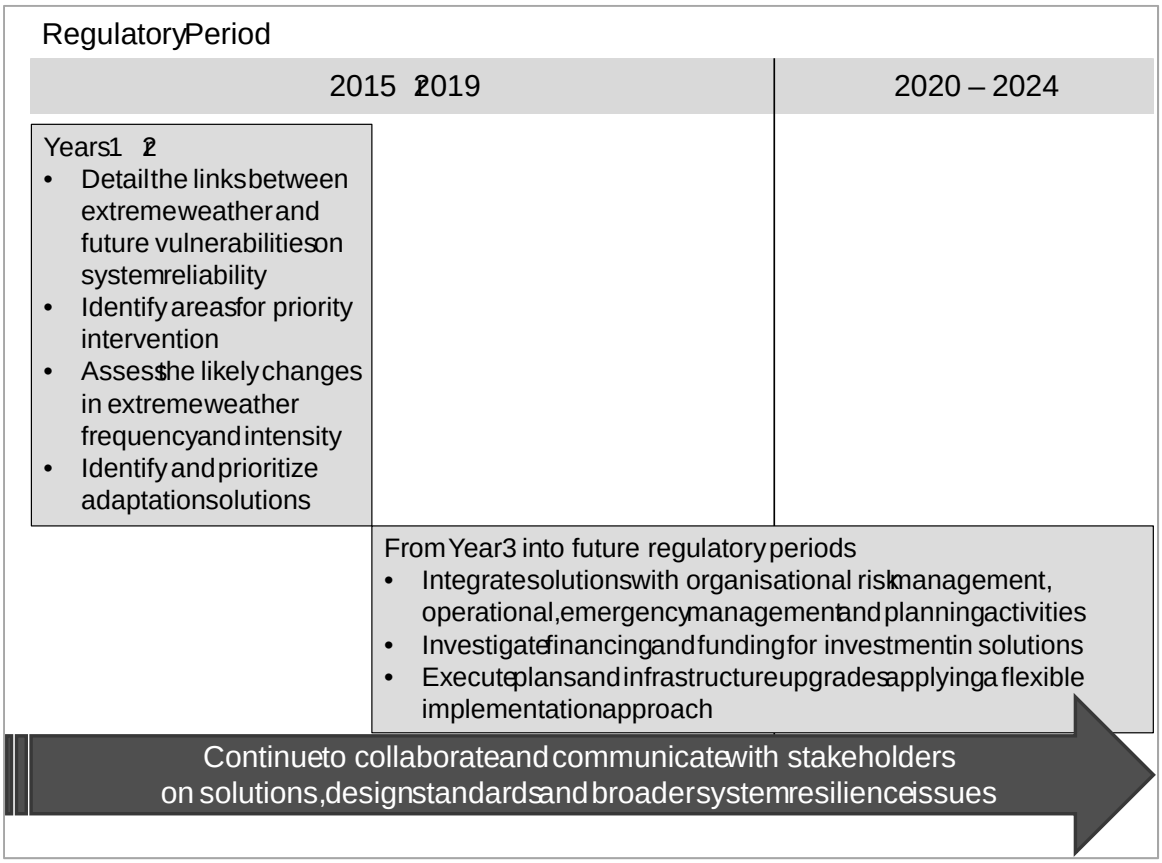
Toronto Hydro has taken the initial steps in its journey toward building a resilient network which supports the broader resilience of the City of Toronto. However, there are limitations in Toronto Hydro's current understanding of its potential network vulnerabilities in the face of climate change. Notably, much of the work to date remains at a preliminary phase, and further work is still required to understand the impacts of a changing climate, including how the course of climate change will evolve, as well as developing, prioritizing, costing and financing the potential adaptation solutions to enhance the resilience of the electrical distribution system to climate change.

In order to address these limitations, a logical, considered, flexible and adaptive plan should be developed to guide Toronto Hydro in building resilience into the its electrical network. The plan should include the following key elements (refer to Figure 15):

- Enhancing understanding of the projected changes in extreme weather event frequencies and intensities (e.g. extreme heat, ice storms);
- Detailing the links between the climate (e.g. extreme weather events and longer term changes in climate) and future vulnerabilities on system reliability by undertaking detailed assessments of component and system vulnerabilities (e.g. interdependencies, redundancies, equipment condition and age, climate induced changes in energy demand profile);
- Projecting impacts of climate change on the number of customer service interruptions and quantifying through reliability measures (i.e. SAIDI, SAIFI) and the costs of outage events;
- Identifying areas for priority intervention in consultation with the City of Toronto based on electrical system vulnerabilities, vulnerable populations, priority service areas (e.g. emergency response and health facilities, shelters etc.);
- Identifying adaptation solutions which include engineering actions, maintenance and operations measures, procurement specifications, emergency response and recovery measures, and increased risk tolerance and insurance measures. These solutions must be identified in conjunction with community and stakeholder engagement and an assessment of organisational and community risk tolerances;
- Evaluating and prioritizing adaptation solutions based on evaluation of costs and benefits, system vulnerabilities, and priority geographic areas for intervention;
- Investigating financing and funding for investment in solutions;

- Developing implementation plans describing solutions, timelines and budgets for implementation. Incorporate flexibility into plans to allow the implementation process to integrate, in so far as possible, advancements in scientific understanding of climate change, ongoing evaluations of system performance, funding opportunities and scheduled upgrade opportunities on which to 'piggyback' integration of climate change resilience measures;
- Integrating solutions within organisational risk management, current operational and maintenance programs, and emergency response management and planning activities;
- Executing plans and infrastructure upgrades in accordance with the flexible implementation approach described above;
- Continuing to monitor system performance and reliability on an ongoing basis; and,
- Reviewing and updating design standards in collaboration with other utilities and the Canadian Standards Association.

Figure 15 Overview of the Proposed Next Steps for Toronto Hydro's Adaptation Planning.



In summary, while the climate has and will continue to affect the reliability and performance of Toronto Hydro's network, with thoughtful planning, preparation and investment Toronto Hydro can proactively address the issues presented by climate change and continue to support the reliability and resilience of Toronto's electricity system (refer to Figure 16).

Figure 16 The Business Case for Investing in Better Understanding and Preparing for the Risks Posed by Climate Change to Toronto Hydro's Network

Historic	Future
x The climate affects network reliability. x The average climate has been stable, with periodic extreme events x Impacts on the network reliability have been relatively stable and predictable	› The climate has changed and will continue to change x There will be increases in the frequency and magnitude of impacts as well as potentially new impacts not previously encountered x Toronto Hydro need to better understand the likely changes to the climate and potential impacts x Toronto Hydro needs support to better manage and prepare for these climate changes and potential impacts.

This document demonstrates Toronto Hydro's recognition of the importance of understanding, planning and acting to address climate change. Toronto Hydro should seek the support of the regulator in its efforts to systematically advance the resilience of the electricity network to the increasing risks posed by climate change.

Having an Adaptation Plan that is logical, considered and flexible is the most sensible path to manage this new challenge. There are many actions that can be incorporated within business as usual operating constraints, but many others require new research, technologies, targeted investment and collaboration amongst agencies.

Toronto Hydro should fully develop its Adaptation Plan, carry out further detailed studies, and seek funding support for enhancing the resilience of its electrical network. Toronto Hydro should also seek longer term support for ongoing consideration of climate change in future operational and investment planning.

Flexibility in the development and execution of the Adaptation Plan (i.e. adaptive management) is necessary to ensure that the results of further detailed studies (that are not known at this time) can direct investment towards

identified high priority, and / or pilot projects to boost the reliability of its network to both gradual climate change related effects as well as potential impacts to the network due to increasingly severe weather events.

Finally, the Adaptation Plan and measures developed and implemented by Toronto Hydro could be used as a template and guide to help other utilities across the electricity distribution sector to enhance the resilience of their systems to climate change.

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9.0 Statement of Qualifications and Limitations

The preceding Document (the "Document") has been prepared by AECOM Consultants Inc. ("Consultant") in accordance with the agreement between Consultant and Torys LLP, including the scope of work detailed therein (the "Agreement").

The information, data, recommendations and conclusions contained in the Document (collectively, the "Information"):

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- may be based on information provided to Consultant which has not been independently verified;
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- must be read as a whole and sections thereof should not be read out of such context; and,
- was prepared for the specific purposes described in the Document and the Agreement;

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Consultant has exercised reasonable care when completing the Document. However, caution must be taken when considering the Information contained within because significant uncertainty remains due to the inherent complexities involved in analysing the past climate and variables typically encountered when modelling future climate change, as well as changing conditions beyond Consultant's control. Consultant cannot guarantee the accuracy of the climate observations and projections described in the Document that are largely based on prior work by others. Consultant agrees that the Information in the Document, developed based on those climate observations and projections, represents its professional judgement as described above and that the Information has been prepared for the specific purpose and use described in the Document and the Agreement, but Consultant makes no other representations, or any guarantees or warranties whatsoever, whether express or implied, with respect to the Document, the Information or any part thereof.

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LOADS, CUSTOMERS AND REVENUE

Toronto Hydro's total load, customer and distribution revenue forecast is summarized in Table 1. The revenue forecast is calculated based on proposed distribution rates, excluding commodity, rate riders, and all other non-distribution rates.

Table 1: Total Load, Revenues and Customers

YEAR		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($M)	Total Customers
2009	Actual	25,572.8	42,754.7	$475.2	689,399
2010	Actual	25,607.2	43,273.3	$519.3	696,729
2011	Actual	25,419.0	43,020.2	$522.2	705,756
2012	Actual	25,639.2	43,544.5	$527.9	713,093
2013	Actual	25,213.2	42,658.7	$529.5	724,144
2014	Bridge	25,018.5	42,712.7	$539.4	736,974
2015	Test	24,993.3	42,697.2	$655.1	749,679
2016	Test	25,027.4	42,806.2	$692.8	763,091
2017	Test	24,841.6	42,631.3	$754.4	773,850
2018	Test	24,696.9	42,584.4	$810.5	785,107
2019	Test	24,611.4	42,529.2	$857.8	796,865

/C

Notes:

1. Total Normalized GWh are purchased GWh (before losses), and are weather normalized to the Test Year heating and cooling degree day assumptions.
2. Total Normalized MVA are weather normalized MVA.
3. Total Distribution Revenue is weather normalized and includes an adjustment for the Transformer allowance.
4. Total Customers are as of mid-year and exclude street lighting devices and unmetered load connections.

The detailed load forecasts by rate class are shown at Exhibit 3, Tab 1, Schedule 1, Appendix B. Forecasts of customers by rate class are shown at Exhibit 3, Tab 1, Schedule 1, Appendix C. Forecast of distribution revenues by rate class are shown at Exhibit 3, Tab 1, Schedule 1, Appendix E.

The information provided for the Load, Customers and Revenue exhibit is prepared according to the Board's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013).

1. HISTORICAL LOADS

Historical total system load (actual and weather-normalized) for Toronto Hydro is illustrated in Figure 1 below.

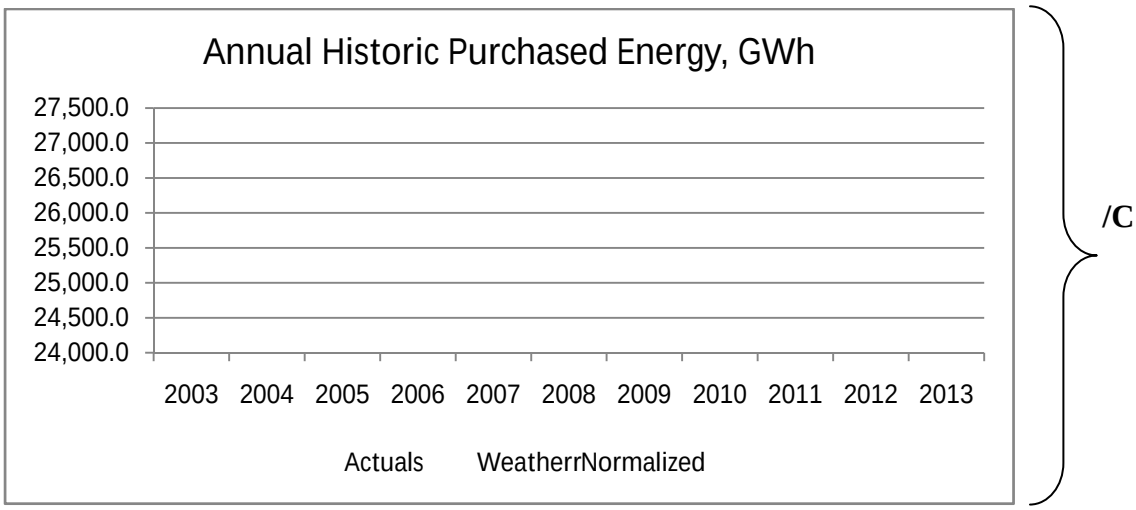


Figure 1: Historical Purchased Energy

Since 2007, there has been a significant decrease in total energy consumption. Essentially flat growth over the 2004-2006 period has been replaced by declining loads over the 2007-2013 period. While it is difficult to precisely attribute this decline to any particular event, Toronto Hydro believes that the effect of conservation activities – both program driven and naturally occurring - continue to have a significant impact on the overall load change. Furthermore, in late 2008 and 2009, economic conditions also

contributed to the load decline. Table 2 shows a summary of the total historical normalized annual loads and growth.

Table 2: Historical Annual Load

Year	Total Normalized GWh	Growth GWh	Percentage Change (%)
2003	26,329.7		
2004	26,659.5	330	1.3%
2005	26,641.7	-18	-0.1%
2006	26,767.2	126	0.5%
2007	26,323.5	-444	-1.7%
2008	26,160.9	-163	-0.6%
2009	25,572.8	-588	-2.2%
2010	25,607.2	34	0.1%
2011	25,419.0	-188	-0.7%
2012	25,639.2	220	0.9%
2013	25,213.2	-426	-1.7%

/C

2. LOAD FORECAST METHODOLOGY

Toronto Hydro's load forecast methodology consists of the three-step process which explicitly takes into account historic and forecast CDM impacts. First, the actual historical cumulative CDM impacts are added back to the system purchased energy. Second, the load (gross of CDM) is forecasted based on multifactor regression techniques. Third, the cumulative forecast CDM impacts are deducted from the gross load forecast to derive to the load forecast (net of CDM).

Energy forecasts are developed for each rate class separately. Peak demand at the rate class level is based on historical relationships between energy and demand. Total system load is summed from the individual rate class loads. The forecast of customers by rate class is determined using time-series econometric methodologies. Revenues are

determined by applying the proposed distribution rates to the rate class billing determinants for the forecast period.

3. kWh LOAD FORECAST

3.1. Multivariate Regression Model

The process of developing a model of energy usage involves estimating multifactor models using different input variables to determine the best fit. Different models were fit based on *a priori* assumptions about which input variables impact energy use. Using stepwise regression techniques, numerous explanatory variables were tested with the ultimate model being determined based on model statistics and judgement.

Models are developed for each rate class separately. This methodology allows for greater detail in modelling loads, and allows for the different interactions to be modelled independently. All of the regression models use monthly kWh per day as the dependent variable, and monthly values of independent variables from July, 2002 through to the latest actual values (December 2013) to determine the monthly regression coefficients.

The main drivers of the energy consumption over time are weather, energy conservation activities – both program and natural related, as well as calendar, economic and demographic conditions. While load impacts related to the CDM program activities are explicitly taken into account prior to and after the modelling (see section below on CDM forecast), the remainder of the effects are captured through the multivariate regression model.

The primary driver of consumption within years remains weather. Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season.

For that reason, both Heating Degree Days ("HDD" – a measure of coldness in winter) and Cooling Degree Days ("CDD" – a measure of summer heat) are captured in the multifactor regression model. In previous rate filings, Toronto Hydro has indicated that the standard definition of HDD, which uses 18 degrees Celsius as the point at which loads start to be impacted by temperature, was not as effective as a measure which uses 10 degrees Celsius as the "balance point" for the HDD measure. Figure 2 below shows the relationship between temperatures and loads for the period of July 2002-December 2013. It is clear that the relationship between heating loads and temperature changes at 10 degrees Celsius. Toronto Hydro uses this 10 degrees Celsius "balance point" for construction of its HDD measure.

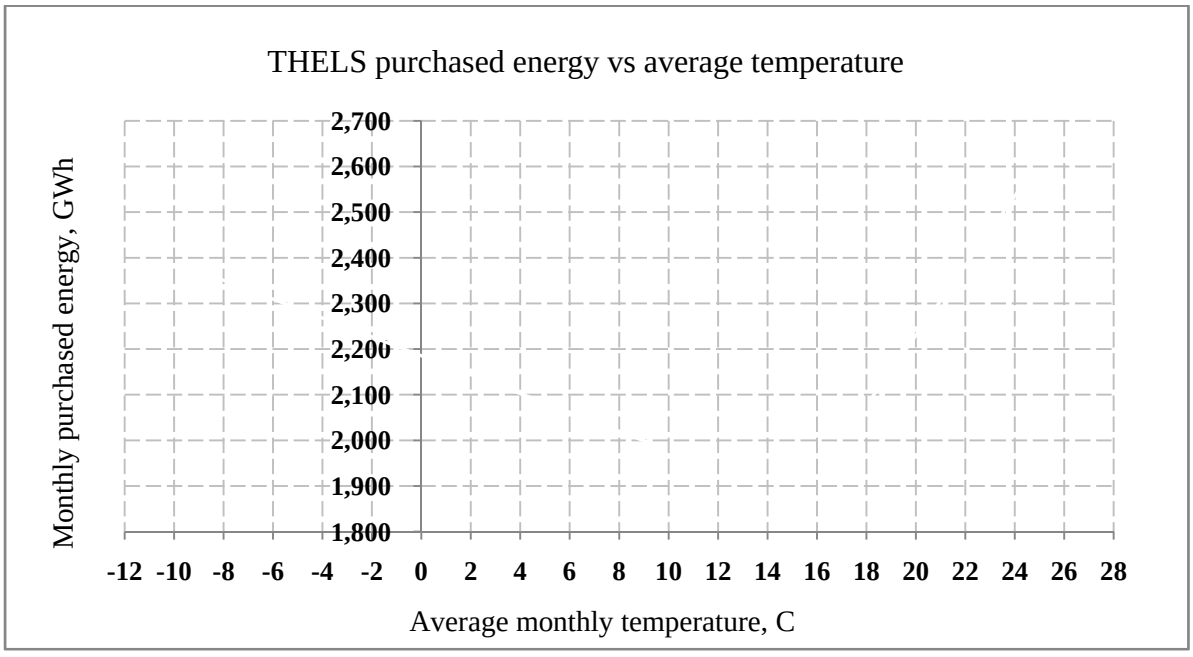


Figure 2: Purchased Energy vs Average Temperature

Dew point temperature is another type of weather factor, included as an explanatory variable for the GS <50 kW, GS 50-999 kW, GS 1000-4999 kW, and Large Use customer classes. This variable captures the impact of humidity on consumption and

shows the positive impact of temperature on loads during summer months and negative impact during winter months.

Demographic, economic conditions and natural related conservation activities are captured within the model by customer, population, Toronto unemployment rate and time trend variables. The Toronto unemployment rate reflects the level of economic fluctuations, and was found to be statistically significant in the GS <50 kW, GS 50-999 kW and GS 1000-4999 kW class models. Population and customer variables capture overall levels of demographic fluctuations, and were found to be statistically significant in the Residential, GS <50 kW, GS 50-999 kW, GS 1000-4999 kW and Large Use class models.

The time trend variables used in the models are intended to capture trends which are not otherwise explained by the other driver variables. The Residential model uses a simple time trend variable which captures the observed downward trend in consumption over the historical period. Since the models are based on consumption with CDM loads "added back" to loads, CDM activities alone cannot explain this trend.

For the GS<50kW and Large Use customer classes, a clear change in trend has occurred. For these two classes, Toronto Hydro has incorporated a linear spline time trend. Consumption for these two classes displays a clear change in trend between the 2002-09 period and the 2010-13 period, and is captured by this type of time trend.

Another factor determining energy use in the monthly model can be classified as "calendar factors". For example, the number of business days in a month will impact total monthly load. To capture the different number of days in the calendar months the modelling of purchased energy was performed on a per-day basis. To reflect different numbers of business days in the month and, consequently, different number of peak

hours, business day percentage was used in those class models. A dummy variable was also included to reflect the impact of the 2003 August blackout on energy use in that month.

Exhibit 3, Tab 1, Schedule 1, Appendix A-1 contains the historical and forecast load and input variable details. The model statistics for each class model are shown in Exhibit 3, Tab 1, Schedule 1, Appendix A-2.

From the regression models, the forecast of energy usage is determined by applying the model coefficients to forecasts of the input variables.

The forecast for heating, cooling degree-days, and dew-point temperature inputs is based on a ten-year historical average of HDD, CDD and Dew. A 10-year average was chosen over the 20-year average based on analysis of the annual HDD and CDD data that shows a definite trend in HDD and CDD (see Figure 3 below). Using an average over the longer time period would therefore be less reflective of the most recent data and an inferior forecast of HDD and CDD. Toronto Pearson International Airport station was used as the climatological measurement point for establishing monthly HDD and CDD.

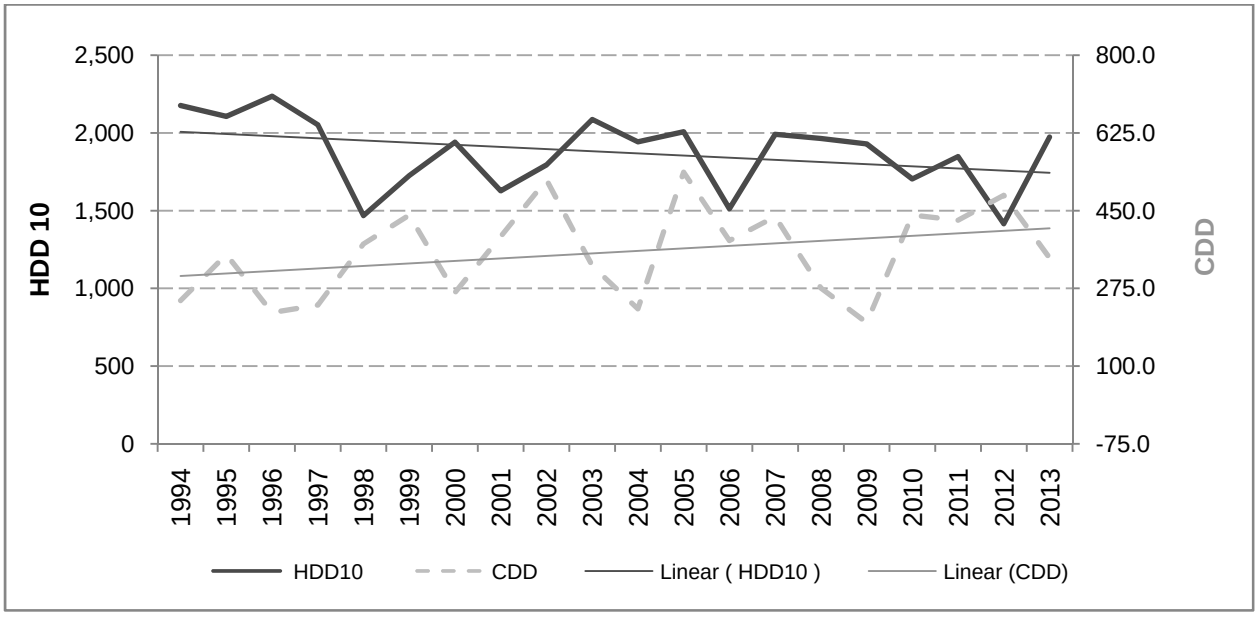


Figure 3: Historic CDD and HDD

The forecast of the City of Toronto unemployment rate and population was derived based on the Conference Board of Canada forecast of the Toronto CMA unemployment rate and population using a pair regression model.

The following table summarizes the variables included in each of the rate class energy models.

Table 3: Regression Variables by Rate Class

Residential	Competitive Sector Multi-unit Residential	GS<50 kW	GS 50-999 kW	GS 1,000-4,999 kW	Large Use	Street lighting	Unmetered Load
HDD10 per day	Normalized Average Use per Customer	HDD10 per day	HDD10 per day	HDD10 per day	HDD10 per day	Average use per device	Simple extrapolation technique
CDD per day		CDD per day	CDD per day	CDD per day	CDD per day		
Toronto City Population		Dew Point Temperature	Dew Point Temperature	Dew Point Temperature	Dew Point Temperature		
Time Trend		Number of GS<50 kW customers	Business Days Percentage	Business Days Percentage	Business Days Percentage		
Blackout dummy		Toronto Unemployment Rate	Toronto Unemployment Rate	Toronto Unemployment Rate	Number of LU customers		
Intercept term		Time Trend	Number of GS 50-999 kW customers	Number of GS 1,000-4,999 kW customers	Time Trend		
		Blackout dummy	Blackout dummy	Blackout dummy	Blackout dummy		
		Intercept term	Intercept term	Intercept term	Intercept term		

3.2. Normalized Average use per Customer ("NAC") Model

The load forecast for Competitive Sector Multi-unit Residential ("CSMUR") was determined using the NAC as the most suitable model for this relatively new rate class. Historically, CSMUR customers were part of Residential rate class, however, as directed by the Ontario Energy Board in EB-2010-0142, Toronto Hydro established a separate rate class with rates implemented as of June 1, 2013.

Similarly to the other rate classes, the forecast for CSMUR consumption explicitly incorporates CDM volumes.

The Normalized Average use per customer for CSMUR rate class is based on hourly load profile sample data from 2012 and is weather–corrected over a ten-year historical average of HDD and CDD. This average use per customer is then multiplied by the forecast of CSMUR customers to arrive at the forecast consumption for this class.

4. CLASS DEMAND FORECAST

The forecast of monthly peak demand by customer class, which is used to determine revenue for those customers billed on a demand basis, is established using historical relationships between energy and demand. The demand forecast is explicitly adjusted to reflect the impacts from the cumulative estimated CDM activities and subsequently, converted based on the billing factors to the peak demand forecast (net of CDM). The cumulative CDM demand forecast consists of incremental CDM forecast as well as persistence from the CDM demand savings. The demand savings for the Demand Response ("DR") programs were excluded from the total CDM demand savings. Toronto Hydro believes that the peak demand savings from the DR programs are not necessarily coincident with customer's individual peak demand for the demand reduction occurrence (see table 5 with the 2014-2019 cumulative CDM kW forecast under the section below).

5. CDM FORECAST

Consistent with the Board's CDM Guideline EB-2012-0003, Toronto Hydro confirms that it has explicitly included the impacts of CDM into its load forecast.

The cumulative CDM forecast deducted from the gross load (step 3 of the three-step process described previously) includes the CDM savings for programs delivered in each year plus the persistence of these programs through subsequent years.

The forecasted CDM savings for the 2015 to 2019 period were developed based on the assumption that there will be a continuation of conservation programs throughout the rate filing period as announced in the Conservation First Framework released on March 31, 2014 by the Ministry of Energy. In the absence of the framework being developed in detail, the projected conservation achievements are based on a number of assumptions that partly rely on Toronto Hydro's experience and progress toward the current provincial targets, and partly on the anticipated target assigned for the 2015 to 2020 conservation planning period.

With respect to the timing of CDM savings in this forecast, there are significant uncertainties due to the fact that there is very little information regarding the landscape of conservation offerings, the level of funding, and target and contribution calculations. However, it is known that the new phase of programming will prioritize customer energy savings, moving away from the peak demand focus of the former saveONenergy strategies. This is most obviously reflected by the fact that the provincial target carries only an energy total, rather than energy and demand requirements. Choosing this as the most reliable starting point, Toronto Hydro forecasts achieving the required energy savings – assuming it will be responsible for achieving approximately 21% of the provincial total of 7 TWh, or 1.5 TWh – by the end of 2020. **/C**

In terms of allocating the Conservation First target alignment, the effects of new program build-up and then eventual market saturation determined the basic assignment of annual savings. From historical program experience, monthly project application patterns and realized monthly energy savings were calculated and extrapolated for the forecast. Furthermore, conservation and efficiency measure persistence has been applied, which is shown to limit the increase of the cumulative conservation totals year after year.

The result of the factors mentioned above produces a CDM energy reduction forecast, with the anticipated end result being a significant step towards realizing the Conservation First target of nearly 1.5 TWh by 2020. It is anticipated that Toronto Hydro will be equipped with the resources to achieve this level of achievement, as is expected with the current suite of programming and the saveONenergy targets that are on track and nearing a close. **/C**

Historical and estimated CDM savings used in the load forecast are “gross” numbers and hence, include “free riders”. Toronto Hydro believes that “gross” CDM savings are the correct values to apply in to the load forecast used to determine billing units. With respect to future lost revenue adjustment mechanism variance account (“LRAMVA”) however, it is Toronto Hydro’s understanding that the CDM applied in this forecast will be the basis for the LRAMVA and that the LRAMVA balance will reflect the difference between estimated and actual CDM savings on a net basis.

Tables 4 and 5 represent the summaries of the cumulative forecast CDM consumption and demand impacts by class used for establishing the load forecast (net of CDM).

Table 4: Cumulative Forecast CDM Consumption Impacts, MWh (Gross)

Year	Residential	CSMUR	GS <50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Total
2014	249,881	1,849	292,894	482,720	255,810	227,806	1,510,960
2015	247,956	2,230	327,287	581,053	272,578	234,702	1,665,806
2016	242,745	2,679	360,162	685,347	286,183	237,405	1,814,521
2017	255,602	3,192	405,522	813,037	306,530	244,800	2,028,683
2018	274,839	3,747	454,912	950,884	331,509	255,922	2,271,813
2019	282,450	4,309	492,150	1,069,040	348,080	260,023	2,456,052

/C

Table 5: Cumulative Forecast CDM Demand Impacts, MW (Gross)

Year	GS 50-999 kW	GS 1000-4999 kW	Large Use	Total
2014	794.81	421.71	412.82	1,629.34
2015	968.59	461.64	450.29	1,880.52
2016	1,137.25	477.49	463.67	2,078.41
2017	1,337.24	509.39	492.62	2,339.25
2018	1,536.51	532.35	512.18	2,581.04
2019	1,725.63	560.20	537.68	2,823.51

/C

Table 6 includes 2014-2019 total gross forecast CDM consumption and demand impacts per year with no prior persistence. Table 7 includes 2014-2019 total gross forecast CDM demand impacts per year with no prior persistence for those customers billed on a demand basis.

Table 6: 2014-2019 Total Gross Forecast CDM Consumption Impact, MWh

	2014	2015	2016	2017	2018	2019
2014 CDM Forecast	92,021	227,454	224,889	219,698	211,783	200,718
2015 CDM Forecast		99,619	246,300	243,546	237,924	229,353
2016 CDM Forecast			120,946	298,801	295,377	288,559
2017 CDM Forecast				147,823	365,202	359,874
2018 CDM Forecast					141,104	348,601
2019 CDM Forecast						127,665
Total	92,021	327,073	592,135	909,868	1,251,390	1,554,770

/C

Table 7: 2014-2019 Total Gross Forecast CDM Demand Impact, MW

	2014	2015	2016	2017	2018	2019
2014 CDM Forecast	120.11	253.80	250.34	242.59	232.87	217.67
2015 CDM Forecast		152.36	321.97	317.58	307.75	295.42
2016 CDM Forecast			164.57	347.77	343.03	332.40
2017 CDM Forecast				201.14	425.05	419.26
2018 CDM Forecast					192.00	405.73
2019 CDM Forecast						173.71
Total	120.11	406.16	736.88	1,109.08	1,500.70	1,844.19

/C

6. CUSTOMER FORECAST

The forecast of new customers for all classes is primarily based on extrapolation models for each rate class. Customer additions in the company's operating area have been fairly flat over recent history, with the exception of the customers from the newly classified CSMUR rate class (implemented on June 1, 2013), whose rate of growth has been increasing as a result of Toronto Hydro's suite metering activities. Historically, CSMUR customers were included in the Residential rate class. With the establishment of the new CSMUR class, historical Residential customers that fall under a current definition of CSMUR class were identified, excluded from the Residential class, and forecasted independently. The detailed forecast of customers by rate class is found in Exhibit 3, Tab 1, Schedule 1, Appendix C-1.

7. ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSES

Table 8 summarizes the variances between actual loads and the last Board-approved loads (filed in Toronto Hydro's EB-2010-0142 2011 rate filing).

Table 8: Forecast vs. Actual Purchased Energy

	Board-Approved Load Forecast	Actual Load		Weather Normalized Actual	
	GWh	GWh	Variance	GWh	Variance
2010	25,374.3	25,639.5	1.0%	25,603.0	0.9%
2011	25,285.6	25,585.8	1.2%	25,409.3	0.5%

Year to year variances in historical loads and customers reflect the impacts of weather, economic conditions, CDM, and normal customer growth. Some year to year variance arises from re-classification of customers. Loads and customers reported for the Residential class are impacted in 2013 by the creation of the new Competitive Sector Multi-Unit Residential class, which was formerly part of the Residential class.

For the forecast periods, year to year variances in loads and customers reflect the impact of model driver variables and CDM assumptions. In addition, some re-classification is anticipated for the General Service and Large Use classes in 2014.

Tables showing year-over-year and actual vs. Board-approved loads and customers can be found in Exhibit 3, Tab 1, Schedules 1, Appendices B-3 and C-2.

Table1:Model Input Data

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col.22	Col.23	Col.24	Col.25	Col. 26	Col. 27	Col. 28	
1	Month	PurchasedEnergy perday, kWh(bycustomerclass)								CumulativeCDMimpacts perday, kWh						HDD10per day	CDD18 perday	Toronto Population ('000)	TimeTrend		Blackout Dummy	DewPoint Temperature	Business Days Percent	Toronto Unemployment Rate	CustomerNumbers				
2																													
3		Residential	Competitive SectorMulti r Unit Residential (CSMUR)	GS<50kW	GS50r999 kW	GS1000 r4999 kW	LargeUse	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50kW	GS50r999 kW	GS1000 r 4999kW	LargeUse				Residenti al	GS<50kW & Large Use					GS<50 kW	GS50r 999kW	GS1000 r 4999kW	Large Use	
4	Jul2002	19,204,87 6		8,649,128	31,276,255	16,527,279	8,820,370	256,949	166,002							0.0	6.2	2,073	1	1	0	15.6	71.0	8.8	66,908	10,576	484	46	
5	Aug2002	18,511,523		8,183,954	29,604,261	15,721,190	8,346,209	246,772	159,547							0.0	4.6	2,072	2	2	0	22.1	67.7	10.4	66,827	10,586	480	46	
6	Sep2002	16,114,72 0		7,687,179	28,298,565	14,984,372	7,895,845	269,652	158,251							0.0	2.9	2,071	3	3	0	13.6	66.7	9.0	66,826	10,619	482	46	
7	Oct2002	14,513,865		6,947,084	25,956,564	13,645,056	7,127,650	306,016	155,740							3.0	0.3	2,072	4	4	0	4.8	71.0	8.2	66,859	10,669	485	46	
8	Nov2002	15,395,003		7,232,335	27,256,662	13,902,998	7,204,315	363,235	158,333							7.1	0.0	2,055	5	5	0	r0.5	70.0	7.3	66,838	10,680	485	46	
9	Dec2002	17,264,325		7,335,346	28,296,964	13,783,673	7,157,154	373,118	162,451							12.0	0.0	2,040	6	6	0	r5.6	64.5	7.9	66,934	10,708	486	46	
10	Jan2003	18,311,915		7,916,178	30,509,950	14,995,396	7,598,243	403,495	163,775							18.3	0.0	2,035	7	7	0	r11.6	71.0	9.3	66,987	10,732	487	46	
11	Feb2003	17,946,872		8,123,903	30,717,592	14,953,503	7,633,376	371,971	162,553							17.0	0.0	2,038	8	8	0	r11.3	71.4	8.0	67,139	10,786	487	46	
12	Mar2003	16,306,69 0		7,612,193	28,018,838	14,110,408	7,296,898	339,070	159,786							10.8	0.0	2,036	9	9	0	r5.5	67.7	7.7	67,113	10,794	485	46	
13	Apr2003	14,622,58 7		7,121,777	26,707,917	13,805,589	7,149,673	288,109	160,638							5.3	0.1	2,043	10	10	0	r1.8	70.0	8.1	67,040	10,809	487	46	
14	May2003	13,572,543		6,652,815	24,857,765	13,226,484	7,017,781	236,326	153,861							0.2	0.0	2,043	11	11	0	6.5	67.7	9.4	67,126	10,828	491	46	
15	Jun2003	14,771,95 9		7,206,195	27,040,865	14,519,362	7,638,136	232,369	158,462							0.0	1.8	2,059	12	12	0	11.9	70.0	8.7	66,958	10,845	489	46	
16	Jul2003	16,298,89 0		7,827,787	29,154,832	15,538,655	7,771,092	252,559	163,533							0.0	3.8	2,054	13	13	0	14.7	71.0	10.6	67,046	10,848	492	46	
17	Aug2003	15,735,50 6		7,524,161	27,792,398	14,449,168	7,483,754	238,901	159,766							0.0	4.1	2,067	14	14	1	16.0	64.5	9.8	67,040	10,850	491	46	
18	Sep2003	14,015,17 8		6,905,035	26,228,274	14,274,728	7,348,513	279,868	157,630							0.0	0.8	2,073	15	15	0	11.7	70.0	9.4	66,964	10,851	492	46	
19	Oct2003	13,928,11 8		6,717,373	25,744,347	13,778,426	6,912,996	326,382	159,766							2.3	0.0	2,059	16	16	0	4.7	71.0	7.9	67,018	10,892	493	46	
20	Nov2003	15,092,61 6		6,999,278	26,923,503	13,922,169	7,029,585	383,778	161,194							5.4	0.0	2,072	17	17	0	1.6	66.7	8.1	66,892	10,874	496	46	
21	Dec2003	16,844,23 4		7,272,589	27,677,189	13,794,288	6,932,811	400,325	161,702							10.1	0.0	2,055	18	18	0	r4.0	67.7	6.9	67,064	10,908	497	47	
22	Jan2004	17,978,692		7,904,747	30,816,801	15,143,333	8,177,818	405,204	167,312							19.4	0.0	2,045	19	19	0	r13.1	67.7	8.4	66,973	10,939	497	47	
23	Feb2004	17,170,19 0		7,700,344	29,663,529	14,662,859	7,211,845	356,252	163,516							13.8	0.0	2,058	20	20	0	r8.3	69.0	7.6	67,046	10,971	497	47	
24	Mar2004	15,629,66 7		7,263,222	27,958,514	14,414,022	7,168,856	341,915	162,663							7.9	0.0	2,051	21	21	0	r2.1	74.2	8.7	67,001	10,986	499	47	
25	Apr2004	14,026,791		6,860,879	26,007,834	13,599,975	7,142,223	284,717	160,004							3.9	0.0	2,061	22	22	0	0.6	70.0	7.5	66,920	11,007	498	47	
26	May2004	13,190,26 0		6,697,193	25,467,554	13,536,594	6,883,795	236,779	158,600							0.6	0.3	2,056	23	23	0	7.9	64.5	9.1	66,875	11,018	498	47	
27	Jun2004	13,682,84 8		6,996,090	26,877,869	14,725,457	7,501,466	230,928	161,946							0.0	1.1	2,058	24	24	0	11.1	73.3	8.2	66,789	11,038	494	47	
28	Jul2004	14,728,572		7,410,303	28,203,152	15,020,716	7,789,243	247,688	164,679							0.0	2.8	2,062	25	25	0	15.5	67.7	10.0	66,753	11,045	495	47	
29	Aug2004	14,329,725		7,313,804	27,825,836	14,779,013	7,491,884	232,359	160,171							0.0	1.9	2,076	26	26	0	14.1	67.7	9.2	66,715	11,076	494	47	
30	Sep2004	13,952,065		7,074,372	27,537,276	15,242,637	7,559,001	287,188	163,732							0.0	1.4	2,083	27	27	0	12.8	70.0	8.2	66,658	11,104	494	47	
31	Oct2004	13,466,693		6,596,275	25,678,284	13,594,246	6,960,710	322,754	159,158							0.8	0.0	2,066	28	28	0	6.0	64.5	8.6	66,496	11,097	495	47	
32	Nov2004	14,734,15 8		6,925,586	26,942,928	14,049,875	7,104,274	380,877	161,489							4.7	0.0	2,091	29	29	0	0.5	73.3	7.7	66,585	11,119	498	47	
33	Dec2004	16,962,96 9		7,498,072	29,200,693	14,274,620	7,287,318	393,686	167,781							12.8	0.0	2,060	30	30	0	r6.1	67.7	7.9	66,505	11,146	498	47	
34	Jan2005	17,644,48 8		7,884,202	31,067,950	14,884,092	7,502,345	415,029	163,047							16.8	0.0	2,070	31	31	0	r10.7	64.5	7.8	66,464	11,167	501	47	
35	Feb2005	16,986,99 4		7,790,034	29,965,306	14,769,846	7,412,682	380,503	159,982							14.0	0.0	2,082	32	32	0	r7.1	71.4	8.9	66,628	11,184	501	47	
36	Mar2005	15,704,99 6		7,441,105	28,955,758	14,554,549	7,319,912	357,292	157,327							11.6	0.0	2,088	33	33	0	r6.2	71.0	8.4	66,630	11,198	504	47	
37	Apr2005	13,765,85 4		6,766,118	26,139,356	13,762,751	6,903,337	296,587	153,933							2.8	0.0	2,107	34	34	0	r0.6	70.0	8.3	68,964	11,426	523	48	
38	May2005	13,739,592		6,518,052	25,117,342	13,271,845	6,822,412	231,600	149,054							0.9	0.0	2,107	35	35	0	4.1	67.7	8.5	66,482	11,185	506	47	
39	Jun2005	17,351,693		7,803,803	30,831,062	16,622,447	8,214,883	239,904	151,947							0.0	4.9	2,093	36	36	0	15.4	73.3	8.6	66,668	11,214	507	47	
40	Jul2005	18,839,64 9		8,166,152	31,728,614	16,122,802	7,757,701	249,964	158,882							0.0	6.1	2,110	37	37	0	16.0	64.5	9.3	66,741	11,233	507	47	
41	Aug2005	17,458,775		7,764,782	30,249,616	16,074,354	7,558,624	245,451	155,642							0.0	4.5	2,111	38	38	0	15.8	71.0	8.9	66,807	11,242	509	47	
42	Sep2005	14,755,81 4		7,084,612	28,045,770	15,354,144	7,374,681	280,008	153,375							0.0	1.7	2,121	39	39	0	13.0	70.0	7.2	66,885	11,255	510	47	
43	Oct2005	13,612,493		6,553,620	26,087,500	14,169,462	6,868,355	320,937	152,229							1.3	0.2	2,098	40	40	0	7.2	64.5	7.2	66,923	11,267	514	47	
44	Nov2005	14,817,652		6,910,069	27,534,293	14,466,500	7,025,394	380,230	149,728							5.4	0.0	2,109	41	41	0	1.1	73.3	6.1	67,066	11,286	515	47	
45	Dec2005	16,564,47 6		7,437,910	29,721,095	14,596,020	7,011,795	390,672	156,298							13.5	0.0	2,097	42	42	0	r6.5	64.5	7.2	67,147	11,498	517	47	
46	Jan2006	16,527,36 0		7,352,899	28,878,874	14,408,784	6,987,662	407,562	155,071	927						9.8	0.0	2,092	43	43	0	r2.8	67.7	7.6	67,209	11,349	519	47	/C
47	Feb2006	16,384,62 4		7,542,777	29,982,830	15,093,663	7,321,461	384,419	156,294	1,756						13.6	0.0	2,105	44	44	0	r7.7	71.4	7.9	67,183	11,358	504	46	/C
48	Mar2006	15,146,885		7,166,823	28,307,388	14,682,471	7,162,165	354,233	153,057	2,678						8.7	0.0	2,101	45	45	0	r5.3	74.2	7.2	67,145	11,358	517	47	/C
49	Apr2006	13,392,11 6		6,457,396	25,422,610	13,533,302	6,820,677	292,933	150,215	11,652						2.6	0.0	2,117	46	46	0	0.7	63.3	7.0	67,108	11,375	519	47	/C
50	May2006	13,394,431		6,470,721	25,888,725	14,286,344	7,184,146	237,248	150,833	11,697						0.3	0.8	2,104	47	47	0	7.9	71.0	7.4	67,030	11,377	512	46	/C
51	Jun2006	15,419,97 4		7,089,496	28,261,902	15,667,781	7,630,593	229,557	164,514	32,163						0.0	2.5	2,111	48	48	0	12.6	73.3	7.1	67,004	11,397	521	48	/C
52	Jul2006	17,329,321		7,820,058	31,081,220	16,376,255	8,226,171	250,990	173,228	35,107						0.0	5.4	2,119	49	49	0	17.4	64.5	8.4	67,009	11,389	520	48	/C
53	Aug2006	15,932,77 6		7,335,937	29,427,040	15,969,371	7,769,925	246,501	167,021	160,021						0.0	3.3	2,120	50	50	0	14.6	71.0	9.0	67,089	11,417	522	49	/C
54	Sep2006	13,457,99 4		6,438,984	25,986,422	14,337,632	7,055,393	275,432	158,610	173,722						0.1	0.4	2,101	51	51	0	11.6	66.7	8.0	67,095	11,430	519	49	/C
55	Oct2006	13,461,70 9		6,406,677	26,187,123	14,215,738	6,993,313	327,134	162,871	77,940						2.4	0.0	2,075	52	52	0	4.8	67.7	7.2	67,051	11,441	521	49	/C
56	Nov2006	14,588,32 4		6,757,402	27,548,591	14,482,704	7,137,127	385,452	162,055	84,382						4.8	0.0	2,104	53	53	0	2.1	73.3	8.2	67,068	11,426	515	49	/C
57	Dec2006	15,730,61 8	422	6,862,288	27,901,327	13,823,127	6,798,357	386,505	161,258	175,754						8.1	0.0	2,101	54	54	0	r2.4	61.3	5.9	67,017	11,444	516	49	/C
58	Jan2007	16,684,01 0	4,394	7,271,139	29,655,098	14,727,419	6,827,020	411,032	163,099	177,628	624	668	625	613		12.9	0.0	2,099	55	55	0	r6.6	71.0	7.1	66,920	11,426	509	49	/C
59	Feb2007	17,358,815	5,057	7,777,090	31,917,997	15,446,009	7,366,222	389,657	166,716	202,210	2,538	2,716	2,541	2,495		18.4	0.0	2,118	56	56	0	r12.4	71.4	7.7	66,923	11,452	519	49	/C
60	Mar2007	15,646,62 6	4,697	7,075,266	28,719,593	14,450,244	7,070,954	353,562	161,555	190,420	4,881	5,223	4,887	4,798		9.8	0.0	2,114	57	57	0	r5.6	71.0	8.5	66,853	11,502	517	48	/C
61	Apr2007	13,920,39 9	5,324	6,612,304	26,879,137	13,824,218	6,946,374	299,516	161,255	95,782	2,704	2,893	2,707	2,658		4.9	0.0	2,124	58	58	0	0.0	66.7	7.3	66,814	11,476	517	49	/C
62	May2007	13,097,781	5,455	6,354,897	26,052,502	14,125,839	6,795,250	234,356	156,695	96,372	3,841	4,110	3,846	3,776		0.2	0.7	2,103	59	59	0	5.8	71.0	8.1	66,682	11,469	508	48	/C

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col.22	Col.23	Col.24	Col.25	Col. 26	Col. 27	Col. 28	
1																													
2	Month	PurchasedEnergy per day, kWh(bycustomerclass)								CumulativeCDMimpacts perday, kWh						HDD10per day	CDD18 perday	Toronto Population ('000)	TimeTrend		Blackout Dummy	DewPoint Temperature	Business Days Percent	Toronto Unemployment Rate	CustomerNumbers				
3		Residential	Competitive SectorMulti r Unit Residential (CSMUR)	GS<50kW	GS50r999 kW	GS1000 r4999 kW	LargeUse	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50kW	GS50r999 kW	GS1000 r 4999kW	LargeUse				Residenti al	GS<50kW & Large Use					GS<50 kW	GS50r 999kW	GS1000 r 4999kW	Large Use	
63	Jun2007	15,101,99 8	5,637	7,181,516	29,645,382	15,724,060	7,633,278	236,262	164,442	256,239		13,716	14,678	13,732	13,482	0.0	3.3	2,122	60	60	0	12.2	70.0	8.1	66,617	11,440	517	49	/C
64	Jul2007	15,738,45 9	5,455	7,148,324	29,111,905	15,078,545	6,903,250	242,518	159,383	259,756		17,195	18,400	17,215	16,901	0.0	3.4	2,135	61	61	0	14.0	67.7	9.9	66,486	11,497	515	49	/C
65	Aug2007	16,005,451	5,444	7,364,570	30,348,722	16,059,800	7,856,461	250,774	164,834	307,303		33,019	35,335	33,058	32,456	0.0	4.5	2,120	62	62	0	14.5	71.0	8.9	66,386	11,537	519	49	/C
66	Sep2007	13,973,95 8	7,191	6,620,416	27,562,310	14,728,023	7,213,923	279,044	159,347	679,252		154,502	165,338	154,685	151,867	0.0	1.6	2,123	63	63	0	11.6	63.3	7.3	66,288	11,556	519	49	/C
67	Oct2007	13,400,60 0	11,386	6,356,059	26,392,511	14,399,737	6,750,659	323,853	159,820	270,285		61,723	66,052	61,796	60,670	0.5	0.6	2,119	64	64	0	9.2	71.0	7.4	66,199	11,550	518	49	/C
68	Nov2007	14,596,76 9	16,049	6,726,474	27,928,334	14,431,840	7,071,983	383,672	162,357	290,387		67,472	72,204	67,552	66,321	7.4	0.0	2,132	65	65	0	r1.4	73.3	7.7	66,143	11,586	519	49	/C
69	Dec2007	16,346,471	17,837	7,019,579	29,503,283	14,144,465	6,992,913	389,185	164,376	609,946		144,507	154,642	144,678	142,043	12.3	0.0	2,113	66	66	0	r5.8	61.3	6.6	66,245	11,590	513	49	/C
70	Jan2008	16,669,56 4	17,859	7,095,017	29,946,486	14,382,654	7,130,668	411,876	163,183	636,864		161,798	171,958	163,186	160,214	12.3	0.0	2,113	67	67	0	r6.2	71.0	7.1	66,054	11,754	517	49	/C
71	Feb2008	16,453,40 8	19,599	7,295,125	30,869,860	14,650,984	7,251,343	384,450	164,250	679,054		173,988	184,850	175,545	172,347	15.3	0.0	2,107	68	68	0	r9.1	69.0	6.1	66,150	11,863	518	48	/C
72	Mar2008	15,291,38 6	18,800	6,860,669	29,057,362	14,257,351	7,114,431	358,313	163,413	635,266		165,821	175,987	167,493	164,442	11.7	0.0	2,101	69	69	0	r7.0	64.5	7.2	66,093	11,929	519	48	/C
73	Apr2008	13,243,31 6	20,489	6,146,928	26,471,036	13,747,990	6,945,132	295,774	159,698	322,264		86,356	91,431	87,446	85,853	2.6	0.0	2,120	70	70	0	0.7	73.3	6.2	66,152	11,977	519	48	/C
74	May2008	12,678,64 0	20,846	5,923,553	25,505,844	13,316,295	6,466,081	234,952	157,052	312,572		85,443	90,357	86,630	85,052	0.4	0.1	2,127	71	71	0	3.9	67.7	7.7	66,094	12,016	520	49	/C
75	Jun2008	14,409,83 9	22,447	6,595,168	28,545,550	14,955,788	7,167,881	232,922	161,925	793,880		222,226	234,691	225,633	221,523	0.0	2.4	2,130	72	72	0	13.6	70.0	8.3	66,311	12,066	520	49	/C
76	Jul2008	15,462,403	24,309	7,164,768	30,378,382	15,306,224	7,438,916	248,421	162,898	882,749		288,428	300,367	296,644	291,241	0.0	3.6	2,120	73	73	0	14.8	71.0	9.5	66,286	12,063	517	49	/C
77	Aug2008	14,082,61 0	26,431	6,687,887	28,913,554	14,413,111	6,932,271	239,612	156,724	851,235		288,835	300,938	297,256	291,841	0.0	2.1	2,131	74	74	0	13.6	64.5	8.7	66,226	12,077	518	49	/C
78	Sep2008	13,529,615	30,208	6,246,406	27,439,128	14,527,535	6,841,760	286,630	161,934	655,521		302,674	315,256	311,745	306,066	0.0	0.9	2,137	75	75	0	12.1	70.0	7.6	66,293	12,105	517	48	/C
79	Oct2008	13,145,46 0	30,479	5,858,959	26,059,808	13,664,718	6,347,112	329,428	161,317	258,222		120,076	125,040	123,702	121,448	2.0	0.0	2,130	76	76	0	3.4	71.0	7.4	65,867	12,095	516	48	/C
80	Nov2008	14,644,232	36,762	6,247,070	27,824,677	13,805,773	6,615,530	386,520	162,065	261,847		125,355	130,487	129,191	126,838	7.3	0.0	2,117	77	77	0	r1.2	66.7	7.5	66,084	12,128	517	47	/C
81	Dec2008	16,217,25 0	40,079	6,657,605	29,255,089	13,439,250	6,314,492	380,803	159,641	508,995		252,340	262,631	260,103	255,365	13.1	0.0	2,126	78	78	0	r7.5	67.7	6.9	65,917	12,156	515	47	/C
82	Jan2009	17,300,972	47,093	7,197,666	31,567,985	14,134,927	6,660,268	417,231	166,009	509,611	7	253,823	264,186	262,099	258,101	18.8	0.0	2,123	79	79	0	r12.9	67.7	8.5	65,700	12,147	516	47	/C
83	Feb2009	16,285,192	61,317	6,856,980	29,978,150	13,842,699	6,741,551	382,752	169,699	571,414	38	287,017	298,569	297,407	293,710	13.7	0.0	2,127	80	80	0	r8.5	67.9	8.9	66,133	12,181	516	47	/C
84	Mar2009	14,742,87 7	58,251	6,503,113	28,464,818	13,584,424	6,441,460	356,765	163,022	518,204	45	261,505	272,011	271,520	268,905	9.2	0.0	2,129	81	81	0	r6.4	71.0	9.4	66,140	12,189	514	47	/C
85	Apr2009	13,165,363	61,010	6,052,581	26,432,699	12,933,325	6,329,454	303,012	163,555	260,797	33	132,484	138,508	140,928	147,994	3.2	0.0	2,148	82	82	0	r1.4	70.0	8.8	65,846	12,163	514	47	/C
86	May2009	12,239,211	62,408	5,710,301	25,225,040	12,784,356	6,065,662	236,904	158,517	254,837	43	130,442	136,488	139,815	148,921	0.4	0.2	2,141	83	83	0	4.6	64.5	10.7	65,798	12,208	515	47	/C
87	Jun2009	12,903,963	65,752	6,024,651	27,257,236	13,841,597	6,814,042	235,165	164,224	648,795	124	333,878	349,144	357,892	380,271	0.0	1.1	2,139	84	84	0	11.1	73.3	11.2	66,074	12,231	515	47	/C
88	Jul2009	13,379,17 8	68,047	6,047,049	27,331,152	13,621,667	6,922,781	242,648	158,771	712,191	446	389,360	404,160	423,901	448,807	0.0	1.4	2,133	85	85	0	13.4	67.7	12.6	65,854	12,287	511	47	/C
89	Aug2009	14,852,36 4	69,259	6,495,327	29,687,323	14,701,541	6,934,078	251,837	163,149	714,850	486	397,254	412,789	435,067	464,430	0.0	2.9	2,137	86	86	0	15.5	64.5	11.6	66,047	12,295	510	47	/C
90	Sep2009	13,136,76 4	77,294	5,836,542	27,174,473	13,903,642	6,738,894	285,097	152,004	712,538	519	413,824	430,428	455,307	490,361	0.0	0.7	2,127	87	87	0	12.0	70.0	9.8	66,100	12,337	510	47	/C
91	Oct2009	12,823,06 4	76,716	5,684,484	26,464,192	13,255,226	6,427,301	333,095	154,586	282,938	213	164,862	171,987	183,769	203,727	2.0	0.0	2,154	88	88	0	4.5	67.7	9.2	65,873	12,316	506	47	/C
92	Nov2009	13,689,071	81,510	5,774,387	26,864,610	13,274,262	6,269,816	388,982	155,243	292,888	226	171,515	179,101	192,120	215,110	4.1	0.0	2,139	89	89	0	2.8	70.0	10.1	65,835	12,384	502	47	/C
93	Dec2009	16,187,121	83,881	6,227,282	29,439,553	13,407,655	6,174,495	391,443	156,359	601,979	518	357,121	368,274	384,218	386,542	12.4	0.0	2,139	90	90	0	r5.9	67.7	8.9	65,883	12,444	509	47	/C
94	Jan2010	16,941,195	97,086	6,523,613	30,750,763	13,765,588	6,416,844	418,962	161,385	666,086	823	456,263	467,471	483,577	484,674	15.2	0.0	2,141	91	90	0	r8.4	64.5	9.8	65,607	12,597	507	47	/C
95	Feb2010	16,131,153	112,485	6,498,495	30,698,825	13,774,106	6,410,897	386,994	160,271	741,876	935	513,718	526,186	544,197	545,898	13.4	0.0	2,138	92	90	0	r7.2	67.9	9.2	66,056	12,574	511	47	/C
96	Mar2010	13,739,555	110,463	5,875,491	27,952,914	13,258,332	6,161,068	357,966	157,363	676,102	877	474,888	486,204	502,634	504,551	5.7	0.0	2,137	93	90	0	r3.4	74.2	9.3	66,156	12,703	510	47	/C
97	Apr2010	11,973,50 0	122,925	5,429,502	26,140,673	12,711,121	5,772,168	301,056	151,092	331,303	449	241,073	249,551	266,250	297,534	1.0	0.0	2,127	94	90	0	0.8	70.0	10.1	65,995	12,826	510	47	/C
98	May2010	13,044,36 8	127,283	5,647,299	27,413,456	13,486,627	6,281,519	245,168	148,588	321,071	439	234,846	243,213	259,859	291,845	0.6	1.5	2,153	95	90	0	8.6	64.5	11.6	65,681	12,829	511	47	/C
99	Jun2010	14,546,45 4	142,363	5,883,774	28,632,970	14,142,478	6,493,122	236,789	146,396	834,659	1,219	630,660	650,612	689,036	755,990	0.0	2.0	2,145	96	90	0	13.9	73.3	10.3	65,799	12,873	509	47	/C
100	Jul2010	17,981,751	147,577	6,717,359	32,483,969	15,238,781	6,870,026	251,509	146,894	810,996	1,182	621,475	640,680	678,837	746,913	0.0	5.3	2,162	97	90	0	17.4	67.7	10.2	66,029	12,906	509	46	/C
101	Aug2010	16,315,27 6	155,337	6,348,438	31,361,847	15,077,201	6,774,897	250,633	145,629	714,533	1,231	638,477	658,326	697,456	768,694	0.0	4.5	2,161	98	90	0	17.1	67.7	12.0	65,895	12,916	507	46	/C
102	Sep2010	12,947,96 9	170,469	5,528,908	27,573,207	13,748,095	6,180,963	287,534	139,740	755,723	1,393	699,444	720,401	761,840	838,321	0.0	1.1	2,158	99	90	0	12.1	70.0	9.9	65,794	12,978	506	46	/C
103	Oct2010	12,196,63 6	168,412	5,254,202	26,339,874	13,058,065	5,815,124	333,276	141,068	292,300	559	279,066	288,243	307,321	347,195	1.2	0.0	2,172	100	90	0	5.4	64.5	9.4	66,041	12,980	505	46	/C
104	Nov2010	13,777,58 0	178,264	5,643,836	27,907,596	13,340,516	6,151,361	388,390	140,793	305,366	608	298,430	308,081	328,297	371,114	5.6	0.0	2,165	101	90	0	0.4	73.3	9.2	65,976	13,021	504	46	/C
105	Dec2010	16,281,83 4	177,287	6,150,643	30,378,506	13,115,897	6,473,654	392,178	139,025	613,265	1,248	610,129	621,932	639,821	644,491	13.8	0.0	2,148	102	90	0	r7.1	67.7	8.1	66,167	13,168	500	50	/C
106	Jan2011	16,873,592	180,664	6,318,722	31,481,376	13,495,704	6,582,885	418,421	129,836	614,993	1,282	612,989	627,879	642,196	645,102	17.0	0.0	2,148	103	90	0	r10.2	64.5	9.4	65,996	13,266	498	50	/C
107	Feb2011	16,318,09 9	203,759	6,324,237	31,435,334	13,664,520	6,646,141	388,767	127,365	682,532	1,452	681,368	700,749	713,164	714,501	15.4	0.0	2,142	104	90	0	r9.1	67.9	8.3	65,942	13,314	498	50	/C
108	Mar2011	14,771,061	187,883	6,043,673	29,569,851	13,379,690	6,590,803	360,148	125,860	623,153	1,444	626,366	656,018	654,640	652,830	10.5	0.0	2,143	105	90	0	r5.2	74.2	9.6	65,945	13,246	501	50	/C
109	Apr2011	12,811,902	204,927	5,587,526	27,199,963	12,571,894	6,432,442	303,774	125,469	313,982	783	317,617	340,868	342,031	368,099	3.6	0.0	2,131	106	90	0	0.9	66.7	9.1	65,856	12,938	503	50	/C
110	May2011	11,895,53 0	215,125	5,264,116	26,620,896	12,588,790	6,625,894	242,522	118,094	307,708	834	313,687	342,910	335,847	356,133	0.2	0.4	2,129	107	90	0	9.3	67.7	10.0	66,224	12,795	503	50	/C
111	Jun2011	13,741,91 9	232,105	5,756,019	28,723,931	13,605,722	7,006,471	234,769	117,692	795,282	2,416	820,217	920,400	868,430	894,273	0.0	1.7	2,139	108	90	0	12.5	73.3	9.5	66,681	12,845	503	50	/C
112	Jul2011	18,235,995	230,700	6,653,288	32,459,985	14,469,914	7,291,672	253,286	127,864	787,734	2,578	814,109	932,230	857,430	871,429	0.0	6.4	2,148	109	90	0	15.8	64.5	10.4	66,723	12,824	503	50	/C
113	Aug2011	15,313,58 6	242,693	6,386,418	31,113,790	14,109,498	7,054,425	246,519	118,097	786,589	2,644	819,231	943,072	859,915	865,144	0.0	3.9	2,167	110	90	0	15.2	71.0	10.1	66,900	12,824	499	50	/C
114	Sep2011	12,625,83 4	258,712	5,673,323	28,408,130	13,312,957	6,773,635	285,201	115,240	816,341	2,833	854,786	991,498	893,886	889,806	0.0	1.3	2,160	111	90	0	13.0	70.0	8.5	67,017	12,791	498	51	/C
115	Oct2011	12,365,59 7	260,259	5,407,198	26,765,559	12,653,562	6,368,251	334,303	116,146	325,502	1,186	342,873	403,020	357,690	353,641	1.6	0.1	2,149	112	90	0	6.7	64.5	8.7	67,050	12,701	495	51	/C
116	Nov2011	13,540,24 8	273,587	5,766,400	27,734,022	12,812,032	5,646,380	390,581	117,427	346,037	1,417	370,174	449,755	384,016	373,276	3.9	0.0	2,168	113	90	0	2.4	73.3	8.7	67,175	12,562	496	51	/C
117	Dec2011	15,208,533	273,074	5,969,677	29,087,341	12,676,968	5,378,275	402,229	119,781	724,116	3,440	791,868	1,006,067	816,458	777,094	9.2	0.0	2,160	114	90	0	r2.7	64.5	8.1	67,261	12,587	498	52	/C
118	Jan2012	15,852,595	279,102	6,308,737	29,730,354	13,188,149	6,454,959	423,256	121,978	722,584	3,474	795,112	1,014,062	817,541	777,349	11.7	0.0	2,163	115	90	0	r5.4	67.7	10.3	67,460	12,357	497	52	/C
119	Feb2012	14,796,84 0	307,931	6,135,297	29,567,120	13,189,416	6,532,245	391,701	115,971	773,830	3,752	852,475	1,091,825	874,043	830,177	10.3	0.0	2,165	116	90	0	r4.7	69.0	8.7	67,536	12,195	498	51	/C
120	Mar2012	12,965,99 4	295,662	5,824,849	27,514,501	12,798,513	6,402,811	360,155	117,866	728,571	3,631	808,457	1,049,043	821,058	777,170	4.7	0.0	2,161	117	90	0	0.5	71.0	8.6	67,538	12,125	498	51	/C
121	Apr2012	12,399,845	311,401	5,638,895	26,182,488	12,099,009	6,315,660	315,028	117,376	363,684	1,836	405,770	529,352	410,613	388,889	3.4	0.0	2,160	118	90	0	r1.3	66.7	9.9	67,538	12,037	497	52	/C
122	May2012	12,157,39 7	304,440	5,595,238	26,862,233	13,867,064	6,508,090	238,309	113,581	353,381	1,818	396,089	521,363	398,182	376,144	0.0	1.2	2,168	119	90	0	8.7	71.0	10.5	67,506	12,116	497	52	/C
123	Jun2012	15,317,112	318,782	6,164,748	29,007,293	14,527,363	6,739,775	236,599	112,514	898,476	4,697	1,010,064	1,339,796	1,009,678	951,262	0.0	3.4	2,164	120	90	0	13.1	70.0	10.0	67,401	12,129	496	52	/C

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col.22	Col.23	Col.24	Col.25	Col. 26	Col. 27	Col. 28	
1																													
2	Month	PurchasedEnergy per day, kWh(bycustomerclass)								CumulativeCDMimpacts perday, kWh						HDD10per day	CDD18 perday	Toronto Population ('000)	TimeTrend		Blackout Dummy	DewPoint Temperature	Business Days Percent	Toronto Unemployment Rate	CustomerNumbers				
3		Residential	Competitive SectorMulti r Unit Residential (CSMUR)	GS<50kW	GS50r999 kW	GS1000 r4999 kW	LargeUse	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50kW	GS50r999 kW	GS1000 r 4999kW	LargeUse				Residenti al	GS<50kW & Large Use					GS<50 kW	GS50r 999kW	GS1000 r 4999kW	Large Use	
124	Jul2012	18,131,90 6	312,904	7,036,091	32,240,688	15,049,425	7,152,922	251,219	120,795	866,923	4,587	978,822	1,303,315	975,292	917,707	0.0	6.4	2,173	121	90	0	15.5	67.7	11.0	67,410	12,159	496	52	/C
125	Aug2012	15,691,202	321,617	6,310,141	29,992,809	14,755,846	7,129,583	250,899	115,291	859,733	4,629	967,394	1,298,007	961,551	903,142	0.0	3.6	2,163	122	90	0	15.2	71.0	11.0	67,513	12,175	495	52	/C
126	Sep2012	12,969,851	337,616	5,770,193	27,148,548	13,684,971	6,711,022	287,762	116,419	881,633	4,831	884,582	1,232,903	875,649	816,233	0.0	1.2	2,164	123	90	0	10.7	63.3	9.6	67,661	12,183	495	52	/C
127	Oct2012	12,290,11 6	330,016	5,432,890	25,916,412	13,459,475	6,545,512	334,221	113,648	348,730	1,933	351,293	492,509	346,060	322,038	1.6	0.0	2,152	124	90	0	6.5	71.0	9.2	67,903	12,184	494	52	/C
128	Nov2012	13,714,743	350,411	5,981,463	27,336,966	13,555,818	6,411,528	387,559	118,414	361,786	2,040	364,125	515,914	356,018	330,187	6.6	0.0	2,150	125	90	0	r1.4	73.3	8.5	67,986	12,205	497	52	/C
129	Dec2012	14,899,013	347,376	6,068,480	27,925,831	12,896,242	6,145,359	390,271	115,694	738,560	4,406	756,234	1,103,805	720,003	659,984	8.4	0.0	2,151	126	90	0	r2.7	61.3	8.4	67,970	12,225	504	52	/C
130	Jan2013	15,740,23 7	355,072	6,455,242	29,450,570	13,845,080	6,290,783	417,003	117,907	740,284	4,447	760,754	1,115,995	721,821	660,495	12.1	0.0	2,155	127	90	0	r6.0	67.7	9.3	67,994	12,259	508	53	/C
131	Feb2013	15,668,885	400,317	6,534,872	30,318,012	13,939,909	6,423,217	388,411	116,638	822,527	4,984	849,973	1,254,761	803,034	733,152	14.6	0.0	2,145	128	90	0	r7.7	67.9	8.8	68,018	12,262	507	53	/C
132	Mar2013	14,241,532	376,762	6,044,355	27,724,888	13,685,711	6,501,719	366,105	118,591	744,906	4,542	772,636	1,145,795	727,748	663,334	9.9	0.0	2,143	129	90	0	r5.2	67.7	8.5	68,091	12,206	510	53	/C
133	Apr2013	12,765,885	391,871	5,719,453	26,595,985	13,583,033	6,119,102	309,020	115,816	372,922	2,295	388,957	580,744	364,813	332,292	4.5	0.0	2,157	130	90	0	0.1	66.7	8.6	68,106	12,199	511	53	/C
134	May2013	11,977,69 8	387,596	5,872,475	25,655,935	13,246,757	6,334,762	254,699	120,029	362,263	2,250	379,932	570,892	354,788	322,436	0.5	0.7	2,144	131	90	0	7.6	71.0	8.7	68,117	12,074	512	53	/C
135	Jun2013	13,489,91 9	404,374	5,866,940	27,810,722	14,505,532	6,132,620	228,110	111,195	922,656	5,792	973,985	1,474,596	904,666	819,547	0.0	2.0	2,157	132	90	0	12.9	70.0	8.5	68,312	11,885	516	52	/C
136	Jul2013	16,308,383	398,051	6,824,582	30,593,698	14,936,165	6,613,001	252,451	122,934	902,849	5,678	951,175	1,451,425	877,631	792,593	0.0	4.4	2,154	133	90	0	16.1	67.7	9.1	68,405	11,924	516	51	/C
137	Aug2013	14,503,28 7	404,870	6,334,413	28,853,754	14,664,508	6,504,285	251,148	113,767	899,090	5,751	960,169	1,474,629	882,350	794,995	0.0	3.0	2,145	134	90	0	14.2	71.0	8.2	68,481	11,913	517	51	/C
138	Sep2013	12,505,48 9	423,555	5,782,171	26,690,786	13,995,162	6,388,175	290,795	115,054	930,121	6,015	1,000,975	1,546,184	916,174	823,665	0.0	0.9	2,148	135	90	0	11.1	63.3	8.7	68,566	11,923	517	51	/C
139	Oct2013	12,041,133	413,172	5,545,162	25,803,765	13,726,575	6,299,234	334,672	113,456	368,811	2,410	399,573	621,692	363,829	326,332	1.6	0.0	2,146	136	90	0	6.5	71.0	9.4	68,661	11,890	519	51	/C
140	Nov2013	13,929,79 9	427,828	6,171,788	27,526,659	13,743,319	6,319,825	392,315	116,957	385,862	2,584	424,513	671,371	381,818	340,102	8.1	0.0	2,166	137	90	0	r2.6	73.3	8.5	68,692	11,904	521	51	/C
141	Dec2013	15,789,31 4	417,804	6,449,029	28,838,788	13,465,665	6,162,732	395,982	120,490	779,626	5,305	866,637	1,384,575	773,114	683,688	14.2	0.0	2,167	138	90	0	r7.7	61.3	9.1	68,702	11,914	521	51	/C
142	Jan2014									776,152	5,330	869,677	1,393,746	774,001	683,612	14.6	0.0	2,168	139	90	0	r8.2	71.0	9.0	68,728	11,913	520	51	/C
143	Feb2014									860,893	5,952	968,766	1,556,795	860,585	759,236	14.2	0.0	2,169	140	90	0	r8.2	67.9	9.0	68,683	11,913	516	52	/C
144	Mar2014									781,677	5,480	885,985	1,431,954	784,065	690,111	9.0	0.0	2,170	141	90	0	r4.6	67.7	8.9	68,753	11,913	516	52	/C
145	Apr2014									390,647	2,772	445,771	723,856	393,475	346,645	3.2	0.0	2,171	142	90	0	0.0	66.7	8.9	68,799	11,981	439	48	/C
146	May2014									379,809	2,732	436,515	712,655	383,929	337,475	0.4	0.6	2,172	143	90	0	6.8	67.7	8.9	68,845	11,969	439	48	/C
147	Jun2014									967,925	7,069	1,121,813	1,842,916	982,565	860,892	0.0	2.4	2,173	144	90	0	12.8	70.0	8.8	68,891	11,957	439	48	/C
148	Jul2014									927,722	6,910	1,091,044	1,804,515	949,771	829,592	0.0	4.5	2,174	145	90	0	15.6	71.0	8.8	68,937	11,944	439	48	/C
149	Aug2014									921,392	6,973	1,098,175	1,821,820	954,457	832,681	0.0	3.4	2,175	146	90	0	15.0	64.5	8.7	68,983	11,932	439	48	/C
150	Sep2014									951,417	7,277	1,142,722	1,901,760	991,131	863,497	0.0	1.1	2,176	147	90	0	12.0	70.0	8.7	69,029	11,920	440	48	/C
151	Oct2014									377,122	2,916	455,625	761,564	394,066	342,873	1.5	0.1	2,177	148	90	0	6.0	71.0	8.6	69,040	11,935	440	48	/C
152	Nov2014									394,344	3,119	481,949	813,072	414,232	358,910	5.8	0.0	2,177	149	90	0	0.3	66.7	8.6	69,052	11,950	440	48	/C
153	Dec2014									805,213	6,589	1,002,127	1,713,495	852,930	732,323	11.8	0.0	2,178	150	90	0	r5.4	67.7	8.5	69,063	11,965	440	48	/C
154	Jan2015									793,193	6,532	990,155	1,708,119	838,636	717,286	14.6	0.0	2,179	151	90	0	r8.2	67.7	8.4	69,074	11,980	440	48	/C
155	Feb2015									878,667	7,282	1,100,930	1,904,184	930,857	795,183	14.2	0.0	2,180	152	90	0	r8.2	67.9	8.3	69,085	11,995	440	48	/C
156	Mar2015									796,043	6,680	1,003,772	1,745,376	846,138	721,082	9.0	0.0	2,181	153	90	0	r4.6	71.0	8.2	69,097	12,010	440	48	/C
157	Apr2015									397,648	3,370	503,747	879,959	423,737	361,391	3.2	0.0	2,182	154	90	0	0.0	66.7	8.2	69,108	12,024	440	49	/C
158	May2015									386,147	3,313	492,319	864,074	413,017	351,485	0.4	0.6	2,183	155	90	0	6.8	64.5	8.2	69,119	12,039	440	49	/C
159	Jun2015									979,731	8,524	1,257,833	2,223,576	1,051,402	891,372	0.0	2.4	2,184	156	90	0	12.8	73.3	8.1	69,131	12,054	440	49	/C
160	Jul2015									940,323	8,339	1,216,027	2,168,039	1,008,957	851,627	0.0	4.5	2,185	157	90	0	15.6	71.0	8.1	69,142	12,069	441	49	/C
161	Aug2015									926,548	8,395	1,220,618	2,183,602	1,011,094	852,117	0.0	3.4	2,186	158	90	0	15.0	64.5	8.1	69,153	12,084	441	49	/C
162	Sep2015									895,923	8,718	1,263,383	2,270,731	1,043,868	877,788	0.0	1.1	2,187	159	90	0	12.0	70.0	8.0	69,164	12,099	441	49	/C
163	Oct2015									354,917	3,486	502,780	907,289	414,523	348,109	1.5	0.1	2,187	160	90	0	6.0	67.7	8.0	69,176	12,114	441	49	/C
164	Nov2015									369,200	3,707	529,249	963,788	434,279	363,099	5.8	0.0	2,188	161	90	0	0.3	70.0	8.0	69,187	12,129	441	49	/C
165	Dec2015									751,264	7,783	1,095,001	2,018,406	892,296	739,460	11.8	0.0	2,189	162	90	0	r5.4	67.7	7.9	69,198	12,144	441	49	/C
166	Jan2016									749,217	7,830	1,079,896	2,010,940	874,903	721,206	14.6	0.0	2,190	163	90	0	r8.2	64.5	7.9	69,210	12,159	441	49	/C
167	Feb2016									803,362	8,434	1,159,567	2,164,190	937,561	771,777	14.2	0.0	2,191	164	90	0	r8.2	69.0	7.9	69,221	12,174	441	49	/C
168	Mar2016									756,236	8,009	1,096,968	2,055,483	883,644	725,522	9.0	0.0	2,192	165	90	0	r4.6	67.7	7.9	69,232	12,189	441	49	/C
169	Apr2016									378,343	4,040	551,413	1,036,672	443,123	364,261	3.2	0.0	2,193	166	90	0	0.0	70.0	7.9	69,243	12,203	441	49	/C
170	May2016									368,257	3,967	539,961	1,018,363	432,520	354,804	0.4	0.6	2,194	167	90	0	6.8	67.7	7.9	69,255	12,218	442	49	/C
171	Jun2016									939,729	10,222	1,381,744	2,620,754	1,101,427	899,670	0.0	2.4	2,195	168	90	0	12.8	73.3	7.9	69,266	12,233	442	49	/C
172	Jul2016									906,906	10,021	1,342,376	2,560,903	1,063,527	865,303	0.0	4.5	2,196	169	90	0	15.6	64.5	7.8	69,277	12,248	442	49	/C
173	Aug2016									900,270	10,103	1,347,448	2,578,531	1,065,198	865,128	0.0	3.4	2,197	170	90	0	15.0	71.0	7.8	69,289	12,263	442	49	/C
174	Sep2016									922,963	10,530	1,394,570	2,680,678	1,098,894	890,116	0.0	1.1	2,198	171	90	0	12.0	70.0	7.8	69,300	12,278	442	49	/C
175	Oct2016									366,303	4,207	555,681	1,071,143	436,696	353,346	1.5	0.1	2,198	172	90	0	6.0	64.5	7.8	69,311	12,293	442	49	/C
176	Nov2016									383,750	4,469	586,573	1,137,788	458,159	369,057	5.8	0.0	2,199	173	90	0	0.3	73.3	7.7	69,323	12,308	442	49	/C
177	Dec2016									786,091	9,340	1,219,849	2,384,567	943,719	752,441	11.8	0.0	2,200	174	90	0	r5.4	64.5	7.7	69,334	12,323	442	49	/C
178	Jan2017									786,664	9,399	1,218,100	2,391,907	939,324	746,724	14.6	0.0	2,201	175	90	0	r8.2	67.7	7.7	69,345	12,338	442	49	/C
179	Feb2017									873,375	10,481	1,355,076	2,666,202	1,042,894	827,816	14.2	0.0	2,202	176	90	0	r8.2	67.9	7.6	69,356	12,353	442	49	/C
180	Mar2017									794,319	9,600	1,239,025	2,445,174	950,770	752,950	9.0	0.0	2,203	177	90	0	r4.6	74.2	7.6	69,368	12,367	442	49	/C
181	Apr2017									397,775	4,837	622,892	1,233,075	476,947	378,479	3.2	0.0	2,204	178	90	0	0.0	60.0	7.6	69,379	12,382	443	49	/C
182	May2017									387,250	4,743	609,726	1,210,612	465,445	368,498	0.4	0.6	2,205	179	90	0	6.8	71.0	7.6	69,390	12,397	443	50	/C
183	Jun2017									988,883	12,204	1,566,044	3,120,420	1,191,033	939,411	0.0	2.4	2,206	180	90	0	12.8	73.3	7.6	69,402	12,412	443	50	/C
184	Jul2017									954,884	11,912	1,499,935	3,027,493	1,127,169	880,477	0.0	4.5	2,207	181	90	0	15.6	64.5	7.5	69,413	12,427	443	50	/C

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col.22	Col.23	Col.24	Col.25	Col. 26	Col. 27	Col. 28	
1																													
2	Month	PurchasedEnergy per day, kWh(bycustomerclass)								CumulativeCDMimpacts perday, kWh						HDD10per day	CDD18 perday	Toronto Population ('000)	TimeTrend		Blackout Dummy	DewPoint Temperature	Business Days Percent	Toronto Unemployment Rate	CustomerNumbers				
3		Residential	Competitive SectorMulti r Unit Residential (CSMUR)	GS<50kW	GS50r999 kW	GS1000 r4999 kW	LargeUse	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50kW	GS50r999 kW	GS1000 r 4999kW	LargeUse				Residenti al	GS<50kW & Large Use					GS<50 kW	GS50r 999kW	GS1000 r 4999kW	Large Use	
185	Aug2017									947,984	12,003	1,507,344	3,049,402	1,130,435	881,475	0.0	3.4	2,208	182	90	0	15.0	71.0	7.5	69,424	12,442	443	50	/C
186	Sep2017									974,868	12,506	1,566,377	3,172,908	1,172,162	912,321	0.0	1.1	2,208	183	90	0	12.0	66.7	7.5	69,435	12,457	443	50	/C
187	Oct2017									387,006	4,992	624,585	1,268,007	466,333	362,650	1.5	0.1	2,209	184	90	0	6.0	67.7	7.5	69,447	12,472	443	50	/C
188	Nov2017									405,816	5,292	661,584	1,348,625	491,612	380,866	5.8	0.0	2,210	185	90	0	0.3	73.3	7.5	69,458	12,487	443	50	/C
189	Dec2017									830,225	11,016	1,376,158	2,823,612	1,014,118	777,125	11.8	0.0	2,211	186	90	0	r5.4	61.3	7.5	69,469	12,502	443	50	/C
190	Jan2018									831,843	11,075	1,373,828	2,829,595	1,009,639	771,467	14.6	0.0	2,212	187	90	0	r8.2	71.0	7.5	69,481	12,517	443	50	/C
191	Feb2018									924,501	12,338	1,526,840	3,149,021	1,120,834	855,496	14.2	0.0	2,213	188	90	0	r8.2	67.9	7.5	69,492	12,532	444	50	/C
192	Mar2018									841,749	11,288	1,392,665	2,878,788	1,020,855	777,900	9.0	0.0	2,214	189	90	0	r4.6	67.7	7.5	69,503	12,546	444	50	/C
193	Apr2018									422,130	5,683	699,274	1,448,668	512,350	391,673	3.2	0.0	2,215	190	90	0	0.0	66.7	7.5	69,514	12,561	444	50	/C
194	May2018									411,610	5,567	683,027	1,418,149	499,836	381,501	0.4	0.6	2,216	191	90	0	6.8	71.0	7.5	69,526	12,576	444	50	/C
195	Jun2018									1,052,615	14,312	1,748,198	3,641,761	1,277,212	971,695	0.0	2.4	2,217	192	90	0	12.8	70.0	7.5	69,537	12,591	444	50	/C
196	Jul2018									1,032,680	14,001	1,691,661	3,546,551	1,230,352	931,453	0.0	4.5	2,218	193	90	0	15.6	67.7	7.5	69,548	12,606	444	50	/C
197	Aug2018									1,027,677	14,096	1,697,819	3,566,376	1,233,469	932,492	0.0	3.4	2,218	194	90	0	15.0	71.0	7.5	69,560	12,621	444	50	/C
198	Sep2018									1,063,504	14,672	1,761,238	3,707,568	1,277,844	964,468	0.0	1.1	2,219	195	90	0	12.0	63.3	7.5	69,571	12,636	444	50	/C
199	Oct2018									422,472	5,850	700,524	1,477,422	507,806	383,130	1.5	0.1	2,220	196	90	0	6.0	71.0	7.5	69,582	12,651	444	50	/C
200	Nov2018									443,294	6,186	737,222	1,561,041	533,489	401,405	5.8	0.0	2,221	197	90	0	0.3	73.3	7.5	69,593	12,666	444	50	/C
201	Dec2018									910,712	12,861	1,521,340	3,240,984	1,096,881	818,089	11.8	0.0	2,222	198	90	0	r5.4	61.3	7.5	69,605	12,681	445	50	/C
202	Jan2019									881,475	12,913	1,500,968	3,227,740	1,074,360	794,861	14.6	0.0	2,223	199	90	0	r8.2	71.0	7.5	69,616	12,696	445	50	/C
203	Feb2019									975,839	14,363	1,666,130	3,586,931	1,191,013	880,129	14.2	0.0	2,224	200	90	0	r8.2	67.9	7.4	69,627	12,710	445	50	/C
204	Mar2019									884,280	13,106	1,515,766	3,268,412	1,081,249	797,570	9.0	0.0	2,225	201	90	0	r4.6	67.7	7.4	69,639	12,725	445	50	/C
205	Apr2019									441,843	6,585	759,804	1,640,741	541,420	400,493	3.2	0.0	2,226	202	90	0	0.0	66.7	7.4	69,650	12,740	445	50	/C
206	May2019									429,886	6,434	741,150	1,601,903	527,310	389,567	0.4	0.6	2,227	203	90	0	6.8	71.0	7.4	69,661	12,755	445	50	/C
207	Jun2019									1,087,042	16,493	1,888,421	4,094,702	1,338,880	984,956	0.0	2.4	2,228	204	90	0	12.8	66.7	7.3	69,673	12,770	445	51	/C
208	Jul2019									1,059,636	16,074	1,833,745	3,986,770	1,294,670	949,290	0.0	4.5	2,229	205	90	0	15.6	71.0	7.3	69,684	12,785	445	51	/C
209	Aug2019									1,048,240	16,157	1,837,067	4,001,736	1,294,817	947,642	0.0	3.4	2,229	206	90	0	15.0	67.7	7.3	69,695	12,800	445	51	/C
210	Sep2019									1,071,694	16,791	1,897,605	4,147,399	1,333,524	972,823	0.0	1.1	2,230	207	90	0	12.0	66.7	7.3	69,706	12,815	445	51	/C
211	Oct2019									424,354	6,680	753,505	1,648,574	528,795	385,600	1.5	0.1	2,231	208	90	0	6.0	71.0	7.3	69,718	12,830	445	51	/C
212	Nov2019									441,428	7,031	789,302	1,731,325	552,058	401,307	5.8	0.0	2,232	209	90	0	0.3	70.0	7.2	69,729	12,845	446	51	/C
213	Dec2019									900,736	14,518	1,622,616	3,567,346	1,129,211	814,653	11.8	0.0	2,233	210	90	0	r5.4	64.5	7.2	69,740	12,860	446	51	/C

Residential Model

Dependent Variable: RES_DAY
Method: Least Squares
Date: 08/12/14 Time: 20:24
Sample: 2002M07 2013M12
Included observations: 138
White HeteroskedasticityrConsistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	trStatistic	Prob.
HDD10_DAY	302,597	7,880	38.40	0.000
CDD18_DAY	988,532	28,208	35.04	0.000
POP	3,056	2,636	1.16	0.248
TREND_JUL2002	r8,776	2,402	r3.65	0.000
BLACKOUT	r1,373,181	107,914	r12.72	0.000
C	6,831,461	5,437,571	1.26	0.211

Rrsquared	93.9%	Mean dependent var	15,259,740.16
Adjusted Rrsquared	93.7%	S.D. dependent var	1,732,538.26
S.E. of regression	434,365.9	Akaike info criterion	28.84
Sum squared resid	24,904,933,065,819	Schwarz criterion	28.97
Log likelihood	r1,984.2	HannanrQuinn criter.	28.90
Frstatistic	409.5	DurbinrWatson stat	1.61
Prob(Frstatistic)	0.0000		

/C

GS<50 kW Model

Dependent Variable: LESS50_DAY
Method: Least Squares
Date: 08/12/14Time: 20:39
Sample: 2002M07 2013M12
Included observations: 138
White HeteroskedasticityrConsistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	trStatistic	Prob.
HDD10_DAY	113,063	7,478	15.12	0.000
CDD18_DAY	268,654	19,496	13.78	0.000
DEW	29,000	6,721	4.32	0.000
TREND_JUL2002_2	r8,891	475	r18.72	0.000
UNEMPL_RATE	r33,141	12,958	r2.56	0.012
CUST_NUMBERS	127	22	5.82	0.000
BLACKOUT	r410,229	32,739	r12.53	0.000
C	r1,727,230	1,478,108	r1.17	0.245

Rrsquared	93.4%	Mean dependent var	6,910,366.12
Adjusted Rrsquared	93.0%	S.D. dependent var	616,035.94
S.E. of regression	162,615.8	Akaike info criterion	26.89
Sum squared resid	3,437,708,167,740	Schwarz criterion	27.06
Log likelihood	r1,847.6	Hannan rQuinn criter.	26.96
Frstatistic	262.3	Durbin rWatson stat	1.39
Prob(Frstatistic)	0.0000		

/C

GS 50r999 kW Model

Dependent Variable: GS350_DAY
Method: Least Squares
Date: 08/12/14Time: 20:44
Sample: 2002M07 2013M12
Included observations: 138
White HeteroskedasticityrConsistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	trStatistic	Prob.
HDD10_DAY	454,377	21,828	20.82	0.000
CDD18_DAY	948,400	42,376	22.38	0.000
BUS_DAYS_PERCENT	31,430	11,310	2.78	0.006
DEW	122,744	18,918	6.49	0.000
CUST_NUMBERS	969	58	16.79	0.000
UNEMPL_RATE	r68,381	36,726	r1.86	0.065
BLACKOUT	r1,878,717	124,937	r15.04	0.000
C	11,919,161	1,001,752	11.90	0.000

Rrsquared	95.5%	Mean dependent var	28,646,861.58
Adjusted Rrsquared	95.2%	S.D. dependent var	1,979,443.79
S.E. of regression	431,665.8	Akaike info criterion	28.84
Sum squared resid	24,223,602,166,814	Schwarz criterion	29.01
Log likelihood	r1,982.3	Hannan rQuinn criter.	28.91
Frstatistic	393.0	Durbin rWatson stat	1.20
Prob(Frstatistic)	0.0000		

/C

GS 1000r 4999 kW Model

Dependent Variable: GS450_DAY
Method: Least Squares
Date: 08/12/14Time: 20:52
Sample: 2002M07 2013M12
Included observations: 138
White HeteroskedasticityrConsistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	trStatistic	Prob.
HDD10_DAY	187,930	14,713	12.77	0.000
CDD18_DAY	305,932	35,048	8.73	0.000
BUS_DAYS_PERCENT	54,716	8,299	6.59	0.000
DEW	117,789	12,913	9.12	0.000
CUST_NUMBERS	10,208	2,246	4.55	0.000
UNEMPL_RATE	r142,025	19,082	r7.44	0.000
BLACKOUT	r886,383	82,964	r10.68	0.000
C	5,033,665	1,355,284	3.71	0.000

Rrsquared	87.7%	Mean dependent var	14,425,799.09
Adjusted Rrsquared	87.0%	S.D. dependent var	835,816.52
S.E. of regression	300,936.5	Akaike info criterion	28.12
Sum squared resid	11,773,157,487,626	Schwarz criterion	28.29
Log likelihood	r1,932.5	Hannan rQuinn criter.	28.19
Frstatistic	132.4	Durbin rWatson stat	1.26
Prob(Frstatistic)	0.0000		

/C

Large Use Model

Dependent Variable: LU_DAY
Method: Least Squares
Date: 08/12/14Time: 20:55
Sample: 2002M07 2013M12
Included observations: 138
White HeteroskedasticityrConsistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	trStatistic	Prob.
HDD10_DAY	85,249	10,902	7.82	0.000
CDD18_DAY	143,786	25,967	5.54	0.000
BUS_DAYS_PERCENT	19,744	7,025	2.81	0.006
DEW	51,924	9,428	5.51	0.000
CUST	40,422	13,206	3.06	0.003
TREND_JUL2002_2	r6,560	721	r9.09	0.000
BLACKOUT	r473,165	67,682	r6.99	0.000
C	3,488,893	824,306	4.23	0.000

Rrsquared	75.5%	Mean dependent var	7,170,595.24
Adjusted Rrsquared	74.2%	S.D. dependent var	478,171.03
S.E. of regression	242,837.8	Akaike info criterion	27.69
Sum squared resid	7,666,124,475,923	Schwarz criterion	27.86
Log likelihood	r1,902.9	Hannan rQuinn criter.	27.76
Frstatistic	57.3	Durbin rWatson stat	1.38
Prob(Frstatistic)	0.0000		

/C

Table1:Loads by Class

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col.11	Col.12	Col.13	Col.14	Col.15	Col.16	Col.17	Col.18	Col.19	
1																				
2			2009Board Approved	2009Actual	2010Board Approved	2010Actual	2011Board Approved	2011Actual	2012Board Approved	2012Actual	2013Board Approved	2013Actual	2014Board Approved	2014Bridge Year	2015TestYear	2016 TestYear	2017 TestYear	2018 TestYear	2019 TestYear	
3	Residential	kWh	5,387,207,866	5,025,855,546	5,081,028,663	5,206,836,373	4,986,768,673	5,172,679,422	n/a	5,145,711,916	n/a	5,007,496,092	n/a	4,933,289,211	4,909,898,145	4,905,620,419	4,851,685,133	4,807,177,718	4,774,297,560	/C
4		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
5	CompetitiveSectorMulti rUnit Residential(CSMUR)	kWh	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	85,122,909	n/a	171,862,499	213,116,822	255,526,309	289,587,529	324,960,737	362,294,376	/C
6		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
7	GS<50kW	kWh	2,545,941,999	2,180,476,274	2,229,476,310	2,095,766,048	2,139,318,076	2,085,497,836	n/a	2,124,568,049	n/a	2,157,353,481	n/a	2,134,640,222	2,118,402,162	2,101,996,032	2,058,843,341	2,016,610,061	1,986,965,125	/C
8		kVA	n/a	n/a	n/a	n/a		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
9	GS50r999 kW	kWh	9,786,256,143	9,844,680,730	10,134,340,212	10,191,135,017	10,116,374,153	10,275,861,063	n/a	9,978,192,876	n/a	9,842,128,168	n/a	9,825,134,003	9,848,614,894	9,838,327,422	9,745,292,849	9,671,927,970	9,616,005,531	/C
10		kVA	25,062,727	25,674,216	26,511,577	26,717,773	26,935,191	26,844,715	n/a	26,409,737	n/a	25,980,090	n/a	26,274,126	26,395,826	26,453,431	26,332,008	26,283,129	26,240,163	/C
11	GS1000 r4999kW	kWh	5,040,303,453	4,786,395,558	4,880,642,723	4,829,372,146	4,626,928,262	4,670,665,638	n/a	4,794,683,898	n/a	4,905,371,169	n/a	4,685,931,494	4,654,535,571	4,669,074,039	4,651,403,293	4,640,828,256	4,634,979,494	/C
12		kVA	11,526,464	10,952,209	11,142,188	10,974,687	10,587,119	10,611,988	n/a	10,885,366	n/a	11,100,609	n/a	10,744,026	10,671,871	10,717,086	10,688,401	10,695,772	10,690,242	/C
13	LargeUse	kWh	2,570,384,339	2,343,905,925	2,378,122,313	2,263,689,663	2,376,778,323	2,340,746,174	n/a	2,367,027,561	n/a	2,272,056,290	n/a	2,246,880,155	2,228,386,374	2,234,712,907	2,229,642,449	2,225,220,101	2,229,610,682	/C
14		kVA	5,360,901	5,358,884	4,974,405	5,268,310	4,993,733	5,441,844	n/a	5,567,061	n/a	5,401,906	n/a	5,370,582	5,305,030	5,310,683	5,285,383	5,279,518	5,272,315	/C
15	StreetLighting	kWh	109,374,973	112,001,096	109,298,944	112,749,995	110,165,016	113,045,004	n/a	113,594,917	n/a	113,643,583	n/a	113,903,287	114,092,929	114,659,005	114,472,212	114,661,853	114,851,495	/C
16		kVA	317,526	321,100	321,183	321,995	322,023	322,481	n/a	322,741	n/a	323,205	n/a	323,962	324,479	324,984	325,489	325,998	326,502	/C
17	UnmeteredScattered Load	kWh	57,420,003	56,413,961	52,413,320	52,107,422	56,231,585	42,759,300	n/a	41,142,371	n/a	41,132,354	n/a	41,132,354	41,132,354	41,245,045	41,132,354	41,132,354	41,132,354	/C
18		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
19	Total	kWh	25,496,888,777	24,349,729,089	24,865,322,485	24,751,656,664	24,412,564,088	24,701,254,438	n/a	24,564,921,588	n/a	24,424,304,046	n/a	24,152,773,226	24,128,179,251	24,161,161,179	23,982,059,160	23,842,519,050	23,760,136,618	/C
20		kVA	42,267,618	42,306,408	42,949,353	43,282,765	42,838,067	43,221,028	n/a	43,184,905	n/a	42,805,809	n/a	42,712,695	42,697,206	42,806,184	42,631,282	42,584,417	42,529,222	/C
21																				
22	Notes																			
23	1.Loads are after losses																			
24	2.CSMURrate class implementation daterJun 01, 2013.Prioryears were included in Residential class.																			

Table1:Weatherrnormalized Loads by Class

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col.11	Col.12	Col.13	Col.14	Col.15	Col.16	Col.17	Col.18	Col.19	
1																				
2			2009Board Approved	2009Actual	2010Board Approved	2010Actual	2011Board Approved	2011Actual	2012Board Approved	2012Actual	2013Board Approved	2013Actual	2014Board Approved	2014BridgeYear	2015 TestYear	2016 TestYear	2017 TestYear	2018 TestYear	2019 TestYear	
3	Residential	kWh	5,525,723,343	5,164,437,210	5,055,074,082	5,180,881,792	4,929,687,760	5,115,598,510	n/a	5,165,553,794	n/a	4,994,099,684	n/a	4,933,289,211	4,909,898,145	4,905,620,419	4,851,685,133	4,807,177,718	4,774,297,560	/C
4		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
5	CompetitiveSectorMulti rUnit Residential(CSMUR)	kWh	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	85,122,909	n/a	171,862,499	213,116,822	255,526,309	289,587,529	324,960,737	362,294,376	/C
6		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
7	GS<50kW	kWh	2,580,489,105	2,215,039,887	2,226,020,092	2,092,309,831	2,123,115,647	2,069,295,407	n/a	2,142,551,878	n/a	2,149,291,815	n/a	2,134,640,222	2,118,402,162	2,101,996,032	2,058,843,341	2,016,610,061	1,986,965,125	/C
8		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
9	GS50r999 kW	kWh	9,902,662,905	9,961,143,114	10,128,586,298	10,185,381,103	10,057,940,914	10,217,427,824	n/a	10,064,244,580	n/a	9,805,746,125	n/a	9,825,134,003	9,848,614,894	9,838,327,422	9,745,292,849	9,671,927,970	9,616,005,531	/C
10		kVA	25,376,418	26,002,406	26,494,179	26,701,650	26,785,282	26,705,690	n/a	26,626,355	n/a	25,889,643	n/a	26,274,126	26,395,826	26,453,431	26,332,008	26,283,129	26,240,163	/C
11	GS1000 r4999kW	kWh	5,073,697,893	4,819,805,955	4,883,613,314	4,832,342,737	4,607,153,970	4,650,891,346	n/a	4,839,335,791	n/a	4,887,703,716	n/a	4,685,931,494	4,654,535,571	4,669,074,039	4,651,403,293	4,640,828,256	4,634,979,494	/C
12		kVA	11,606,563	11,034,020	11,148,133	10,979,591	10,542,113	10,569,944	n/a	10,983,190	n/a	11,062,014	n/a	10,744,026	10,671,871	10,717,086	10,688,401	10,695,772	10,690,242	/C
13	LargeUse	kWh	2,586,685,544	2,360,214,920	2,379,178,661	2,264,746,010	2,367,382,216	2,331,350,067	n/a	2,387,122,968	n/a	2,264,048,080	n/a	2,246,880,155	2,228,386,374	2,234,712,907	2,229,642,449	2,225,220,101	2,229,610,682	/C
14		kVA	5,396,384	5,397,208	4,976,654	5,270,103	4,975,030	5,422,124	n/a	5,612,186	n/a	5,383,830	n/a	5,370,582	5,305,030	5,310,683	5,285,383	5,279,518	5,272,315	/C
15	StreetLightin g	kWh	109,374,973	112,001,096	109,298,944	112,749,995	110,165,016	113,045,004	n/a	113,594,917	n/a	113,643,583	n/a	113,903,287	114,092,929	114,659,005	114,472,212	114,661,853	114,851,495	/C
16		kVA	317,526	321,100	321,183	321,995	322,023	322,481	n/a	322,741	n/a	323,205	n/a	323,962	324,479	324,984	325,489	325,998	326,502	/C
17	UnmeteredScattered Loa d	kWh	57,420,003	56,413,961	52,413,320	52,107,422	56,231,585	42,759,300	n/a	41,142,371	n/a	41,132,354	n/a	41,132,354	41,132,354	41,245,045	41,132,354	41,132,354	41,132,354	/C
18		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
19	Total	kWh	25,836,053,768	24,689,056,142	24,834,184,711	24,720,518,889	24,251,677,108	24,540,367,458	n/a	24,753,546,299	n/a	24,340,788,264	n/a	24,152,773,226	24,128,179,251	24,161,161,179	23,982,059,160	23,842,519,050	23,760,136,618	/C
20		kVA	42,696,892	42,754,733	42,940,148	43,273,338	42,624,448	43,020,239	n/a	43,544,473	n/a	42,658,691	n/a	42,712,695	42,697,206	42,806,184	42,631,282	42,584,417	42,529,222	/C
21																				

Notes
1.NormalizedtoTestYear HDDand CD D
2.CSMURrate class implementation daterJun 01, 2013.Prioryears were included in Residential class

Table1:VariancesrLoads by Class

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col.11	Col.12	Col.13	Col.14	
1															
2			2010Actual(norm) vs 2009Actual(norm)	2011Actual(norm) vs 2010Actual(norm)	2011Actualvs2011 BoardApproved	2011Actual(norm) vs 2011BoardApproved (norm)	2012Actual(norm) vs 2011Actual(norm)	2013Actual(norm) vs 2012Actual(norm)	2014BridgeYear vs2013 Actual(norm)	2015TestYear vs2014 Bridge Year	2016TestYear vs 2015TestYear	2017TestYear vs 2016TestYear	2018TestYear vs2017 Test Year	2019TestYear vs2018 Test Year	
3	Residential	kWh	16,444,582	r65,283,282	185,910,749	185,910,749	49,955,284	r171,454,110	r60,810,473	r23,391,067	r4,277,726	r53,935,286	r44,507,415	r32,880,157	/C
4		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
5	CompetitiveSectorMulti rUnit Residential(CSMUR)	kWh	n/a	n/a	n/a	n/a	n/a	85,122,909	86,739,590	41,254,323	42,409,487	34,061,219	35,373,208	37,333,639	/C
6		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
7	GS<50kW	kWh	r122,730,056	r23,014,423	r53,820,240	r53,820,240	73,256,471	6,739,937	r14,651,593	r16,238,060	r16,406,130	r43,152,691	r42,233,280	r29,644,935	/C
8		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
9	GS50r999 kW	kWh	224,237,989	32,046,721	159,486,910	159,486,910	r153,183,244	r258,498,456	19,387,878	23,480,891	r10,287,472	r93,034,573	r73,364,879	r55,922,438	/C
10		kVA	699,244	4,039	r90,477	r79,593	r79,334	r736,712	384,482	121,701	57,605	r121,423	r48,879	r42,966	/C
11	GS1000 r4999kW	kWh	12,536,782	r181,451,391	43,737,376	43,737,376	188,444,445	48,367,925	r201,772,222	r31,395,923	14,538,468	r17,670,746	r10,575,037	r5,848,762	/C
12		kVA	r54,429	r409,647	24,868	27,831	413,246	78,823	r317,988	r72,155	45,215	r28,685	7,371	r5,530	/C
13	LargeUse	kWh	r95,468,910	66,604,057	r36,032,149	r36,032,149	55,772,900	r123,074,888	r17,167,925	r18,493,782	6,326,533	r5,070,457	r4,422,348	4,390,581	/C
14		kVA	r127,105	152,021	448,111	447,094	190,062	r228,356	r13,247	r65,553	5,653	r25,299	r5,866	r7,203	/C
15	StreetLighting	kWh	748,900	295,009	2,879,988	2,879,988	549,913	48,666	259,704	189,641	566,077	r186,794	189,641	189,641	/C
16		kVA	895	487	458	458	260	464	757	517	505	505	509	504	/C
17	UnmeteredScattered Load	kWh	r4,306,539	r9,348,121	r13,472,285	r13,472,285	r1,616,929	r10,017	0	0	112,691	r112,691	0	0	/C
18		kVA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	/C
19	Total	kWh	31,462,747	r180,151,431	288,690,350	288,690,350	213,178,841	r412,758,034	r188,015,039	r24,593,975	32,981,928	r179,102,019	r139,540,110	r82,382,431	/C
20		kVA	518,605	r253,099	382,961	395,790	524,234	r885,782	54,004	r15,489	108,978	r174,903	r46,865	r55,195	/C
21															

Notes
1.NormalizedtoTestYear HDDand CD D
2.CSMURrate class implementation daterJun 01, 2013.Prioryears were included in Residential class.

Table 1: Customers by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19
1																			
2			2009 Board Approved	2009 Actual	2010 Board Approved	2010 Actual	2011 Board Approved	2011 Actual	2012 Board Approved	2012 Actual	2013 Board Approved	2013 Actual	2014 Board Approved	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
3	Residential	Customers	611,808	609,439	614,841	616,394	623,406	624,649	n/a	632,147	n/a	606,350	n/a	611,150	612,985	614,819	616,654	618,488	620,322
4	Competitive Sector MultirUnit Residential (CSMUR)	Customers	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	36,156	n/a	43,591	54,122	65,384	73,991	83,099	92,706
5	GS <50 kW	Customers	66,191	66,074	65,747	65,799	65,792	66,681	n/a	67,401	n/a	68,312	n/a	68,891	69,131	69,266	69,402	69,537	69,673
6	GS 50r999 kW	Customers	11,719	12,231	12,276	12,873	13,067	12,845	n/a	12,129	n/a	11,885	n/a	11,957	12,054	12,233	12,412	12,591	12,770
7	GS 1000r4999 kW	Customers	530	515	517	509	514	503	n/a	496	n/a	516	n/a	439	440	442	443	444	445
8	Large Use	Customers	49	47	47	47	47	50	n/a	52	n/a	52	n/a	48	49	49	50	50	51
9	Street Lighting	Devices	162,450	162,219	162,353	162,964	162,777	163,071	n/a	163,210	n/a	163,426	n/a	163,825	164,098	164,371	164,644	164,916	165,189
10	Unmetered Scattered Load	Customers	1,135	1,093	1,124	1,107	1,130	1,028	n/a	868	n/a	873	n/a	898	898	898	898	898	898
11		Connections	19,907	21,286	21,782	12,159	21,729	12,499	n/a	11,697	n/a	11,784	n/a	11,720	11,720	11,720	11,720	11,720	11,720
12	Total	Customers	691,432	689,399	694,551	696,729	703,956	705,756	n/a	713,093	n/a	724,144	n/a	736,974	749,679	763,091	773,850	785,107	796,865
13		Connections/devices	182,357	183,505	184,136	175,123	184,506	175,570	n/a	174,907	n/a	175,210	n/a	175,545	175,818	176,091	176,364	176,636	176,909
14																			
15	Notes																		
16	1. Customer and Connection/Device values are midryear																		
17	2. CSMUR rate class implementation dater Jun 01, 2013. Prior years were included in Residential class.																		

Table 1: Variancesr Customers by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
1													
2			2010 Actual vs 2009 Actual	2011 Actual vs 2010 Actual	2011 Actual vs 2011 Board Approved	2012 Actual vs 2011 Actual	2013 Actual vs 2012 Actual	2014 Bridge Year vs 2013 Actual	2015 Test Year vs 2014 Bridge Year	2016 Test Year vs 2015 Test Year	2017 Test Year vs 2016 Test Year	2018 Test Year vs 2017 Test Year	2019 Test Year vs 2018 Test Year
3	Residential	Customers	6,955	8,255	1,243	7,498	r25,797	4,800	1,835	1,834	1,835	1,834	1,834
4	Competitive Sector MultirUnit Residential (CSMUR)	Customers	n/a	n/a	n/a	n/a	36,156	7,435	10,531	11,262	8,607	9,108	9,607
5	GS <50 kW	Customers	r275	882	889	720	911	579	240	135	136	135	136
6	GS 50r999 kW	Customers	642	r28	r222	r716	r244	72	97	179	179	179	179
7	GS 1000r4999 kW	Customers	r6	r6	r11	r7	20	r77	1	2	1	1	1
8	Large Use	Customers	0	3	3	2	0	r4	1	0	1	0	1
9	Street Lighting	Devices	745	107	294	139	216	399	273	273	273	272	273
10	Unmetered Scattered Load	Customers	14	r79	r102	r160	5	25	0	0	0	0	0
11		Connections	r9,127	340	r9,230	r802	87	r64	0	0	0	0	0
12	Total	Customers	7,330	9,027	1,800	7,337	11,051	12,830	12,705	13,412	10,759	11,257	11,758
13		Connections/devices	r8,382	447	r8,936	r663	303	335	273	273	273	272	273
14													
15	Notes												
16	1. Customer and Connection/Device values are midryear												
17	2. CSMUR rate class implementation dater Jun 01, 2013. Prior years were included in Residential class												
18	3. USL variance in 2010 Actual to 2009 Actual, 2011 Actual to 2011 BoardrApproved, and 2012 Actual to 2011 Actual due to billing system adjustmen												

Table1:Weatherrnormalized Loads perCustomerby Class

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col.11	Col.12	Col.13	
1														
2			2009Actual	2010Actual	2011Actual	2012Actual	2013Actual	2014Bridge Year	2015Test Year	2016Test Year	2017Test Year	2018Test Year	2019Test Year	
3	Residential	kWh/cust	8,474	8,405	8,190	8,171	8,236	8,072	8,010	7,979	7,868	7,772	7,696	/C
4	CompetitiveSectorMulti rUnit Residential(CSMUR)	kWh/cust	n/a	n/a	n/a	n/a	2,354	3,943	3,938	3,908	3,914	3,911	3,908	/C
5	GS<50kW	kWh/cust	33,524	31,799	31,033	31,788	31,463	30,986	30,643	30,347	29,665	29,001	28,518	/C
6	GS50r999 kW	kWh/cust	814,418	791,220	795,440	829,767	825,052	821,706	817,041	804,245	785,151	768,162	753,015	/C
7	GS1000 r4999kW	kWh/cust	9,358,847	9,493,797	9,246,305	9,756,725	9,472,294	10,674,104	10,578,490	10,563,516	10,499,782	10,452,316	10,415,684	/C
8	LargeUse	kWh/cust	50,217,339	48,186,085	46,627,001	45,906,211	43,539,386	46,810,003	45,477,273	45,606,386	44,592,849	44,504,402	43,717,857	/C
9	StreetLightin g	kWh/dev	690	692	693	696	695	695	695	698	695	695	695	/C
10	UnmeteredScattered Load	kWh/conn	2,650	4,286	3,421	3,517	3,491	3,510	3,510	3,519	3,510	3,510	3,510	/C
11	Total	kWh/cust	35,812	35,481	34,772	34,713	33,613	32,773	32,185	31,662	30,991	30,368	29,817	/C
12														
13														
14	Notes													
15	1.Customerand Connection/Device valuesare mid ryear													
16	2.Loads are weather normalized toTestyear HDDand CDD													
17	3.CSMURrate class implementation daterJun 01, 2013.Prioryears were included in Residential class.													

Table1:Revenues by Clas s

Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col.11	Col.12	Col.13	Col.14	Col.15	Col.16	Col.17	Col.18	Col.19	
		2009Board Approved	2009Actual	2010Board Approved	2010Actual	2011Board Approved	2011Actual	2012Board Approved	2012Actual	2013Board Approved	2013Actual	2014Board Approved	2014Bridge Year	2015TestYear	2016 TestYear	2017 TestYear	2018 TestYear	2019 TestYear	
Residential	CustomerCharge	$ 125,425,779	$ 124,940,074	$ 136,520,338	$ 136,865,151	$ 138,422,132	$ 138,698,105	n/a	$ 140,362,973	n/a	$ 135,962,871	n/a	$ 138,526,315	$ 169,445,400	$ 178,330,300	$ 194,392,979	$ 208,817,011	$ 220,757,092	/C
	DistributionCharge	$ 77,144,817	$ 71,970,251	$ 79,873,771	$ 81,851,468	$ 75,798,884	$ 78,624,727	n/a	$ 78,214,821	n/a	$ 76,164,016	n/a	$ 75,873,988	$ 92,109,689	$ 96,591,666	$ 103,826,062	$ 110,132,442	$ 115,299,286	/C
CompetitiveSectorMulti rUnit Residential(CSMUR)	CustomerCharge	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ 7,548,650	n/a	$ 9,201,697	$ 12,445,354	$ 15,774,871	$ 19,408,826	$ 23,334,753	$ 27,442,367	/C
	DistributionCharge	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ 2,203,832	n/a	$ 4,497,642	$ 6,075,961	$ 7,645,347	$ 9,417,386	$ 11,315,133	$ 13,296,204	/C
GS<50kW	CustomerCharge	$ 17,266,106	$ 17,235,623	$ 19,438,004	$ 19,453,474	$ 19,451,451	$ 19,714,238	n/a	$ 19,927,106	n/a	$ 20,387,603	n/a	$ 20,786,711	$ 25,594,485	$ 26,908,571	$ 29,308,812	$ 31,447,065	$ 33,212,422	/C
	DistributionCharge	$ 50,282,354	$ 43,064,406	$ 50,609,112	$ 47,573,889	$ 48,070,477	$ 46,861,136	n/a	$ 47,739,044	n/a	$ 48,928,777	n/a	$ 48,947,300	$ 59,611,837	$ 62,071,943	$ 66,068,283	$ 69,310,888	$ 71,987,746	/C
GS50r999 kW	CustomerCharge	$ 4,660,902	$ 4,864,615	$ 5,300,602	$ 5,558,497	$ 5,653,199	$ 5,557,346	n/a	$ 5,247,571	n/a	$ 5,191,170	n/a	$ 5,279,354	$ 6,398,645	$ 6,815,147	$ 7,514,390	$ 8,163,522	$ 8,727,039	/C
	DistributionCharge	$ 130,888,593	$ 134,082,058	$ 150,096,766	$ 151,264,158	$ 152,811,870	$ 152,298,566	n/a	$ 149,830,800	n/a	$ 148,813,053	n/a	$ 152,151,564	$ 183,793,699	$ 193,295,112	$ 209,107,303	$ 223,516,879	$ 235,224,656	/C
	TransformerAllowance	(3,263,711)	(3,181,459)	(3,319,551)	(3,300,697)	(3,283,350)	(3,586,925)	n/a	(3,618,183)	n/a	(3,563,945)	n/a	(3,571,778)	(3,587,324)	(3,594,720)	(3,578,454)	(3,571,786)	(3,565,882)	/C
GS1000 r4999kW	CustomerCharge	$ 4,550,112	$ 4,419,606	$ 4,149,424	$ 4,086,031	$ 4,296,929	$ 4,201,021	n/a	$ 4,142,557	n/a	$ 4,351,031	n/a	$ 3,742,449	$ 4,452,100	$ 4,693,251	$ 5,112,203	$ 5,486,973	$ 5,796,894	/C
	DistributionCharge	$ 50,520,973	$ 48,003,988	$ 45,682,570	$ 44,995,820	$ 47,763,803	$ 47,875,997	n/a	$ 49,109,344	n/a	$ 50,562,117	n/a	$ 49,476,043	$ 58,330,030	$ 61,470,766	$ 66,628,213	$ 71,401,200	$ 75,225,034	/C
	TransformerAllowance	(5,595,547)	(5,358,542)	(5,435,318)	(5,384,155)	(5,219,569)	(5,220,656)	n/a	(5,404,286)	n/a	(5,575,354)	n/a	(5,337,927)	(5,302,746)	(5,325,112)	(5,310,981)	(5,314,965)	(5,312,395)	/C
LargeUse	CustomerCharge	$ 1,573,308	$ 1,509,091	$ 1,643,460	$ 1,643,460	$ 1,720,709	$ 1,830,542	n/a	$ 1,903,764	n/a	$ 1,922,073	n/a	$ 1,793,738	$ 2,187,330	$ 2,295,385	$ 2,545,534	$ 2,726,015	$ 2,930,957	/C
	DistributionCharge	$ 21,387,047	$ 21,378,998	$ 21,612,378	$ 22,889,314	$ 24,002,088	$ 26,155,908	n/a	$ 26,757,753	n/a	$ 26,213,693	n/a	$ 26,348,106	$ 31,089,485	$ 32,659,873	$ 35,325,690	$ 37,788,405	$ 39,778,312	/C
	TransformerAllowance	(3,254,452)	(3,207,880)	(2,963,777)	(3,145,318)	(2,976,922)	(3,217,346)	n/a	(3,358,865)	n/a	(3,272,558)	n/a	(3,222,780)	(3,183,523)	(3,186,889)	(3,171,749)	(3,168,202)	(3,163,878)	/C
StreetLighting	ServiceCharge (perdevice)	$ 1,759,059	$ 1,756,561	$ 2,607,396	$ 2,617,202	$ 2,574,590	$ 2,579,240	n/a	$ 2,581,438	n/a	$ 2,604,738	n/a	$ 2,631,030	$ 2,635,414	$ 2,779,788	$ 3,024,785	$ 3,230,430	$ 3,416,659	/C
	DistributionCharge	$ 6,360,852	$ 6,432,436	$ 9,514,299	$ 9,538,348	$ 9,378,515	$ 9,391,867	n/a	$ 9,399,435	n/a	$ 9,503,477	n/a	$ 9,630,523	$ 9,645,892	$ 10,138,149	$ 11,035,260	$ 11,836,160	$ 12,495,777	/C
UnmeteredScattered Load	Cust/ConnCharge	$ 132,004	$ 136,119	$ 199,795	$ 140,231	$ 196,064	$ 135,053	n/a	$ 120,852	n/a	$ 122,186	n/a	$ 125,269	$ 155,273	$ 162,828	$ 177,502	$ 189,986	$ 200,169	/C
	DistributionCharge	$ 2,396,711	$ 2,354,719	$ 3,191,971	$ 3,173,342	$ 3,413,257	$ 2,595,490	n/a	$ 2,497,342	n/a	$ 2,520,591	n/a	$ 2,548,149	$ 3,154,440	$ 3,319,401	$ 3,597,436	$ 3,852,868	$ 4,060,997	/C
Total	CustomerCharge	$ 155,367,270	$ 154,861,689	$ 169,859,019	$ 170,364,047	$ 172,315,074	$ 172,715,544	n/a	$ 174,286,262	n/a	$ 178,090,321	n/a	$ 182,086,563	$ 223,314,000	$ 237,760,141	$ 261,485,031	$ 283,395,755	$ 302,483,599	/C
	DistributionCharge	$ 338,981,346	$ 327,286,857	$ 360,580,867	$ 361,286,339	$ 361,238,894	$ 363,803,690	n/a	$ 363,548,540	n/a	$ 364,909,555	n/a	$ 369,473,316	$ 443,811,034	$ 467,192,257	$ 505,005,632	$ 539,153,974	$ 567,368,012	/C
	TransformerAllowance	(12,113,709)	(11,747,881)	(11,718,646)	(11,830,170)	(11,479,841)	(12,024,926)	n/a	(12,381,333)	n/a	(12,411,857)	n/a	(12,132,485)	(12,073,593)	(12,106,720)	(12,061,183)	(12,054,953)	(12,042,156)	/C
TotalDistribution Revenue		$ 482,234,908	$ 470,400,665	$ 518,721,240	$ 519,820,216	$ 522,074,126	$ 524,494,308	n/a	$ 525,453,469	n/a	$ 530,588,019	n/a	$ 539,427,394	$ 655,051,441	$ 692,845,678	$ 754,429,480	$ 810,494,775	$ 857,809,455	/C

Notes

1.Basedon Approvedrates foreachrate yea r

2.CSMURrate class implementation daterJun 01, 2013.Prioryears were included in Residential class.

Table1:Weatherrnormalized Revenues by Class

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col.11	Col.12	Col.13	Col.14	Col.15	Col.16	Col.17	Col.18	Col.19	
1																				
2			2009Board Approved	2009Actuals	2010Board Approved	2010Actual	2011Board Approved	2011Actual	2012Board Approved	2012Actual	2013Board Approved	2013Actual	2014 Board Approved	2014Bridge Year	2015TestYear	2016 TestYear	2017 TestYear	2018 TestYear	2019 TestYear	
3	Residential	CustomerCharge	$ 125,425,779	$ 124,940,074	$ 136,520,338	$ 136,865,151	$ 138,422,132	$ 138,698,105	n/a	$ 140,362,973	n/a	$ 135,962,871	n/a	$ 138,526,315	$ 169,445,400	$ 178,330,300	$ 194,392,979	$ 208,817,011	$ 220,757,092	/C
4		DistributionCharge	$ 79,128,358	$ 73,954,741	$ 79,465,765	$ 81,443,462	$ 74,931,254	$ 77,757,097	n/a	$ 78,516,418	n/a	$ 75,960,256	n/a	$ 75,873,988	$ 92,109,689	$ 96,591,666	$ 103,826,062	$ 110,132,442	$ 115,299,286	/C
5	CompetitiveSectorMulti rUnit	CustomerCharge	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ 7,548,650	n/a	$ 9,201,697	$ 12,445,354	$ 15,774,871	$ 19,408,826	$ 23,334,753	$ 27,442,367	/C
6	Residential(CSMUR)	DistributionCharge	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ 2,203,832	n/a	$ 4,497,642	$ 6,075,961	$ 7,645,347	$ 9,417,386	$ 11,315,133	$ 13,296,204	/C
7	GS<50kW	CustomerCharge	$ 17,266,106	$ 17,235,623	$ 19,438,004	$ 19,453,474	$ 19,451,451	$ 19,714,238	n/a	$ 19,927,106	n/a	$ 20,387,603	n/a	$ 20,786,711	$ 25,594,485	$ 26,908,571	$ 29,308,812	$ 31,447,065	$ 33,212,422	/C
8		DistributionCharge	$ 50,964,660	$ 43,747,038	$ 50,530,656	$ 47,495,433	$ 47,706,409	$ 46,497,068	n/a	$ 48,143,141	n/a	$ 48,745,938	n/a	$ 48,947,300	$ 59,611,837	$ 62,071,943	$ 66,068,283	$ 69,310,888	$ 71,987,746	/C
9	GS50r999 k W	CustomerCharge	$ 4,660,902	$ 4,864,615	$ 5,300,602	$ 5,558,497	$ 5,653,199	$ 5,557,346	n/a	$ 5,247,571	n/a	$ 5,191,170	n/a	$ 5,279,354	$ 6,398,645	$ 6,815,147	$ 7,514,390	$ 8,163,522	$ 8,727,039	/C
10		DistributionCharge	$ 132,526,828	$ 135,796,015	$ 149,998,264	$ 151,172,876	$ 151,961,388	$ 151,509,833	n/a	$ 151,059,744	n/a	$ 148,294,977	n/a	$ 152,151,564	$ 183,793,699	$ 193,295,112	$ 209,107,303	$ 223,516,879	$ 235,224,656	/C
11		TranformerAllowance	(3,304,560)	(3,223,774)	(3,317,373)	(3,299,101)	(3,265,076)	(3,570,178)	n/a	(3,647,641)	n/a	(3,551,895)	n/a	(3,571,778)	(3,587,324)	(3,594,720)	(3,578,454)	(3,571,786)	(3,565,882)	/C
12	GS1000 r4999k W	CustomerCharge	$ 4,550,112	$ 4,419,606	$ 4,149,424	$ 4,086,031	$ 4,296,929	$ 4,201,021	n/a	$ 4,142,557	n/a	$ 4,351,031	n/a	$ 3,742,449	$ 4,452,100	$ 4,693,251	$ 5,112,203	$ 5,486,973	$ 5,796,894	/C
13		DistributionCharge	$ 50,872,050	$ 48,362,568	$ 45,706,941	$ 45,015,926	$ 47,560,758	$ 47,686,318	n/a	$ 49,550,679	n/a	$ 50,386,320	n/a	$ 49,476,043	$ 58,330,030	$ 61,470,766	$ 66,628,213	$ 71,401,200	$ 75,225,034	/C
14		TranformerAllowance	(5,634,431)	(5,399,531)	(5,438,218)	(5,386,664)	(5,197,381)	(5,199,455)	n/a	(5,450,082)	n/a	(5,556,139)	n/a	(5,337,927)	(5,302,746)	(5,325,112)	(5,310,981)	(5,314,965)	(5,312,395)	/C
15	LargeUse	CustomerCharge	$ 1,573,308	$ 1,509,091	$ 1,643,460	$ 1,643,460	$ 1,720,709	$ 1,830,542	n/a	$ 1,903,764	n/a	$ 1,922,073	n/a	$ 1,793,738	$ 2,187,330	$ 2,295,385	$ 2,545,534	$ 2,726,015	$ 2,930,957	/C
16		DistributionCharge	$ 21,528,604	$ 21,531,890	$ 21,622,152	$ 22,897,102	$ 23,912,192	$ 26,061,123	n/a	$ 26,974,645	n/a	$ 26,125,976	n/a	$ 26,348,106	$ 31,089,485	$ 32,659,873	$ 35,325,690	$ 37,788,405	$ 39,778,312	/C
17		TranformerAllowance	(3,275,992)	(3,230,866)	(2,965,117)	(3,146,463)	(2,965,773)	(3,205,587)	n/a	(3,385,838)	n/a	(3,261,583)	n/a	(3,222,780)	(3,183,523)	(3,186,889)	(3,171,749)	(3,168,202)	(3,163,878)	/C
18	StreetLighting	ServiceCharge (perdevice)	$ 1,759,059	$ 1,756,561	$ 2,607,396	$ 2,617,202	$ 2,574,590	$ 2,579,240	n/a	$ 2,581,438	n/a	$ 2,604,738	n/a	$ 2,631,030	$ 2,635,414	$ 2,779,788	$ 3,024,785	$ 3,230,430	$ 3,416,659	/C
19		DistributionCharge	$ 6,360,852	$ 6,432,436	$ 9,514,299	$ 9,538,348	$ 9,378,515	$ 9,391,867	n/a	$ 9,399,435	n/a	$ 9,503,477	n/a	$ 9,630,523	$ 9,645,892	$ 10,138,149	$ 11,035,260	$ 11,836,160	$ 12,495,777	/C
20	UnmeteredScattered Load	Cust/ConnCharge	$ 132,004	$ 136,119	$ 199,795	$ 140,231	$ 196,064	$ 135,053	n/a	$ 120,852	n/a	$ 122,186	n/a	$ 125,269	$ 155,273	$ 162,828	$ 177,502	$ 189,986	$ 200,169	/C
21		DistributionCharge	$ 2,396,711	$ 2,354,719	$ 3,191,971	$ 3,173,342	$ 3,413,257	$ 2,595,490	n/a	$ 2,497,342	n/a	$ 2,520,591	n/a	$ 2,548,149	$ 3,154,440	$ 3,319,401	$ 3,597,436	$ 3,852,868	$ 4,060,997	/C
22	Total	CustomerCharge	$ 155,367,270	$ 154,861,689	$ 169,859,019	$ 170,364,047	$ 172,315,074	$ 172,715,544	n/a	$ 174,286,262	n/a	$ 178,090,321	n/a	$ 182,086,563	$ 223,314,000	$ 237,760,141	$ 261,485,031	$ 283,395,755	$ 302,483,599	/C
23		DistributionCharge	$ 343,778,064	$ 332,179,406	$ 360,030,049	$ 360,736,490	$ 358,863,774	$ 361,498,795	n/a	$ 366,141,403	n/a	$ 363,741,367	n/a	$ 369,473,316	$ 443,811,034	$ 467,192,257	$ 505,005,632	$ 539,153,974	$ 567,368,012	/C
24		TransformerAllowance	(12,214,983)	(11,854,172)	(11,720,707)	(11,832,228)	(11,428,230)	(11,975,219)	n/a	(12,483,561)	n/a	(12,369,618)	n/a	(12,132,485)	(12,073,593)	(12,106,720)	(12,061,183)	(12,054,953)	(12,042,156)	/C
25																				
26	TotalDistribution Revenue		$ 486,930,351	$ 475,186,924	$ 518,168,360	$ 519,268,309	$ 519,750,618	$ 522,239,120	n/a	$ 527,944,104	n/a	$ 529,462,070	n/a	$ 539,427,394	$ 655,051,441	$ 692,845,678	$ 754,429,480	$ 810,494,775	$ 857,809,455	/C
27	Notes																			
28	1.Basedon Approvedrates foreachrate year																			
29	2.CSMURrate class implementation daterJun 01, 2013.Prioryears were included in Residential class.																			
30	3.NormalizedtoTestYear HDDand CDD																			

Table1:VariancesrRevenues by Class

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col.11	Col.12	Col.13	Col.14	
1															
2			2010Actual (norm)vs2009 Actual(norm)	2011Actual(norm) vs2010 Actual (norm)	2011Actualvs 2011Board Approved	2011Actual (norm)vs2011 BoardApproved (norm)	2012Actual(norm) vs 2011Actual(norm)	2013Actual(norm) vs 2012Actual(norm)	2014BridgeYear vs2013 Actual (norm)	2015TestYear vs2014 Bridge Year	2016TestYear vs2015 Test Year	2017TestYear vs2016 Test Year	2018TestYear vs2017 Test Year	2019TestYear vs2018 Test Year	
3	Residential	CustomerCharge	$ 11,925,077	$ 1,832,954	$ 275,973	$ 275,973	$ 1,664,868	r$ 4,400,102	$ 2,563,444	$ 30,919,086	$ 8,884,900	$ 16,062,679	$ 14,424,032	$ 11,940,081	/C
4		DistributionCharge	$ 7,488,721	r$ 3,686,364	$ 2,825,843	$ 2,825,843	$ 759,320	r$ 2,556,161	r$ 86,268	$ 16,235,701	$ 4,481,977	$ 7,234,396	$ 6,306,380	$ 5,166,845	/C
5	CompetitiveSectorMulti rUnit Residential(CSMUR)	CustomerCharge	n/a	n/a	n/a	n/a	n/a	$ 7,548,650	$ 1,653,047	$ 3,243,657	$ 3,329,517	$ 3,633,955	$ 3,925,927	$ 4,107,613	/C
6		DistributionCharge	n/a	n/a	n/a	n/a	n/a	$ 2,203,832	$ 2,293,809	$ 1,578,319	$ 1,569,387	$ 1,772,039	$ 1,897,746	$ 1,981,071	/C
7	GS<50kW	CustomerCharge	$ 2,217,851	$ 260,763	$ 262,787	$ 262,787	$ 212,868	$ 460,497	$ 399,109	$ 4,807,774	$ 1,314,086	$ 2,400,240	$ 2,138,254	$ 1,765,357	/C
8		DistributionCharge	$ 3,748,395	r$ 998,365	r$ 1,209,341	r$ 1,209,341	$ 1,646,073	$ 602,798	$ 201,362	$ 10,664,537	$ 2,460,106	$ 3,996,340	$ 3,242,605	$ 2,676,859	/C
9	GS50r999 kW	CustomerCharge	$ 693,882	r$ 1,151	r$ 95,852	r$ 95,852	r$ 309,775	r$ 56,402	$ 88,184	$ 1,119,291	$ 416,502	$ 699,243	$ 649,131	$ 563,518	/C
10		DistributionCharge	$ 15,376,861	$ 336,958	r$ 513,303	r$ 451,555	r$ 450,089	r$ 2,764,767	$ 3,856,587	$ 31,642,136	$ 9,501,413	$ 15,812,191	$ 14,409,575	$ 11,707,777	/C
11		TranformerAllowance	r$ 75,326	r$ 271,077	r$ 303,575	r$ 305,102	r$ 77,463	$ 95,745	r$ 19,882	r$ 15,546	r$ 7,397	$ 16,267	$ 6,668	$ 5,903	/C
12	GS1000 r4999kW	CustomerCharge	r$ 333,574	$ 114,989	r$ 95,908	r$ 95,908	r$ 58,464	$ 208,473	r$ 608,582	$ 709,651	$ 241,151	$ 418,952	$ 374,770	$ 309,921	/C
13		DistributionCharge	r$ 3,346,641	$ 2,670,391	$ 112,193	$ 125,559	$ 1,864,361	$ 835,641	r$ 910,276	$ 8,853,987	$ 3,140,735	$ 5,157,447	$ 4,772,987	$ 3,823,834	/C
14		TranformerAllowance	$ 12,868	$ 187,209	r$ 1,086	r$ 2,074	r$ 250,627	r$ 106,057	$ 218,212	$ 35,180	r$ 22,365	$ 14,130	r$ 3,984	$ 2,571	/C
15	LargeUse	CustomerCharge	$ 134,369	$ 187,081	$ 109,833	$ 109,833	$ 73,222	$ 18,309	r$ 128,334	$ 393,591	$ 108,055	$ 250,150	$ 180,480	$ 204,942	/C
16		DistributionCharge	$ 1,365,212	$ 3,164,020	$ 2,153,820	$ 2,148,931	$ 913,522	r$ 848,669	$ 222,130	$ 4,741,378	$ 1,570,388	$ 2,665,817	$ 2,462,716	$ 1,989,906	/C
17		TranformerAllowance	$ 84,402	r$ 59,123	r$ 240,424	r$ 239,814	r$ 180,252	$ 124,255	$ 38,803	$ 39,258	r$ 3,366	$ 15,140	$ 3,547	$ 4,324	/C
18	StreetLighting	ServiceCharge (perdevice)	$ 860,640	r$ 37,962	$ 4,650	$ 4,650	$ 2,199	$ 23,300	$ 26,291	$ 4,384	$ 144,374	$ 244,997	$ 205,645	$ 186,230	/C
19		DistributionCharge	$ 3,105,912	r$ 146,482	$ 13,352	$ 13,352	$ 7,569	$ 104,041	$ 127,047	$ 15,369	$ 492,257	$ 897,111	$ 800,900	$ 659,616	/C
20	UnmeteredScattered Load	Cust/Conn Charge	$ 4,112	r$ 5,178	r$ 61,011	r$ 61,011	r$ 14,200	$ 1,334	$ 3,083	$ 30,003	$ 7,556	$ 14,674	$ 12,483	$ 10,183	/C
21		DistributionCharge	$ 818,623	r$ 577,852	r$ 817,768	r$ 817,768	r$ 98,148	$ 23,249	$ 27,559	$ 606,291	$ 164,961	$ 278,034	$ 255,432	$ 208,130	/C
22	Total	CustomerCharge	$ 15,502,358	$ 2,351,497	$ 400,471	$ 400,471	$ 1,570,718	$ 3,804,060	$ 3,996,242	$ 41,227,437	$ 14,446,141	$ 23,724,890	$ 21,910,723	$ 19,087,844	/C
23		DistributionCharge	$ 28,557,084	$ 762,306	$ 2,564,796	$ 2,635,021	$ 4,642,608	r$ 2,400,037	$ 5,731,949	$ 74,337,718	$ 23,381,223	$ 37,813,375	$ 34,148,341	$ 28,214,039	/C
24		TransformerAllowance	$ 21,944	r$ 142,991	r$ 545,085	r$ 546,990	r$ 508,342	$ 113,944	$ 237,133	$ 58,892	r$ 33,128	$ 45,537	$ 6,230	$ 12,797	/C
25															
26	TotalDistribution Revenue		$ 44,081,385	$ 2,970,811	$ 2,420,182	$ 2,488,502	$ 5,704,984	$ 1,517,967	$ 9,965,324	$ 115,624,047	$ 37,794,237	$ 61,583,802	$ 56,065,295	$ 47,314,680	/C
27	Notes														
28	1.Basedon Approvedrates foreachrate year except fortestyears														
	2.Testyears basedon proposed rates foreachrate year														
29	3.CSMURrate class implementation daterJun 01, 2013.Prioryears were included in Residential class.														

Table 1: Alternative Weather Forecastr 20rYear Trend

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1					
2					
3		Heating Degree Days 10		Cooling Degree Days	
		10rYear	20rYear	10rYear	20rYear
4	Year	Average	Trend	Average	Trend
5	2014	1,824.6	1,725.6	375.3	415.5
6	2015	1,824.6	1,711.8	375.3	421.2
7	2016	1,838.8	1,711.4	375.3	426.8
8	2017	1,824.6	1,684.2	375.3	432.4
9	2018	1,824.6	1,670.4	375.3	438.1
10	2019	1,824.6	1,656.6	375.3	443.7
11					
12	Notes:				
13	1. 10rYear Average calculated over 2004r2013				
14	2. Trend forecast based on linear trend from 1994r2013				
15					

Table1:AIternative WeatherForecastrLoad Forecast

	Col.1	Col.2	Col.3	Col.4	
1					
2					
3		Assuming10rYear AverageHDD&CDD	Assuming20rYear TrendHDD&CDD	Variance	
4	Year	GWh	GWh	%	
5	2014	25,018.5	25,012.1	0.0%	/C
6	2015	24,993.3	24,986.1	0.0%	/C
7	2016	25,027.4	25,018.5	0.0%	/C
8	2017	24,841.6	24,832.9	0.0%	/C
9	2018	24,696.9	24,687.4	0.0%	/C
10	2019	24,611.4	24,601.0	0.0%	/C
11					

REVENUE OFFSETS

1. INTRODUCTION

In addition to revenues recovered through distribution rates, Toronto Hydro earns other revenue from non-distribution related services, property and facility rentals, specific service charges from services provided to customers, and short-term investment income. Toronto Hydro also receives income and recoveries from shared services that it provides to its affiliates. With the transfer of former street-OLJKWLQJ DVVHWV LQWR 7RUR ratebase (refer to Exhibit 2A, Tab 5), Toronto Hydro will also be receiving a portion of contract revenue from the City of Toronto to offset the maintenance costs of these assets. Together, these revenue V IRUP 7RURQWR +\GUR. ¶These revenues are H[SHFWHG 2IIVHWV broken out into the following sub-categories as summarized in Table 1 below.

Table 1: Revenue Offsets Summary

Description	Actual Year 2011	Actual Year 2012	Actual Year 2013	Bridge Year 2014	Test Year 2015
Specific Service Charges Excluding Pole Attachment (4235)	$5.7	$6.3	$6.4	$6.4	$9.8
Late Payment Charge (4225)	$4.2	$4.0	$3.8	$4.0	$4.0
Other Distribution Revenue Excluding Duct Rental (4082,4084,4090,4210,4215,4220)	$3.9	$3.7	$3.7	$3.4	$11.5
Other Income & Deductions Including Pole Attachments (4210, 4235, 4324, 4325,4330,4335,4355,4375,4398,4405)	$18.8	$5.3	$11.5	$12.0	$18.2
Total Revenue Offset	**$32.6**	**$19.4**	**$25.4**	**$25.7**	**$43.6**

/C

A complete breakdown of the Revenue Offsets accounts is shown in OEB Appendix 2-H ±Other Operating Revenue (Exhibit 3, Tab 2, Schedule 2).

2. REVENUE FROM SPECIFIC SERVICE CHARGES

Toronto Hydro charges user fees for certain services. Some of these services, such as DFFRXQW VHWXS DUH SURYLGHG DW WKH FXVWRPHUV¶ UH

Hydro's business operations, such as collection fees resulting from customers' non-payment of bills. To account for the passage of time and changing business requirements, Toronto Hydro has proposed to update its specific service charges for 2015, as detailed in Exhibit 8, Tab 2. Excluding pole attachments, Toronto Hydro expects its revenue from service charges to increase by approximately $2.4 million in 2015.

The historic variance between 2011 and 2012 is primarily due to the billing system conversion in 2011, which delayed the processing of various collection activities from 2011 into 2012.

3. LATE PAYMENT CHARGES

Late payment charges are applied on overdue customer balances in accordance with all applicable regulations. Based on historical trends, annual late payment charges are expected to be stable and remain consistent with historical amounts.

4. OTHER DISTRIBUTION REVENUE

Other Distribution Revenue includes revenues from SSS Administration Charges and Retail Service Charges. Beginning in 2015, Other Distribution Revenue will also include partial revenues allocated from Toronto Hydro's contract with the City of Toronto for the maintenance of former street-lighting assets being transferred into ratebase (refer to Exhibit 2A, Tab 5 for details). This transfer results in an $8.1 million increase to the forecast 2015 amount. **/C**

5. OTHER INCOME

Toronto Hydro also earns revenue by providing services to customers and third parties, through gains on the sale of scrap metal, and gains on the disposal of utility property. As well, Toronto Hydro earns income and recoveries by providing shared services to its

affiliates and through interest income from short-term investments of its idle cash balances.

Toronto Hydro divides its Other Income into the following four categories:

- Merchandise and Jobbing
- Gains from Sale of Utility Properties
- Shared Services Income and Recoveries
- Interest Income from Short-Term Investment

5.1. Merchandise and Jobbing

Some Toronto Hydro business units provide services to customers and third parties for a fee. These services exclude those covered by the various Specific Service Charges approved by the OEB, and are generally comprised of the following activities:

- Customer requests for isolation, protection and temporary removals of lines;
- Repair of damaged distribution plant to be reimbursed by third parties;
- Maintenance of third party facilities located within Toronto Hydro property;
- Rental income charged for pole attachments;
- Rental income derived from Toronto Hydro properties such as ducts; and
- Gains on sale of scrap metal

A breakdown of merchandise and jobbing components are shown in Table 2 below:

Table 2: Merchandise and Jobbing Summary

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test	
Revenue						
Line Hose Removal	(5.3)	-	-	-	-	
Isolation	548.9	709.4	368.8	319.7	665.9	
Temp Service Contruction	2,754.7	4,006.8	1,598.1	1,583.1	1,764.6	
Customer Services	5,738.7	381.3	2,983.3	3,460.6	3,168.0	
Scrap Sales	5,378.1	3,066.5	4,182.0	3,600.0	2,520.0	
Accident Claims	2,382.6	2,690.8	2,092.0	1,567.6	1,299.6	
Pole & Duct Rental	7,292.1	9,484.8	9,609.3	10,740.8	16,990.2	/C
Other	870.8	589.8	1,289.2	592.2	485.3	
Total	24,960.6	20,929.3	22,122.8	21,864.0	26,893.7	/C
Expenses						
Line Hose Removal	(34.7)	(4.5)	(17.0)	-	-	
Isolation	(599.2)	(791.0)	(416.2)	(243.2)	(579.5)	
Temp Service Contruction	(3,368.0)	(3,673.0)	(1,401.7)	(1,449.4)	(1,372.0)	
Customer Services	(3,954.5)	(2,543.1)	(2,521.2)	(2,896.2)	(2,478.5)	
Scrap Sales	(1,666.5)	(1,124.6)	(898.9)	(1,139.7)	-	
Accident Claims	(1,823.0)	(1,928.4)	(1,761.0)	(1,363.2)	(1,110.8)	
Pole & Duct Rental	(2,906.3)	(7,082.2)	(4,405.8)	(6,942.6)	(6,942.6)	
Other	(114.4)	(426.9)	(771.8)	(317.8)	(225.0)	
Total	(14,466.5)	(17,573.7)	(12,193.6)	(14,352.0)	(12,708.5)	
Net Revenue						
Line Hose Removal	(40.0)	(4.5)	(17.0)	-	-	
Isolation	(50.3)	(81.6)	(47.4)	76.5	86.4	
Temp Service Contruction	(613.3)	333.8	196.4	133.7	392.6	
Customer Services	1,784.3	(2,161.7)	462.1	564.4	689.5	
Scrap Sales	3,711.6	1,942.0	3,283.1	2,460.3	2,520.0	
Accident Claims	559.6	762.3	331.0	204.5	188.8	
Pole & Duct Rental	4,385.8	2,402.6	5,203.5	3,798.1	10,047.6	/C
Other	756.4	162.8	517.5	274.4	260.3	
Total	10,494.1	3,355.6	9,929.2	7,512.0	14,185.2	/C

The revenues and expenses from Merchandise and Jobbing vary significantly from year to year, depending on the number and type of activities requested by customers. As such,

variances between 2011 to 2013 mainly reflect changes in customer demand. Forecast of the activities, revenues and expenses in 2014 and 2015 are based on historical experience and any forecast identified changes.

The variance from pole attachment and duct rental between 2011 and 2012 is mainly due to the increase in the number of poles and ducts rented in 2012 in comparison to 2011, and the creation of the Assets Attachments department in August 2011 to facilitate the increase in customer demand. For 2015, Toronto Hydro has proposed to update its pole attachment rental fee, as detailed in Exhibit 8, Tab 2. As a result, the Pole Attachments revenue is expected to increase from $2.3 million, to approximately $6.5 million. **/C** Additional increases are expected from higher forecast duct rentals.

Toronto Hydro generates income from the sale of scrap metal materials. Scrap metals are sold at market rates and any revenue depends on the strength of the market at the time of disposition and the volume of scrap that is available for processing. Variances between 2011 to 2013 are mainly a reflection of the volume of scrap available for sale. The net revenue that is projected for scrap metal sales in 2014 is reflective of historical trends. By the last quarter of 2014, Toronto Hydro expects to outsource the processing and VHOOLQJ RI VFUDS PHWDO PDWHULDOV WR D WKLUG SDUW of disposing the scrap metal materials will be remitted to Toronto Hydro. As a result of this new processing approach, Toronto Hydro expects the revenue from scrap sales to decrease in 2015, with a corresponding reduction in costs.

Other variances related to Merchandise and Jobbing net revenues are primarily due to the one-time pass-through Special Purpose Charge collected on behalf of the Ministry of Energy and Infrastructure in 2011 for energy conservation and renewal programs of $3.1 million, the write-off in 2012 of uncollectible revenues related to 2010 to 2011 accrued

revenues of $2.1 million, and a forecast increase of $0.5 million in each of 2014 and 2015 for telecom and network services provided to Hydro One.

5.2. Gains from Sale of Utility Properties

THESL disposes of obsolete facilities and real estate on a periodic basis.

In 2011, gains of $3.9 million primarily resulted from the following:
the disposal of Toronto Hydro idle properties such as Fairside, Mimico, Ontario, Milvan, Kingston Road, Algie, Windsor South, Whitbread, Evans Avenue, Pottery Road and Sterling Road; and the recognition of $1.4 million in actual gains from the sale of certain named properties as part of the OEB's Decision in THESL's EB-2010-0142 rate application.

In 2012, gains of $1.8 million primarily resulted from the disposal of Toronto Hydro idle properties such as Cherry St., St. Clair – Pharmacy, Upperhighland and Cummer Avenue.

In 2013, gains of $1.3 million primarily resulted from the disposal of Toronto Hydro idle properties such as 3077 Kingston Rd., 104A Hollis Avenue, 327 Cedarvale Avenue, 450 Commissioners St and 88 North Queen Rd.

In 2014, gains of $0.5 million are expected primarily as a result of the expected disposal of Toronto Hydro idle properties at 10 Gamble Avenue and 1255 York Mills Rd.

In 2015, Toronto Hydro expects to sell idle properties at 5800 Yonge and 28 Underwriters. Given the relatively large value of these properties, these gains are not recorded as part of revenue offsets, but are proposed to be treated as regulatory liabilities to be refunded to customers over a multi-year period. The details of this proposed clearance is further discussed in Exhibit 8, Tab 1, Schedule 1.

/C

5.3. Shared Services Income and Recoveries

Toronto Hydro provides shared services to its affiliates and receives income and recoveries based on transfer prices, which are determined based on ARC requirements. Details on shared services are further provided in Exhibit 4A, Tab 5 – Shared Services.

5.4. Interest Income from Short-Term Investment

Toronto Hydro actively manages idle working capital cash balances by investing excess cash in low risk Canadian and U.S. money market instruments. The interest earned from cash management reduces Toronto Hydro's long-term and short-term interest expense and since it is an offset to overall distribution revenue, other things being equal, ratepayers benefit from lower overall rates than in the absence of such a revenue offset.

Variances between 2011 and 2012 are mainly due to a higher cash balance in 2011 in comparison to 2012 as a result of significant capital spending throughout 2011. Variances between 2012 and 2013 are mainly due to the early refinancing of notes payable, which matured in May 2013, with a new notes issuance on April 2013 creating excess cash to be invested until the maturing notes were repaid. Variances between 2013 to 2015 are mainly due to the forecasted capital spending combined with diligent liquidity management resulting in lower cash balances for 2014 and 2015.

OEB Appendix 2-H: Other Operating Revenues

	Col. 1	Col. 2			Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	
2	**Uniform System of Account #**	**Description**	**Expense Element**	**Reported OEB Acc't**	**2011 Actual**	**2012 Actual**	**2013 Actual**	**2014 Bridge**	**2015 Test**	
3	**Other Distribution revenue**									
4	4082	Retailers' Fixed charge	1029	4082	$5.2	$5.3	$5.6	$5.5	$5.5	
5	4082	Retailers' Variable Charge	1031	4082	$484.7	$393.3	$320.4	$300.0	$300.0	
6	4082	Distributor Consolidated Billing (DCB) Charges	1033	4082	$277.6	$225.0	$180.8	$171.0	$171.0	
7	4082	Retail Consolidated Billing (RCB) Credit	1035	4082	-$11.0	-$8.7	-$8.5	-$8.6	-$8.6	
8	4082	Other Retailer Service fees	1047	4082	$0.2	$0.0	$0.0	$0.0	$0.0	
9	4084	Retailer Service Transaction Request	1039	4084	$8.2	$9.6	$9.3	$6.8	$9.6	
10	4084	Retailer Service Transaction Processing	1041	4084	$12.3	$12.7	$11.4	$13.0	$13.0	
11	4090	SSS Admin Charge	1071	4090	$1,993.5	$2,021.3	$2,099.8	$2,115.0	$2,115.0	
12	4210	Misc Revenue	1206	4210	$0.0	$106.6	$26.6	$0.0	$0.0	
13	4210	Parking Rental	1303	4210	$6.6	$8.0	$35.2	$0.0	$0.0	
14	4210	Miscellaneous Rent	1304	4210	$0.4	$0.0	$0.0	$0.0	$0.0	
15	4210	Interval Meter Phone Line Charges	1305	4210	$0.0	$0.0	$0.0	$0.0	$0.0	
16	4210	Property Rental	1308	4210	$15.0	$16.6	$24.9	$0.0	$0.0	
17	4215	TTC Rectification	1204	4215	$303.9	$303.9	$303.9	$303.9	$303.9	
18	4215	Misc Revenue	1206	4215	$16.1	$14.0	$0.6	$0.0	$0.0	
19	4215	Settlement Discounts Taken	1400	4215	$249.3	$277.4	$250.0	$200.0	$200.0	
20	4215	Stale Dated Cheques	1409	4215	$506.9	$352.4	$443.4	$250.0	$350.0	
21	4220	Street Lighting	1132/1202	4220	$0.0	$0.0	$0.0	$0.0	$8,084.9	
22	**Late Payment Charges**									
23	4225	Late Payment Charges	1055	4225	$4,220.9	$4,047.1	$3,827.3	$4,000.0	$4,000.0	
24	**Specific Service Charges**									
25	4235	Account Set Up Charge	1027	4235	$2,676.6	$2,816.1	$2,740.6	$2,550.0	$3,811.9	
26	4235	Special Meter Read	1051	4235	$0.0	$0.0	$0.0	$0.0	$0.0	
27	4235	NSF Collection Charges	1057	4235	$91.4	$81.9	$68.8	$75.0	$113.9	
28	4235	Collection Service Charges	1059	4235	$2,566.4	$3,026.3	$3,075.5	$3,300.0	$4,969.1	
29	4235	Connection-Reconnection Charge	1061	4235	$231.3	$336.2	$476.7	$444.0	$859.3	
30	4235	Easement Letter	1064	4235	$19.3	$18.8	$21.4	$0.0	$23.1	
31	4235	Duplicate Invoices for previous billing	1065	4235	$6.5	$7.7	$5.0	$5.7	$2.9	
32	4235	Income Tax Letter	1066	4235	$0.0	$0.0	$0.0	$0.0	$0.0	
33	4235	Request for Other Billing or System Information	TBD	4235	$0.0	$0.0	$0.0	$0.0	$31.0	
34	4235	Account History	TBD	4235	$0.0	$0.0	$0.0	$0.0	$6.0	
35	4235	Service Call - Customer Owned equipment or customer missed appointment	TBD	4235	$0.0	$0.0	$0.0	$0.0	$2.0	
36	4235	Misc Revenue	1206	4235	$90.6	$0.0	$0.0	$0.0	$0.0	
37	**Other Income and Deductions**									
38	4324	Special Purpose Charge Recovery	1220	4324	$3,050.5	$0.0	$0.0	$0.0	$0.0	
		Special Meter Reads	1051	**4325**	$0.0	$0.0	$0.0	$0.0	$0.0	
		Consumer Trouble	1053	**4325**	$0.0	$0.0	$0.0	$0.0	$0.0	
		TTC Rectification	1204	**4325**	$0.0	$0.0	$0.0	$0.0	$0.0	
		Misc Revenue	1206	**4325**	$14,740.4	$8,587.9	$11,822.2	$11,017.2	$11,657.2	
		Misc Revenue (Excl AG22)	-1206	**4325**	$0.0	$0.0	$0.0	$0.0	$0.0	
		EHS Consulting Revenue	1209	**4325**	$5.0	-$5.0	$0.0	$0.0	$0.0	
		Plant Relocates	1210	**4325**	$430.4	$432.5	$31.9	$0.0	$0.0	
		Line Hose Removal/Install	1212	**4325**	-$5.3	$0.0	$0.0	$0.0	$0.0	
		Temporary Service Construction	1214	**4325**	$2,754.7	$4,006.8	$1,598.1	$1,583.1	$1,764.6	
		Plant Removals/Demo	1216	**4325**	$102.2	$301.3	$174.4	$0.0	$0.0	
		Other Banner Revenue	1218	**4325**	$325.1	$55.5	$47.5	$0.0	$0.0	
		Other Banner Revenue	1218	**4235**	$0.0	$0.0	$0.0	$215.3	$215.3	
		Duct Rental	1301	**4210**	$4,620.5	$5,261.2	$6,000.0	$6,743.7	$6,743.7	
		Pole Attachment Rental	1302	**4235**	$1,987.6	$2,256.1	$2,133.4	$0.0	$0.0	
		Pole Attachment Rental	1302	**4210**	$0.0	$0.0	$0.0	$2,304.6	$6,512.7	/Cs
		Trades Training	1207	**4325**	$0.0	$0.0	$64.0	$0.0	$0.0	
		Trades Training	1207	**4375**	$0.0	$33.0	$251.5	$0.0	$0.0	
		Shared Serv Recovery	9949	**4375**	$0.0	$0.0	$0.0	$0.0	$0.0	
39	4325	Merchandise and Jobbing Revenue	various	4325	$24,960.6	$20,929.3	$22,122.8	$21,864.0	$26,893.6	/Cs
		Merchandise and Jobbing Costs	2901	**4330**	-$14,466.5	-$17,573.7	-$12,193.6	-$14,352.0	-$12,708.5	
		Cost Of Value Added Services	2906	**4330**	$0.0	-$2.3	$0.0	$0.0	$0.0	
40	4330	Merchandise and Jobbing Costs	2901	4330	-$14,466.5	-$17,576.0	-$12,193.6	-$14,352.0	-$12,708.5	
41	4355	Gain/Loss on disposals	1501	4355	-$164.5	$989.9	$17.9	$0.0	$0.0	
42	4335	Gain/Loss on disposals	1501	4335	$0.0	$0.0	-$17.9	$0.0	$0.0	
43	4375	Gain/Loss on disposals	1501	4375	$164.5	-$989.9	$0.0	$0.0	$0.0	
44	4375	Shared Services Recovery	9949	4375	$0.0	$0.0	$0.0	$3,381.2	$3,399.5	

	Col. 1	Col. 2			Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	
2	**Uniform System of Account #**	**Description**	**Expense Element**	**Reported OEB Acc't**	**2011 Actual**	**2012 Actual**	**2013 Actual**	**2014 Bridge**	**2015 Test**	
45	4355	Gain on Disposition of Utility and Other Property	9601	4355	$3,885.3	$1,804.8	$1,279.6	$453.5	$0.0	
		Gain/Loss On Foreign Exch	7501	**4398**	$53.5	-$292.7	-$778.9	$0.0	$0.0	
		Foreign Exchange Conversion	7505	**4398**	$50.5	$212.5	-$129.3	$0.0	$0.0	
46	4398	Foreign Exchange Gain/(Loss)	7505	4398	$104.1	-$80.2	-$908.2	$0.0	$0.0	
		Dividend Income	1606	**4405**	$0.0	$0.0	$0.0	$0.0	$0.0	
		Investment Int Income	1608	**4405**	$1,267.8	$221.3	$1,183.4	$660.0	$660.0	
		Regulated Assets Cchgs-Revenue	1613	**4405**	$0.0	$0.0	$0.0	$0.0	$0.0	
47	4405	Investment Interest Income	1608	4405	$1,267.8	$221.3	$1,183.4	$660.0	$660.0	
48	**Specific Service Charges Excluding Pole Attachment (4235)**		various		$5,682.0	$6,287.1	$6,388.0	$6,374.7	$9,819.2	
49	**Late Payment Charge (4225)**		various		$4,220.9	$4,047.1	$3,827.3	$4,000.0	$4,000.0	
50	**Other Distribution Revenue Excluding Duct Rental (4082,4084,4090,4210,4215,4220)**		various		$3,869.0	$3,737.4	$3,703.3	$3,356.6	$11,544.3	
51	**Other Income & Deductions Including Pole Attachments (4210, 4235, 4324, 4325,4330,4335,4355,4375,4398,4405)**		various		$18,801.8	$5,299.3	$11,484.1	$12,006.7	$18,244.5	/Cs
52	**Total Revenue Offset**				**$32,573.7**	**$19,370.8**	**$25,402.6**	**$25,738.0**	**$43,608.0**	/Cs

OVERVIEW OF THE OPERATING, MAINTENANCE AND ADMINISTRATION (OM&A) EXPENDITURES

The purpose of this schedule is to provide a brief summary of Toronto Hydro's Operations, Maintenance and Administration (OM&A) evidence that describes the utility's OM&A expenditures as well as the analytical work, activities and obligations underlying them. The schedule also details the top-down and bottom-up budgetary considerations driving the preparation of the 2015 Test Year OM&A forecasts.

1. CONCORDANCE WITH CHAPTER 2 FILING REQUIREMENTS

As discussed in Exhibit 1B, Tab 2, Schedule 2 ("Alignment with The Renewed Regulatory Framework"), in preparing its 2015-2019 Custom IR OM&A evidence, Toronto Hydro consulted the OEB's filing requirements with respect to the OM&A guidance provided in Chapter 2 of the Ontario Energy Board's (OEB's) Filing Requirements for Electricity Distribution Rate Applications, as updated on July 17, 2013. A key evolution in the OEB's guidance concerns the manner of presentation and the subsequent review of the OM&A evidence on the basis of output / program-based expenditure presentation – a departure from the previous approach which focused on discrete OM&A cost inputs[2].

Consistent with the OEB guidance, Toronto Hydro presents its Historical, Bridge and Test Year OM&A expenditures as a sum of 19 discrete programs, and a grouping of utility-wide costs and adjustments that cannot be readily assigned to a single program and/or presented as a standalone program. The descriptions and variance analysis for these programs and associated expenditures and adjustments can be found in Exhibit 4A, Tab 2, Schedules 1 through 21. In an effort to balance the OEB's guidance on program-based OM&A cost review with the objective of providing a thorough cost analysis,

[2] Ontario Energy Board, Application Filing Requirements, Chapter 2, S 2.7 p. 27, 17 July, 2013

Toronto Hydro has further broken down a number of OM&A Programs into Segments – i.e., discrete activity-based areas that address different facets of a single program. Each segment description includes an overview of the activities comprising the segment, the requirements driving the work, and a variance analysis. /C

As noted by the OEB in the July 2013 update of Chapter 2 Filing Requirements, adopting a program-based approach to presenting the OM&A activities entails a transition period for the utility. While Toronto Hydro submits that the manner of presentation of its 2015 OM&A activities is consistent with the OEB guidance, the utility notes that its work in developing a meaningful program/Segment OM&A presentation involved a significant amount of assumptions and complex analytic work, given that Toronto Hydro internal OM&A tracking procedures do not fully lend themselves to the approach contemplated by the OEB.

At Toronto Hydro, OM&A plans are generally presented on a operating department or "Responsibility Centre" (RC) basis, whereby each RC is tied to the operational management of broad, but discrete functional areas such as customer care, finance, regulatory, safety, IT, HR or legal. That is, on the basis of the areas of discrete responsibility and type of departmental expenditures, rather than the (often cross-functional) activities or programs that the utility at large undertakes. In this way, for areas with multiple activities, financial plans are presented at their highest level on the basis of the type of the expenditure (e.g., payroll), rather than the program that those expenditures correlate to (e.g., work program execution). In a number of cases, although a department tracks its financial plan on an RC basis, they may also break down and track certain line items on the basis of files or activities. For example, maintenance programs that may require resources from several departments to complete the activities have separate work orders that field employees use to charge their time. This approach helps

to track and manage the costs associated with the maintenance programs consistently across the utility and track year-over-year variances.

This transition from RC to activity-based presentation is particularly salient with respect to the OM&A evidence contained within Exhibit 4A, Tab 2, Schedules 6 through 9, describing the programs that in previous filings (e.g., EB-2011-0144) were presented as a single cost item described as Operations Support. Given a number of important and functionally distinct activities captured within the previous Operations Support definition, Toronto Hydro has made best efforts to provide dedicated descriptions and variance analysis for each of the four ensuing programs and the associated segments. However, for the reasons noted above, the utility employed estimates to determine the particular program/segment expenditures for the Historical and Bridge years.

2. OVERVIEW OF THE OM&A PROGRAMS AND EXPENDITURES

Toronto Hydro's total 2015 forecasted OM&A expenditures are $269.5 million – 13.2% or $31.5 million above the 2011 expenditures approved by the OEB ($238 million) in Toronto Hydro's latest rebasing application (EB-2010-0142), and $30.9 million or 13% above the 2011 actual expenditures ($238.6 million).[2] Overall, the cost increase from 2011 to 2015 represent an average of 3.3% a year. Toronto Hydro notes that Section 3 of this schedule details the process and considerations informing Toronto Hydro's budgeting of the 2015 Test Year OM&A budget, including the constraint and restraint exercised with deference to several inter-related factors including ratepayer impact, and the utility's operational needs and obligations. **/C**

[2] Because OM&A was settled on an envelope basis in the utility's last rebasing application (EB-2010-0142), and because 2011 OEB-Approved and 2011 actual expenditures were very similar ($238 OEB-Approved vs. $238.6 actuals expenditures), Toronto Hydro has only reported 2011 actual expenditures in the OEB appendices filed at Exhibit 4A, Tab 1, Schedules 2-5. **/C**

Table 1 below provides a breakdown of Toronto Hydro's Historical (2011-2013), Bridge and Test Year OM&A expenditures, broken down by program.

Table 1: Historical, Bridge and Test Year OM&A Expenditures by Program[3]

($M)	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Preventative & Predictive Maintenance	13.7	16.0	12.8	16.1	20.1
Corrective Maintenance	25.8	21.5	17.0	19.0	22.2
Emergency Response	13.3	13.9	26.3	16.2	15.3
Disaster Preparedness Management	0.9	-	-	-	2.4
Control Centre	8.4	8.3	8.9	8.2	8.4
Customer-Driven Work	6.0	5.9	7.0	8.2	10.1
Planning	9.0	9.0	11.5	10.3	12.9
Work Program Execution Management and Support	5.0	5.5	5.6	5.8	6.1
Work Program Execution	14.9	13.8	13.0	14.3	15.2
Fleet and Equipment Services	8.7	8.5	8.7	8.4	8.9
Facilities Management	24.6	23.5	24.2	27.2	27.5
Supply Chain Services	7.1	6.6	9.0	10.3	9.9
Customer Care	41.9	37.5	39.7	42.2	46.1
Human Resources and Safety	13.7	13.2	15.3	15.3	16.1
Finance	16.1	14.7	15.7	17.0	17.9
Information Technology	30.3	28.5	31.0	33.4	34.9
Rates and Regulatory Affairs	7.2	7.8	8.4	6.4	8.4
Legal Services	5.5	4.3	4.5	5.3	5.5
Charitable Donations (LEAP)	0.7	0.7	0.7	0.7	0.8
Common Costs and Adjustments	5.7	(6.0)	0.5	2.3	1.0
Allocations and Recoveries	(19.9)	(17.4)	(13.3)	(19.9)	(20.2)
Restructuring Costs	-	27.7	-	-	-
Total OM&A	**238.6**	**243.5**	**246.4**	**246.6**	**269.5**

[3] Numbers may not add up due to rounding.

As noted above, description and variance analysis of each the above programs can be found in Exhibit 4A, Tab 2, Schedules 1 – 21. For additional context of the planning and budgeting activities underlying Toronto Hydro's 2015 Test Year OM&A ask, please refer to the following section of this schedule.

3. OM&A PLANNING AND BUDGETING

Toronto Hydro approached this rate application from the perspective of seeking to build an OM&A plan that facilitates the utility operating within an IRM framework for non-capital expenditures.[4] Accordingly, it structured a financial planning process for 2015-2019 around the principles of the 4th Generation Incentive Rate Making regime (4GIRM). In particular, the utility approached its 2015 proposed OM&A expenditures from the perspective of savings it has achieved over the 3GIRM period together with resource requirements for 2015 and forward. Further, Toronto Hydro viewed 2016-2019 as years where its funding request would be consistent with the IRM framework – i.e., less than inflation and determined on the basis of a Price Cap Index-based formulaic adjustment. /C

An outcome of the Financial Planning process as described in Exhibit 1C, Tab 3, Schedule 2 is the operating, maintenance and administration ("OM&A") plan. In developing the funding request for OM&A, Toronto Hydro's plans were informed by a number of factors including operational needs such as asset investment requirements, maintenance requirements, staffing requirements, reliability, safety and legislative and

[4] Subject to special considerations for capital, and reasonable off-ramps for potential expenditures that are unanticipated or unknown at the time of bringing this application. See Exhibit 1B, Tab 2, Schedule 3 for a discussion of Toronto Hydro's proposed off-ramp or Z-factor adjustments. Also see Exhibit 1B, Tab 2, Schedule 3 for discussion of Toronto Hydro's approach to building capital expenditures into a formulaic approach to ratemaking (which represents a modified IRM approach). /C

regulatory obligations. The plans are also informed by other important considerations such as customer needs (including service levels and consumption-management tools), rate impacts, value-for-money, productivity, and maintaining the financial health and viability of the utility, etc. These considerations roll up to the four pillars discussed at Exhibit 1C, Tab 3, Schedule 1 and Schedule 2.

No one of these considerations is determinative of the utility's ultimate financial plan, but they all inform ultimate funding requests. For example, Toronto Hydro believes that staffing levels beyond the operating costs proposed in this application are optimal based on the utility's assessment of its operating requirements, its retirement projections for the next five to 15 years, and the significant lead time for training certified and skilled trades (four to six years). However, the utility has moderated its funding request in light of other considerations, such as rate impacts.

Informed by the considerations described above, Toronto Hydro developed the OM&A plan on the basis of both a top-down and bottom-up approach as described in Exhibit 1C, Tab 3, Schedule 2. In general, Toronto Hydro's objective was to put forward a plan that largely maintained functional requirements such as safe and reliable grid operations and system performance, service levels and legal, regulatory and statutory compliance in an efficient manner.

Toronto Hydro used both general and specific cost and economic assumptions in its 2015 forecast of the operating costs. Labour costs have been adjusted to reflect the annual rate adjustments that Toronto hydro has committed to in its collective agreements. The labour cost forecast was also adjusted to reflect market-competitive pay increases for non-unionized employees. For more information, refer to Exhibit 4A, Tab 4, Schedule 5. Otherwise, a general inflation factor of 1.7% was applied, consistent with the OEB's current inflation factor.

4. APPROACH

The planning approach is predicated on the concept of a top-down, bottom-up process. Senior Management establishes the top-down constraints. Based on those top-down constraints, the business units exercised discipline and restraint in developing their bottom-up requests for OM&A funding.

The planning approach started as a top-down exercise in which, as noted above, the utility decided that it would seek to operate within the incentive-based environment underlying the IRM framework for OM&A for the five-year plan term. In this way, an objective of building the financial plan was to exercise constraint (top-down) on the overall plan, and restraint (bottom-up) in developing funding requests. Toronto Hydro was also mindful that any constraint and restraint also needed to be situated in the context of Toronto Hydro's ability to comply with its obligations/conditions of licence, its strategic pillars (Exhibit 1C, Tab 3, Schedule 1), as well as to respond to the resourcing needs driven by new or modified activities that have arisen since the utility's last rebasing in 2011.

To this end, Toronto Hydro's financial planning process for operating expenditures was informed by a business planning approach that examined underlying elements of existing budgets, as well as incremental requests for budget increases. In other words, departments were asked to outline the allocation of current expenditures, as well as justifying additional requests for 2015. Part of obtaining the full picture involved generally considering expenditures that were incremental since Toronto Hydro's last rebasing year (2011).

The practical application of Toronto Hydro's approach of integrating the top-down and bottom-up needs identification into its OM&A planning process entailed the utility's departments coming forward with plans and requests for ongoing and incremental

activities, which were then examined on a top-down basis for alignment with key considerations, such as the potential rate impact of the aggregate OM&A request for 2015.

5. RESULTS

In the result, while Toronto Hydro is putting forward in this application a 2015 rebasing plan that includes a number new or materially-expanded OM&A activities that it expects will be sustained over the period of the plan, these requests are largely driven by functional requirements. Examples of these new or materially-expanded programs include:

- The Disaster Preparedness Management Program aimed at enhancing the utility's capabilities to plan for and operate during major contingency events;
- Increased Billing, Remittance and Meter Data Management expenditures to enable deployment and maintenance of technology upgrade projects to support meter reading infrastructure renewal, and accommodate significant Canada Post service fee increases; and
- Increased Preventative and Predictive Maintenance expenditures to optimize the asset maintenance cycles, driven, among other factors, by the results of the Reliability Centered Maintenance (RCM) analysis.

For additional details on the evolution of Toronto Hydro's OM&A cost drivers and business environment changes, please refer to Exhibit 4A, Tab 2, Schedules 1 through 21, as well as financial schedules provided in Exhibit 4A, Tab 1.

By contrast, this also means that Toronto Hydro did not put forward other possible sustained and reasonable OM&A requests that would represent what the utility may believe is operationally optimal or required. As noted above, and in line with the

Strategic Pillars, the utility made these decisions on the basis of the spectrum of input considerations, such as rate impacts.

An example of an area in which Toronto Hydro did not put forward the full possible sustained and reasonable OM&A request is Toronto Hydro's proposed staffing plan. To constrain compensation costs over the rate period, Toronto Hydro has limited its proposed workforce hiring and replacement strategy, despite the increasing wave of retirements that the utility projects to experience in the next five to ten years (25% of the workforce is eligible to retire by 2019) and notwithstanding apprenticeship and training period required for a Certified and Skilled Trades or Designated Technical Professionals (four to six years). Instead of ramping up its hiring plan, Toronto Hydro has implemented a multi-faceted staffing strategy to maintain quality service and value to rate payers, and to plan for upcoming retirements. For example, Toronto Hydro constrained its compensation costs by approximately $3 million by employing contingent resources rather than full-time employees to deliver a variety of administrative and support functions. Although the utility would prefer to have the continuity of knowledge and experience, and the security of full-time resources, it has opted for a different staffing model in this respect, in an effort to constrain costs.[5] /C

In building its five-year OM&A plan, while Toronto Hydro endeavoured to consider foundational expenditure requirements, including potential emerging requirements (e.g., extreme weather preparedness) that can be reasonably anticipated, it did not engage in a detailed five-year financial planning exercise. However, it did consider two important factors in assessing its ability to "live within" IRM for OM&A over the term of the CIR plan.

[5] Exhibit 4A, Tab 2, Schedule 3 /C

As discussed in further detail above, the first factor is the importance of sufficient Test Year funding in light of the anticipated resourcing needs, driven by both ongoing and incremental requirements. Absent a sufficient level of funding in the test/rebasing year, an IRM plan for the successive four years would not be sustainable. As discussed above, Toronto Hydro engaged in a detailed financial planning exercise, based on functional requirements, informed by the four pillars, and designed to provide the utility sufficient funding levels for the next five years.

Second, a corollary of Toronto Hydro's OM&A proposal - and a consideration in how it engaged in financial planning - is its proposal regarding the Z-Factor (Exhibit 1B, Tab 2, Schedule 3). While Toronto Hydro has endeavoured to consider foundational expenditure requirements, including potential emerging requirements as can be known today, for any regulated utility that operates in a dynamic environment such as Toronto Hydro, there will inevitably be material events over a five year time horizon that are outside the known, anticipated and quantified scope of requirements. Examples of activities covered under these include changes in legal instruments or government/OEB policy and unforeseen weather events. This aspect of Toronto Hydro's CIR plan and request is discussed in further detail in Exhibit 1B, Tab 2, Schedule 3. By proposing the Z-Factor approach to be used if and when determined to be appropriate, Toronto Hydro attempts to balance the considerations of customer impacts with the necessity of maintaining safe and efficient system operation under a variety of potential conditions.

As a result of the process and considerations discussed above, Toronto Hydro believes that it has put forward an OM&A (and capital) plan that enables it to manage within funding levels it has proposed, subject to the Z-Factor events. In addition, the plan also pushes the utility to find additional efficiencies and savings throughout the term because Toronto Hydro's ordinary annual course cost increases well exceed the funding that the IRM formula provides. Toronto Hydro projects that in the ordinary course, its OM&A

costs would increase at an approximate average of 2-3% year-over-year during the term of the CIR plan. By proposing that the OM&A component of rates increase only by a standard IRM-adjustment from 2016 to 2018, which is materially lower than this amount, Toronto Hydro is providing an up-front sharing of productivity/stretch (or "X-factor") benefits to ratepayers, consistent with the tenets of incentive rate regulation. The utility then bears the risk of finding the delta between what is funded in rates and ordinary course cost increases - through identifying and implementing productivity and efficiency initiatives over the term of the plan. While Toronto Hydro sees this as a stretch goal in light of past productivity improvements and the constrained OM&A test year amount, it also appreciates the importance of fulfilling OEB policy objectives and seeking innovative ways to create value-for-money for ratepayers.

OEB Appendix 2-JA
Summary of Recoverable OM&A Expenses

(in$Millions)

	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Bridge Year	2015 Test Year	
Reporting Basis	**CGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**MIFRS**	**MIFRS**	**/C**
Operations	$ 59.7	$ 55.9	$ 59.5	$ 58.5	$ 58.5	$ 70.3	
Maintenance	$ 56.1	$ 54.8	$ 66.8	$ 59.3	$ 59.3	$ 61.2	
SubTotal	**$ 115.8**	**$ 110.7**	**$ 126.4**	**$ 117.8**	**$ 117.8**	**$ 131.5**	
%Change (year over year)		-4.4%	14.1%	-6.8%	0.0%	11.6%	
%Change (Test Year vs Last Rebasing Year - Actual)						13.6%	
Billing and Collecting	$ 40.6	$ 36.0	$ 35.2	$ 37.9	$ 37.9	$ 41.5	
Community Relations	$ 2.9	$ 2.9	$ 2.9	$ 2.7	$ 2.7	$ 2.7	
Administrative and General	$ 72.6	$ 67.8	$ 75.0	$ 81.2	$ 79.9	$ 86.5	/C
Taxes Other Than Income Taxes	$ 5.9	$ (2.3)	$ 6.4	$ 6.5	$ 6.5	$ 6.5	
Donations	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.8	
SubTotal	**$ 122.7**	**$ 105.1**	**$ 120.1**	**$ 128.8**	**$ 127.5**	**$ 138.0**	/C
%Change (year over year)		-14.4%	14.3%	7.3%	-1.0%	8.2%	/C
%Change (Test Year vs Last Rebasing Year - Actual)						12.4%	
Total	**$ 238.6**	**$ 215.8**	**$ 246.4**	**$ 246.6**	**$ 245.3**	**$ 269.5**	/C
Restructuring Costs (OEB Account 6310 - Extraordinary Deduction)		$ 27.7					
Total - Including Restructuring Costs	**$ 238.6**	**$ 243.5**	**$ 246.4**	**$ 246.6**	**$ 245.3**	**$ 269.5**	/C
%Change (year over year)		2.1%	1.2%	0.1%	-0.5%	9.9%	/C

	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Bridge Year	2015 Test Year	
Operations	$ 59.7	$ 55.9	$ 59.5	$ 58.5	$ 58.5	$ 70.3	
Maintenance	$ 56.1	$ 54.8	$ 66.8	$ 59.3	$ 59.3	$ 61.2	
Billing and Collecting	$ 40.6	$ 36.0	$ 35.2	$ 37.9	$ 37.9	$ 41.5	
Community Relations	$ 2.9	$ 2.9	$ 2.9	$ 2.7	$ 2.7	$ 2.7	
Administrative and General	$ 72.6	$ 67.8	$ 75.0	$ 81.2	$ 79.9	$ 86.5	/C
Taxes Other Than Income Taxes	$ 5.9	$ (2.3)	$ 6.4	$ 6.5	$ 6.5	$ 6.5	
Donations	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.8	
Restructuring Costs (OEB Account 6310 - Extraordinary Deduction)	-	$ 27.7	-	-	-	-	
Total	**$ 238.6**	**$ 243.5**	**$ 246.4**	**$ 246.6**	**$ 245.3**	**$ 269.5**	/C
%Change (year over year)		2.1%	1.2%	0.1%	-0.5%	9.9%	/C

	Last Rebasing Year (2011 Actuals)	Variance 2011 BA - 2011 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Bridge Year	Variance 2014 Bridge vs. 2013 Actuals	2015 Test Year	Variance 2015 Test vs. 2014 Bridge
Operations	$ 59.7	-	$ 55.9	$ (3.7)	$ 59.5	$ 3.6	$ 58.5	$ (1.0)	$ 70.3	$ 11.8
Maintenance	$ 56.1	-	$ 54.8	$ (1.4)	$ 66.8	$ 12.0	$ 59.3	$ (7.5)	$ 61.2	$ 1.9
Billing and Collecting	$ 40.6	-	$ 36.0	$ (4.7)	$ 35.2	$ (0.7)	$ 37.9	$ 2.6	$ 41.5	$ 3.6
Community Relations	$ 2.9	-	$ 2.9	$ 0.0	$ 2.9	$ (0.1)	$ 2.7	$ (0.2)	$ 2.7	$ 0.1
Administrative and General	$ 72.6	-	$ 67.8	$ (4.8)	$ 75.0	$ 7.2	$ 81.2	$ 6.2	$ 86.5	$ 5.3
Taxes Other Than Income Taxes	$ 5.9	-	$ (2.3)	$ (8.2)	$ 6.4	$ 8.7	$ 6.5	$ 0.1	$ 6.5	$ 0.0
Donations	$ 0.7	-	$ 0.7	$ (0.1)	$ 0.7	$ (0.0)	$ 0.7	-	$ 0.8	$ 0.2
Restructuring Costs (OEB Account 6310 - Extraordinary Deduction)			$ 27.7							
Total OM&A Expenses	$ 238.6	-	$ 243.5	$ (22.8)	$ 246.4	$ 30.7	$ 246.6	$ 0.2	$ 269.5	$ 22.9
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)			$ 27.7							
Total Recoverable OM&A Expenses	$ 238.6	-	$ 215.8	$ (22.8)	$ 246.4	$ 30.7	$ 246.6	$ 0.2	$ 269.5	$ 22.9
Variance from previous year			$ (22.8)		$ 30.7		$ 0.2		$ 22.9	
Percent change (year over year)			-9.6%		14.2%		0.1%		9.3%	
Percent Change: Test year vs. Most Current Actual					9.37%					
Simple average of % variance for all years										3.5%
Compound Annual Growth Rate for all years										2.5%
Compund Growth Rate 2013 Actuals vs. 2011 Actuals					1.1%					

Note:

1 "BA" = Board-Approved

2 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

3 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

OEB Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2011 Board-Approved)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year	
Reporting Basis	CGAAP	USGAAP	USGAAP	USGAAP	MIFRS	/C
Opening Balance	**$238.0**	**$238.6**	**$215.8**	**$246.4**	**$246.6**	
Workforce Compensation (net)						
Salary, Wages and Benefits		($19.0)	$7.4	($1.7)	$4.9	/C
Program execution - Capitalized Labour		$14.2	($8.6)	$2.4	($0.6)	/C
Program execution - O&M Labour Recovery		($7.1)	$4.2	$13.8	($2.9)	/C
Distribution Operations Programs						
Preventative and Predictive Maintenance		$2.6	($3.0)	$3.3	$3.7	
Corrective Maintenance		($2.2)	($4.0)	$0.8	$3.2	
Emergency Maintenance - 'Sandy' Storm Restoration		$1.5	($1.5)	-	-	
Emergency Maintenance - 'Ice' Storm Restoration		-	$10.2	($6.8)	($3.4)	
Emergency Maintenance - Other		$1.0	$3.8	($3.3)	$2.5	
Planning		$1.5	$0.9	($4.6)	$3.0	
Program Delivery		$0.8	$0.1	($4.3)	$0.0	
Work Program Execution		($1.0)	($1.1)	$0.1	$2.4	
Customer Driven Work		$0.4	$0.3	$1.2	$2.0	
Customer Service and Communications						
Billing, Remittance & Meter Data Management		($0.4)	$1.1	$0.1	$1.1	
Collection Services		$0.2	$1.3	$1.5	$0.3	
Customer Communications and Relationship Management		$1.1	($0.7)	($0.4)	$0.8	
Bad Debt Expenses	$0.7	($2.5)	$0.0	($0.2)	$0.7	
Low-Income Energy Assistance Program (LEAP)		-	-	-	$0.2	
Printing and Postage Costs		$0.2	($0.2)	$0.5	$0.7	
Human Resources						
Legal Fees		$0.1	$0.6	($0.5)	$0.0	
Talent Management and Acquisition		($0.7)	$0.4	$0.0	$0.6	
Information Technology services						
Information Technology services		($0.0)	$0.8	$2.2	$0.8	
Telecomunications One Time Loyalty Bonus		($1.1)	$1.1	-	-	
Common Corporate Costs						
Disallowed recovery of deferred IFRS conversion costs	$3.1	($3.1)	-	-	-	
Scientific Research and Educational Development credits	($1.4)	$1.4	-	-	-	
Property Taxes reassessment and change in regulation completed by the Ministry of Finance of Ontario		($8.7)	$8.7	-	-	
Decrease in legal provision from Late Payment charges class action settlement		($1.6)	$1.6	-	-	
Refundable and Non-Refundable Tax Credits (ITC)	($1.7)	$0.9	$0.1	$0.0	($1.3)	
Financing Costs		($0.3)	($0.4)	($0.3)	$0.0	
Facilities Maintenance						

OM&A	Last Rebasing Year (2011 Board-Approved)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year	
Reporting Basis	CGAAP	USGAAP	USGAAP	USGAAP	MIFRS	/C
Building & Stations Maintenance		($1.2)	$0.8	$2.8	$0.5	
Property Taxes		$0.5	($0.2)	$0.1	($0.2)	
Rentals & Leases		$0.6	$0.0	$0.2	$0.1	
Utilities & Communications		($0.1)	$0.3	$0.2	($0.1)	
Other Various						
Control Centre Operations		($1.4)	($1.2)	($1.7)	($0.1)	
Disaster Preparedness Management		$0.9	-	-	$2.4	
Fleet and Equipment Services		($0.2)	$0.2	$0.0	$0.3	
Regulatory Costs		$0.4	$0.6	($2.3)	$1.9	
Procurement Costs		$0.5	$2.2	$2.2	($0.3)	
Legal Services Costs		($0.7)	$0.2	$0.4	$0.0	
Finance Consulting and Auditing Fees		($0.3)	$0.3	$1.0	$0.1	
Smart Meter Clearance		-	$7.1	($7.1)	-	
Allocations and Recoveries		$2.5	($3.1)	$0.6	($0.3)	
Special Purpose Charges		($3.1)	-	-	-	
Miscellaneous	($0.1)	$0.6	$0.3	($0.1)	$0.0	
Closing Balance	**$238.6**	**$215.8**	**$246.4**	**$246.6**	**$269.5**	
Restructuring Costs[1]		$27.7				
Closing Balance - Including Restructuring Costs	**$238.6**	**$243.5**	**$246.4**	**$246.6**	**$269.5**	

[1] OEB Account 6310 - Extraordinary Deduction

Notes:

1 Foreachyear, adetailed explanation foreachcostdriver and associated amount is required in Exhibit 4.

2 Forpurposes ofassessing incrementalcostdrivers, theclosing balance foreachyear becomestheopening balanceforthenextyear.

3 Ifithasbeenmore than three years sincetheapplicant last filed acostofservice application, additional years ofhistorical actuals should beincorporated into thetable,asnecessary, togobacktothelast costofservice application.Iftheapplicant last filed acost ofservice application lessthan three years ago,aminimum of threeyears ofactual information is required.

4 OpeningBalancefor"LastRebasing Year" (cell B15)should beequal totheBoardrApprovedamount.

OEB Appendix 2-JC
OM&A Programs Table

(in$Millions)

Programs	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Bridge Year	2015 Test Year	Variance (Test Year vs. 2013 Actuals)	Variance (Test Year vs. Last Rebasing Year (2011 Board-Approved)	
Reporting Basis	**CGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**MIFRS**	**MIFRS**			**/C**
Common Corporate Costs and Adjustments									
Common Corporate Costs and Adjustments	2.1	(9.6)	(2.7)	(0.7)	(2.0)	(2.0)	0.7	(4.1)	**/C**
Governance	1.2	1.5	1.5	1.5	1.5	1.6	0.1	0.4	
Short-Term Interest Expenses on Line of Credit and Customer Deposits	2.4	2.1	1.7	1.4	1.4	1.4	(0.3)	(1.0)	
							r	r	
							r	r	
Sub-Total	5.7	(6.0)	0.5	2.3	1.0	1.0	0.5	(4.7)	**/C**
HR&Safety Program Expenses									
Labour Relations & Human Resources	4.7	5.2	6.2	5.7	5.7	5.8	(0.4)	1.2	
Employee Health & Safety	2.3	2.2	2.4	2.7	2.7	2.8	0.3	0.5	
Talent Acquisition & Organizational Development	6.7	5.9	6.6	6.9	6.9	7.5	0.9	0.8	
							r	r	
							r	r	
Sub-Total	13.7	13.2	15.3	15.3	15.3	16.1	0.8	2.4	
Customer Care Program Expenses									
Billing, Remittance & Meter Data Management	14.5	13.7	14.6	16.4	16.4	18.7	4.1	4.2	
Collections	12.3	8.9	11.1	12.2	12.2	13.1	2.0	0.8	
Customer Relationship Management	12.1	11.5	10.1	10.4	10.4	11.3	1.3	(0.8)	
Communications & Public Affairs	3.0	3.3	4.0	3.1	3.1	3.0	(1.0)	0.0	
							r	r	
Sub-Total	41.9	37.5	39.7	42.2	42.2	46.1	6.4	4.2	
LEAP Program Expenses									
LEAP	0.7	0.7	0.7	0.7	0.7	0.8	0.2	0.1	
							r	r	
							r	r	
							r	r	
							r	r	
Sub-Total	0.7	0.7	0.7	0.7	0.7	0.8	0.2	0.1	

(in$Millions)

Programs	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Bridge Year	2015 Test Year	Variance (Test Year vs. 2013 Actuals)	Variance (Test Year vs. Last Rebasing Year (2011 Board-Approved)	
Reporting Basis	**CGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**MIFRS**	**MIFRS**			**/C**
IT Program Expenses									
IT Governance	1.3	1.2	1.1	1.5	1.5	1.5	0.4	0.1	
IT Operations	25.6	24.5	28.0	29.7	29.7	30.9	3.0	5.3	
Project Execution	1.3	0.9	0.5	0.8	0.8	1.1	0.6	(0.3)	
Security & Enterprise Architecture	2.0	2.0	1.4	1.4	1.4	1.4	0.0	(0.6)	
							r	r	
Sub-Total	30.3	28.5	31.0	33.4	33.4	34.9	3.9	4.6	
Legal Program Expenses									
Corporate, Commercial & Real Property	3.2	2.5	2.1	2.9	2.9	3.1	1.0	(0.1)	
Litigation & Claims	2.3	1.8	2.4	2.4	2.4	2.5	0.1	0.2	
							r	r	
							r	r	
							r	r	
Sub-Total	5.5	4.3	4.5	5.3	5.3	5.5	1.0	0.1	
Finance Program Expenses									
Controllership	5.3	5.4	6.4	6.7	6.7	7.3	0.9	2.1	
External Reporting	2.9	2.6	2.6	3.1	3.1	3.2	0.6	0.3	
Financial Services	7.9	6.7	6.7	7.2	7.2	7.4	0.7	(0.5)	
							r	r	
							r	r	
Sub-Total	16.1	14.7	15.7	17.0	17.0	17.9	2.2	1.8	
Rates & Regulatory Program Expenses									
Rates & Regulatory Program Expenses	7.2	7.8	8.4	6.4	6.4	8.4	0.1	1.2	
							r	r	
							r	r	
							r	r	
							r	r	
Sub-Total	7.2	7.8	8.4	6.4	6.4	8.4	0.1	1.2	

(in$Millions)

Programs	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Bridge Year	2015 Test Year	Variance (Test Year vs. 2013 Actuals)	Variance (Test Year vs. Last Rebasing Year (2011 Board-Approved)	
Reporting Basis	**CGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**MIFRS**	**MIFRS**			**/C**
Control Centre Operations Program Expenses									
Control Centre Operations Program Expenses	8.4	8.3	8.9	8.2	8.2	8.4	(0.4)	0.0	
							r	r	
							r	r	
							r	r	
							r	r	
Sub-Total	8.4	8.3	8.9	8.2	8.2	8.4	(0.4)	0.0	
Disaster Preparedness Management Program Expenses									
Disaster Preparedness Management Program Expenses	0.9	r	r	r	r	2.4	2.4	1.5	
							r	r	
							r	r	
							r	r	
							r	r	
Sub-Total	0.9	r	r	r	r	2.4	2.4	1.5	
Facilities Management Program Expenses									
Facilities Maintenance Services	11.9	10.0	10.4	13.0	13.0	13.5	3.1	1.6	
Rentals & Leases	4.4	5.0	5.0	5.2	5.2	5.2	0.2	0.8	
Utilities & Communications	2.2	2.1	2.4	2.6	2.6	2.4	0.1	0.2	
Property Taxes	6.1	6.5	6.4	6.5	6.5	6.2	(0.1)	0.2	
							r	r	
Sub-Total	24.6	23.5	24.2	27.2	27.2	27.5	3.3	2.8	
Fleet and Equipment Services Program Expenses									
Equipment and Lab Services	8.7	8.5	8.7	8.4	8.4	8.9	0.2	0.2	
							r	r	
							r	r	
							r	r	
							r	r	
Sub-Total	8.7	8.5	8.7	8.4	8.4	8.9	0.2	0.2	

(in$Millions)

Programs	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Bridge Year	2015 Test Year	Variance (Test Year vs. 2013 Actuals)	Variance (Test Year vs. Last Rebasing Year (2011 Board-Approved)	
Reporting Basis	**CGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**MIFRS**	**MIFRS**			**/C**
Supply Chain Services Program Expenses									
Supply Chain Services Program Expenses	7.1	6.6	9.0	10.3	10.3	9.9	0.9	2.8	
							r	r	
							r	r	
							r	r	
							r	r	
Sub-Total	7.1	6.6	9.0	10.3	10.3	9.9	0.9	2.8	
Operations Support Program Expenses									
Corrective Maintenance	25.8	21.5	17.0	19.0	19.0	22.2	5.2	(3.6)	
Customer Driven Work	6.0	5.9	7.0	8.2	8.2	10.1	3.0	4.1	
Emergency Response	13.3	13.9	26.3	16.2	16.2	15.3	(11.0)	1.9	
Planning	9.0	9.0	11.5	10.3	10.3	12.9	1.4	4.0	
Preventative & Predictive Maintenance	13.7	16.0	12.8	16.1	16.1	20.1	7.3	6.4	
Program Delivery	5.0	5.5	5.6	5.8	5.8	6.1	0.5	1.0	
Work Program Execution	14.9	13.8	13.0	14.3	14.3	15.2	2.1	0.2	
							r	r	
Sub-Total	87.7	85.6	93.3	89.9	89.9	101.8	8.5	14.1	
Allocations & Recoveries Program Expenses									
On-cost recovery	(9.3)	(7.8)	(10.7)	(11.0)	(11.0)	(10.7)	(0.0)	(1.4)	
Fleet Recovery Offset	(10.8)	(10.7)	(10.3)	(12.4)	(12.4)	(13.2)	(3.0)	(2.4)	
(IT, Occupancy Charges)	(0.6)	(0.5)	(0.5)	(0.6)	(0.6)	(0.5)	0.0	0.1	
Shared Services	1.2	1.6	1.0	4.1	4.1	4.2	3.2	2.9	
Other Allocated Costs (Smart Meter Recognition, miscellaneous etc.)	(0.4)	(0.0)	7.1	r	r	r	(7.1)	0.4	
								r	
							r	r	
Sub-Total	(19.9)	(17.4)	(13.3)	(19.9)	(19.9)	(20.2)	(6.9)	(0.3)	
Miscellaneous							**r**	**r**	
Total	**238.6**	**215.8**	**246.4**	**246.6**	**245.3**	**269.5**	**23.2**	**30.9**	**/C**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

OEB Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE

	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Bridge Year	2015 Test Year	
Reporting Basis	**CGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**MIFRS**	**MIFRS**	/C
Number of Customers (mid-year)	**705,756.00**	**713,093.00**	**724,144.00**	**736,974.00**	**736,974.00**	**749,679.00**	
Total Recoverable OM&A from Appendix 2-JB	$238.6	$215.8	$246.4	$246.6	$245.3	$269.5	/C
OM&A cost per customer	**$ 338.08**	**$ 302.63**	**$ 340.26**	**$ 334.68**	**$ 332.91**	**$ 359.51**	/C
Number of FTEs	**1,737**	**1,601**	**1,527**	**1,537**	**1,537**	**1,564**	/C
Customers/FTEs	**406.30**	**445.46**	**474.10**	**479.62**	**479.62**	**479.49**	/C
OM&A Cost per FTE	**137,360.81**	**134,806.50**	**161,319.54**	**160,517.12**	**159,671.09**	**172,378.66**	/C

Notes:

1 Ifithasbeenmore than three years sincetheapplicant last filed acostofservice application, additional years ofhistorical actuals should beincorporated intothetable,asnecessary, togobacktothelast costofservice application. Iftheapplicant last filed acostofservice application lessthan three years ago, aminimum ofthree years ofactual information is required.

2 Themethodofcalculating thenumberofcustomersmustbeidentified.

3 Themethodofcalculating thenumberofFTEs mustbeidentified. Seealso Appendix 2rK

4 Thenumberofcustomersand thenumberofFTEs should correspond tomid ryearoraverage ofJanuary1and December 31figures.

5 TorontoHydronotesthatits OM&Apercustomermetrics do not account foranestimated300,000 behind rtherbulkrmetermulti runitdwelling customers.

PREVENTATIVE & PREDICTIVE MAINTENANCE PROGRAM

1. SUMMARY

Table 1: Preventative & Predictive Program Expenditures ($ Millions)

	2011	2012	2013	2014	2015
Preventative and Predictive Maintenance	$13.7	$16.0	$12.8	$16.1	$20.1

This schedule details Toronto Hydro's Preventative and Predictive Maintenance Program. The program maintains both distribution and stations assets. The key program components can be summarized as follows:

- **Preventative Maintenance** involves inspections and maintenance tasks that are typically conducted on a fixed cycle. These activities emphasize preserving asset performance over the expected life of the asset, and maintaining public and employee safety. Maintenance cycles are defined based on the mean time between failures of a given asset class, and are intended to maintain the asset before it is statistically likely to experience a failure. An example of a preventive maintenance task is the inspection of wood poles, which is carried out on a ten-year cycle.
- **Predictive Maintenance** entails testing and inspection of equipment for predetermined conditions that are indicative of a potential failure. These activities are effective on assets that exhibit conditions that can be identified, practically monitored and corrected prior to failure. An example of a predictive maintenance task is Dissolved Gas Analysis of power transformer mineral oil. The presence of dissolved gases and other chemical compounds in the oil will indicate potential

failure modes such as overheating, excessive moisture, or breakdown of the insulating paper.

The Preventative and Predictive Maintenance Program is complimented by the Corrective Maintenance Program (Exhibit 4A, Tab 2, Schedule 2), which corrects the deficiencies and addresses substandard conditions that are identified by preventative and predictive maintenance activities. By proactively identifying deficiencies and substandard conditions, the Preventative and Predictive Maintenance Program aims to minimize the expenditures in the Emergency Response Program (Exhibit 4A, Tab 2, Schedule 3).

2. PROGRAM DESCRIPTION

The Preventative and Predictive Maintenance Program is divided into ten segments. The table below contains Toronto Hydro's Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for each of these segments.

Table 2: Summary of Predictive & Preventative Maintenance Program Expenditures ($ Millions)

Segment	Historical			Bridge	Test
	2011	2012	2013	2014	2015
1. Overhead Line Patrols and Pole Inspections	0.3	0.4	0.4	0.5	0.7
2. Overhead Switch Maintenance and Insulator Washing	0.8	1.2	1.0	1.5	2.0
3. Vegetation Management	2.5	2.5	2.8	2.6	4.4
4. Below-Grade Equipment Maintenance	1.7	2.2	2.2	2.1	2.8
5. Pad-mounted Equipment Maintenance	0.2	0.4	0.4	0.4	1.1
6. Customer Location Maintenance	0.9	1.9	1.2	3.2	3.2

Segment	Historical			Bridge	Test
	2011	2012	2013	2014	2015
7. Metering Services	4.5	4.9	1.9	2.3	2.2
8. Station Inspections and Auxiliary Equipment Maintenance	1.0	0.9	1.0	1.2	1.2
9. Station Switchgear Maintenance	1.2	0.9	1.3	1.3	1.4
10. Station Equipment Maintenance	0.6	0.5	0.7	0.8	0.9
Total	**$13.7**	**$16.0**	**$12.8**	**$16.1**	**$20.1**

Expenditures between 2011 and 2014 have fluctuated as a result of the following:

- From 2011 to 2012, the increase is predominantly driven by increases of $0.5 million in Overhead Switch Maintenance, $0.4 million in Below-Grade Equipment Maintenance, and $1.0 million in Customer Location Maintenance;
- From 2012 to 2013, the decrease is predominantly driven by a decrease of $3.0 million in Metering Services;
- From 2013 to 2014, the increase is predominantly driven by increases of $2.0 million in Customer Location Maintenance and $0.3 million in Overhead Switch Maintenance.

Planned expenditures in 2015 are $4.0 million greater than forecasted 2014 expenditures. As described in greater detail in the segment discussions that follow, the predominant drivers for these increases are:

- $1.8 million increase in Vegetation Management to improve reliability and harden the distribution system against storm events;
- $0.5 million to conduct cable testing as part of Pad-Mounted Equipment Maintenance;

- x $0.5 million to conduct PCB testing on Below-Grade Equipment, Pad-mounted Equipment, and at Customer Locations; and
- x $0.5 million in Overhead Switch Maintenance and Insulator Washing.

The activities comprising the individual segments within the Preventative and Predictive Maintenance Program are designed to maintain asset performance and to mitigate a wide variety of risks. The philosophy that is at the core of many of the segments is Reliability-Centered Maintenance ("RCM"). RCM defines maintenance tasks and frequencies for a particular asset class to maximize reliability based on the asset's function and its criticality to the distribution system. Tasks are also designed to minimize overall costs and to account for risks and other factors such as the safety of Toronto Hydro work crews and the public, environmental stewardship and obligations, statutory and regulatory requirements, manufacturers' recommendations, and industry best practices.

In addition to RCM, Toronto Hydro's Preventative and Predictive Maintenance program is influenced by "Condition-based Maintenance" principles and an emphasis on maximizing productivity. Condition-based Maintenance promotes the adjustment of maintenance frequencies based on the condition of a particular asset as opposed to a strictly frequency-based approach. Toronto Hydro is currently developing data sets and analytics to enable greater usage of Condition-based Maintenance, particularly in the stations environment. For example, the emphasis on transformer oil testing at Stations and Customer Substations is partially motivated by the desire to implement more Condition-based Maintenance. By utilizing condition data, analytics tools such as Asset Condition Assessments ("ACA") and Health Indices, Toronto Hydro is striving to establish key parameters for assets such as: (i) which assets are in need of either enhanced maintenance or replacement based on their health; (ii) a list of assets where it is more cost effective to replace as opposed to maintain; and (iii) a list of assets that require maintenance on a higher priority than the rest of the asset base.

Toronto Hydro has placed significant emphasis on achieving greater output for the same or reduced input in each of the segments within the Preventative and Predictive Maintenance Program. In an effort to achieve greater productivity, Toronto Hydro has adjusted maintenance tasks and frequencies that are based in RCM and Condition-based Maintenance principles. Examples of these adjustments include:

- standardizing station maintenance cycles at four years wherever possible to minimize the need for multiple equipment outages (and significant switching resources), enable bundling of maintenance work, and minimize the need for multiple trips to particular sites;
- implementing "find and fix" protocols in which crews that identify minor deficiencies with assets are expected to address the deficiencies, which include lubricating components, replacing nomenclature, replacing faulted circuit indicators, replacing sump pumps, clearing drains, caulking ducts and roof slabs, and addressing missing or defective guy guards, pole ground wire, locks, hinges or handles by replacing them onsite as opposed to only logging the deficiencies for the Corrective Maintenance Program;
- issuing longer-term inspection maintenance contracts to third party service providers that result in reductions to unit costs and increase service quality levels over time; and
- introducing new tools or making greater use of technology such as Cable Diagnostic Testing, Infrared Thermography, Electronic Maintenance Sheets, Furan Sampling, Doble Testing, Dissolved Gas Testing, Online Partial Discharge Testing, Ultrasonic Testing and Enhanced Battery Testing.

The following sections describe and justify each of the ten segments that make up the Preventative and Predictive Maintenance program.

3. OVERHEAD LINE PATROLS AND POLE INSPECTIONS SEGMENT

Toronto Hydro conducts Overhead Line Patrols to inspect the more than 4,100 kilometres of primary and 10,900 kilometres of secondary lines that make up the overhead distribution system. The inspections cover all overhead distribution equipment including pole-mounted transformers, conductors, lightning arrestors, insulators, poles, switches, and other peripheral attachments. Approximately 8,400 overhead switches, 31,000 overhead transformers, and 135,000 poles are currently being inspected annually through Line Patrols.

In addition to Line Patrols, Toronto Hydro also conducts dedicated Pole Inspections and treatments on wood poles. Wood poles installed in the distribution system range in size from 30 to 55 feet, with a typical height of 40 feet. The most widely used wood species in the distribution system are Red Pine, Jack Pine and Western Red Cedar. All distribution poles are either butt or full length treated against rot.

As illustrated in Figure 1 below, Overhead Line Patrols are designed to identify deficiencies that are visible to the naked eye, such as leaking transformers, loose or broken attachments (e.g., cross-arms, insulator brackets), and damaged poles, as well as those that can be identified through infrared thermography. This technology identifies thermal anomalies, such as the 60°C increase in temperature at the secondary connection point of the pole-mounted transformer in Figure 1. If undetected and not addressed, such a deficiency can lead to a failure of the connection over time and result in safety and environmental risks due to arcing, which can lead to a transformer fire and rupture of the oil tank. The Institute of Electrical and Electronics Engineers ("IEEE"), American National Standards Institute ("ANSI") and the International Electrotechnical Commission ("IEC") all publish standard temperature ratings for assets which are used to determine if an electrical component has a temperature above the recommended value. Thermography

is an accepted and an encouraged practice in the utility industry as evidenced by the National Fire Protection Association's *NFPA 70B: Recommended Practice for Electrical Equipment Maintenance*.[1]

Figure 1: Secondary connection on pole-mounted transformer (Left) with an infrared thermography image of the same asset denoting a hot spot at A1 (Right)

Line Patrols are conducted annually on primary conductors and equipment, and every three years on secondary lines, in compliance with the Ontario Energy Board's ("OEB") Distribution System Code's Minimum Inspection Requirements (Appendix C).[2] Beginning in 2015, Line Patrols will also visually inspect assets that were formerly considered to be part of the streetlighting system.[3]

[1] National Fire Protection Association, *NFPA 70B: Recommended Practice for Electrical Equipment Maintenance*, (2013 Edition) (Simcoe: National Fire Protection Association, 2013).
[2] Ontario Energy Board, *Distribution System Code*, (Toronto: Ontario Energy Board, 2013), at Appendix C ["DSC"].
[3] As discussed in Exhibit 2A, Tab 5, Schedule 1, Toronto Hydro proposes to allocate a portion of the revenue received by TH Energy from the City of Toronto for street lighting maintenance and operation to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

The dedicated Wood Pole Inspection activity is conducted on a ten-year cycle and involves a visual assessment of each pole, and a sounding test using a hammer to check for internal cavities, which are an indication of an infested or internally decayed pole. Based upon the results from this assessment, additional steps may be taken, which include one or more of the following:

- a bore test, using a 12mm diameter bit to drill into the pole, and assess the condition of the shavings from the interior;
- a resistograph test, using a 2mm diameter needle drill bit and an electronic resistance measurement device to drill into the pole to determine: the presence of wood decay, stages of rot, and hollow areas;
- treatment using a boron glass rod or copper-boron glass rod wood preservative;
- treatment using an external copper napthenate wrap; and
- treatment using an internal fumigant.

Many of Toronto Hydro's wood poles and other assets that make up the overhead distribution system are approaching their end-of-life. For example the expected useful life of a:

- wood pole is 45 years and approximately 31% of poles will exceed 45 years by 2015;
- overhead switch is 45 years and approximately 33% of switches will exceed 45 years by 2015; and
- pole-mounted transformer is 40 years and approximately 24% will exceed 40 years by 2015.

For wood poles, the primary indicator of health and remaining life is mechanical strength, given that the main function of poles is to act as support structures. As a natural material, a wood pole undergoes a different degradation process than most other distribution assets. The degradation processes are primarily biological and accumulate with age.

They consist of insect infestation, moisture ingress, and bird or fungi attacks, which result in wood decay. Decay causes a wood pole to lose its strength and functionality, which increases the risk of a structural failure. Poles, which often support and withstand significant static loads such as transformer banks and conductors, and dynamic loads such as high winds, typically fail with the onset of age and the loss of structural strength.

Toronto Hydro utilizes the information gathered from pole inspections to assess the overall condition of its wood poles. Asset Condition Assessment ("ACA") results indicate that approximately 11% of the wood pole population are in poor or very poor condition and require replacement. Figure 2 illustrates the ACA results. [4]

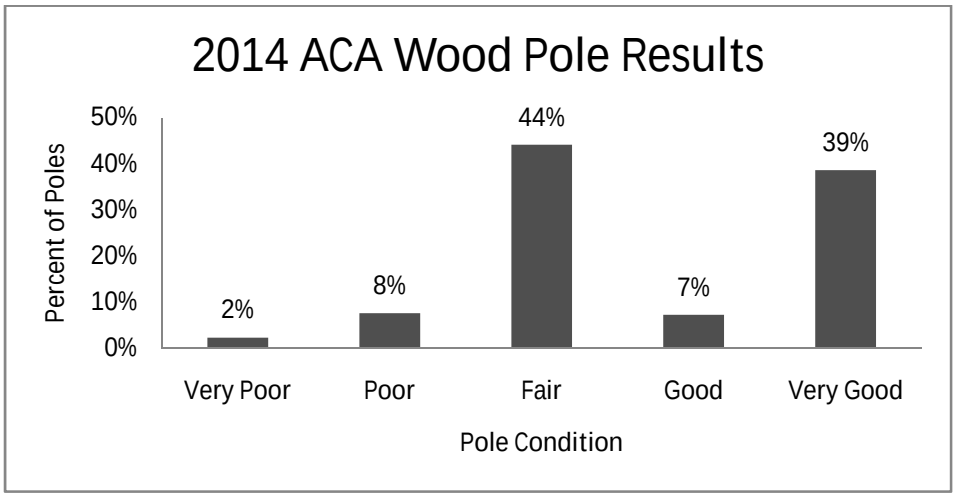


Figure 2: 2014 ACA for Wood Poles

Overhead Line Patrols and Pole Inspections serve to assess system conditions and identify deficiencies that can arise on overhead lines as a result of aging assets, exposure to weather, animals, trees, or other elements. Condition and deficiency information that is gathered during these activities is utilized to prioritize capital and corrective

[4] For more information about the ACA, refer to Exhibit 2B, Section D, Appendix A.

maintenance work such that public and employee safety, environmental, system reliability, and financial risks can be mitigated. In the case of pole treatments, activities are undertaken to extend the life of the pole and mitigate the risk of decay.

In 2013, Toronto Hydro identified over 2,400 deficiencies during Line Patrols. Deficiencies identified include loose or deteriorated connections, missing guy guards, tracking insulators, rusted equipment, oil leaks, vegetation interference, damaged conductors and conductor splices. Identifying these conditions and addressing them reduces the likelihood of a component failure and the associated risks. For example, an aging conductor splice that fails could result in a live conductor falling to the ground, creating a safety risk to the public and Toronto Hydro employees, and causing a power interruption that may impact hundreds of customers. Thermography mitigates this risk as it enables Toronto Hydro to identify deficiencies in splices.

Dedicated Wood Pole Inspections identify poles that have lost their mechanical strength and are likely to fail, and possibly collapse to the ground, if they remain on the system. As noted above, and further illustrated in Figures 3-7 below, deficiencies such as internal and external rot, excessive cracking, and infestation are common causes of failure. During the 2011-2013 period, Toronto Hydro identified on average over 80 danger poles annually.

Figure 3: Internal rot at base of a pole

Figure 4: External rot at base of a pole

Figure 5 : Large crack along pole length

Figure 6: Woodpecker hole on a pole

Figure 7: Infestation

Wood poles are found predominantly along sidewalks, roadways, and other areas of high pedestrian and vehicular traffic. Without routine inspection, there is an unacceptable risk that poles and their attachments could collapse onto sidewalks, roadways, and even residences as shown in Figure 8 below. The collapse of a pole can also cause oil spills from ruptured transformer tanks, electrical arcs, flashovers, and fires, which can result in environmental risks and safety risks to the public and Toronto Hydro employees. Minimizing the likelihood of a pole failure is expected to mitigate these unacceptable risks.

Figure 8: Fallen pole due to rotten base

In 2013, there were a total of 252 incidents of overhead asset failures (excluding major event days) that impacted the system. These failures were primarily attributed to overhead switches, transformers, conductors, insulators, and poles. These incidents resulted in over 131,000 customer interruptions and over 102,000 customer hours of interruption. In 2011 and 2012, Toronto Hydro experienced 299 and 218 outage incidents respectively from overhead assets. Line Patrols and Pole Inspection activities are in place to identify deficiencies that if left unaddressed may lead to incidents that impact system reliability.

In addition to mitigating public safety, environmental, and system reliability risks, the Pole Inspection activity, and in particular pole treatments such as the application of boron rods, copper napthenate wraps, and internal fumigant, extend the life of poles and allow

for a more efficient and structured capital pole replacement program. During the 2011-2013 period, Toronto Hydro treated approximately 29% of all poles inspected.

3.1. Segment Costs

The following table contains the historic and planned expenditures for this segment.

Table 3: Historical and Forecasted Segment Spending ($ Millions)

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	0.3	0.4	0.4	0.5	0.7

Historic expenditures during the 2011-2013 period for Overhead Line Patrols and Pole Inspections were relatively consistent from one year to the next. An average of 9,000 poles were inspected annually during this period. In 2014, expenditures are forecasted to rise as a result of: (1) an increase in wood pole inspections to 10,000 to maintain a ten-year cycle; and (2) expanded usage of infrared thermography as part of the Line Patrol program.

3.2. Test Year Segment Costs

In 2015, expenditures for Overhead Line Patrols and Pole Inspections are expected to increase from $0.5 to $0.7 million due to the addition of patrols and inspections of assets that were formerly serving the street lighting system in Toronto.[5] The expenditures are expected to enable Toronto Hydro to identify deficiencies on overhead lines assets and address the deficiencies through capital and corrective maintenance activities. Currently, approximately 44% of wood poles have been assessed to be in "fair" condition and these poles are expected to deteriorate to "poor" condition in the coming years. As a result of this and the fact that 31% of Toronto Hydro's poles will have surpassed their expected

[5] As discussed in Exhibit 2A, Tab 5, Schedule 1, Toronto Hydro proposes to allocate a portion of the revenue received by TH Energy from the City of Toronto for street lighting maintenance and operation to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

life spans by 2015, Line Patrol and Pole Inspection expenditures are critical to mitigating the risk of asset failures and associated public safety, system, reliability, environmental, and financial risks.

4. OVERHEAD SWITCH MAINTENANCE AND INSULATOR WASHING

This segment entails two general sets of maintenance activities on the overhead distribution system:

(1) maintenance of overhead switches; and

(2) washing of porcelain insulators.

4.1. Overhead Switches

Overhead switches are typically installed on the main (or trunk) portion of feeders and subdivide feeders into smaller portions, known as line sections. Switches are also used for interconnections, or tie points, between different feeders. The practice of breaking feeders into sections, which is referred to as "sectionalizing" a feeder, and tying feeders together, serves two main purposes. First, in an outage situation, where the station breaker has opened due to a fault on a distribution line emanating from the station, the faulted line section can be isolated by opening and closing appropriate switches. This isolates the faulted line section from the system, allowing re-energization of the feeder and restoration of power to customers that are not directly fed by the faulted line section. Second, in situations where load needs to be removed from a particular feeder due to maintenance or capital work, switches at tie points can be opened or closed to supply power to customers from an alternate feeder.

Toronto Hydro maintains overhead switches on a three-year cycle. There are three main types of switches that are maintained in Toronto Hydro's distribution system:

- **Supervisory Control and Data Acquisition (SCADA) Switches (or SCADA-Mate Switches):** These switches are motorized, and can be operated remotely by the Control Room via wireless communication, or operated locally by field crews. To enable communication and remote operation during a system failure, the switches and related equipment utilize a battery system that is capable of providing power for switch operation and communication. This switch's insulators are made of polymer, and the insulation and arc quenching medium is Sulphur Hexafluoride ("SF_6") gas in a sealed unit. Maintenance of SCADA switches involves verifying the switch's remote and local operation along with lubrication of the pivot points on the visible air-gap isolation mechanism. It also includes battery replacements for the switch and repeater radio (in accordance with manufacturer's recommendations), and Remote Terminal Unit ("RTU") testing to verify proper communication with the Control Room. Figure 9 below shows a typical SCADA switch.

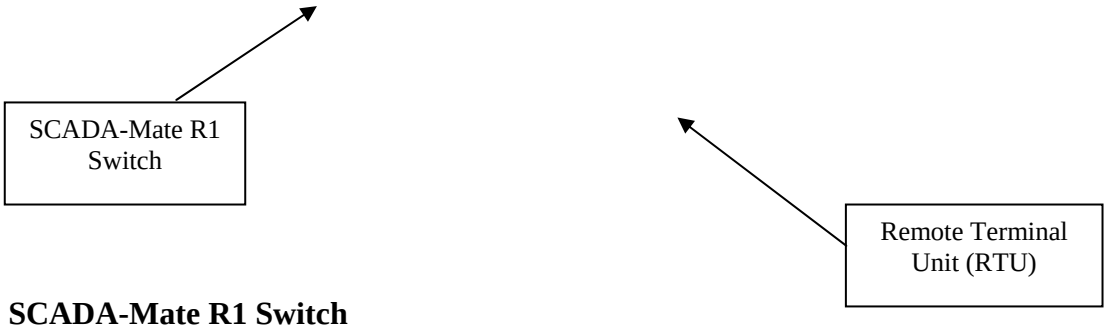


Figure 9: SCADA-Mate R1 Switch

- **Three Phase Gang-Operated Switches**: These switches are found throughout Toronto Hydro's overhead system and unlike the SCADA switches, are not capable of remote operation. The vast majority are manually operable at the physical switch location, while some have motorized controls. The insulation medium for these switches is air, and the insulators are made of porcelain. The scope of work to maintain these switches involves verifying correct blade alignment, blade penetration, travel stops, arc interrupter operation, and mechanical operation. The contacts are cleaned and greased and the switch is tested for correct operation. Figure 10 below shows a Gang-Operated switch.

Figure 10: Manual Gang-Operated Switch

- **Single Phase Porcelain In-Line Disconnect Switches**: Single Phase 600 amp (A) Porcelain Switches are found on the trunk portion of 27.6kV feeders where they were previously installed as a more cost-effective alternative to manual

ganged switches. While sometimes installed on all three phases at a given location, they are only operable one phase (or switch) at a time, using a live line tool such as a hot stick. Maintenance involves a visual inspection of the switch for any corrosion on the switch blades, and any cracks on the porcelain insulators.

In total, Toronto Hydro maintains approximately 2,400 overhead switches made up of 800 SCADA switches, 1,300 Three-Phase Gang Operated Switches; and 300 Single Phase 600A Porcelain Switches. Beginning in 2015, Toronto Hydro plans to also verify the integrity and function of surge arresters connected to overhead switches, and to replace units as required.

4.2. Insulator Washing

Conductors and switches that are used on the overhead distribution system have historically been attached to poles and structural infrastructure using porcelain insulators. Porcelain insulators possess a high dielectric strength and good mechanical properties, including hardness and resistance to chemical erosion and thermal shock. However, porcelain has a poor ability to resist contamination build-up, which causes tracking (i.e., leakage of electricity across the insulator). The accumulation of dirt and salt, combined with moisture (during misty or foggy days), reduces the effective insulation levels and can lead to insulator tracking, flashover and potential pole fires.

More than half of Toronto Hydro's overhead distribution system utilizes porcelain insulators. This equates to approximately 70,000 pole locations that are vulnerable to contamination building up on insulators. Thousands of these locations are at an increased risk as they are close to industrial areas, adjacent to busy arterial roads and highways such as the 401, 400, 427, and the Don Valley, Allen, and Gardner Expressways, where salt that has been used to melt snow or ice in the winter months becomes airborne through "salt spray" and deposits on the insulators. To mitigate the risk of contamination

and insulator tracking, insulators at the highest risk locations are washed twice a year. Insulator washing utilizes a high-pressure intermittent water jet to remove contaminants. Washing is performed while lines are energized. Figure 11 shows an example of a porcelain insulator being washed.

Figure 11: Porcelain Insulator Washed using a High Pressure Water Jet

As Toronto Hydro's capital program replaces porcelain insulators with polymer insulators,[6] the need for insulator washing is expected to diminish, as polymer insulators are hydrophobic, and are not susceptible to the same failure mode due to contamination. However, given the high proportion of insulators on the system that are still porcelain, the need will not diminish appreciably in the short-term and continued insulator washing is expected to be required over the next five years.

[6] Exhibit 2B, E7.6

Overhead Switch Maintenance and Insulator Washing serve to mitigate a wide variety of public and employee safety, system reliability, and financial risks. Beginning with Switch Maintenance and employee safety, manual switching is a common and high risk activity undertaken by Toronto Hydro crews. Switches that are not regularly maintained can be difficult to operate and can lead to strains and injuries for crew members. Regular maintenance enables the detection and prediction of common failure modes. One such mode is the failure of switch's porcelain insulators. Figure 12 illustrates a Porcelain (In-Line Disconnect) Switch where part of the porcelain insulator has broken off. Porcelain switches pose high safety risks due to their susceptibility to contamination build-up and electrical tracking, which can lead to cracking and result in broken shards falling from installations mounted as high as 50 feet (i.e., over 15 metres), posing a safety risk to employees or members of the public below.

Figure 12: Porcelain Insulation Failure on a Switch

Figure 13 below shows a picture of a switch installation where the center-phase insulator broke off entirely and fell to the ground.

Figure 13: Insulator Failure on a Gang-Operated Switch

A second common failure mode, which is illustrated in Figure 14 below, is corrosion of the metal blades. This naturally occurs from contaminants such as road salt and water settling on the switch blades. It can result in excessive heating of the blade and over time, can lead to the blade failing to conduct electricity. Contaminants and corrosion present on a switch blade during a load break operation may also cause the electrical arc to elongate, which causes additional damage to the blade and can lead to blade failure. Associated safety risks caused by corrosion include burns from an arc-flash and overexertion injuries to an employee, if a switch requires a significant amount of force to operate.

Figure 14: Corrosion of Switch Blade

Other common failure modes include switch seizure – due to the drying out of lubrication, excessive arcing due to the misalignment of blades, and in the case of SCADA switches, failure of batteries – all of which can lead to switch malfunction, and pose a risk of injury to Toronto Hydro employees. These deficiencies are addressed by Overhead Switch Maintenance activities such as identifying and correcting deteriorated insulators and corroded switch blades, ensuring blades are properly aligned, lubricating switches, and replacing batteries proactively.

From a system reliability perspective, reducing the likelihood of switch failures can reduce the number of customer interruptions and customer hours of interruptions. Switches are designed to allow line sections to be isolated from the distribution system when a fault occurs. They can also be used to isolate a line section for the purposes of undertaking planned work. Their function and their impact on system reliability can be illustrated using the example in Figure 15 below.

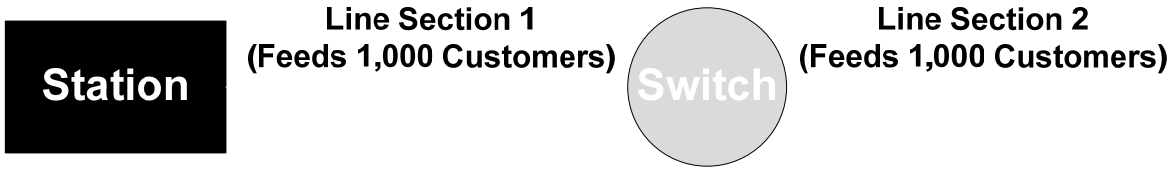


Figure 15: Example of Overhead Switch Impact on System Reliability

Assume a feeder that serves 2,000 customers is divided into two line sections using a switch, with each section serving 1,000 customers. When a fault occurs on Line Section 2, the switch can be operated to isolate that line section such that the station can continue to supply the customers on Line Section 1. Without an operable switch, 2,000 customer interruptions would result as the feeder would be isolated in its entirety from the station. The presence of the switch has the potential to reduce that number to 1,000 customer interruptions as only Line Section 2 would be isolated. Assuming that in this theoretical example a fault is equally likely to occur on Line Section 1 or Line Section 2, an operable switch would improve system reliability by 33%.

Over the 2011-2013 period, the distribution system averaged 58 power interruptions due to switch failures annually, which resulted in an average of 44,300 customer interruptions and 22,700 customer hours of interruption annually.

Removing contamination through insulator washing reduces the risk of electrical tracking, pole fires and insulator failures. From a safety perspective, pole fires and insulator failures in Toronto's dense urban areas can cause injury to individuals at ground level. The primary failure mode for porcelain equipment is cracking, which may start as a hairline crack, but has the potential to lead to a catastrophic failure with shards of debris falling to the ground that could strike anyone in the vicinity. Figure 16 below shows a

close-up view of damage to a porcelain insulator that has been caused by electrical tracking over time along the surface.

Figure 16: Close-up of Damaged Porcelain Insulator showing tracking

From a system reliability perspective, insulator failures, depending on where they occur on a feeder, will cause a power interruption for tens to possibly thousands of customers. During the 2011-2013 period, Toronto Hydro experienced a high of 16 pole fires in 2011 and a low of 3 pole fires in 2013. A pole fire on September 5, 2012, caused by a defective porcelain insulator resulted in 4,030 customers impacted and 2,506 customer hours interrupted. More recently, a contaminated porcelain insulator caused a pole fire on July 20, 2013; this incident resulted in 6,979 customers impacted and 7,199 customer hours interrupted.

From a financial perspective, pole fires due to insulator tracking necessitate emergency response, equipment replacement costs, and in some instances, the payment of damage claims. Emergency response and equipment replacement costs can exceed $10,000, especially when transformers and switches must be replaced in addition to poles.

Damage claims associated with pole fires can add thousands of dollars more to the cost of the failure.

Given the public and employee safety, system reliability, and financial risks associated with contaminated porcelain insulators, routine Insulator Washing is a necessary and prudent means of reducing the likelihood of contingencies resulting from debris build-up on insulators. Reductions in the amount of insulator washing could result in increased incidents of insulator tracking and poles fires. In the first half of 2014 alone, 14 pole fires resulted in 25,463 customer interruptions and 19,358 customer hours of interruption. A contributing factor to these events was the particularly harsh winter and the quantity of salt that was used during the winter months by road authorities. Nevertheless, these incidents followed 2013, a year in which Insulator Washing accomplishments were below historic levels.

4.3. Segment Costs

The following table contains the historic and planned expenditures for this segment.

Table 4: Historical and Forecasted Segment Spending ($ Millions)

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	0.8	1.2	1.0	1.5	2.0

Historic expenditures during the 2011-2013 period fluctuated as a result of fluctuations in the number switches maintained and insulators washed, and fluctuations in unit costs. The number of switches maintained has increased from a low of 484 units in 2011 to a high of 799 units in 2013. The number of pole locations that received insulator washing decreased from a high of approximately 8,400 locations in 2011 to a low of approximately 1,450 locations in 2013. Expenditures in 2014 are planned to increase

driven by the re-introduction of switch maintenance on 600 A Porcelain Switches and the need to maintain a greater number of Three-Phase Gang-Operated Switches to achieve a three-year maintenance cycle.

4.4. Test Year Segment Costs

Planned expenditures in 2015 are $2.0 million, which is $0.5 million greater than 2014 expenditures. This increase is driven predominantly by two factors. The first is an increase in Insulator Washing from 3,000 planned units in 2014 to 9,500 in 2015 to mitigate the risks posed by insulator contamination. The second is the addition of lightning arrestor replacement to switch maintenance activities. Overall, the $2.0 million budget allows Toronto Hydro to maintain 2,400 switches on a three-year cycle and to wash 4,750 of Toronto Hydro's 70,000 pole locations. These maintenance activities are designed to address conditions that lead to common failure modes among overhead switches and porcelain insulators, and to mitigate public and employee safety, financial and system reliability risks.

5. VEGETATION MANAGEMENT SEGMENT

Toronto Hydro's system contains 927 overhead primary feeders that extend for almost 4,200 circuit kilometres along Toronto's arterial thoroughfares, rights-of-way, and residential streets. These feeders co-exist with the City of Toronto's mature and abundant tree canopy, which includes 600,000 City-owned "street trees" and thousands of trees located on customer properties. (In total, there are over 10 million trees in the City of Toronto.) Over 125,000 of these street trees are immediately adjacent to primary overhead feeders, and can potentially interfere with the safe and reliable distribution of electricity.

Vegetation interference is one of the most common causes of power interruptions, as overhead feeders are prone to tree branch contacts. Trees may make contact with distribution feeders as a result of natural growth, or when severe weather causes branches to break and fall into lines, or causes branches to bend and make intermittent contact. Conductors on feeders can also naturally stretch and sag due to ice and snow build-up, heavy loading or warm weather, bringing the lines closer to tree limbs. Branch contacts with lines result in the tree creating a new path for current to travel, causing it to become energized and posing a safety risk.

Tree-caused power interruptions have a significant impact on system reliability and are second only to defective equipment as the leading cause of system outages. Statistics from 2011-2013 show that tree contacts are responsible for approximately 120 power interruptions a year, as shown in Figure 17 below, and cause approximately 125,000 customer interruptions and 150,000 customer hours of interruption annually. These statistics exclude interruptions that occurred on major event days. During such days, the distribution system is particularly vulnerable to tree contacts and costly tree damage. When all interruptions are considered, trees account for 14% of all customer interruptions and 21% of all customer hours of interruption.

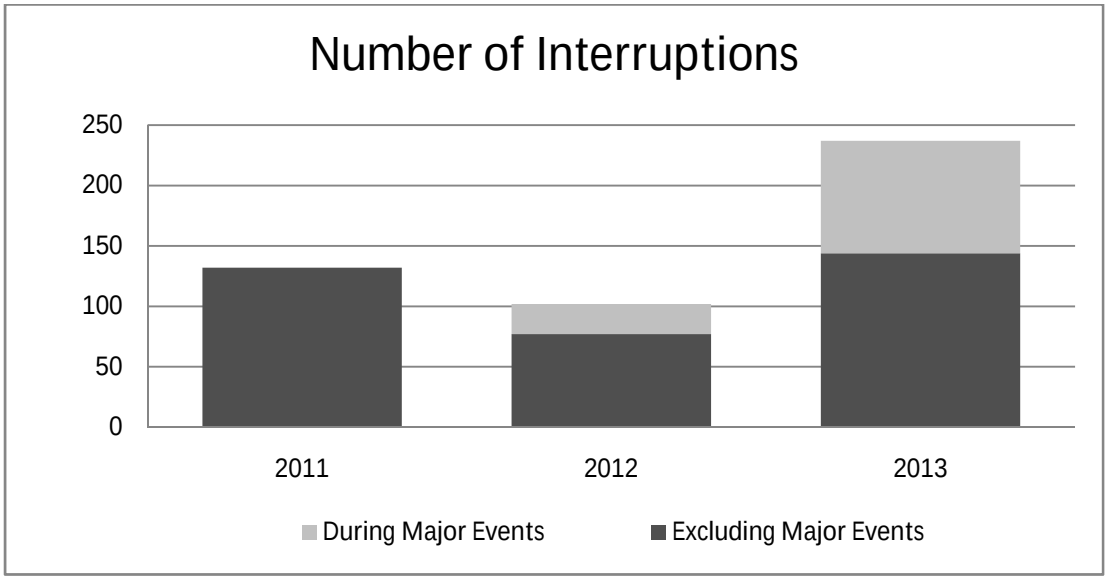


Figure 17: Number of power interruptions involving tree contacts

Vegetation Management mitigates the risk of vegetation interference by pruning trees that are near Toronto Hydro's overhead feeders. Each year, Toronto Hydro identifies the feeders that are in greatest need of tree pruning based on prioritization criteria that include feeder reliability history, the number of customers supplied by each feeder, and the amount of time that has elapsed since the trees surrounding the feeder were last pruned. The prioritization results in trees surrounding feeders being pruned once every two to five years, with the system average being approximately three years. On average, Toronto Hydro pruned 1,565 circuit kilometres and almost 47,000 trees annually during the 2011-2013 period. As a result, the state of Toronto Hydro's overhead distribution system with respect to Vegetation Management is illustrated below.

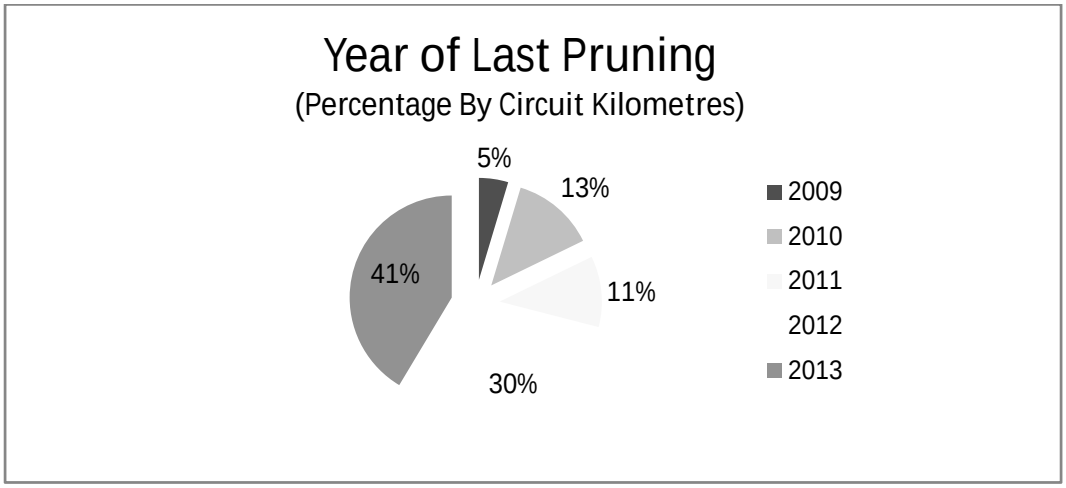


Figure 18: Historical Pruning (2009-2013)

Although 41% of the system was pruned in 2013, 29% has not been pruned since 2011. As discussed in more detail below, as more time passes since the last tree pruning activities on a particular feeder, it becomes more likely that tree contacts will occur and associated risks will arise. This increased likelihood raises a wide variety of risks including system reliability, financial, and safety risks. These risks can be effectively mitigated through tree trimming.

From a reliability standpoint, Figure 19 illustrates the number of vegetation-related interruptions that can be expected relative to time elapsing since pruning and trimming activities. An average feeder that is cleared after having experienced three to four years of growth is expected to exhibit a reduction of approximately 20% to 40% in the number of tree-caused interruptions.

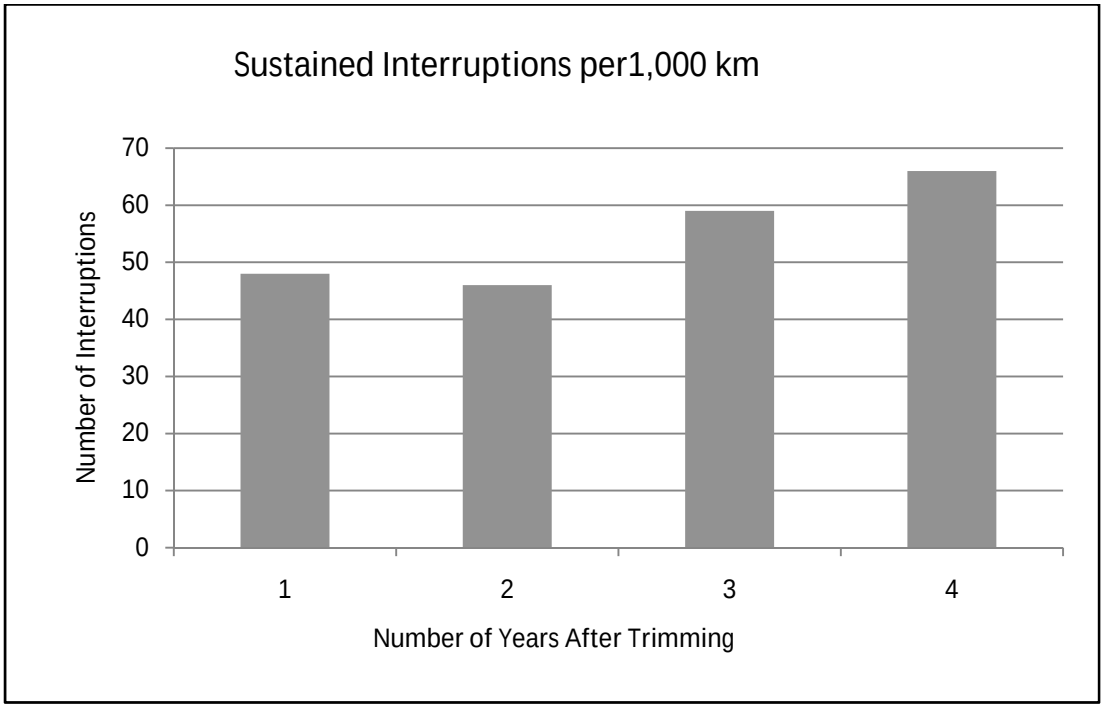


Figure 19: Expected number of tree-related interruptions.

Vegetation Management is also a widely accepted means of effectively "storm-hardening" a system and thus proactively mitigating storm damage and system reliability risks. Storm hardening involves selectively removing portions of the tree canopy to reduce the "sail effect" of branches during high winds and to reduce the likelihood that broken branches will contact lines. More frequent tree pruning further reduces risks posed by severe weather.

Toronto Hydro's system is susceptible to severe weather and storm damage, as evidenced by the three major events experienced between 2011 and 2013: (1) Hurricane Sandy on October 29 and 30, 2012; (2) a major thunderstorm on July 8, 2013; and (3) a major ice storm on December 21, 2013. In many cases, the effects of these storms continue well after the storm has passed, as broken and weakened trees and tree limbs continue to pose a threat to overhead lines until the next tree pruning date.

Given the increasing frequency of storms, and climate change studies that indicate warmer year-round temperatures,[7] Toronto Hydro plans to increase expenditures on Vegetation Management activities to mitigate storm damage and system reliability risks. From a financial perspective, increases in planned Vegetation Management are expected to reduce reactive (e.g., corrective and emergency) expenditures. Toronto Hydro's reactive expenditures during the 2011-2013 period included:

- an average of $1.8 million per year on major event and storm damage restoration expenditures (excluding the 2013 ice storm);
- an additional $13 million for emergency response and reactive capital during the aforementioned 2013 ice storm event; and
- $1.6 million on customer demand and reactive tree pruning activities.

In total, over $20 million was spent on reactive expenditures over the 2011-2013 period. These expenditures, which largely relate to tree contacts and tree-caused damage, illustrate the significance of the financial risks associated with tree growth and trees located close to overhead distribution lines.

In addition to system reliability and financial risks, Vegetation Management serves to mitigate safety risks. One set of safety risks is attributed to trees and vegetation that grows or is blown into power lines. This vegetation can become energized, and in rare situations, can cause fires or step and touch potential (flow of current through an individual) risks to the general public. Another set of safety risks is caused by falling branches or trees that bring energized conductors to the ground when they fall, which can result in safety hazards to the public. Vegetation Management is expected to mitigate these risks.

[7] Refer to the report, entitled Future Impacts of Climate Change on Toronto Hydro's Distribution System, at Exhibit 2B, E8.8, Appendix A.

Within Toronto, vegetation risks have been increasing in recent years due to invasive species infestation such as the Emerald Ash Borer and the Asian Long-Horned Beetle. Both these species compromise a tree's structural integrity and greatly increase the risk of a branch or tree falling into overhead feeders. It is estimated that Toronto will lose approximately 860,000 of its ash trees to the Emerald Ash Borer,[8] while the Asian Long-Horned Beetle poses a risk to 42% of all street trees.[9] More frequent tree pruning is expected to enable Toronto Hydro to mitigate the risks associated with invasive species by removing the dead and dying tree limbs that they cause.

Planned Vegetation Management activities are executed by contractors with support from Toronto Hydro's internal resources. Trees and branches are pruned according to minimum clearance standards based on American National Standards Institute (ANSI) A300 – Standard Practices for Trees, Shrubs and other Woody Plant Maintenance,[10] and the City of Toronto Forestry Pruning Guidelines. In addition to the minimum clearance standards, Toronto Hydro considers other factors including but not limited to:

- x species and growth patterns of a tree: fast-growing trees are trimmed more and slow-growing trees are trimmed less;
- x natural trimming practices: branches are pruned back to a natural point of growth in the crown of the tree and leaders are "trained" (shaped) to grow away from the lines;
- x distance of major limbs that exhibit minimal growth, versus minor branches that can exhibit aggressive growth;
- x directional pruning practices: maintenance of tree shape and branch patterning;

[8] City of Toronto, *Emerald Ash Borer in Toronto: Managing Public and Private Trees*, (Toronto: City of Toronto, 2013).
[9] City of Toronto, *Trees Under Threat: The Asian Long-horned Beetle in Greater Toronto*, (Toronto: City of Toronto, 2014), online: City of Toronto <http://www1.toronto.ca/wps/portal/contentonly?vgnextoid=f26fdada600f0410VgnVCM10000071d60f89RCRD&vgnextchannel=17f4cacb759e0410VgnVCM10000071d60f89RCRD>.
[10] American National Standards Institute, *American National Standard for Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance — Standard Practices (Pruning)*, (A300 (Part 1)-2001) (Washington: American National Standards Institute, 2001).

- overall aesthetics and balance of the tree;
- removal of dead limbs; and
- storm hardening: select removal of branches within the canopy to minimize the possible effects of wind and severe weather, but maintain the overall tree appearance.

Toronto Hydro avoids the practice of "tree topping", which is the indiscriminate removal of branches to reduce the size of the tree crown. As a result of this and the various aforementioned factors considered during trimming, Toronto Hydro mandates the use of trained Arborists for Vegetation Management activities. The personnel involved in tree pruning are certified Utility Arborists, with training, knowledge and certification in the practice of arboriculture.

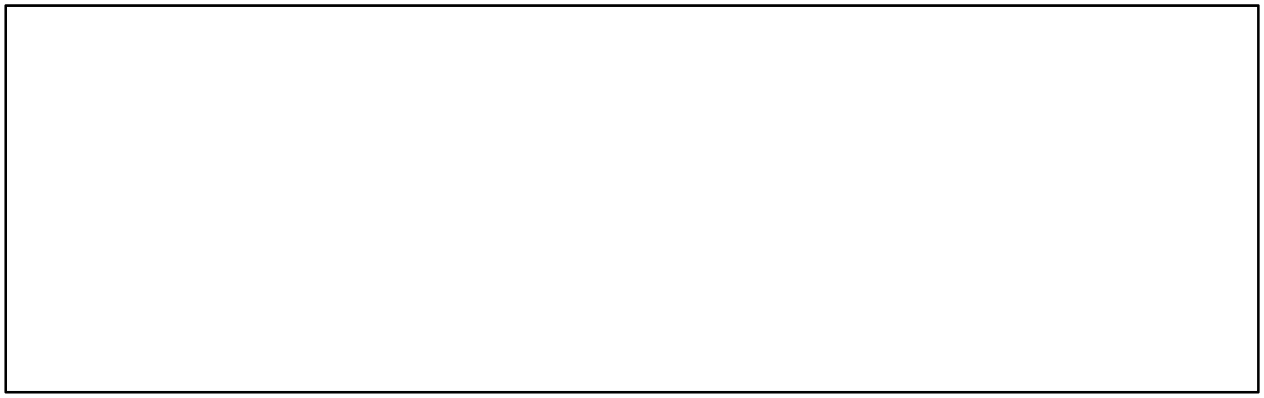


Figure 20: Tree Trimming of an Overhead Feeder

5.1. Segment Costs

The following table contains the historic and planned expenditures for this segment.

Table 5: Historical and Forecasted Segment Spending ($ Millions)

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	2.5	2.5	2.8	2.6	4.4

/C

Historical spending for Vegetation Management has been relatively consistent between 2011 and 2014. The slight increase in 2013 is attributed to an increase in the number of kilometres of line where trees were pruned.

5.2. Test Year Segment Costs

The increase in expenditures in 2015 is attributed to two factors: (1) an increase in market prices provided by contractors; and (2) a need to increase accomplishments to mitigate safety, system reliability and financial risks, especially during severe weather.

During the 2011-2013 period, Toronto Hydro had entered into an agreement with one contractor to provide tree pruning services and this agreement expired in 2014. Following a competitive tendering process, Toronto Hydro expects to award a new contract in 2014 and forecasts a 16% increase in average unit costs (i.e., the cost to prune trees on one circuit kilometre of line) as a result of increases in market prices. This increase is reflected in the 2015 forecast.

Aside from an increase in unit costs described above, the 2015 expenditures are greater than those in prior years due to plans to increase tree pruning accomplishments by approximately 30% over historic averages and to “storm harden” the system. (During 2011 to 2013, Toronto Hydro pruned 46,726 trees on 1,565 circuit kilometres of line on average each year.) More frequent vegetation management and storm-hardening activities are expected to improve system reliability and reduce the damage sustained during severe weather events.

6. BELOW-GRADE EQUIPMENT MAINTENANCE SEGMENT

This segment entails inspections and maintenance of underground vaults, cable chambers, and the equipment that is housed within them. These structures, which are located below-grade, are constructed out of reinforced or un-reinforced concrete, and house transformers, switches, cables, and other electrical distribution equipment. Inspections and maintenance activities are conducted on various types of below-grade structures including network vaults, compact radial distribution ("CRD") vaults, underground residential distribution ("URD") vaults, submersible vaults, and cable chambers.

Network vaults are primarily located in the downtown core of Toronto and were constructed in the 1950s and 1960s. These vaults are the largest of the below-grade structures, and house interconnected electrical equipment used for the secondary network system that provides reliable supply to large and critical customers in the city's dense downtown core. There are four main electrical components that are housed within network vaults: (1) the primary switch, which isolates the feed to the transformer; (2) the transformer itself; (3) a network protector, which protects the transformer and the primary side of the system from faults on the secondary side; and (4) a fuse panel, which protects the cables feeding the secondary grid. The transformer and the network protector are referred to as a network unit, an example of which is illustrated in Figure 21. Toronto Hydro owns 1,067 network vaults and 1,892 network units; approximately 7% of the network units are of the fibertop type, which is a very high-risk legacy asset. The civil structure of network vaults is inspected on a six-month cycle and the electrical assets are inspected annually; network protectors are also overhauled on a three-year cycle. **/C**

Figure 21: A Network Unit

The CRD and URD systems were constructed in the early 1990s and 2000s respectively. CRD vaults were designed to be a less expensive alternative to network vaults due to a simpler design, which lacks the supply redundancy that a network system provides. CRD vaults typically supply small retail, apartment, and commercial office buildings. URD vaults were used for 4kV to 13.8kV conversion projects and primarily power small residential or commercial buildings. Toronto Hydro owns 690 CRD and URD vaults, which are inspected annually.

Submersible vaults are small civil structures installed on the public road allowance, or private property, and are used for residential electricity distribution. These vaults contain transformers, switches, loop-through primary conductors, and secondary circuits. The

vaults are sized to accommodate a transformer and secondary connections only. They are not sized for personnel to enter into. There are 9,990 submersible transformer vaults in Toronto Hydro's distribution system. They are inspected on a three-year cycle. Figure 22 illustrates a submersible vault.

Figure 22: A Network Unit

Cable chambers are civil structures typically installed on the public road allowance, and contain primary and secondary cables and cable splices, and in many cases, third party installations such as Toronto Transit Commission ("TTC") power cables, television cable, and phone lines. Cable chambers facilitate cable installation in underground ducts and are found along the route length of underground feeders. Toronto Hydro owns 10,900 cable chambers, to be inspected on an eight-year maintenance cycle.

Below-Grade Equipment Maintenance, regardless of the type of vault or chamber, includes visual inspections of the civil infrastructure and electrical equipment, thermographic scans, and drainage and sump pump tests. Any oil testing that is required to enable Toronto Hydro to comply with *PCB Regulations*[11] under the *Canadian Environmental Protection Act, 1999*[12] is also undertaken as part of Below-Grade Equipment Maintenance.

The average life of below-grade structures including network vaults, CRD and URD vaults and submersible vaults is 60 years. The roofs of those structures however are expected to last for only 25 years, due to greater exposure to the environment and dynamic loads such as pedestrian and vehicular traffic. The equipment that is housed within below-grade structures is expected to have an average life between 30 and 45 years depending on the type of equipment. Network protectors, in particular fibertop types, have been linked to the cause of network vault fires in the past and have an average useful life of 30 years. Approximately 74% of all fibertop units have already reached the end of their expected-lives.

The ages of Toronto Hydro's vaults vary from the relatively new URD and CRD vaults to the older network vaults in the downtown areas of the city. Approximately 60% of all network vaults will reach their expected life within the next ten years, and approximately 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life. The majority of URD vaults are less than 25 years old and all CRD vaults are less than 15 years old. These vaults are less of a concern than the significantly older network vault and cable chamber populations.

As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of

[11] Canada SOR/2008-273. ["*PCB Regulations*"]
[12] S.C. 1999, c. 33. ["*Environmental Protection Act*"]

supports such as beams and rebar. Once degradation and corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below-grade structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow. Figures 23 to 27 depict structural deficiencies that are common in older vaults.

Figure 23: Vault Roof Exposed Rebar

Figure 24: Vault Wall Exposed Rebar

Figure 25: Corroded I-Beams

Figure 26: Cracked Vault Roof

Figure 27: Cracked Vault Wall

Below-Grade Equipment Maintenance mitigates the risks that deterioration of civil and electrical assets pose, including public and employee safety, financial, environmental, and system reliability risks. Toronto Hydro mitigates these risks by identifying deficiencies in below-grade structures before they cause a failure and associated consequences. As illustrated in Figure 28 below, Toronto Hydro has identified on average over 5,000 deficiencies each year since 2011. Of those, 37% on average are in network vaults and 25% in cable chambers.

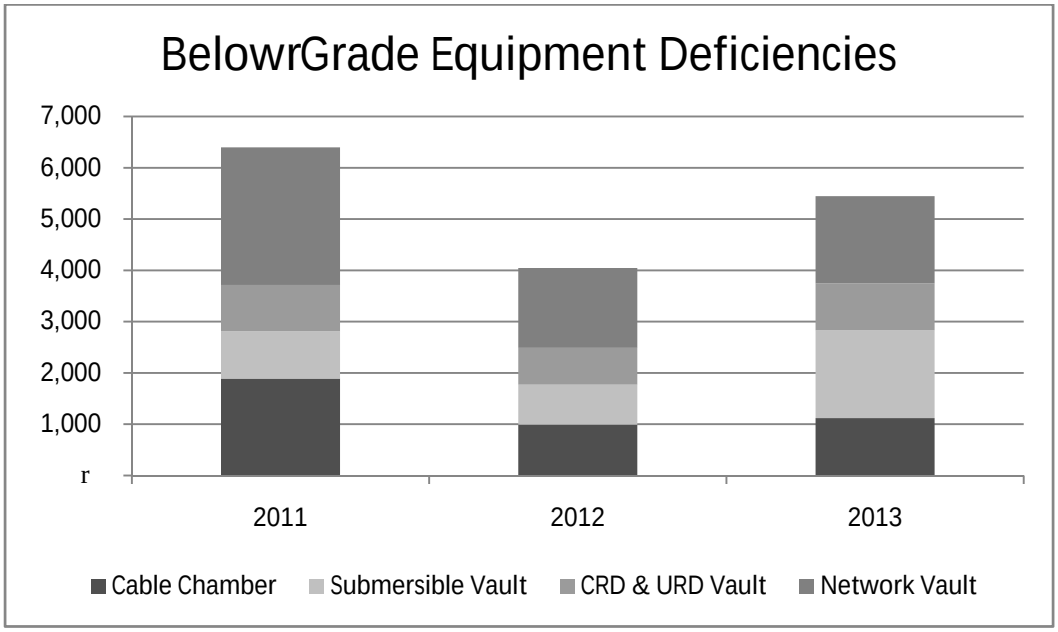


Figure 28: Below-Grade Equipment deficiencies identified between 2011 and 2013

If not identified, and allowed to remain unaddressed, deficiencies can pose significant public and employee safety risks. Below-grade structures are typically installed underneath roadways, pedestrian walkways or in residential neighbourhoods. The collapse of the vault roof exposes the public and employees to a fall hazard, or injury from exposure to energized equipment. Furthermore, fires can occur at network vaults with fibertop units; these can pose health risks to firefighters and other personnel that would be involved in extinguishing the fire and restoring power, as fibertop units are often connected to the secondary grid using asbestos-insulated lead covered ("AILC") secondary cables.

In addition to being structurally sound, vaults must be relatively clean, and must contain appropriate nomenclature, functional lighting and drainage systems. If neglected, vaults can result in safety risks to employees such as slipping and tripping hazards. Reductions in inspections and maintenance can result in deficiencies such as exposed rebar, cracked

walls and roofs, corroded I-beams, excessive dirt and debris, and flooding existing undetected within structures. These deficiencies can increase the public and employee safety risks from the failure of the vault civil structure.

From a financial risk perspective, inspections and maintenance mitigate the risk of costly failures. For example, identifying a vault with significant dirt and debris, such as the one depicted in Figure 29, enables corrective action and reduces the risk that the debris will act as a catalyst for corrosion on assets (Figure 30), potentially resulting in an arc flash or fire.

Figure 29: Vault full of Dirt and Debris

Figure 30: Corrosion on top of a Transformer

When equipment failures occur, emergency response together with equipment replacements can result in expenditures that exceed tens of thousands of dollars. For example, an underground transformer replacement can approach $100,000 and a structural rebuild of a vault can exceed $100,000 and even approach $1 million. These expenditures can often be mitigated through proactive maintenance activities.

In addition to safety and financial risks, Below-Grade Equipment Maintenance mitigates environmental risks. For example, inspections enable the early identification of corroded

equipment before the corrosion can cause an oil leak to develop, potentially washing into a drainage system and causing an adverse effect on the environment. Figure 31 below depicts an oil leak within a vault. This deficiency is addressed by cleaning activities as shown in Figure 32.

Figure 31: Oil Leak at the bottom of the Transformer

Figure 32: Crews Cleaning a Network Vault after a Network Transformer Leaked Oil

Maintenance also includes transformer oil sampling and testing to identify transformers that are contaminated with PCBs. Environment Canada's *PCB Regulations* require Toronto Hydro to identify and dispose of transformer oil that is PCB contaminated. Below-Grade Equipment Maintenance enables Toronto Hydro to test these units, mitigate environmental risks, and comply with regulations.

In addition to the value provided by mitigating the aforementioned safety, financial, and environmental risks, Below-Grade Equipment Maintenance provides value to customers by mitigating system reliability risks associated with civil infrastructure or electrical

equipment failures. In the past, failures on aging network protector units, particularly legacy fibertop units, have resulted in significant system reliability impacts. A network protector failure and subsequent fire at a network vault requires power system controllers to interrupt between two and six feeders, which can leave several city blocks without power for up to four hours. This procedure is necessary to enable fire fighters to safely extinguish a fire. After the fire is extinguished, service may continue to be affected to customers supplied from the vault for more than 12 additional hours. Once service is restored, the process of replacing equipment and possibly rebuilding the vault proceeds at a significant incremental cost.

An example of a recent vault fire attributed to a network protector failure occurred on January 28, 2013 at 95 St. Clair Avenue West, which resulted in a 49-hour outage for customers in the building. The damage from that failure, depicted in Figure 33, resulted in outages to 16 high rise buildings ranging from one to 16 hours in length as two feeders needed to be interrupted to enable fire fighters to put out the fire. Following the fire, all equipment inside the vault was replaced and the entire civil structure rebuilt. The process of designing and rebuilding the vault took just over one year.

Figure 33: Damage from the 95 St. Clair Network Vault Fire

Other examples include failures and subsequent fires on March 24, 2007 at Richmond and Bay Streets and on June 21, 2010 at Erskine Avenue. The 2007 incident interrupted over 70 MVA of load in the heart of downtown Toronto for eight hours. The 2010 incident interrupted over 30 MVA for over four hours. Figures 34 to 38 contain pictures from those events.

Figure 34: Extinguishing the fire.

Figure 35: Asbestos clean after the fire.

Figure 36: Damaged network unit and burned AILC cables. (March 24, 2007)

Figure 37: (Left) Vault 4557 with roof slabs off, signs of heavy smoke apparent in vault. (Right) damaged Fibertop Network Unit. (June 1, 2010)

Figure 38: Vault fire on Erskine Avenue, near Yonge and Eglinton (June 1, 2010)

Since increasing the frequency and scope of maintenance on network protectors (e.g., protector overhauls) in 2011 and 2012, Toronto Hydro has experienced a reduction in the number of catastrophic failures. However, the recent failure in January of 2013 serves as evidence of the risks that remain and the importance of continuing to execute maintenance on a regular basis.

In addition to network vaults, failures can occur in other below grade structures. For example, in September of 2013, a faulted cable inside a cable chamber caused the chamber's lid to blow off, exposing nearby members of the public to a safety risk. This incident resulted in 3,121 customers being interrupted and 10,096 customer hours of interruption. Failures also occur on CRD, URD, and submersible vaults and these failures can increase public safety risks and system reliability risks (e.g., interruptions to tens and even hundreds of customers).

The risk of equipment failure and the related system reliability risks are not only mitigated by the visual inspections, but also by thermographic scanning. Thermographic, or infrared scanning, identifies thermal anomalies in the equipment being scanned, and is an effective predictor of equipment failure. Figure 39 below shows an example of a thermographic photograph of cable splices inside a cable chamber. The deficiency, evidenced by a 36°C increase in temperature on one of the splices, is not visually evident (left); however, this defect is easily identified using the infrared image (right), and can be corrected before leading to a failure.

Figure 39**: Cables inside a cable chamber (left) with a with a thermographic image of the same (right)**

6.1. Segment Costs

The following table contains the historic and planned expenditures for this segment.

Table 6: Historical and Forecasted Segment Spending ($ Millions)

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	1.7	2.2	2.2	2.1	2.8

Aside from the 2011 figure, historic expenditures have been relatively consistent. The increase in 2012 over 2011 is attributed to two factors. The first factor is an increase in the number of cable chambers inspected. Only 341 cable chambers were inspected in 2011 as compared to 962 in 2012. (At the time, approximately 1,100 cable chamber inspections were needed annually to achieve the maintenance cycle.) The second factor was an increase in maintenance of network protectors to mitigate the risk of failure and vault fires. In 2012, an annual fibertop protector cleaning activity was introduced. In addition, the number of protector overhauls increased from 346 in 2011 to 490 in 2012. (At the time, in excess of 500 network protectors needed to be overhauled annually to achieve the maintenance cycle.)

6.2. Test Year Segment Costs

In 2015, planned expenditures are $2.8 million, which is $0.7 million greater than the 2014 forecast. This increase is attributed to three drivers. One driver is an increasing number of cable chamber inspections. The inspection cycle is moving from a ten-year cycle to an eight-year cycle, resulting in the need to execute 1,350 cable chamber inspections in 2015 as opposed to 1,100 in 2014. The second driver is additional oil testing to identify transformers that exceed allowable PCB concentrations pursuant to Environment Canada's *PCB Regulations*. A third driver is increases in the number of submersible vaults inspected. Transformers in these vaults have shown increasing rates of corrosion and oil leaks and Toronto Hydro has supplemented cyclical inspections with

condition-based inspection frequencies for units that may be approaching the end of their lives.

Overall, the 2015 expenditure level allows Toronto Hydro to conduct various maintenance activities on cycles that range from six months to eight years on over 21,000 below-grade structures and the equipment that they house. These activities are expected to identify over 5,000 deficiencies in 2015. Identifying deficiencies proactively helps to enable Toronto Hydro to prevent catastrophic failures at below-grade structure locations and to mitigate public and employee safety, financial, environmental, and system reliability risks.

7. 2.5 PAD-MOUNTED EQUIPMENT MAINTENANCE SEGMENT

Pad-mounted transformers and switches (collectively "pad-mounted equipment"), are metal-clad enclosures with lockable cabinet doors located above grade atop of a concrete pad within road allowances or on private properties. These assets are found on the underground distribution system where cables enter the equipment from underground, through the pad. Pad-mounted transformers (Figure 40) supply residential areas or commercial buildings, and pad-mounted switches (Figure 41) allow for sectionalizing of underground feeders.

Figure 40: Pad-mounted Transformer in Residential Neighbourhood

Figure 41: Pad-mounted SF6-Insulated Switch

Pad-mounted Equipment Maintenance entails a visual inspection of the pad and protective bollards for damage or deterioration; a visual inspection of the elevation of the pad in relation to the grade; removal of overgrown vegetation that may be encroaching on the pad; and a visual inspection and verification of equipment labels and danger signs. Visual inspections focus on both the mechanical components (e.g., doors, locks, hinges, handles, latches, and paint) and electrical components (e.g., terminations, bushings, elbow connectors, transformer tank, primary and secondary switches, fuses, disconnects, barriers, fault indicators, relays, oil levels). In addition, maintenance includes thermographic scans of electrical connections and any oil testing that may be required to enable Toronto Hydro to comply with *PCB Regulations* under Canada's *Environmental Protection Act*.

For pad-mounted switches, which are similar in functionality to overhead switches used for sectionalizing and fault protection, maintenance includes a number of additional

activities. Batteries in SCADA switches are replaced once every three years. Gas levels are verified on units that are filled with SF_6 gas. Cable duct entries are inspected to ensure they are sealed, and ultrasonic testing is conducted to identify any partial discharge. Air-insulated switches with exposed electrical terminations (live front type) that are found to have significant dirt build-up on the insulators, or show evidence of tracking, are scheduled for CO_2 cleaning at a later time. CO_2 cleaning is performed as part of the Corrective Maintenance Program[13] and is performed with the equipment energized. This activity removes dirt and other contaminants from the switch, which could cause tracking and result in an arc flash and equipment failure.

Toronto Hydro carries out the above activities on a three-year cycle for pad-mounted transformers and an annual cycle for pad-mounted switches. Regular maintenance cycles help Toronto Hydro maintain properly functioning pad-mounted equipment and meet the Minimum Inspection Requirements.[14]

In addition to the aforementioned maintenance activities on pad-mounted equipment, in 2015 Toronto Hydro plans to begin performing diagnostic testing on underground primary cables. The two most common types of cables installed on Toronto Hydro's underground system are Paper Insulated Lead Covered (PILC) and Cross-Linked Polyethylene ("TR-XLPE" and XLPE) as shown in Figure 42. There are many PILC and XLPE cables on the system that have surpassed their expected service lives. It is neither prudent nor feasible to replace all cables that are beyond their expected useful lives as age does not necessarily correlate to poor cable condition. Up to 2014, Toronto Hydro planned replacements on the basis of failure trends. Cable diagnostic testing is now being introduced to enable more predictive analysis of cables and to allow planners and engineers to determine more clearly which cable segments on the system are or will be at high risk of failure prior to failure occurring. Cable diagnostic testing provides a more

[13] Exhibit 4A, Tab 2, Schedule 2.
[14] DSC, s*upra* note 2.

accurate assessment of the condition of underground cables, splices, joints, and terminations.

Figure 42: Example of XLPE Cable (Left) and PILC Cable (Right)

Cable diagnostic testing is an accepted practice industry-wide and used in numerous other electrical utilities in Canada and the United States. IEEE 400-2012, IEC 60060, IEC 60085 and IEC 60502 are some of the standards that support and provide guidelines for cable testing in the field. Diagnostic testing is expected to provide more reliable service to customers, and to allow for more effective use of limited capital funds as it provides a stronger basis for informed underground project planning and prioritization. Toronto Hydro plans to focus initial testing on direct buried XLPE cable, which has the highest rate of failure amongst underground cable installations.

Toronto Hydro owns 5,993 pad-mounted transformers, 873 pad-mounted switches, 1,300 kilometres of PILC cables, and 727 kilometres of XLPE cable. The average useful life of pad-mounted transformers and switches are 35 and 30 years respectively. The expected life of underground cable varies by type and construction; the expected life of XLPE

cable is 25 years for direct buried installations, and 40 years for concrete duct installations; the expected life of PILC cable is 75 years. Approximately 18% of pad-mounted transformers have reached or surpassed their expected service life, while the pad-mounted switch population is significantly younger and none of the units have exceeded 30 years. Approximately 95% of the PILC and XLPE cable populations being targeted for cable testing have reached their expected useful lives as PILC cable installations began in the early 1900s and XLPE installations in the 1950s.

As pad-mounted transformers, switches, and cables age, the likelihood of failure increases as a result of:

- for equipment, current surges, ingress of moisture, dirt, and salt leading to excessive corrosion, mechanical damage, and the degradation of insulating barriers; and
- for cables, moisture ingress, water treeing, electrical treeing, and insulation breakdown.

For XLPE cables, a shorter life cycle can be expected when the direct burial installation method was used as opposed to installation inside concrete duct structures. The direct burial method was a common practice in the districts of North York, East York, York, Scarborough and Etobicoke up until the 1990s. In addition, cables will experience aging differently depending on various factors which include, but are not limited to:

- manufacturing quality;
- damage during installation and workmanship issues;
- installation environment (e.g., areas with high moisture levels result in water penetration of the insulation (water treeing) and cause insulation failure);
- operating temperature and loading (e.g., higher loading and resultant temperatures accelerate the aging process); and

- ambient temperature of the installation environment (e.g., higher temperatures accelerate the aging process).

Maintenance of pad-mounted transformers and switches, and diagnostic testing of cables is designed to locate and rectify advanced stages of degradation and deficiencies prior to the units failing and posing unacceptable risks as discussed below. As illustrated in Figure 43 below, Toronto Hydro's maintenance activities identify between 1,500 and in excess of 3,000 deficiencies on pad-mounted equipment each year. Identifying and subsequently addressing these deficiencies serves to mitigate a wide variety of safety, environmental and system reliability risks. Mitigating these risks is particularly important given that much of this equipment is located in residential areas.

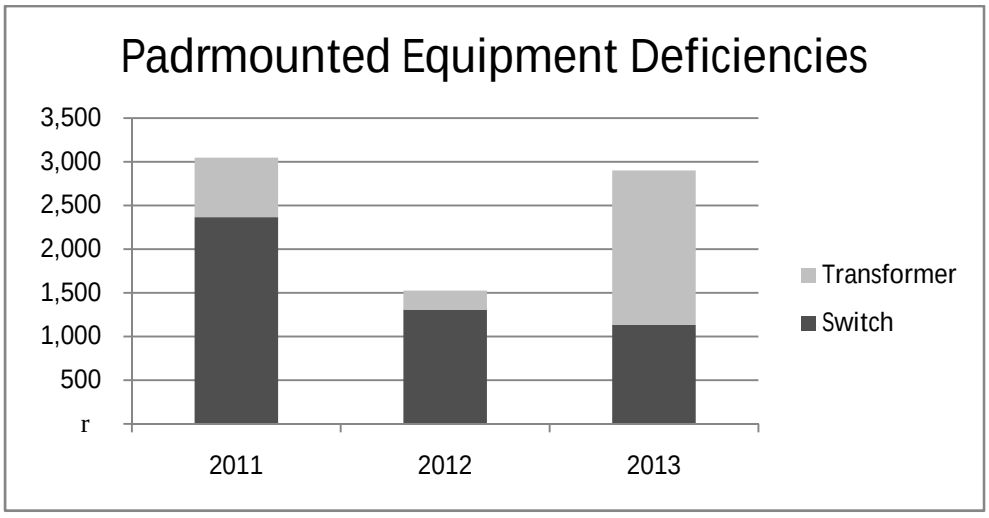


Figure 43: Pad-mounted equipment deficiencies identified between 2011 and 2013

One example of risk mitigation is the identification of an enclosure that is corroding, as illustrated in Figure 44 below. (Corrosion may also be present on internal components.) If not identified and addressed, extreme corrosion can lead to environmental, safety and reliability risks.. Maintenance activities also rectify the instances of switches with broken

springs, which prevent the switch from opening and closing as shown in Figure 45 below. This condition, if undetected, can result in an arc flash from the failure of the switch to clear a fault when an employee attempts to operate the switch, possibly resulting in injury or equipment failure.

Figure 44: Pad-mounted Transformer with surface corrosion

Figure 45: Pad-mounted Switch with broken coil spring

Another example is the identification of excessive vegetation growth, or the planting of vegetation near equipment. If unaddressed, vegetation can not only hinder access to the transformer during an emergency, but can also pose a safety and fire risk; electricity can arc or flashover to nearby vegetation, even without physical contact. Figure 46 below illustrates an extreme example of excessive vegetation.

Figure 46: Pad-mounted Transformer requiring vegetation removal

On occasion, transformers also require maintenance where the locks, hinges, or warning signage have been vandalized, broken, or removed. If unaddressed, these conditions can lead to safety incidents if someone inadvertently comes into contact with pad-mounted equipment.

Pad-mounted unit failures also impact Toronto Hydro's system reliability, affecting anywhere from several residential and commercial customers (when a transformer fails), to hundreds of customers in the case of a switch failure. In the event of a total failure of the switch unit, multiple feeders can experience a power interruption, as switches often act as a tie point for multiple feeders. Maintenance activities are designed to mitigate the risk of such failures and also ensure that SCADA switches do not contain failed batteries that render switches inoperable remotely. As illustrated in Figures 47 and 48 below, the distribution system experiences in excess of 300 customer interruptions and 1,000 customer hours of interruption each year due to failures of pad-mounted equipment.

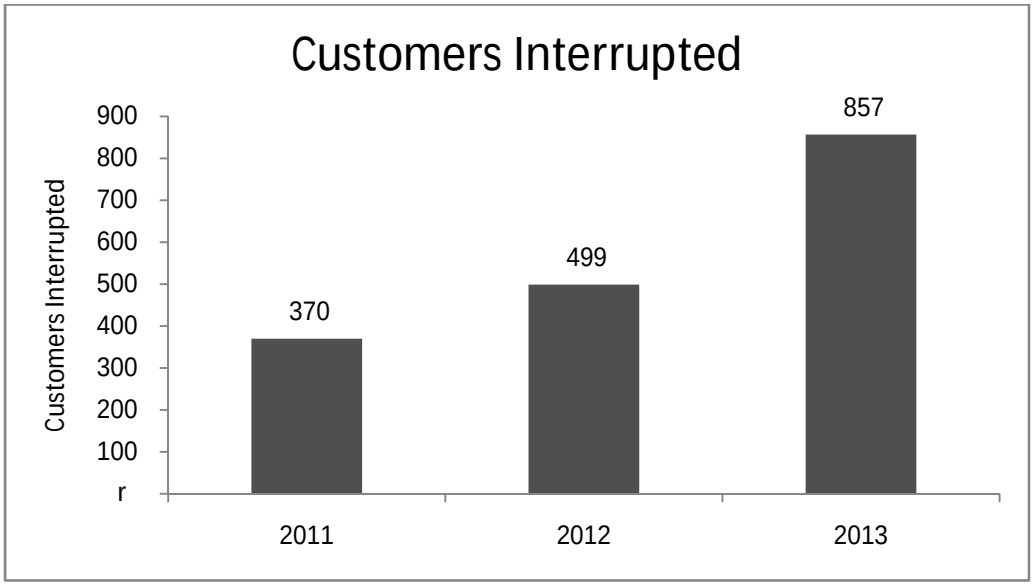


Figure 47: Total Customers Interrupted (CI)

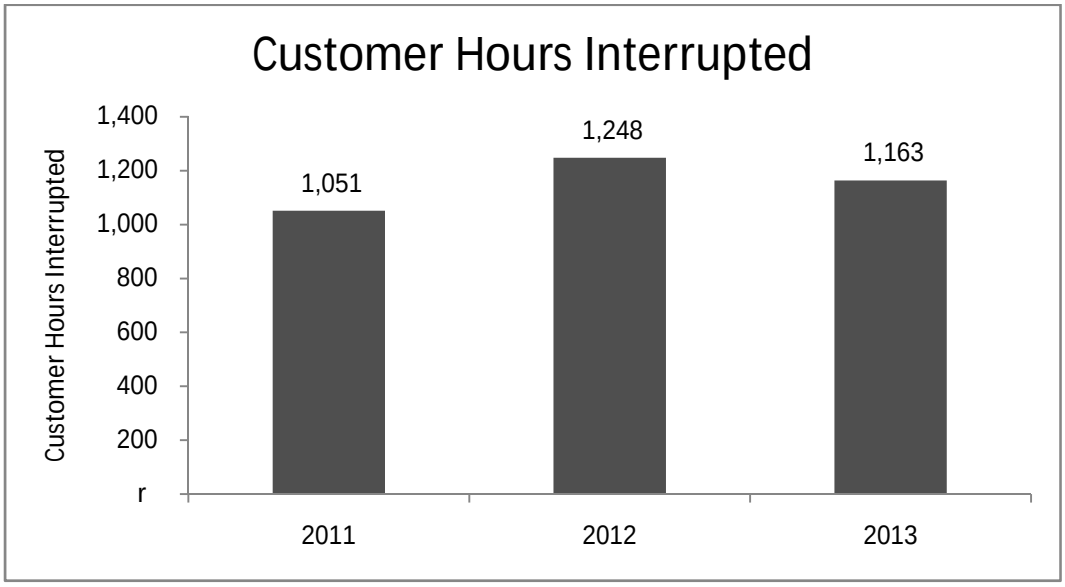


Figure 48: Total Customer Hours Interrupted (CHI)

In addition to the reliability figures in Figures 47 and 48 above, Toronto Hydro experienced 606 interruptions related to defective underground primary cables between 2011 and 2013. These interruptions resulted in 187,000 customers losing power for a

total of 149,000 customer hours of interruption. When a cable fails once, field experience shows that repeated failures are very likely. For example, in 2012, a cable segment on feeder NYSS3M7 in North York had four repeated failures despite multiple repairs. When cables are prone to failure they not only impact system reliability, but also raise safety and environmental risks. For example, in December 2011, a PILC cable faulted and resulted in a near-miss arc flash while crews were working. Upon investigation of the incident, crews discovered numerous PILC cables leaking oil in the cable chambers along the feeder route. Figures 49 to 51 depict failed and leaking cables.

Figure 49: Oil Leakage from PILC Cable

Figure 50: Electrical Treeing on Cable

Figure 51: Aftermath of a cable failure resulting in a fire

7.1. Segment Costs

The following table contains the historic and planned expenditures for this segment.

Table 7: Historical and Forecasted Segment Spending ($ Millions)

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	0.2	0.4	0.4	0.4	1.1

Although maintenance cycles have remained consistent, expenditures increased between 2011 and 2012 predominantly due to expanded usage of thermography to enable the detection of deficiencies that are not visible to the naked eye. Since 2012, expenditures have remained consistent at $0.4 million.

7.2. Test Year Segment Costs

Pad-mounted Equipment Maintenance expenditures for 2015 are forecasted to be $1.1 million. This increase of $0.7 million is mainly required to fund diagnostic testing on primary underground cables and oil testing for the purpose of complying with *PCB* /C

Regulations under the *Canadian Environmental Protection Act*. Overall, the 2015 expenditures are expected to enable Toronto Hydro to: maintain its approximately 6,000 pad-mounted transformers and 873 pad-mounted switches on three and one-year cycles respectively; to test underground cables; and to mitigate public safety and employee risks associated with deteriorated and damaged equipment enclosures in residential neighbourhoods, environmental risks associated with oil leaks and PCBs, and system reliability and financial risks associated with equipment failures. /C

8. CUSTOMER LOCATION MAINTENANCE SEGMENT

A subset of Toronto Hydro's customers is supplied by electrical equipment such as transformers and switches, that are located within customer-owned buildings (vaults) or dedicated areas on customer premises. These vaults and areas are found in or adjacent to industrial or commercial buildings, hospitals, schools, apartments and condominiums, and are secured to prevent unauthorized access to energized equipment.

The equipment contained in these vaults and areas is typically owned by Toronto Hydro and requires regular inspection and maintenance. In cases where the equipment is not owned by Toronto Hydro, it is nevertheless necessary to conduct switching operations at the location; as a result, inspections of the location are required to ensure operability and safety. There are approximately 7,500 customer-owned locations that Toronto Hydro must either maintain equipment at or inspect.

Of the 7,500 customer-owned locations, 5,300 contain Toronto Hydro-owned equipment, including 13,000 transformers. For maintenance purposes, these 5,300 locations are divided into two subsets based on customer load requirements. One subset is locations where the transformation capacity is less than 1000 kVA. These locations are referred to as Customer Building Vaults. The second subset is locations that have transformers with

a capacity that exceeds 1000 kVA. These locations are referred to as Customer Substations.

Toronto Hydro maintains Customer Building Vaults on a three-year cycle, in compliance with the DSC's Minimum Inspection Requirements (Appendix C).[15] Maintenance of Customer Building Vaults includes a visual inspection of the vault and equipment, thermographic scans of all electrical equipment and connections to detect thermal anomalies, and general cleaning to reduce contamination build-up and electrical tracking risks. Maintenance may also include taking oil samples from transformers to test for PCB levels to comply with *PCB Regulations*. Deficiencies that are noted during inspections are either addressed immediately or identified and subsequently addressed through corrective maintenance. The condition of the customer's civil structure is also assessed and any identified deficiencies are communicated to the customer for remediation.

Customer Substations are inspected every six months and maintained every four years. Inspections ensure that ventilation, access, and drainage systems are operating as required and that equipment is not leaking, defective, or corroded. Maintenance includes visual inspection, thermographic scans, functional tests, oil testing, and general cleaning. The typical layout of a Customer Substation consists of two incoming feeders connected to respective load break switches, with one switch normally open (standby) and the other normally closed (supply). Toronto Hydro maintains 850 Customer Substations.

Customer Location Maintenance identifies deficiencies in electrical equipment and verifies the integrity and security of the structures that house the equipment at Customer Building Vaults and Customer Substations. Identifying deficiencies and subsequently

[15] *Supra* note 2.

addressing them minimizes the likelihood that equipment will fail, and mitigates public safety, environmental, financial, and system reliability risks.

As illustrated in Figure 52 below, Toronto Hydro identifies on average over 1,500 deficiencies at Customer Locations each year.

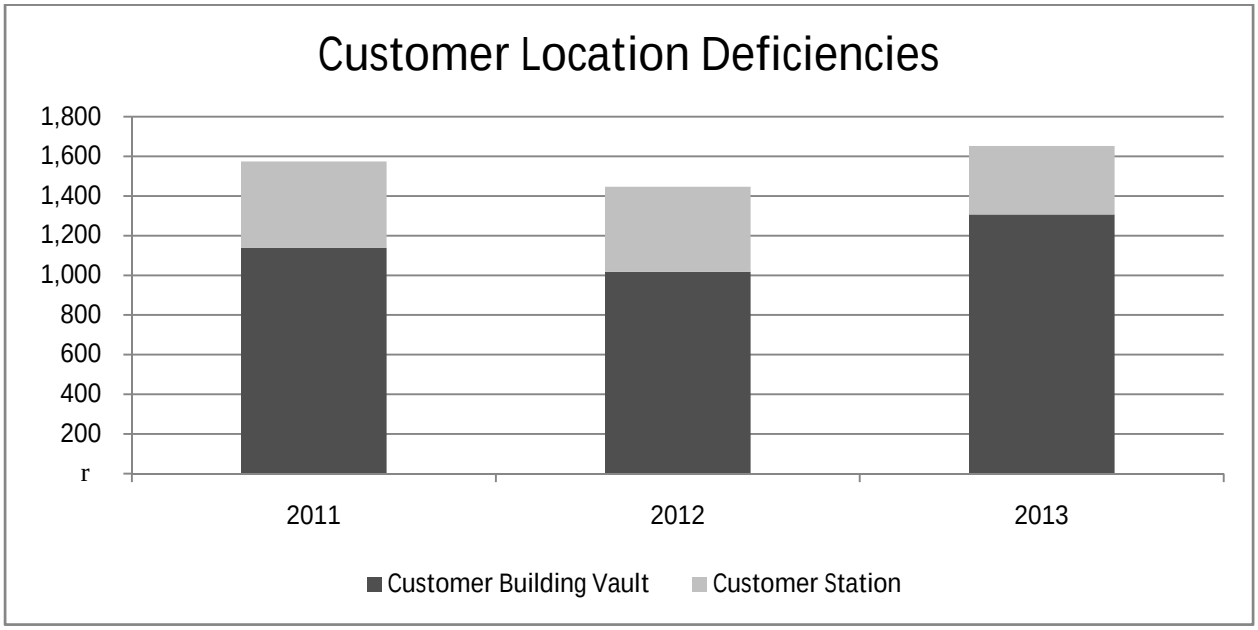


Figure 52: Customer Location deficiencies identified between 2011 and 2013

If not identified and addressed, these deficiencies can raise significant public safety, environmental, financial, and system reliability risks.

Specific examples of deficiencies identified and their associated risks include:

- dirty vaults that require cleaning to reduce the risk of flashover caused by contamination build-up and equipment failing prematurely, which can result in risk of injury to employees and customers near these vaults, and property damage;

- corrosion of equipment, locks and doors (as illustrated in Figure 53 below), which can result in unauthorized entry, posing a safety risk to individuals making contact with live components; /C
- oil leaking from cables or transformers (as illustrated in Figure 54 below) that can be addressed prior to oil entering the drainage system, which poses the risk of oil spilling into environmentally sensitive areas;
- "hot spots" on equipment and components identified using a thermographic scan before they burn insulation and cause electrical faults, potentially resulting in a vault fire and associated safety risks.
- degradation of a transformer's insulating oil properties (e.g., the presence of concentrations of certain gases such as Hydrogen, Carbon Monoxide, Methane, and Acetylene) identified using transformer oil testing, which can indicate an elevated risk of transformer failure.

Beyond the electrical equipment, Customer Location Maintenance activities include the inspections of the civil infrastructure housing the equipment. Although the civil infrastructure is owned by Toronto Hydro's customers, it is not uncommon for structural elements to be in poor condition and neglected to the point that walls (as illustrated in Figure 55 below) and roofs are at risk of collapsing in on Toronto Hydro's equipment.

Apart from the civil structure, unmaintained landscaping and vegetation growth for outdoor customer locations can pose safety risks (e.g., vegetation becoming energized and possibly catching fire) and prevent Toronto Hydro crews from entering the sites to operate equipment (as illustrated in Figure 56 below). Very serious deficiencies such as these are communicated to customers so that they can be addressed.

Figure 53: Rusted Door

Figure 54: Transformer Leaking Oil

Figure 55: Cracked Walls

Figure 56: Vegetation Overgrowth

By preventing equipment failures and non-electrical deficiencies, Customer Location Maintenance also prevents power interruptions. A failure at a Customer Building Vault will typically impact one or more customers for a period of time that can exceed three

hours depending on the type of failure. Failures at Customer Substations have a greater impact as greater than 1000 kVA of load may be interrupted for similar durations.

Toronto Hydro also mitigates the risk of equipment failure at customer locations where the customer owns all civil and electrical equipment, by conducting a safety inspection of the premises and the equipment. Even though the assets are not owned by Toronto Hydro, an equipment failure at this location will still have an impact on the reliability of the system, especially if the customer's protection equipment is not coordinated with the distribution system's protection devices or if the equipment fails to operate.

Toronto Hydro crews may also be required to perform switching operations at these locations in contingency situations, to protect the customer's equipment and provide an alternate source of power. Manual switching can pose significant risks to employees and as a result, it is important that Customer Locations remain safe and accessible for crews to respond to during emergency situations.

8.1. Segment Costs

The following table contains the historic and planned expenditures for this segment.

Table 8: Historical and Forecasted Segment Spending ($ Millions)

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	0.9	1.9	1.2	3.2	3.2

The fluctuations and increasing expenditures during the 2011 to 2014 period are attributed to the number of Customer Substations being inspected and maintained annually. During 2011-2013, Toronto Hydro conducted an average of approximately 1,200 Customer Substation inspections annually and maintained 51, 155, and 61 Customer Substations in 2011, 2012, and 2013 respectively. During this time, labour

resources that were capable and available to conduct this work were constrained due to competing demands from other station maintenance and capital work. Beginning in 2014, increasing efforts to engage contractor resources are expected to enable Toronto Hydro to achieve the targeted cycles (i.e., six-month inspection cycle and four-year maintenance cycle) at Customer Substations. To accomplish this, Toronto Hydro must conduct 1,700 inspections and maintain 215 Customer Substations annually. These numbers of inspections and maintenance represent increases over historic accomplishments and are the primary drivers for increases in expenditures for the 2014 Bridge Year.

8.2. Test Year Segment Costs

Toronto Hydro's planned 2015 expenditures equal those of 2014. These expenditures represent increases over the annual expenditures during the 2011-2013 period to enable Toronto Hydro to achieve targeted six-month and four-year inspection and maintenance cycles. In addition, the 2015 expenditures also include a provision for oil testing at Customer Building Vaults to enable Toronto Hydro to comply with the *PCB Regulations*.

Aside from ensuring compliance with legislative and regulatory requirements, regular maintenance of electrical and civil equipment at customer locations allows Toronto Hydro to mitigate public and employee safety, environmental, financial, and system reliability risks.

9. METERING SERVICES SEGMENT

Toronto Hydro and its customers rely on metering equipment to track accurate and timely electricity consumption information for customer billing and market settlement purposes. The Metering Services segment is responsible for maintaining this equipment to ensure

proper functionality and compliance with applicable legislative and regulatory requirements.

Toronto Hydro's metering assets include both meters and the communication systems that enable meter data collection and tracking. The maintenance of metering equipment is critical to ensuring the ongoing accuracy of meter reads and the associated billing and settlement data. Moreover, meter testing is a requirement under the *Electricity and Gas Inspection Act*,[16] administered by Measurement Canada. Metering Services maintains Toronto Hydro's 734,000 smart and suite meters and 92 wholesale meter installations (as of December 31, 2013 see Figure 59), examples of which are illustrated in Figures 57 and 58 below.

Figure 57: Smart meter installation at customer location.

Figure 58: Wholesale meter installation at Transformer Station.

[16] R.S.C., 1985, c. E-4. ["*Electricity and Gas Inspection Act*"]

The activities conducted by Toronto Hydro as part of Metering Services can be grouped into three major functional categories:

(1) Meter Testing;

(2) Wholesale Meter Maintenance; and

(3) Field Response.

9.1. Meter Testing

Meter Testing verifies the accuracy of meters and includes audits undertaken on large customer meters. This work helps ensure that Toronto Hydro remains in compliance with Measurement Canada regulations under the *Electricity and Gas Inspection Act* and the *Weights and Measures Act*.[17] These regulations permit the use of meters for a set period of time, also referred to as a "seal period", before they must be either tested (i.e., re-verified) or replaced. For smart meters, this time span is typically ten years. When meters are tested and re-verified for accuracy, the seal period is extended, which allows Toronto Hydro to continue utilizing the meters legally for billing purposes.

For meter testing purposes, Measurement Canada permits utilities to form isolation lots (groups of meters with homogeneous meter characteristics), and test only a small number called the sample group from the isolation lot. Typically 3% of randomly selected meters from each isolation lot form the sample group. This sampling is allowed given the large number of meters that are in-service. The number of meters that are to be tested is determined in accordance with Measurement Canada's specification S-S-06, *Sampling Plans for the Inspection of Isolated Lots of Meters in Service, Annex C, Table 2, Limiting Quality 3.15*.[18] The seal period of the isolation lot of meters can be extended if the accuracy statistics for the sample group meet tolerances stipulated in Measurement Canada's specification. It should be noted that some unique meters do not belong to any

[17] R.S.C., 1985, c. W-6. ["*Weights and Measures Act*"]
[18] Measurement Canada, *S-S-06—Sampling Plans for the Inspection of Isolated Lots of Meters in Service,* (Markham: Measurement Canada, 2010).

isolation lot and must be removed from service and tested individually before their seal periods expire. Table 9 lists the number of meters with a seal period that will expire during the 2015-2019 period. It also lists the number of meters that will need to form the sample groups for Meter Testing based on the sample size for each isolation lot, to enable Toronto Hydro to comply with Measurement Canada's regulations.

Table 9: Number of Seal Expiring Meters in 2015-2019 and Sampling Units

Year	Seal-Expiring Meters	Sample Group Meters
2015	14,527	436
2016	194,000	5,820
2017	214,652	6,440
2018	146,498	4,395
2019	55,563	1,667
Total	**625,240**	**18,758**

To conduct Meter Testing, Toronto Hydro relies on field crews to remove meters that are part of a sample group and return them to Toronto Hydro's accredited service provider for testing. Test results are forwarded to Toronto Hydro for record updating and any other actions based on the test results. A pass will result in an update to the meter records and the extension of seal periods, based on the tested accuracy levels. When it comes to the utility's smart meters with a ten-year initial seal period, providing the meters pass, the seals will be extended for all of the meters within the group by an additional eight years.

9.2. Wholesale Meter Maintenance

Wholesale meters, including instrument transformers, are installed at transmission grid supply points to measure electricity supplied from Hydro One Networks Inc. ("HONI") to Toronto Hydro. Wholesale Meter Maintenance involves re-verifying (i.e., testing every six years) and troubleshooting wholesale meters, and ensuring compliance with all

applicable regulations, such as the requirement to notify the Independent Electricity System Operator ("IESO") of Meter Trouble Reports within 48 hours pursuant to the IESO's *Market Rules*[19] and *Market Manual*.[20] Meter Trouble Reports are issued if there is any failure in data communication or if the data is suspected to contain errors. Data communication failures can arise from issues with the Sonnet network, network infrastructure, Bell phone lines, or either the meter itself or the modem. If such a failure occurs, Toronto Hydro attempts to resolve the issue remotely. If the remote resolution is unsuccessful, Toronto Hydro deploys field crews to the site of the particular wholesale meter to address the issue directly.

Prior to market opening in 2002, HONI was the Meter Service Provider ("MSP") for all wholesale meters. As the MSP, HONI was the owner of the wholesale meter installations and was responsible for the meters, their communications, maintenance, troubleshooting, and replacement. Beginning in 2002, Local Distribution Companies ("LDCs") in Ontario, such as Toronto Hydro, began taking ownership of the installations. Since that time, Toronto Hydro has upgraded wholesale metering points and taken over ownership of 92 installations from HONI as of the end of 2013. The number of installations owned by Toronto Hydro is expected to grow to 155. Figure 59 illustrates the number of installations that have been transferred and the meters subject to transfer in the coming years.

[19] Independent Electricity System Operator, *Market Rules for the Ontario Electricity Market*, (Issue 54.0) (Toronto: Independent Electricity System Operator, 2014). ["*Market Rules*"]
[20] Independent Electricity System Operator, *Meter Trouble Report: A Guide for Market Participants*, (Issue 6.0) (Toronto: Independent Electricity System Operator, 2005). ["*Market Manual*"]

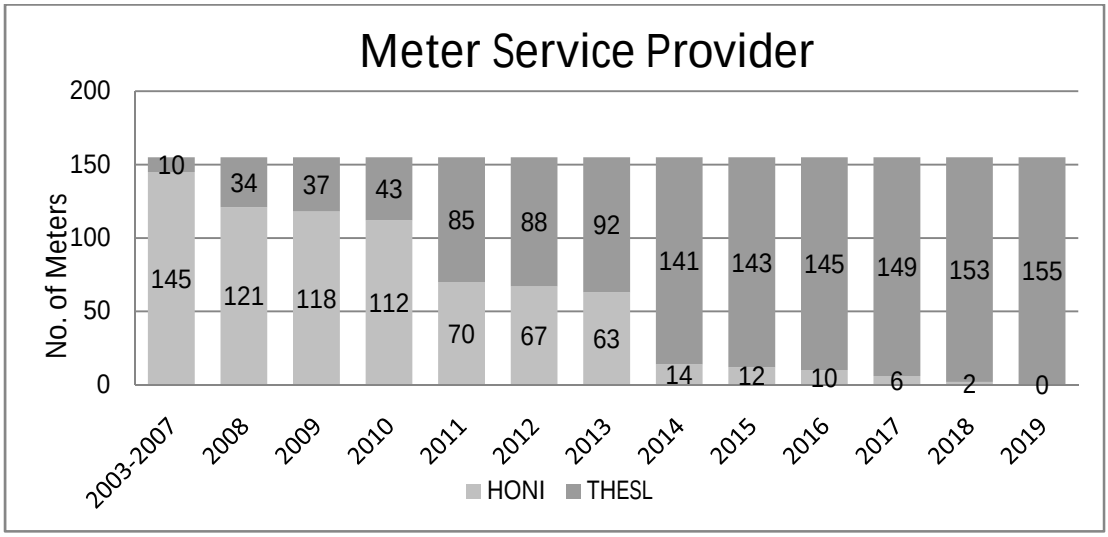


Figure 59: Summary of Wholesale Meter Ownership Transfer from Hydro One to Toronto Hydro

9.3. Field Response

The third category of activities within Metering Services is Field Response, which includes activities such as investigating communication issues, troubleshooting metering issues, converting legacy flat rate services (e.g., water heaters) into metered activities, and installing reused meters following accuracy testing. Toronto Hydro's 650,000 smart meters have a failure rate of 1.5% (i.e., approximately 10,000 units annually). The majority of the failures are related to the use of radio frequency mesh technology to deliver the meter reading data back to Toronto Hydro's centralized meter reading software. As failures occur, staff and field crews must investigate failure causes and restore communications in a timely manner. Where economically viable, Toronto Hydro reuses meters with active seals, which is expected to save the utility an estimated $1.4 million over the 2015-2019 period.

Overall, a significant portion of the work undertaken by Metering Services is not discretionary because it is either driven by statutory or regulatory obligations, or a need

to resolve a meter issue in the field on a reactive basis. Consequences of non-compliance can include: (1) fines of $1,000 per violation when meters are not tested and re-verified upon their seal periods expiring; and (2) fines ranging from $2,000 to $1 million if IESO *Market Rules* are breached with respect to wholesale meter functionality.

9.4. Segment Costs

The following table contains the historic and planned expenditures for Metering Services.

Table 10: Historical and Forecasted Spending ($ Millions)

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	4.5	4.9	1.9	2.3	2.2

/C

From 2011 and 2012 to 2013, expenditures decreased significantly predominantly due to the transfer of Metering Customer Service Requests from Metering Services (within Field Services) to Billing, Remittance, and Meter Data Management segment of the Customer Care program.[21] Forecasted expenditures in 2014 are expected to rise slightly from $1.9 million in 2013 to $2.3 million due to additional Metering Testing and Wholesale Meter Maintenance that is required.

9.5. Test Year Segment Costs

The Test Year costs for Metering Services are planned to be $2.2 million. This is a slight $0.1 reduction from forecasted 2014 expenditures. The reduction is attributed to reduced expenditures in Field Response as a result of reductions in Flat Rate Water Heater Conversions as these types of legacy installations will have been almost entirely replaced. The $2.2 million budget in 2015 is expected to enable Toronto Hydro to maintain its 734,000 meters and to comply with non-discretionary legal requirements

/C

/C

[21] Exhibit 4A, Tab 2, Schedule 13.

under the *Electricity and Gas Inspection Act*, administered by Measurement Canada, and the IESO *Market Rules*.

10. STATION INSPECTIONS AND AUXILIARY EQUIPMENT MAINTENANCE SEGMENT

Toronto Hydro owns equipment at 35 Transformer (or Terminal) Stations (TS) and 164 Municipal Stations (MS) throughout the city. Equipment is either located inside buildings, or outside in fenced yards. The Station Inspections and Auxiliary Equipment Maintenance segment funds the following two sets of work:

1) Periodic inspections of all TSs and MSs and their housed equipment; and
2) Maintenance of auxiliary equipment housed our used at stations including station batteries, cranes, fire alarm systems, air compressors, and testing equipment.

Figures 60 to 62 below show a typical MS found in a residential neighbourhood and a TS yard.

Figure 60: Residential area MS (front view)

Figure 61: Residential area MS (rear view)

Figure 62: The station yard at Cavanagh TS

Periodic inspections of stations are conducted on two sets of cycles: monthly and semi-annually (i.e., in the spring and fall). During monthly inspections, crews look for any signs of transformer oil leaks, confirm transformer cooling fan operation, check battery electrolyte levels, verify the condition of equipment alarms, and look for any visual signs of equipment deterioration or imminent failure. During these inspections, crews will also look for deficiencies in station fences, gates, doors, building walls, roofs, danger signs, and lighting. During semi-annual inspections which occur in the spring and fall, adjustments to heating and ventilation systems are performed to ensure assets are protected from damage due to temperature (e.g., turning on or turning off control cabinet heaters) and in the fall, oil samples are collected from power transformers and sent for testing.

In addition to inspections, maintenance of station auxiliary equipment is performed. This equipment provides a support or service function and can be described as being peripheral to station power and protection and control equipment. Station auxiliary equipment includes: (1) Battery Banks; (2) Station Fire Alarm and Protection Systems; (3) Station Cranes; (4) Station Compressed Air Systems; and (5) other miscellaneous

station apparatus including specialized environmental protection systems and testing equipment. This equipment is described as follows:

1) **Battery Banks:** The protection and control equipment in stations is powered by a DC supply from battery banks that are similar to those depicted in Figure 63 below, and are charged by station rectifiers (chargers). Stations typically have lead-acid batteries or nickel cadmium ("Ni-Cd") batteries. Specialized inspections and tests on these battery banks are conducted every six months and include cleaning, measurements of specific gravity, voltage, electrolyte level, and temperature, inspection for corrosion on terminals, connections, battery racks and cabinets, and load cycle testing. **/C**

2) Fire Alarm Systems: Toronto Hydro has 32 stations equipped with a Cerberus Pyrotronic System 3 fire alarm system consisting of a control panel, remote annunciator panel, manual pull stations, smoke detector devices and horn strobe alarm signalling devices. Fire alarm systems require periodic inspection and testing in accordance with the *Ontario Fire Code*[22] under the *Fire Protection and Prevention Act, 1997*.[23] Inspections and tests are conducted either once or twice a year depending on the type of equipment. **/C**

3) **Station Cranes:** Nine of Toronto Hydro's station buildings are equipped with overhead cranes or hoists that are required for servicing equipment. Crane inspection and maintenance is conducted annually in accordance the *Occupational Health and Safety Act*,[24] and the *Industrial Establishments Regulation*[25] made under that Act. **/C**

4) **Compressed Air Systems:** These systems are required to supply dry compressed air for the operation of air blast circuit breakers. Air blast circuit breakers use compressed air to open their arcing contacts, and to extinguish the electrical arc **/C**

[22] Ontario Regulation 213/07 made under the *Fire Protection and Prevention Act, 1997,* S.O. 1997, C. 4 ["*Ontario Fire Code*"].
[23] S.O. 1997, c. 4. ["*Fire Protection and Prevention Act*"]
[24] R.S.O. 1990, c. O.1. ["*Occupational Health and Safety Act*"]
[25] RRO 1990, Reg. 851. ["*Industrial Establishments Regulation*"]

that forms during breaker operation. There are 18 air compressors used in Toronto Hydro's 4.16kV and 13.8kV stations. These assets are inspected and maintained twice a year.

Figures 63 to 66 depict examples of the aforementioned auxiliary equipment.

Figure 63: Station Battery System at George and Duke MS

Figure 64: Fire Alarm Control Panel

Figure 65: Air Compressor System **Figure 66: Station Crane**

Station Inspections and Auxiliary Equipment Maintenance are undertaken to address two broad sets of needs. The first set is the need to mitigate the risks posed by deficient or failed equipment and components including public and employee safety, environmental, financial, and system reliability risks. The second set is the need to remain in compliance with the *Ontario Fire Code*.[26] and the *Occupational Health and Safety Act*. The following paragraphs provide further details for both of these sets of needs.

10.1. Station Inspections

Each year, Station Inspections identify approximately over 800 deficiencies on average. As illustrated in Figure 67, these deficiencies are of various types, and once identified,

[26] Ontario Regulation 213/07 made under the *Fire Protection and Prevention Act, 199,* S.O. 1997, C. 4 ["*Ontario Fire Code*"].

are addressed through the Corrective Maintenance program,[27] or equipment replacement programs as discussed in the Distribution System Plan.[28]

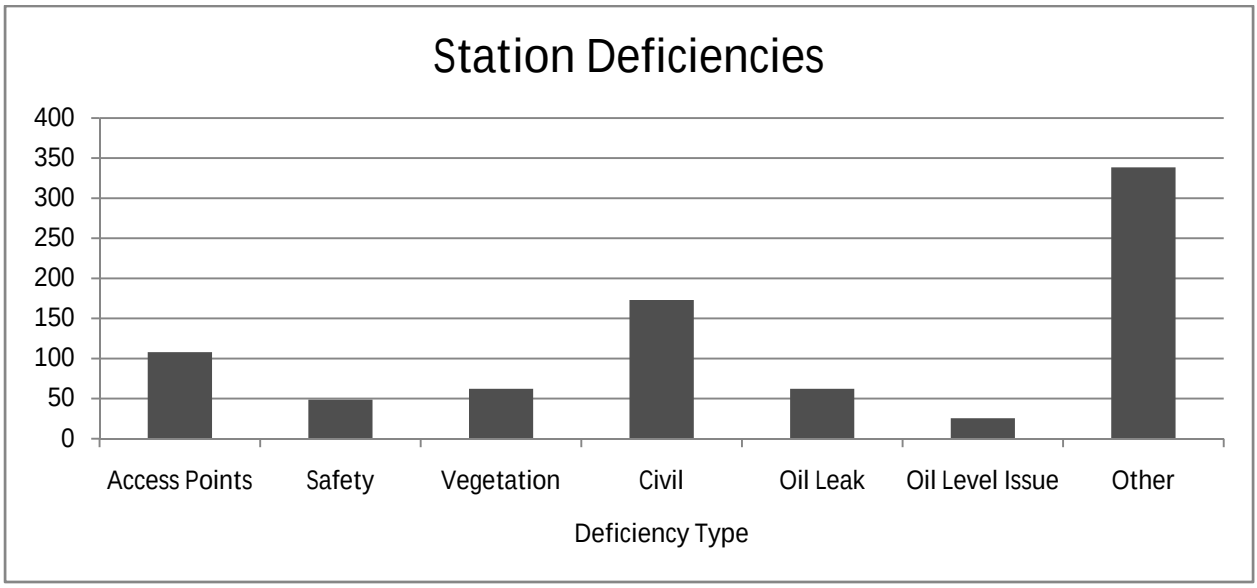


Figure 67: Average Number of Deficiencies Found Annually

From a safety perspective, deficiencies at stations within urban and often residential settings can pose significant risks. For example, deficiencies at access points such as gates, doors, fences, signs, and other security infrastructure can result in a station becoming accessible to the general public. These deficiencies, which can arise at any time due to degradation or other common causes including vandalism and wildlife, can become a contributing factor to risk of injury to the general public. Frequent inspections are critical to maintaining secure station sites in a densely populated environment.

From an employee safety perspective, inspections identify deficiencies with station safety features such as alarms, emergency lightning, burn kits, eyewash stations, first aid kits,

[27] Exhibit 4A, Tab 2, Schedule 2.
[28] Exhibit 2B, E6.

and fire extinguishers. This equipment is critical in protecting employees during emergency situations such as station fires. Inspections also enable Toronto Hydro to remain compliant with the Ontario *Fire Protection and Prevention Act* which requires fire extinguishers to be inspected monthly.

From an environmental perspective, inspections identify pieces of equipment that are leaking oil as depicted in Figure 68 below. Leaking transformers or cables pose environmental risks, where oil can enter waterways, ground water and potentially sensitive ecological areas. In addition, frequent inspections can identify signs of leaking oil, which indicates that assets that are at risk of failing. Once indentified, Toronto Hydro can address the leak and prevent equipment failures.

Figure 68: Oil Leak on a Station Transformer

Inspections also identify vegetation concerns and damage to grading and landscaping as depicted in Figure 69. Failure to address these deficiencies can result in damage to stations because of poor drainage, customer complaints and safety risks for employees including accessibility risks from vegetation overgrowth and slipping and falling risks from poor landscaping.

Figure 69: Damaged Landscaping

In addition to identifying deficiencies that mitigate safety and environmental risks, Station Inspection work obtains oil samples from power transformers and conduct oil testing that is used to mitigate financial and system reliability risks. Industry-standard oil tests are performed to identify poor conditions and abnormalities that cannot otherwise be detected without a complete disassembly of the transformer. The oil analysis tests include: Dissolved Gas Analysis ("DGA"), Furan analysis, acid levels, moisture levels, and other oil quality tests. /C

DGA testing allows Toronto Hydro to monitor trends in the gas levels of transformer oil and helps to predict failures. The rate of decomposition and the type of gases generated during the natural aging process of the oil and insulating parts, especially in the case of thermal or electrical failures due to thermal overloading or electrical faults, are effective and accurate predictors of transformer health. Furan analysis shows the condition of the cellulose paper insulation within the transformer core. Over time, the cellulose insulating material will experience degradation. The presence and level of furanic compounds in the oil are used to determine an average expected degree of polymerization for the paper in the equipment. The calculated degree of polymerization is used to estimate the percentage of solid insulation life remaining inside the transformer. Oil quality tests indicate the moisture levels, particle count, interfacial tension, and acidity of the oil, which are all factors in the accelerated degradation of the transformer.

Oil testing is particularly valuable because it allows Toronto Hydro to identify transformers that may be at a high risk of failure and to schedule corrective action such as oil reclamation or replacement before a catastrophic event can occur. Consequences of such an event can include oil spills, fire, emergency response and equipment replacement costs exceeding hundreds of thousands of dollars, or a power interruption affecting hundreds if not thousands of customers for possibly three to eight hours.

10.2. Auxiliary Equipment Maintenance

In addition to Stations Inspections, Auxiliary Equipment Maintenance is performed to mitigate a variety of risks. Maintenance of station backup battery systems reduces the risk that a station's protection and control system will not operate as required during a power interruption. During such an event, the system's DC power source allows all station protection and control equipment to function and communicate normally. Loss of the backup power supply can have consequences ranging from loss of communication

and remote operation capability, to failure of a protecting device to function posing both safety and system reliability risks.

Maintenance of fire alarm systems is designed to ensure that the systems are fully functional at all times and in particular when they are called upon to operate. The failure of a fire alarm system in the event of a station fire could delay the communication of the event to employees inside the station and the Toronto Hydro control centre until damage to the station is so great that either the equipment faults and triggers an alarm to the control center, or it becomes noticeable to a member of the public, who in turn notifies emergency authorities. The sooner Toronto Hydro is notified of a fire, the more likely that damage and associated safety and environmental risks can be minimized. These risks include employees receiving severe burns and the release of harmful contaminants and greenhouse gases into the environment such as oil, fire fumes and SF_6 gas. Experience with station fires over the past number of years (e.g., at Lesmil MS in North York area, and at Station J, in the East York area) indicates that the cost to repair the damage can easily reach millions of dollars.

Maintenance of station cranes is designed to ensure that cranes are capable of lifting and positioning their rated load (which can be as high as 35 tons) and are fully functional to enable other station capital and maintenance work to proceed. The failure of a station crane (hoist or cables breaking) during operation can lead to safety risks to crews when lifting and moving heavy loads, such as transformers and switchgear cabinets, and can cause damage to the station itself if loads were to fall as a result of the failure.

Maintenance of compressed air systems are designed to ensure that air blast circuit breakers are available to operate as designed when called upon to do so. These breakers require compressed air and without a certain pressure and volume of air available, the circuit breakers will not close or trip, which will result in their failure to operate during

fault conditions, exposing employees to severe burns from arc flashes. When this occurs, protection devices upstream of the circuit breaker would need to operate resulting in outages to a far greater number of customers than would otherwise occur. For example, the failure of an air blast circuit breaker to clear a fault in July 2012 at George and Duke MS resulted in interruptions to 6,500 customers for nearly eight hours. Replacement costs for an air blast circuit breaker can range from $60,000 to $200,000 depending on various factors including type, voltage rating, and location. Maintenance tasks that mitigate the risks described above include inspections of all components for deficiencies, cleaning of filters, replacement of pressure relief valves and pump-up time testing which is used to determine their correct operation.

10.3. Segment Costs

The following table contains the historic and planned expenditures for this segment.

Table 11: Historical and Forecasted Segment Spending ($ Millions)

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	1.0	0.9	1.0	1.2	1.2

During the 2011-2013 period, expenditures remained stable due to the cyclical nature of inspections and maintenance. Beginning in 2013, oil sampling was standardized for all power transformers and the suite of tests was expanded to include Furan analysis. The costs associated with additional oil sampling and testing are the predominant drivers for the increasing costs in 2013 and 2014.

10.4. Test Year Segment Costs

Planned expenditures for 2015 are $1.2 million and are constant relative to 2014. These expenditures are planned for funding the inspections of equipment at Toronto Hydro's 35 TS's and 164 MS's and the maintenance of auxiliary equipment such as battery banks,

fire alarm systems, cranes, and compressed air systems. These expenditures are expected to enable Toronto Hydro to identify and address deficiencies at stations and to mitigate the risk of equipment failures and associated safety, environmental, financial and system reliability risks such as injury to Toronto Hydro personnel, extensive collateral damage to station equipment and system outages. In addition, the expenditures would allow Toronto Hydro to comply with non-discretionary statutory requirements in the *Ontario Fire Code* and *Occupational Health and Safety Act*.

11. STATION SWITCHGEAR MAINTENANCE SEGMENT

Station Switchgear Maintenance includes testing and maintenance of Toronto Hydro's switchgear units and circuit breakers that are located at Transformer and Municipal Stations ("TSs" and "MSs", respectively) across the utility's service territory. A switchgear unit is a combination of switching devices and their associated controls, measuring, protection, and regulating equipment. Assemblies of these devices and equipment, with associated interconnections, accessories, enclosures and supporting structures, are found at Toronto Hydro's distribution stations. There are 252 switchgears installed within the distribution system and they collectively contain approximately 1,880 circuit breakers. /C

Switchgears and circuit breakers must operate quickly and reliably when an electrical interference or equipment failure causes a fault on the distribution system. Switchgear maintenance activities mitigate the risk that the equipment will malfunction during a contingency, failing to protect the downstream feeders and equipment and possibly leading to a safety incident involving the public or Toronto Hydro employees. Maintenance is particularly critical for the fleet of switchgear owned by Toronto Hydro, as many circuit breakers have surpassed their expected lives and rely on obsolete technology such as brick and mortar enclosures, non-arc resistant interrupting devices

(e.g., air blast or air magnetic circuit breakers), and electromechanical relays with no supervisory feedback or control.

Toronto Hydro owns and maintains two types of switchgears:

- the exposed bus type, used mainly for outdoor installations; and
- the enclosed type, further subdivided into metal clad, metal-enclosed, and brick structures, which are mainly used for indoor installations.

Examples switchgears are illustrated in Figure 70 below.

Figure 70: (Left) Outdoor Enclosure Housing Metalclad Switchgear. (Right) Indoor Metalclad Switchgear

Station Switchgear Maintenance includes three sets of activities.

- **Circuit Breaker Maintenance** – Circuit breaker maintenance work includes a visual inspection and verification of the integrity of the mechanical and electrical components in circuit breakers, functional testing of the unit, and replacement of worn components. Circuit breakers (Figure 71) use various mediums to extinguish the electric arc that forms during an interruption operation. Toronto

Hydro owns and maintains the following types of circuit breakers: air magnetic, air blast, Sulphur Hexafluoride (SF_6), oil, and vacuum units. Maintenance frequencies, which are based on reliability-centred maintenance (RCM) principles, are: (1) every four years for air-magnetic and oil circuit breakers; every three years for air blast circuit breakers; and (3) every eight years for vacuum and SF_6 circuit breakers.

Figure 71**: (Left) Oil KSO Circuit Breaker, (Right) Vacuum Circuit Breaker**

x **<u>Protection & Control (P&C) Maintenance</u> –** The P&C equipment maintenance includes inspection and testing of sensing devices and relays that monitor the magnitude and flow of electrical power. In the event of a fault on the distribution system, the protective relays detect the fault and trigger interrupting devices, such as circuit breakers, to operate and isolate the circuit, protecting the system from further damage. A protective relay system has to be periodically tested and

verified to ensure the system remains protected, the settings are appropriate for the current state and loads, and that a failure event does not result in cascading outage events. More specifically, maintenance activities involve verifying the AC voltage and current to the fault detecting relay, testing the operating characteristics of the relay, validating relay settings, verifying the operation of auxiliary relays, and verifying output functions such as alarms and annunciations. This equipment is maintained every four years.

- **Thermography and Ultrasonic Testing –** A thermographic scan of a switchgear unit provides Toronto Hydro with an advanced warning of developing electrical faults by identifying thermal anomalies on the equipment. Ultrasonic testing identifies high-frequency noise associated with surface tracking and corona, which are also indicators of impending failure. All load break switches, disconnect switches, and bolted electrical connections undergo thermographic scans and ultrasonic tests every eight years.

These three sets of activities are designed to reduce the likelihood of switchgear or breaker failure and to mitigate the associated risks. One way that this is accomplished is by identifying deficiencies that can lead to common switchgear failure modes. These deficiencies include worn components, loose connections, degradation, corrosion, and contamination. Examples of these are shown in Figures 72 and 73, which illustrate a corroded switchgear enclosure and pest infestation inside an outdoor switchgear.

Figure 72: Rusted Switchgear Enclosure

Figure 73: Pests inside Outdoor Switchgear

Figure 74 below shows an example of an internal arc fault, which can be destructive and pose a risk of injury because of the energy levels reached within the confined compartment. /C

Figure 74: Impact of Internal Arc Fault in a Switchgear /C

As illustrated in Figure 75 below, Toronto Hydro has identified more than 200 deficiencies on switchgear assets each year since 2011.

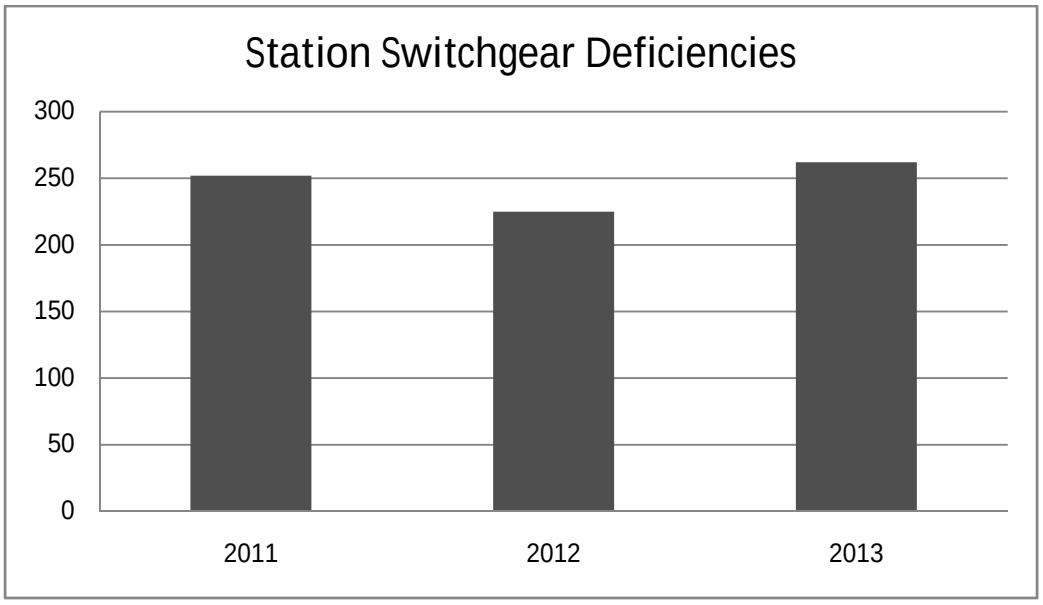


Figure 75: Switchgear deficiencies identified between 2011 and 2013

The likelihood of deficiencies existing and leading to a failure increases as switchgear and breakers age and approach their end-of-lives. The average expected lives of switchgear enclosures and circuit breakers are 50 and 45 years respectively. Figures 76 and 77 illustrate (in red) the percentage of Toronto Hydro's switchgears and circuit breakers that are beyond their expected useful life.

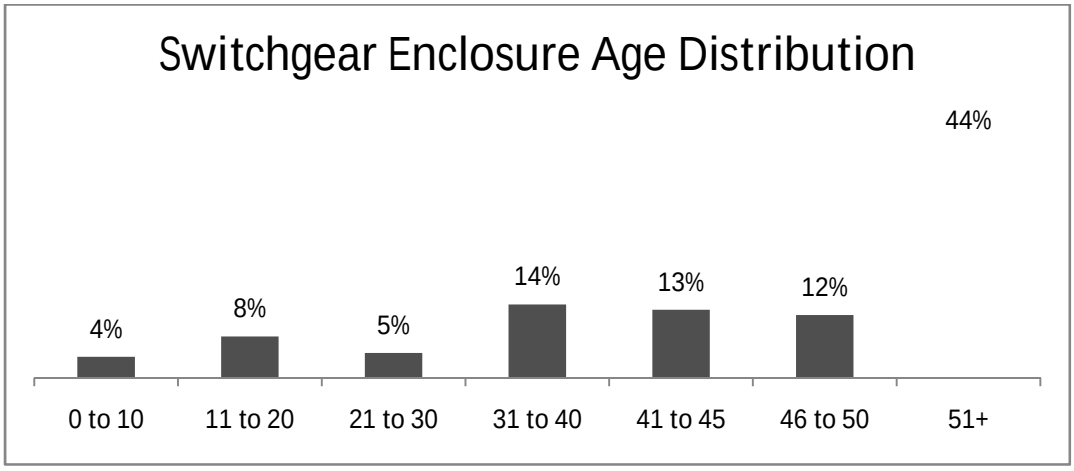


Figure 76: Age Distribution of Metalclad Switchgear Enclosure as of 2013

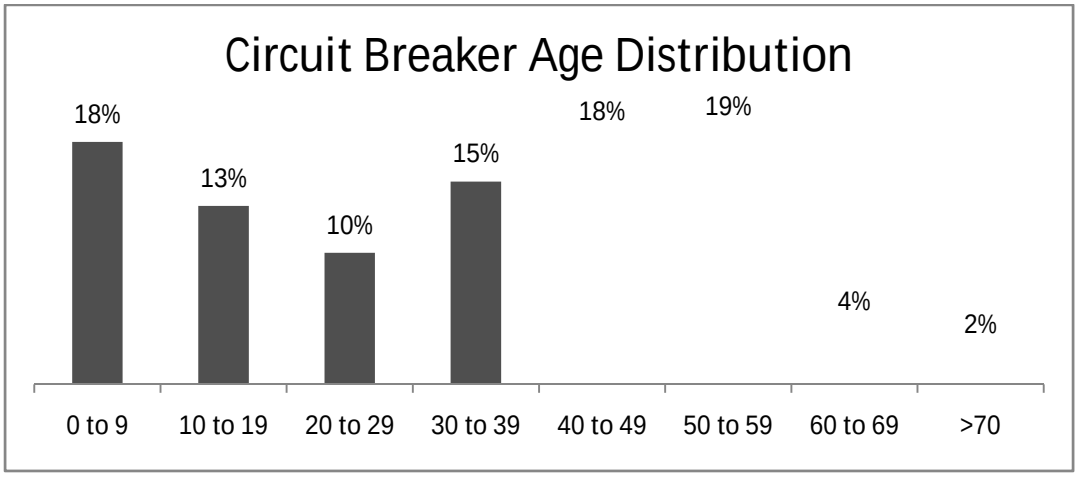


Figure 77: Age Distribution of Circuit Breakers as of 2013

As shown from the above figures, approximately 44% of Toronto Hydro's switchgear enclosures and 43% of the circuit breakers that they house have surpassed their expected useful life. Of particular concern are the high numbers of air magnetic, air blast and oil breakers that have exceeded their expected life. The likelihood of failure increases for these assets due to wear and tear that has been caused by high numbers of operations, contamination, loose connections, and corrosion. Toronto Hydro's ACA tool shows that

42% of the population of switchgear are in poor or very poor condition[29] and are at an increased likelihood of failure. A failure of one of these assets has the potential to lead to a catastrophic fire, the release of harmful contaminants into the environment (e.g., oil spills, combustion by-products), and safety risks in the form of debris or arc-flashes that can cause injury and property damage. The replacement of worn and corroded components, the alignment of switch blades, the lubrication of switches, and the removal of dirt and other contamination during maintenance mitigates the risk of failures and associated employee safety, financial, environmental, and system reliability risks that are associated with switchgear failure.

An example of a catastrophic station failure occurred at Station J in East York in 2009. The station was over 50 years old, and a fire ensued following a switchgear failure and subsequent fault. The switchgear had surpassed its expected life and the fault resulted in the destruction of Station J. Maintenance, including thermographic scans and ultrasonic tests, serves to prevent similar occurrences by detecting defective components (closing coil, pallet switch, closing spring and relay systems) and incipient faults in loose connections, contacts, and insulators that could develop into a catastrophic failure from the failure of a protection and control asset to operate and clear a fault.

The financial consequences of failures of switchgear and circuit breakers are also significant. The replacement of a circuit breaker can exceed $100,000 and approach $1 million depending on various factors including type, voltage rating, and location. The total replacement cost of transformer station switchgear, including the costs of the enclosure and circuit breakers is approximately $6 million. These costs significantly exceed the annual cost of switchgear maintenance activities and the prevention of even one catastrophic failure over a multi-year period will offset the planned maintenance expenditures during the period.

[29] For more information about the ACA, refer to Exhibit 2B, Section D, Appendix A.

In addition to safety, environmental, and financial risks, Switchgear Maintenance provides customer value by mitigating system reliability risks. A failure of station switchgear or a circuit breaker can result in a large number of customer interruptions and long interruption durations. The specific impact will vary depending on the configuration of equipment within the distribution system. During the 2011 and 2013 period, Toronto Hydro experienced between five and nine incidents annually that were related to switchgear failures. Figures 78 and 79 illustrate the system reliability impacts that these incidents caused, which averaged 12,858 customers impacted and 31,874 customer hours interrupted during the three-year period.

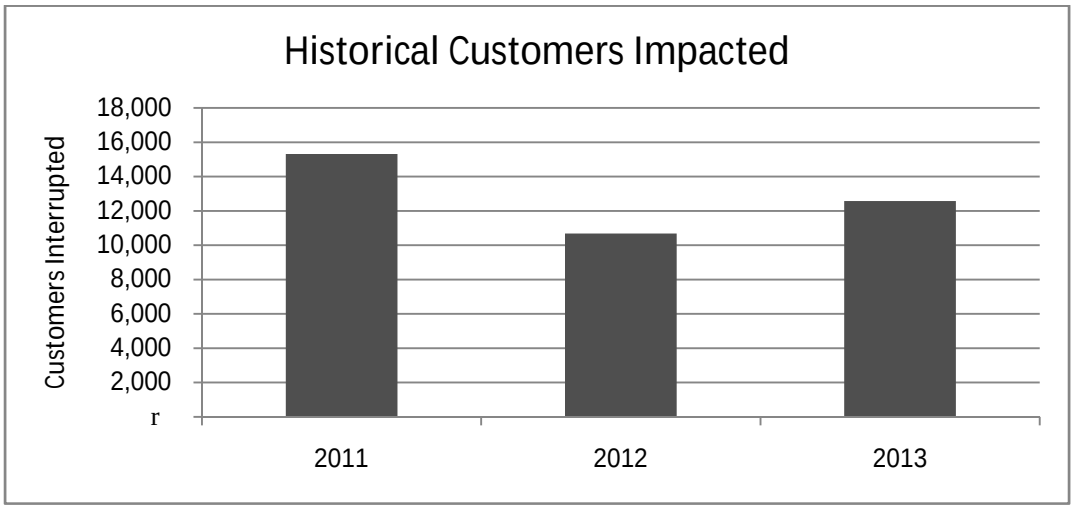


Figure 78: Total Customers Interrupted (CI)

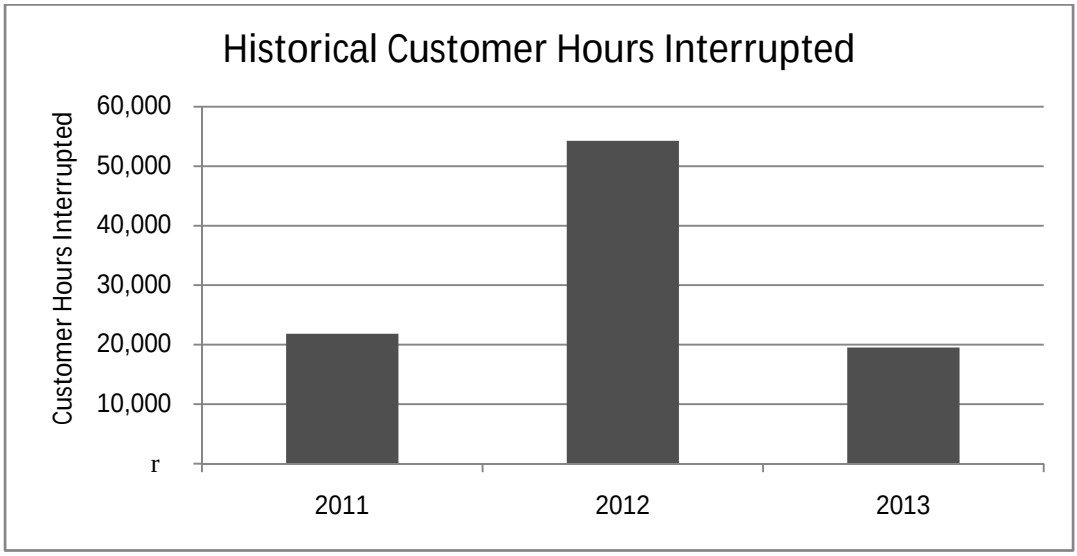


Figure 79: Total Customer Hours Interrupted (CHI)

Not all switchgear failures are catastrophic in nature and some are as small as the failure of a breaker to open and close. Nevertheless, these failures impact system reliability, as protection systems are designed to coordinate with each other, with the intent of isolating the fault or failure to the smallest possible area within the distribution system. If a protection device were to fail to function, a protection device located further upstream would operate. Such a scenario results in outages impacting greater numbers of customers and system assets as well as increasing the safety risks to employees and bystanders near stations. Failure of protection devices on the distribution system could also result in the fault migrating to the transmission system, resulting in even larger outages. Maintenance tasks are designed to ensure protection devices operate as designed. During maintenance, crews verify and correct improper settings onsite such as (1) verifying that the voltage and current settings on the fault detecting relays are correct for the system element being protected; (2) verifying that the operating characteristics of the fault detecting relays are correct for the applied setting; and (3) verifying that the operation of auxiliary relays and output functions, such as circuit breaker tripping and annunciation, are correct.

11.1. Segment Costs

The following table contains the historic and planned expenditures for this segment.

Table 12**: Historical and Forecasted Segment Spending ($ Millions)**

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	1.2	0.9	1.3	1.3	1.4

With the exception of a decrease in 2012, expenditures have increased gradually. Toronto Hydro maintained 205 circuit breakers in 2012, as compared to 303 and 358 in 2011 and 2013, respectively. However, this level of accomplishment has lagged behind the number of breakers that require maintenance. In accordance with reliability-centred maintenance principles, Toronto Hydro needs to maintain approximately 440 breakers annually, but has only averaged 290 over the 2011-2013 period. The reason for this deficit is the need to take significant numbers of planned equipment outages at stations to accommodate the varying maintenance cycles (i.e., three years, four years, and eight years). This need has posed a work execution risk to maintenance activities, as it can be difficult to align the outage availability times (due to system loading restrictions) with the availability of labour resources (switching crews and distribution system technologists) to complete the work.

11.2. Test Year Segment Costs

2015 expenditures are planned to be $1.4 million, which is $0.1 million greater than the 2014 planned expenditure. The increase is driven by a need to increase the number of circuit breakers maintained annually to align with prescribed maintenance cycle frequencies. To facilitate this effort, Toronto Hydro is taking steps to mitigate the work execution risks by better coordinating station equipment maintenance activities, and in particular Station Switchgear Maintenance and Station Equipment Maintenance to reduce the number of planned station equipment outages that are required. Where possible,

entire station outages are now coordinated to allow work crews to maintain station equipment units at once, without the need for multiple planned outages. This is expected to result in reduced safety risks for employees from reductions in manual switching operations to perform maintenance. Toronto Hydro coordinates these activities on a four-year cycle. For transmission stations and stations in downtown Toronto, where entire station outages are not possible, planned outages continue to be taken for subsets of station equipment as necessary. In addition to mitigating work execution risks and enabling Toronto Hydro to accomplish maintenance on a greater number of circuit breakers, this approach has resulted in productivity savings.

12. STATION EQUIPMENT MAINTENANCE SEGMENT

The Station Equipment Maintenance segment oversees equipment that is located at all of Toronto Hydro's 35 TS and 164 MS locations, including 248 station transformers. /C Transformer stations are points of power supply from HONI's transmission system to Toronto Hydro's distribution system, which step down supply voltages from 230 kV or 115 kV to 27.6 kV or 13.8 kV, utilizing transformers that, with one exception, are owned by HONI. Municipal stations are stations within Toronto Hydro's distribution system and are supplied by Toronto Hydro feeders, at 27.6 kV or 13.8 kV, and step down voltage to 13.8 kV or 4.16 kV. Toronto Hydro owns and maintains all equipment at MSs, including the transformers, and a large number of equipment at TSs. At TSs, Toronto Hydro does not own the power transformers.

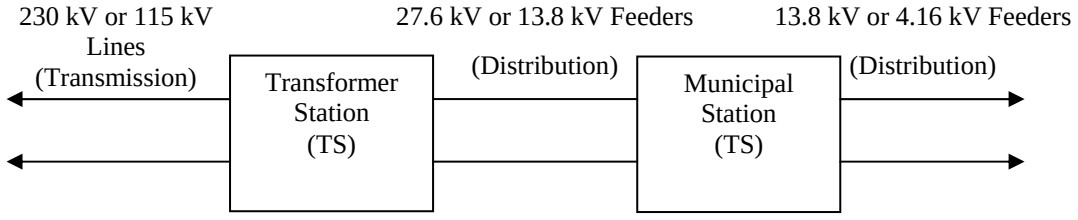


Figure 80: System Configuration

Figures 81 and 82 below depict station power transformers at Toronto Hydro's stations.

Figure 81: Power Transformer at Cavanagh TS

Figure 82: Power Transformer at Neilson Dr. MS

Toronto Hydro's station equipment is aging and much of it has surpassed its expected useful life. The best indicator of this is the age demographics for power transformers, which are essential components of every station. Approximately two-thirds of Toronto Hydro's transformers were installed in the 1950s through the 1970s. The average useful life of these units is 45 years and a significant percentage of them have surpassed this age. Approximately 52% of the entire population will exceed 45 years of age by 2015 as shown in Figure 83. In addition, Toronto Hydro's ACA tool shows that 15% of power transformers are in poor or very poor condition.[30]

[30] For more information about the ACA, refer to Exhibit 2B, Section D, Appendix A.

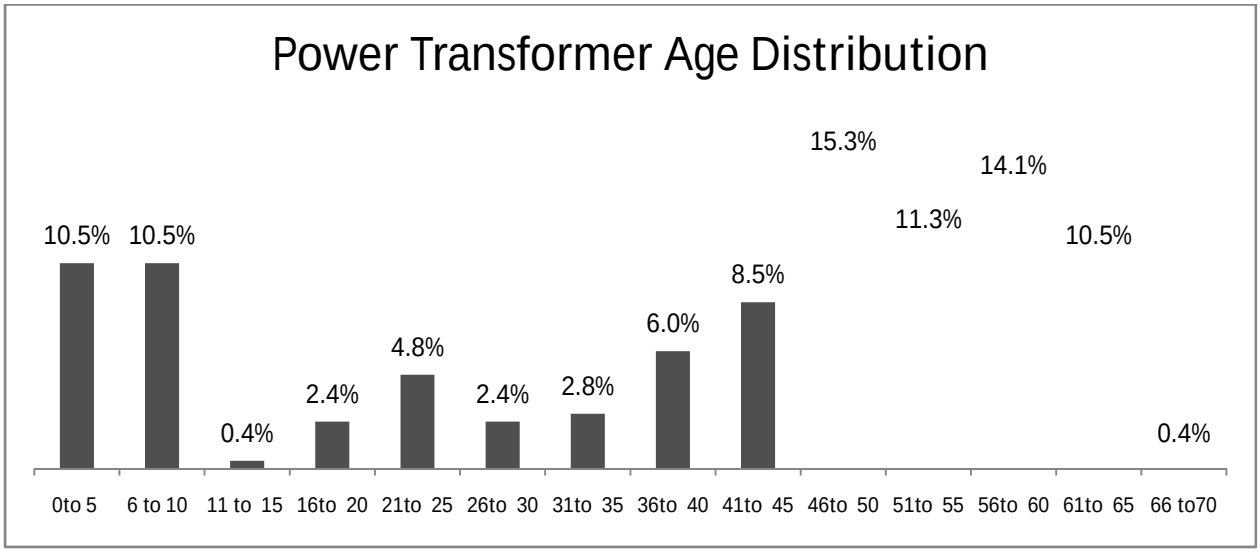


Figure 83: Age Distribution of Power Transformers as of 2015

As transformers age, maintenance becomes increasingly important to ensure that the core and windings continue to function within acceptable parameters, insulating properties do not deteriorate excessively, and that auxiliary equipment such as gauges and alarms are functioning properly to detect and provide early warnings of problems such as oil leakage, gases in the oil, and overheating.

Maintenance activities are focused on inspecting, testing, and cleaning of assets, including power transformers and their auxiliary equipment, current transformers, potential transformers, station service transformers, DC batteries, chargers, disconnect switches, load break switches, fuses, interconnect cables and remote terminal units. Failures of this equipment, and in particular, failures of power transformers, can result in station fires, oil leaks, significant emergency response and equipment replacement costs, and power interruptions impacting in excess of 5,000 customers. Maintenance activities are vital for mitigating the risk of such failures and associated consequences, and extending the useful life of equipment as they identify failing insulation, deterioration of

insulating oil, and transformer winding irregularities such as shorted turns, all of which can lead to catastrophic equipment failure if not addressed.

The Station Equipment Maintenance segment does not include maintenance of station switchgear, which is captured in the dedicated Station Switchgear Maintenance segment. Examples of activities that are undertaken as part of Station Equipment Maintenance are:

- comprehensive transformer testing including winding resistance and power factor testing to evaluate the insulation integrity of the core and windings;
- cleaning of power transformer bushings to remove contamination that can lead to tracking and flashovers;
- inspections and calibrations of transformer auxiliary equipment such as relays, temperature and oil gauges, and alarms;
- verifying the integrity of all clamped and bolted connections on primary feeders, insulators, bushings, secondary feeders and buses;
- cleaning and testing of on-load tap changers, which are devices used to regulate voltage; and
- testing of transfer trip relays between a MS transformer (at 4 kV) and the upstream 13.8kV or 27.6kV supply feeder.

Station Equipment Maintenance, including the aforementioned activities, requires planned outages and is scheduled on a four-year cycle. These activities are critical to preventing an equipment failure within a station as the preventative and predictive tools and tests that are employed during maintenance enable Toronto Hydro to prevent and identify deterioration on equipment that can lead to failures and associated consequences.

When equipment failures do occur, for example on a power transformer, they pose significant safety, environmental, financial, and system reliability risks. An example of a transformer failure occurred at Dupont MS in 2003. The 49-year old transformer failed

and resulted in a fire that caused damage to two other power transformers at the station and caused oil and fluids to spill into the station. This event interrupted 5,675 customers, resulting in over 23,341 customer hours interrupted. The entire outage lasted for 6.6 hours. Figures 84 to 86 show the damage caused by this incident.

Figure 84: Failed Power Transformer

Figure 85: Damages to the MS wall on the Left

Figure 86: Leaking fluids from failed transformer

The safety risks associated with a failure of this nature include station fires and flashovers which can cause injury to employees in a station; environmental risks include the spillage of oil from ruptured transformer oil tanks which can contaminate ground water and environmentally sensitive locations and the release of hazardous combustion by-products.

During 2011-2013, Toronto Hydro experienced nine outage incidents cause by failed station transformer equipment. Fortunately, none of these incidents were of the magnitude of the failure at Dupont MS in 2003; however, they did cause 8,680 customer interruptions and 9,915 customer hours of interruption over the three-year period and thousands of dollars in emergency response. From a financial perspective, transformer failures can result in emergency response and equipment replacement expenditures that range between $0.2 million and $4 million. Given these figures, the mitigation of even one costly failure in a year or period of time can result in savings that substantially offset the cost of Station Equipment Maintenance.

Although power transformer failures pose the greatest risk within stations, it is important to note that Station Equipment Maintenance mitigates failures on various other types of station equipment which can also cause significant safety, environmental, financial and system reliability risks. One example is load break switches, which are used to supply and isolate the primary voltage feed to a power transformer at municipal stations. These switches are installed in outdoor enclosures at 27.6 kV. A failure of such a switch can cause a station outage and significant safety risks as these switches are often operated manually. Maintenance activities ensure the successful operation of a switch during fault conditions and include cleaning insulators, lubricating contacts and gears, checking blade alignment, and conducting electrical tests such as contact resistance, insulation resistance and fuse resistance tests. Another example is station service equipment, which supplies batteries, ventilating systems, lighting, and cranes. A failure of this equipment can result in the loss of power to station protection equipment, the loss of remote communication and control functions, overheating of switchgear, and various other risks. Maintenance mitigates the risk of these failures occurring.

12.1. Segment Costs

The following table contains the historic and planned expenditures for this segment.

Table 13: Historical and Forecasted Segment Spending ($ Millions)

Total Spending	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	0.6	0.5	0.7	0.8	0.9

Expenditures have been increasing to enable Toronto Hydro to achieve a four-year maintenance cycle. Similar to work undertaken as part of Station Switchgear Maintenance, accomplishments in Station Equipment Maintenance have lagged behind the number required as a result of the need to take a large number of planned outages on critical and at times difficult to take out-of-service assets due to system constraints. As

described in the Station Switchgear Maintenance segment, Toronto Hydro has addressed this issue by harmonizing maintenance cycles and plans to continue the gradual increases in 2015 to fully achieve a four-year maintenance cycle.

12.2. Test Year Segment Costs

The proposed 2015 test year costs are $0.9 million, which is $0.1 million greater than forecasted costs in 2014. The increase is attributed to the planned increase in maintenance activities to achieve the four-year maintenance cycle and nominal inflationary pressures.

Maintenance activities are becoming increasingly important as Toronto Hydro's station assets are aging, as evidenced by the fact that 52% have reached or surpassed their expected life and are at an increased risk of failure. The preventative and predictive tools and activities employed during maintenance serve to reduce the risk of equipment failures and their associated safety, environmental financial and system reliability risks. The mitigation of even one catastrophic transformer failure could possibly save $1 million in expenditures, prevent an outage impacting thousands of customers, and prevent a spill of 5,000 to 55,000 litres of oil at a station.

CORRECTIVE MAINTENANCE PROGRAM

1. SUMMARY

Table 1: Corrective Maintenance Program Expenditures ($ Millions)

	2011	2012	2013	2014	2015
Corrective Maintenance	25.8	21.5	17.0	19.0	22.2

This schedule provides information about Toronto Hydro's Corrective Maintenance program. The program undertakes actions to address the deficiencies or substandard conditions on the distribution system that have been identified during the normal course of operations. This typically includes the deficiencies or substandard conditions identified through activities undertaken by the Preventative and Predictive Maintenance program[1], or through the Emergency Response program[2].

2. PROGRAM DESCRIPTION

Corrective Maintenance activities typically involve short planning horizons given the risks that deficiencies and substandard conditions can pose if left unaddressed. Examples of corrective activities include investigating the thermal anomalies, also referred to as "hot spots" that have been identified on equipment by overhead line patrols, or conducting transformer oil reclamation following the findings of high concentrations of particular gases in transformer oil during station inspections.

The Corrective Maintenance program as a whole has been experiencing a general downward trend in expenditures as a result of increases in some capital and maintenance

[1] Exhibit 4A, Tab 2, Schedule 1.
[2] Exhibit 4A, Tab 2, Schedule 3.

activities as discussed in the Distribution System Plan[3] and the Preventative and Predictive Maintenance program[4].

The work comprising the distribution and stations corrective maintenance activities includes repairs of deficiencies found on distribution and stations assets that must be addressed within a short planning horizon (typically less than one year). The scope of the corrective maintenance work includes overhead and underground assets, primary and secondary lines, and Toronto Hydro's 164 Municipal Stations ("MS") and 35 Transformer Stations ("TS"). The scope of work does not include emergency repairs, which are managed and discussed in the Emergency Response Program[5]. It does, however, include permanent repairs to assets that have been temporarily repaired during an emergency event.

A significant portion of distribution and stations corrective maintenance is driven by deficiencies identified through the execution of Preventative and Predictive Maintenance activities.[6] Corrective maintenance tasks typically involve restoring assets to their normal operating conditions by undertaking maintenance, refurbishment, or component replacements. Toronto Hydro performs all corrective activities using a prioritization system, through which it responds first to deficiencies and situations posing the greatest risk to public or employee safety, the environment, and system reliability.

The Corrective Maintenance program consists of the following activities:

- Distribution Overhead Maintenance: Corrective repairs of defective or failed equipment and replacement of components that are part of the overhead distribution system, including conductor, conductor splices, insulators, brackets, lightning arresters, pole-mounted transformers, and overhead switches.

[3] Exhibit 2B.
[4] Exhibit 4A, Tab 2, Schedule 1.
[5] Exhibit 4A, Tab 2, Schedule 3.
[6] Exhibit 4A, Tab 2, Schedule 1.

- Distribution Underground Maintenance: Repairs of defective or failed equipment and replacement of components that are part of the underground and network distribution system, including cable, cable splices, vaults, ducts, vents, hatchways, sump pumps, network transformers and protectors, underground switches, vault transformers, pad-mounted transformers, and pad-mounted switches.
- Stations Maintenance: Corrective repairs to station equipment such as transformers, tap changers, cooling systems, switchgear, bus-bars, air compressors, circuit breakers, station auxiliary and DC power supplies, current transformers, potential transformers, relays, meters, fire alarms, remote terminal units and SCADA systems.
- Vegetation Management: Responses to off-cycle requests and spot trimming needs identified by Toronto Hydro crews or direct customer feedback, including dying or damaged tree limbs and branches, storm damage, or excessive tree growth that threatens overhead distribution lines or has created system reliability issues.
- Equipment CO_2 Washing: Cleaning excessive dirt, dust, and contamination from energized equipment in below-grade and pad-mounted installations to prevent arcing and flashover risks.
- Worst Performing Feeder Maintenance: This work targets feeders that are at risk of experiencing seven or more power outages in a single year and may consist of tree trimming, switch maintenance, line patrols, and insulator washing depending on the needs of particular feeders.
- Oil Reclamation: Filtering of transformer oil that has been found to contain excessive levels of moisture or contaminants and the restoration of the oil's properties to near-new condition.

These activities are critical to maintaining lines and stations assets. These assets are exposed to normal degradation processes, (e.g. corrosion, water ingress, heavy loading)

and external forces (e.g., adverse weather, tree contacts, foreign interference) that cause deficiencies and at times accelerate the degradation of the assets. The Preventative and Predictive Maintenance program[7] illustrates the number of deficiencies that Toronto Hydro identifies annually for a variety of assets. Figure 1 below provides this number in the aggregate, which ranges between 15,000 and 25,000 deficiencies on lines and stations assets combined.

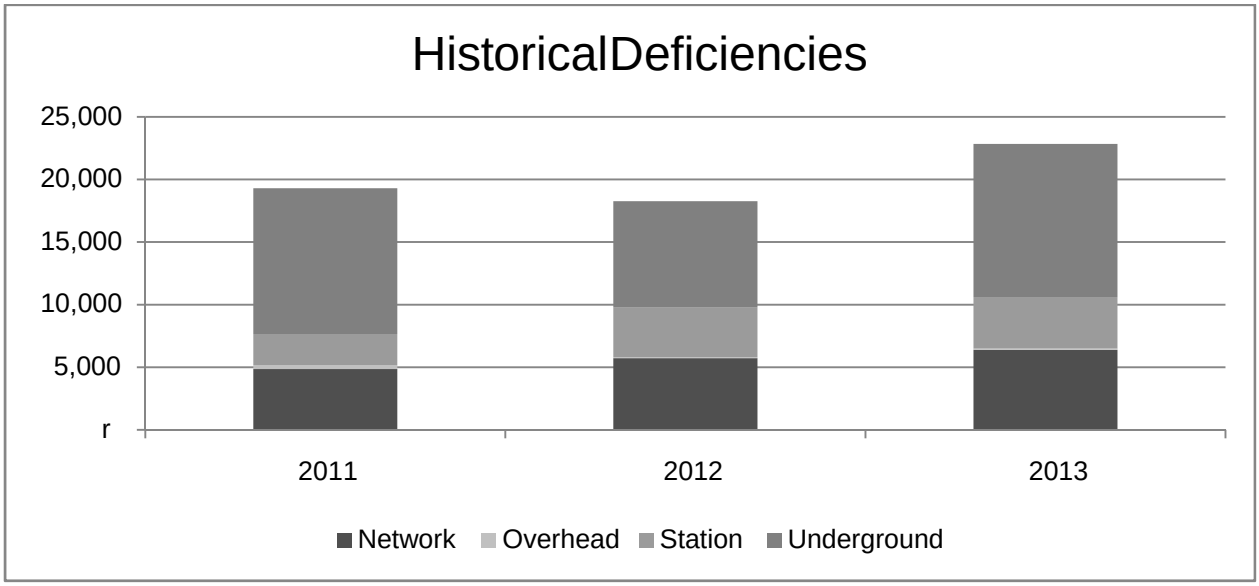


Figure 1: Historical Deficiencies

When deficiencies or substandard conditions are identified, they can be addressed through a variety of programs. As mentioned above, some are addressed immediately when found as part of the Preventative and Predictive Maintenance program. Others are addressed through capital programs. The majority however, are addressed through corrective maintenance work requests. Figure 2 below shows a breakdown of the number and types of corrective work requests that were made during the 2011 to 2013 period.

[7] Exhibit 4A, Tab 2, Schedule 1.

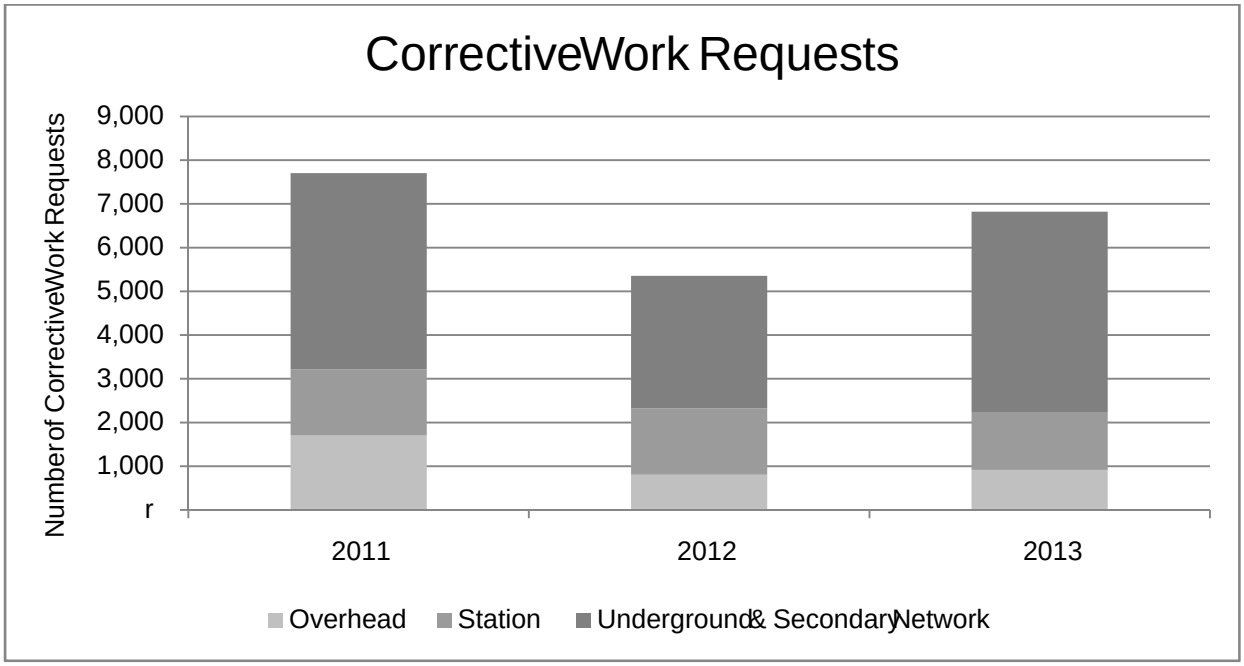


Figure 2: Historical Corrective Work Requests

During this three-year period, approximately 5,500 to 8,000 corrective work requests were issued each year, with the majority relating to underground system assets such as vaults, cable chambers, pad-mounted equipment, and cables. As is evident from Figures 1 and 2 above, the number and type of work requests vary from one year to the next, and do not exhibit a one-to-one relationship with the number of deficiencies found. For example, over 19,000 deficiencies were found in 2011 and almost 8,000 corrective work requests were issued. This equates to less than one work request for every two deficiencies found. In 2013, this figure was one for every three deficiencies found. In general, corrective maintenance needs are ad hoc and vary both in number and in type from one year to the next.

Distribution and stations corrective maintenance, and the thousands of work requests that are addressed each year, serve to mitigate a wide variety of risks including public and employee safety, environmental, system reliability, and financial risks.

From a safety perspective, corrective maintenance addresses deficiencies that if ignored, could expose members of the public and Toronto Hydro employees to safety risks. For example, a deficiency that is routinely found during Overhead Line Patrols, using infrared thermography, is a thermal anomaly, or "hot spot", on a conductor splice. The hot spot is evidence of an issue with the splice and, if not addressed in a timely manner, the splice may fail resulting in a live conductor falling to the ground and energizing the surrounding area. Such a condition presents an unacceptable risk that must be mitigated through corrective maintenance in a timely manner.

The "hot spot" example on a conductor splice also raises system reliability risks. The failure of the splice, depending on the specification of the conductor, may result in a power interruption to hundreds of customers for an hour or more. Other deficiencies that pose similar system reliability risks include deteriorated components such as insulators, mounting brackets and cross-arms, broken ground wire or guy wires, overgrown vegetation and dying branches, failed circuit indicators with depleted batteries, failed surge arresters, conductor clearance issues (e.g., excessive conductor sag), transformer oil with high moisture or acid levels, and excessively dirty installations (e.g., vaults, pad-mounted transformers and switches). In aggregate, these individual deficiencies pose significant reliability risks. For example, over the 2011-2013 period, Toronto Hydro tallied 660 pieces of defective assets annually (on average). During this same period, defective equipment caused approximately one-third of all interruptions on overhead feeders and over 90% of all interruptions on underground feeders.

From an environmental standpoint, corrective maintenance mitigates the risk of oil leaks and of premature equipment failures. For example, cables that are leaking oil must be repaired in a timely manner to prevent oil from entering soil, drains, and waterways. Oil-filled equipment that is at risk of corroding should be maintained in a clean state, free of contaminants that can act as catalysts for corrosion. Corrective maintenance cleans dirty

vaults and pad-mounted installations and applies corrosion inhibiting coatings to equipment to prevent excessive corrosion and the possibility of subsequent oil leaks.

Corrective maintenance (such as the above-noted activities) directed at preventing corrosion, also serves to mitigate financial risks. Maintenance work extends the life of assets and defers capital equipment replacement expenditures. An example of this is caulking that is applied to civil infrastructure such as vaults and ducts. Caulking seals cracks in concrete and minimizes damage from moisture ingress. If caulking is not applied, cracks can grow to threaten the structural integrity of civil infrastructure and result in expensive vault rebuilds that cost hundreds of thousands of dollars. Water ingress can also accelerate corrosion of equipment, leading to premature failure and associated costs.

2.1. Program Costs

The following table contains the historical and planned expenditures for this segment.

Table 2: Historical and Forecasted Segment Spending ($ Millions)

Corrective Maintenance	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	25.8	21.5	17.0	19.0	22.2

Historic expenditures have shown a downward trend due to an increasing emphasis in recent years on planned capital and preventative maintenance activities, particularly on distribution assets, and more efficient corrective work execution practices. Specific areas that have experienced reduced levels of expenditure since 2011 are work requests on overhead distribution lines, activities to address contact and step voltage issues and the worst performing feeders. These areas account for an approximately $6 million reduction between 2011 and 2013. In addition, Toronto Hydro further emphasized "find and fix" practices (in 2013) in the Preventative and Predictive Maintenance program[8], which promote the on-site repair of minor deficiencies as they are identified. Examples of

[8] Exhibit 4A, Tab 2, Schedule 1.

minor deficiencies and associated corrective actions include lubricating components, replacing nomenclature, replacing faulted circuit indicators, replacing sump pumps, clearing drains, caulking ducts and roof slabs, installing missing guy guards, repairing or replacing locks, hinges, and handles. Addressing these deficiencies while on site during Preventative and Predictive Maintenance inspections eliminates the need to dispatch a Corrective Maintenance crew and reduces expenditures.

Despite the above, reductions in expenditures to the level experienced in 2013 are not sustainable in the short term. As described in the Preventative & Predictive Maintenance program, Toronto Hydro continues to identify a large number of deficiencies on both distribution and stations assets. Furthermore, significant proportions of these assets have surpassed their expected lives and are at an increasing risk of failure. As a result of this combination of factors, Toronto Hydro is forecasting that corrective expenditures will exceed 2013 levels in 2014 and 2015.

2.2. Test Year Segment Costs

For 2015, Toronto Hydro is forecasting a Corrective Maintenance expenditure of $22.2 million. This figure is based on 19,000 deficiencies on distribution and stations assets and the issuance of 6,700 work requests. The increase over the 2014 forecast of $19.0 million is primarily attributed to the inclusion of $1.6 million for corrective maintenance of assets that were formerly part of the street lighting system.[9] Excluding this $1.6 million, Corrective Maintenance expenditures are well below the levels experienced in 2011 and 2012. Further reductions to the existing level will adversely affect Toronto Hydro's efforts to mitigate public and employee safety, environmental, system reliability, and financial risks.

[9] As discussed Exhibit 2A, Tab 5, Schedule 1 Toronto Hydro proposes to allocate a portion of the revenue received by TH Energy from the City of Toronto for street lighting maintenance and operation to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

EMERGENCY RESPONSE

1. SUMMARY

Table 1: Emergency Response Program Costs ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Emergency Response	13.3	13.9	26.3	16.2	15.3

/C

The Emergency Response program funds the 24 hour, 7 days a week, 365 days a year, response to unplanned and urgent events involving Toronto Hydro's distribution system assets. Toronto Hydro operates within a dynamic, dense, urban environment where emergency response is required for a wide variety of reasons including but not limited to equipment failure, severe weather, power quality issues, motor vehicle accidents (as shown in Figure 1), equipment isolations, and Toronto emergency services needs (i.e., police, fire, ambulance). The demands on the Emergency Response Program can vary considerably from one year to the next due to impacts from significant system events and extreme weather.

Figure 1: Motor Vehicle Accident with Distribution Pole

The Emergency Response Program is comprised of three segments:

1) Dispatch Logistics;
2) Grid Response; and
3) Significant System Disturbance Response

Dispatch Logistics involves the intake of communications (e.g., telephone calls) from external parties (customers, authorities), collecting information about incidents and events that have occurred on the distribution system, and assigning the appropriate field resources to attend to situations that arise. The Grid Response segment covers the resources that Toronto Hydro dispatches to address the emergency events. Significant System Disturbance Response involves efforts to restore power after major events such as the 2013 ice storm and flood, extended losses of transmission supply, and damage arising from severe but increasingly common weather related events.

The following table summarizes the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Emergency Response program and its segments.

Table 2: Emergency Response Program and Segment Costs ($ Millions)

Program Segments	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Dispatch Logistics	1.6	2.3	2.2	1.7	1.7
Grid Response	10.5	9.4	11.7	12.7	11.9
Significant System Disturbances	1.2	2.2	12.4	1.7	1.6
Total	**13.3**	**13.9**	**26.3**	**16.2**	**15.3**

/C

/C

Expenditures in 2013 were significantly greater than previous years due to $10.2 million expended during the 2013 Ice Storm. Excluding the Ice Storm, expenditures in 2015 are projected to be $0.9 million greater than the average annual expenditure during the 2011 to 2013 period. This increase is attributed to an increasing trend in the number of calls and events that must be responded to and additional funds required for Grid Response related to assets that were formerly part of the street lighting system in Toronto.[1]

2. DISPATCH LOGISTICS SEGMENT DESCRIPTION

The Dispatch Logistics segment funds the intake of trouble calls (inbound) and the coordination and dispatch (outbound) of crews responding to trouble call events. This function is performed 24 hours a day, 7 days a week by a complement of communications personnel ("dispatchers").

[1] As discussed in the Exhibit 2A, Tab 5, Schedule 1, Toronto Hydro proposes to allocate a portion of the revenue received by TH Energy from the City of Toronto for street lighting maintenance and operation to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

Dispatchers receive inbound communications that alert Toronto Hydro of particular events involving, or occurring in the vicinity of, Toronto Hydro's distribution assets that require immediate or time-sensitive responses. These calls are placed by customers, members of the public, emergency authorities, Toronto Hydro's internal crews, and external contractors.

For each call, dispatchers must interpret the nature of the event that has occurred, prioritize the event, and then dispatch (outbound) the appropriate resources to the event. To accomplish this, dispatchers gather information and interact with various systems including Toronto Hydro's Outage Management System ("OMS"), the Distribution Management System ("DMS"), the Geospatial Information System ("GIS"), and the Customer Information System ("CIS ").

During the 2011 to 2013 period, dispatchers attended to between 35,000 and 59,000 telephone calls annually, as illustrated in Figure 2 below. The number of event calls has increased steadily in recent years and peaked during the 2013 Ice Storm. When major events such as the 2013 Ice Storm are excluded, Toronto Hydro anticipates attending to 40,000 event-related telephone calls annually.

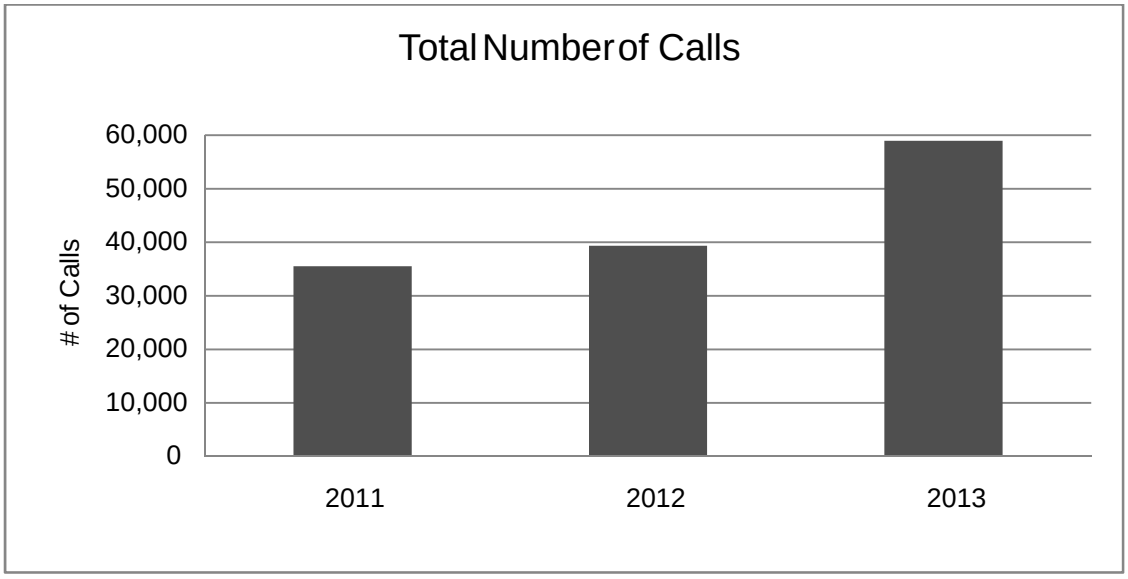


Figure 2: Total Number of Calls Received

Given Toronto Hydro's dense urban environment, which is characterized by large numbers of critical loads (e.g., major hospitals, pumping stations, Toronto Transit Commission), dispatchers attend to telephone calls twenty-four hours per day. As illustrated in Figure 3 below, the company receives the greatest number of calls between 8:00 am and 4:00 pm, while the lowest portion of events occurs between midnight and 8:00 am. The volume of calls received between midnight and 8:00 am is significant and amounts to an average of 7,000 calls per year.

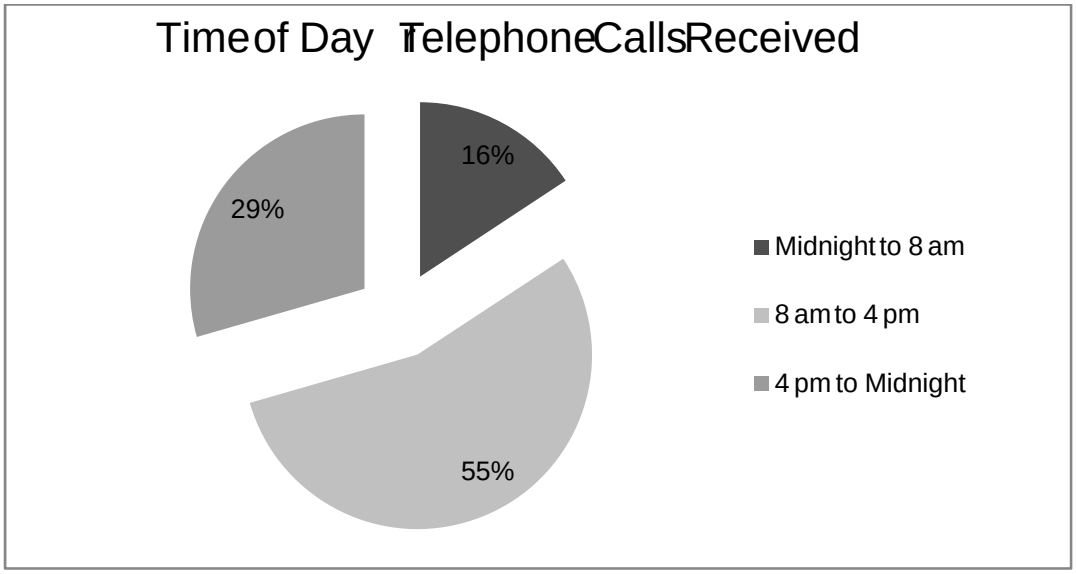


Figure 3: Time of day that telephone calls are received

The telephone calls that Toronto Hydro receive relate to an average of 24,000 events each year. Toronto Hydro classifies these events into four main categories:

1) Emergency calls, including calls made by Toronto EMS (i.e., police, fire, and ambulance);
2) "Power Off" calls attributed to power interruptions on primary facilities (i.e., on the primary side of the distribution transformer);
3) "Power Off" calls attributed to interruptions on secondary facilities (i.e., the distribution transformer or equipment on the secondary side of transformer) and "Power On" events where power has not been interrupted but an issue has been identified on primary facilities; and
4) Other situations such as sagging wires, contact on wires, feeder patrol findings, and planned outages.

Figure 4 below illustrates the number of events that occurred under each category during the 2011 to 2013 period.

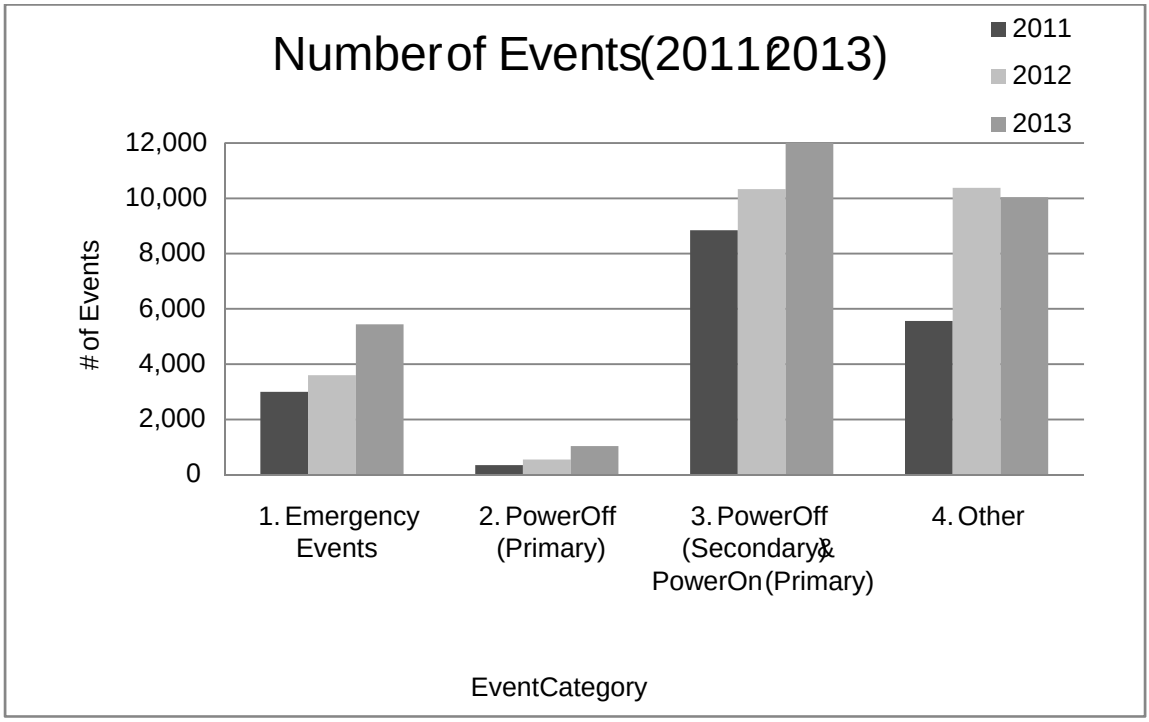


Figure 4: Time of day that telephone calls are received

Categories 1 and 2 (i.e., emergency and primary "power off" events) are the highest priority events for dispatchers to attend to. (1) emergency calls reported by Toronto police, fire or ambulance services (or members of the public) may involve public health and safety risks; and (2) primary "power off" events involve power disruption to sizeable loads and large numbers of customers. In the case of emergency calls, Toronto Hydro is required to have a crew arrive at the location of the event within one hour of being notified of the event 80% of the time.[2] Categories 3 and 4 are of lower priority, but still important, as they typically involve power interruptions to small numbers of customers or lower risk situations.

[2] Ontario Energy Board, *Distribution System Code*, (Toronto: Ontario Energy Board, 2013), at section 7.9.1 and 7.9.2 ["DSC"].

Toronto Hydro's complement of dispatchers is critical to effecting timely field response and mitigating public and employee safety, system reliability, productivity, and regulatory compliance risks. Beginning with public and employee safety, any reductions in dispatch staff will raise the risk of incidents occurring on the system. For example, an emergency situation involving a motor vehicle accident that has damaged a pole line can lead to a live conductor falling to the ground if dispatch delays occur. Other examples relate to the need for field crews to coordinate actions and communicate developments with dispatchers. When crews muster at an underground installation (e.g., cable chamber or a vault), they must obtain a confined space "hold-off", which is a notification to the control centre that they are entering the location. This is necessary to ensure that the control centre is aware of the employees' presence such that it can take the necessary precautions should a system disturbance threaten their safety. Dispatchers assist with coordinating the hold-off and also confirm if there are controlled or designated substances (e.g., asbestos) or other serious deficiencies that the crews should be aware of before entering the confined space. In addition, dispatchers assist field crews when they encounter issues that require additional resources (e.g., more crews), or coordination with other emergency services such as the police or the fire department. As a result, dispatchers are not only necessary to initially dispatch a crew, but are also crucial for ongoing communications throughout the event.

Any time delays caused during the outbound dispatch process may also adversely affect system reliability and resource productivity. Power interruptions that are not restored in a timely manner as a result of delays in crew dispatch, or communications between crews and dispatchers, increase the duration of outages (i.e., SAIDI) causing prolonged inconvenience or safety risks to the affected customers. These delays can also result in crews being unable to move on to other work, thereby eroding resource productivity.

Finally, delays caused during outbound dispatch can challenge Toronto Hydro's ability to meet regulatory service quality requirements as set out in the Distribution System Code. Within its urban service territory, Toronto Hydro is required to respond to emergency calls within 60 minutes at least 80% of the time on a yearly basis.[3] Given that a response is defined as the arrival of a qualified service person on site, delays during dispatch can raise regulatory compliance risks. Within Toronto's dense environment, Toronto Hydro received approximately 1,300 police, fire and ambulance calls on average during the 2011 to 2013 period.

2.1. Segment Costs

The following table contains the historical and planned expenditures for the Trouble Call Dispatch segment.

Table 3: Historical and Forecasted Segment Costs ($ Millions)

Total	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	1.6	2.3	2.2	1.7	1.7

In mid-2011, the Trouble Call Dispatch function was re-organized to improve customer service and increase productivity. The re-organization combined separate Customer Service Dispatchers and Trouble Dispatchers. Customer Service Dispatchers were previously part of the Customer Relationship Management program[4] and as a result, the above costs for 2011 do not fully capture the total Trouble Call Dispatch segment costs in that year. After the re-organization, costs in 2012 and 2013 were stable at $2.3 and $2.4 million respectively, despite increasing demands associated with greater call volumes and major events. Although call volumes have been increasing, Toronto Hydro expects that the peak number of calls received in 2013 (i.e., 59,000 calls) will not repeat in 2014 and

[3] Supranote 2.
[4] Exhibit 4A, Tab 2, Schedule 13.

2015. As a result of this and productivity initiatives that are underway, costs for 2014 and 2015 are expected to be lower at $1.7 million annually.

2.2. Test Year Segment Costs

As shown in the above table, Trouble Call Dispatch segment costs for the 2015 Test Year are expected to be $1.7 million. This amount is required to fund the intake and dispatch of approximately 40,000 calls and 24,000 events each year. Reductions to these amounts could increase safety and regulatory compliance risks, and may adversely affect system reliability and productivity.

3. GRID RESPONSE SEGMENT DESCRIPTION

The Grid Response segment funds the crews to response to the wide variety of emergency events that occur within Toronto Hydro's service territory.

As discussed in the Dispatch Logistics segment, approximately 24,000 events occur annually that each require a crew to attend to one or more locations typically involving:

- power interruptions,
- deficiencies found during inspections that present an immediate risk to the public, employees or system reliability, and
- police, fire or ambulance needs.

These events, which as illustrated by Figure 5 occur daily and are part of the utility's routine operations, necessitate timely response by crews that are properly equipped and trained to address situations that arise. Due to the frequency with which these events occur, Toronto Hydro must assign dedicated staff to Grid Response.

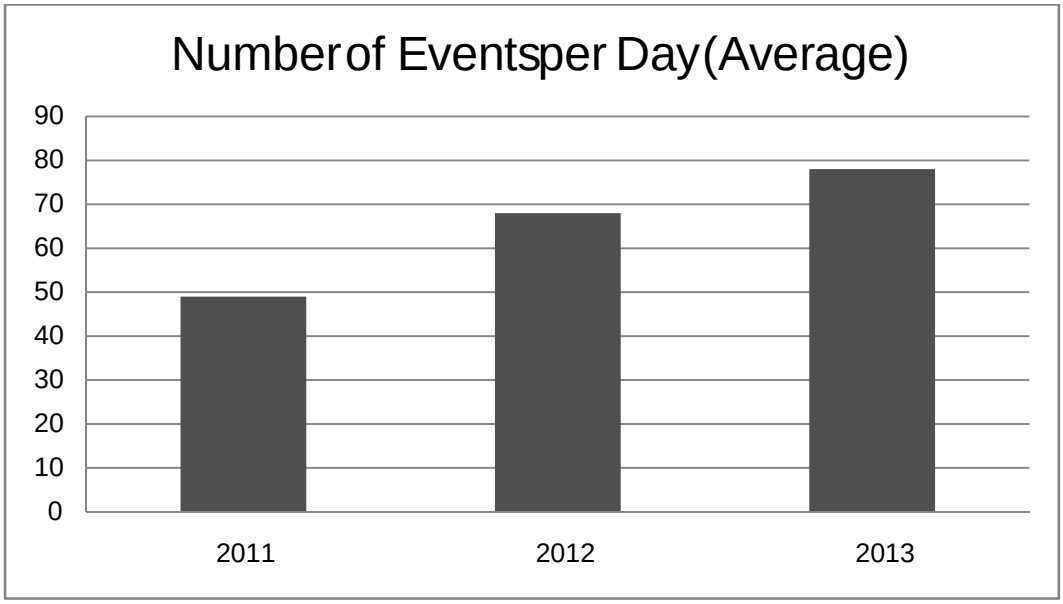


Figure 5: Number of events per day requiring Grid Response.

One set of events that Grid Response attends is power interruptions. Toronto Hydro experiences approximately 1,900 power interruptions annually. (The average customer on Toronto Hydro's system between 2011 and 2013, experienced approximately 1.5 interruptions totalling an hour and a half without power annually). This number does not include interruptions that occur on major event days such as days with significant storm damage. Grid Response in these situations typically results in:

- an emergency crew restoring power to all customers and making all necessary permanent repairs (e.g., when current limiting fuses have ruptured, primary or secondary conductors are down, or transformers or arrestors have failed);
- an emergency crew restoring power to all customers but only by making temporary repairs or isolating the deficiency;[5] or
- an emergency crew arriving on site and, after assessing the situation and making the area safe for the public and employees, determining that the scope of the

[5] Such actions typically necessitate follow-up repairs, usually commencing the next day.

repair is beyond that crew's capabilities and that construction or civil crews are required to fully address the situation.[6]

Another set of events that Grid Response addresses are deficiencies with equipment or components that are identified in the course of planned activities and that require immediate attention. For example, Toronto Hydro's Preventative and Predictive Maintenance program[7] identifies approximately 20,000 deficiencies each year. A subset of these deficiencies raise the need for immediate action on an emergency basis to address unacceptable safety, environmental, and system reliability risks.

A third set of events that Grid Response responds to is calls from emergency services (police, fire, and ambulance) and members of the public reporting emergency events. On average, Toronto Hydro receives approximately 1,300 calls a year where crews must attend a location, as requested by emergency services personnel. Figure 6 illustrates the call volumes between 2011 and 2013.

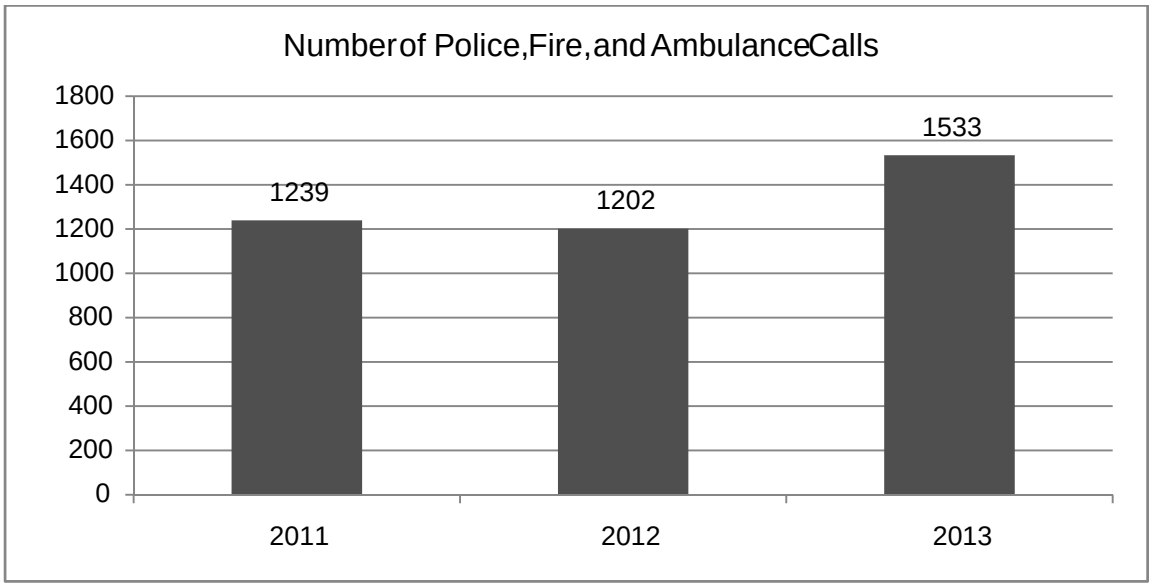


Figure 6: Call Volumes from 2011 to 2013

[6] When needed as part of Grid Response, construction civil crew costs are funded from this segment.
[7] Exhibit 4A, Tab 2, Schedule 1.

Given the nature of the events that Grid Response attends to, the vast majority of the work is non-discretionary. For example, restoration efforts after power interruptions must be expedient to minimize the duration of time that customers experience without power, maintain system reliability, and meet customer expectations. Timely responses to police, fire, and ambulance calls are a requirement of the Distribution System Code, which mandates that emergency calls be responded to within 60 minutes at least 80% of the time in Toronto's urban environment.[8] Responses to serious equipment deficiencies (e.g., damaged cable chamber roofs as illustrated in Figure 7, which is likely to collapse and could result in significant harm to members of the public; oil leaking from a transformer as illustrated in Figure 8, which can contaminate residential and environmentally sensitive areas) are necessary to mitigate potential public safety, environmental, and system reliability risks.

Figure 7: Cable Chamber roofdamaged by road work

[8] Supranote 2.

Figure 8: Response to a leaking transformer in a residential area. Response pictures are before, during, and after remediation work undertaken by a Grid Response crew.

3.1. Segment Costs

The following table presents the historic and planned expenditures for the Grid Response segment.

Table 4: Historical and Forecasted Segment Costs ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Total	10.5	9.4	11.7	12.7	11.9

/C

Given that the number and nature of specific Grid Response activities can fluctuate from one year to the next, historic expenditures have varied slightly during the 2011 to 2013. The increase in forecasted expenditures in 2014 is a result of incremental Grid Response resources to improve response times, including performance related to the Distribution System Code's Emergency Response measure.[9]

[9] *Supra* note 2.

In recent years, Toronto Hydro has taken steps to maximize the efficiency of dedicated Grid Response resources. For example, when not responding to emergency events, Grid Response resources perform corrective maintenance work that is small in scope (e.g., missing guy guards, broken grounds) such that crews can be fully utilized without reducing crew capacity and the ability to redirect crews quickly when emergency events arise. In 2014, Toronto Hydro is piloting a number of small-scale corrective maintenance tasks that will lead to productivity improvements and greater utilization of available resources. These improvements are expected to result in cost savings beginning in 2014 and fully realized in 2015.

3.2. Test Year Segment Costs

Expenditures for 2015 are forecasted to be $11.9 million. This amount is required to fund the response to an increasing number of events (an average of 24,000 events during the 2011 to 2013 period, approximately 1,900 of which were power interruptions) within Toronto's dense, urban environment. **/C**

Out of the total budget of $11.9 million, $0.2 million is forecasted for emergency expenditures on assets that were formerly part of the street lighting system in Toronto.[10] **/C**

Grid Response is a non-discretionary activity that mitigates public safety, system reliability, and regulatory compliance risks. The importance of the activity is particularly pronounced within Toronto Hydro's dense, urban service territory where customers and the public expect service 24 hours a day, 7 days a week as evidenced by the more than 6,000 telephone calls that are received annually between the hours of 12 midnight and 8 am.

[10] As discussed in the Exhibit 2A, Tab 5, Schedule 1, Toronto Hydro proposes to allocate a portion of the revenue received by TH Energy from the City of Toronto for street lighting maintenance and operation to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

4. SIGNIFICANT SYSTEM DISTURBANCE RESPONSE SEGMENT

Severe weather systems and other events (e.g., events involving loss of upstream supply from Hydro One Networks Inc.) can necessitate significant crew effort on a number of days each year. The effort is typically in response to widespread damage on the distribution system and power interruptions to customers. The largest of these events are referred to as "Major Events". During the 2011-2013 period, Toronto Hydro experienced three major events as listed in Table 5 below.

Table 5: List of Major Events from 2011 to 2013

Dates	Major Event Description
October 29-30, 2012	Hurricane Sandy
July 8-9, 2013	Significant Thunderstorm
December 21, 2013 to January 3, 2014	Ice Storm

Irrespective of storm events achieving the status of a major event, the damage that they inflict on the distribution system can require significant crew effort and resources to repair. The Significant System Disturbance Response segment funds the necessary maintenance expenditures to return the distribution system to normal condition following storm and major events. The following figures illustrate examples of damage that has been repaired in recent years.

Figure 9: Damage caused during a storm on February 19, 2011.

Figure 10: Damage caused during Hurricane Sandy on October 30, 2012.

Figure 11: Damage caused during a severe thunderstorm on July 19, 2013.

Figure 12: Tree branches and damage to overhead conductors caused during the 2013 Ice Storm.

When major events and storm damage occur, Toronto Hydro directs requisite resources to repair the damage and restore power. For events such as the 2013 Ice Storm, which caused tremendous and widespread damage, all available resources, including internal resources (e.g., crews on planned projects) or external resources (e.g., contractors, mutual aid crews from other utilities) are utilized and funded through the Significant System Disturbance Response segment. This approach is necessitated by customer expectations, the need to ensure that critical infrastructure and services such as transit, hospitals and water pumping stations are functional, and to generally meet the needs of the dynamic, urban environment in which Toronto. The approach is also necessitated by a need to mitigate public and employee safety (e.g., downed conductors, damaged poles), system reliability (e.g., long durations of customer interruptions), and environmental risks (e.g., failed transformers leaking oil) that storm damage and major events raise.

4.1. Segment Costs

The following table contains the historical and planned expenditures for Major Event and Storm Damage Restoration segment.

Table 6: Historical and Forecasted Segment Costs ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Total	1.2	2.2	12.4	1.7	1.6

Expenditures can be particularly volatile given the unpredictable nature of major events and storms. Historic expenditures have ranged from a low of $1.2 million in 2011, which was a year with no major event days, to over $12 million in 2013, which was a year with 12 major event days.

4.2. Test Year Segment Costs

Expenditures for 2015 are forecasted to be $116 million. This amount is based on the average annual expenditures incurred during the 2011 to 2013 period (after excluding expenditures associated with the 2013 Ice Storm event[11]) and has been adjusted for savings that are expected to result from increased Vegetation Management accomplishments (i.e., storm-hardening activity) as discussed in the Preventative and Predictive Maintenance program.[12]

[11] Ice storm restoration expenditures were excluded due to the extent of the damage that was caused and the fact that such an event is not expected to occur frequently.
[12] Exhibit 4A, Tab 2, Schedule 1.

DISASTER PREPAREDNESS MANAGEMENT (DPM) PROGRAM

1. SUMMARY

Table 1: Disaster Preparedness Management Program Costs ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Total	0.9	-	-	-	2.4

Events such as the October 2012 Hurricane Sandy, July 2013 flash flood and December 2013 ice storm have places an emphasis on Toronto Hydro's capability for timely and effective response to major contingency events affecting a large proportion of the utility's customer base and the major urban environment it serves. While the utility has responded to these events in a timely and effective manner reflective of its capabilities and the combination of external constraints characterising each event, subsequent analysis, industry comparisons and feedback from customers and partner organizations indicate that Toronto Hydro and its customers would benefit from a more comprehensive and robust framework for disaster preparedness planning, management and operation under major contingencies.

Toronto Hydro has been, and remains compliant with all the applicable Ontario Energy Board ("OEB") and Independent Electricity System Operator ("IESO") emergency preparedness requirements. However, recent experience indicates that the utility needs to direct additional efforts towards entrenching and enhancing the existing emergency operating procedures, and conducting regular training and simulation activities to ensure that these frameworks are fully understood by the utility's employees and can be put into action when required on short notice. The need for the proposed program is driven by the increasing frequency of major weather events affecting the City in recent years, driven,

among other factors, by climate change[1], the insights gained from responding to such events, and the critical nature of the load served by Toronto Hydro in Ontario's and Canada's context.

The proposed program includes the following components:

- Enhancement of the existing Incident Management System ("IMS") and Incident Command System ("ICS") frameworks;
- Development of Toronto Hydro's grid scenario analysis and contingency planning capabilities;
- Preparation for and execution of targeted Mutual Assistance Agreements and plans with utilities serving systems similar to Toronto Hydro's; and
- Implementation of comprehensive training and exercise programs to ensure staff understanding of and proficiency with the new disaster preparedness and management frameworks.

The elements of the proposed program align with the recommendations of the recently released report by an Independent Review Panel entitled "The Response of Toronto Hydro-Electric System Limited to the December 2013 Ice Storm" discussed in more detail in Table 1 and filed as Appendix A to this schedule. Toronto Hydro's current funding levels allocated to emergency management and corporate disaster preparedness do not permit it to undertake the required scope of program development and implementation. Accordingly, the expenditures proposed with this schedule are not currently reflected in Toronto Hydro's rates.

[1] Tiffany Finley and Ryan Schuchard, Adapting to Climate Change: A Guide for the Energy and Utility Industry, online: Business for Social Responsibility <http://bsr.org>.

2. PROGRAM DESCRIPTION

Toronto is a largest city in Canada, and is a home to Canada's major financial services institutions and a host of a number of critical organizations that directly affect the well being of Ontarians and Canadians beyond the City's municipal boundaries. These include:

- Ontario provincial government and its agencies;
- Major hospital networks;
- Major transportation hubs and links;
- Media outlet headquarters;
- Water distribution and treatment facilities.

Moreover, the City frequently hosts major events of provincial, national and global significance, such as the 2010 G20 Summit, 2014 World Pride and the upcoming 2015 Pan American and Parapan Games. While these the City of Toronto's magnitude and strategic significance presents operating challenges under normal circumstances, the situation is significantly complicated during major contingency events such as natural disasters (Ice Storm), health epidemics (SARS) or major civil unrest (G20 riots). The unique characteristics of each emergency event can challenge a utility's ability to effectively respond to and facilitate the event's timely resolution in different ways, but also often help the utility identify certain gaps or vulnerabilities that warrant subsequent improvement. To effectively identify and correct for such gaps, utilities require a comprehensive emergency preparedness framework and dedicated resources and processes to research, identify, evaluate and implement the requisite adjustments and enhancements to the existing practices.

While storms and other emergencies require a concerted response from across the utility's staff, these events put an equal strain on the utility's operating structures themselves, as the nature of the response activities and the decision-making underlying

their execution are inherently different from the decision-making that occurs under normal circumstances. To be effective under emergency conditions, the utility requires a fundamentally different set of operating procedures that accord the employees with requisite flexibility. These operating procedures must empower responders at all levels to make critical decisions, to facilitate fast and efficient event resolution. At the same time, customer expectations as to the nature and range of utility services remain unchanged, or are even heightened during major emergency events. To enhance the utility's ability to effectively operate during major events, Toronto Hydro needs to invest in development, implementation and training of industry-leading emergency operating procedures now to satisfy customer expectations, maintain adequate service levels and ensure public safety during the major events.

Finally, while much research and emphasis goes into studying the effects of disasters on communities, often overlooked is the impact of the disasters on emergency responders themselves. For example, the December 2013 Ice Storm affected Toronto Hydro staff and their families in the same way as it did all Torontonians, by exposing them to obstructed roads, icy driving conditions and dark sky owing to de-energized street lights. Notable employee health and safety risks due to falling branches, traffic accidents, cold temperatures and icy conditions added to the complexity of power restoration efforts during the 2013 Ice Storm. To improve employees' abilities to cope with prolonged contingency events while ensuring operational health and safety, Toronto Hydro would benefit from enhancements and broader scope of its major contingency response training and exercises.

The proposed Disaster Preparedness Management ("DPM") program addresses the above-noted considerations by seeking to enhance the utility's planning, communication and coordination work prior to, during and after the major events that result in significant

and widespread interruptions of electricity supply and/or significant threats to public safety. The proposed program would enable:

- enhanced scenario analysis and disaster planning;
- enhanced communication and coordination with key partner agencies such as Emergency Management Ontario and the City of Toronto's Office of Emergency Management;
- improved access to mutual aid assistance provided by partner utilities;
- more comprehensive emergency response training for Toronto Hydro employees;
- frequent exercise and testing of disaster response roles and systems; and
- continuous improvement of the disaster preparedness management.

More specifically, the proposed program consists of three discrete but inter-related program areas, subdivided into further components, namely: Corporate Disaster Preparedness; Distribution System Disaster Planning; and Training, Exercising and Testing.

2.1. Corporate Disaster Preparedness

Corporate Disaster Preparedness refers to the enhancement of the existing framework, and implementation of an overarching management system, and corporate standards for the development, implementation and continuous improvement of all disaster preparedness functions (emergency management, business continuity, contingency planning). This program area consists of two components:

(a) Enhancements of the Incident Management System ("IMS"); and

(b) Incident Command System ("ICS").

2.2. Distribution System Disaster Planning

Implementation of ongoing grid-specific scenario building, analysis, planning and response processes and procedures to ensure sustainment and effective restoration of the electrical service, along with implementation of detailed agreements and plans to

access additional crews via mutual aid assistance. This program area also consists of two components:

(a) Grid Scenario Analysis and Contingency Planning; and

(b) Mutual Aid Planning.

2.3. Training, Exercise and Testing

Development and delivery of all requisite theoretical training and practical training programs, scenario-based exercises and maintenance of emergency response skills underlying the implementation of the first two program components. This program consists of two streams:

(a) Disaster preparedness training; and

(b) Disaster preparedness exercise and testing.

The elements of the proposed program align with the recommendations of the report prepared by the Independent Review Panel (the "Panel") which was established to evaluate Toronto Hydro's response to the 2013 Storm. The report, which is filed at Appendix A to this schedule, provides a number of recommendations to Toronto Hydro, including:

- Update emergency response plans to align with vision and strategy, incorporate the documentation of key processes and procedures, and train response roles and structure;
- Improve situational awareness capabilities to enable development of accurate estimated time of restoration and facilitate focus on critical priorities;
- Develop capacity to provide customers with access to report and obtain critical information related to their outages, during day-to-day, as well as large-scale outages;
- Educate customers and stakeholders to ensure that they understand their responsibilities and are better prepared and more fully informed when incidents

occur (e.g., impacts requiring repair of damaged equipment on customer property);

- Codify the process for rapid access to and deployment of trained, certified, and equipped resources;
- Pre-define restoration approaches that are scaled to outage levels and can be executed efficiently and safely; and
- Enhance collaboration between Toronto Hydro and the City to integrate outreach, messaging, and education to improve citizen preparedness and awareness of major events.

The following chart shows the manner in which the components of the Disaster Preparedness Management program, discussed in more detail below, align with the Panel's recommendations.

Table 2: Program Alignment with Panel Recommendations

IRP Recommendations	Program Area 1		Program Area 2		Program Area 3	
	Program Components					
	IMS	ICS	Grid Prep	Mutual Aid	Training	Testing
Update emergency response plans to align with vision.	X	X	X		X	
Improve situational awareness capabilities.		X	X		X	X
Develop capacity to provide customers access to outage info.	X					
Educate stakeholders to ensure understanding & preparedness	X	X	X		X	X
Codify the process for rapid access to resource deployment.			X	X		
Pre-define restoration approaches that are scaled to outages.			X		X	X

IRP Recommendations	Program Area 1		Program Area 2		Program Area 3	
	Program Components					
	IMS	ICS	Grid Prep	Mutual Aid	Training	Testing
Enhance collaboration between Toronto Hydro and the City.	X				X	

3. CORPORATE DISASTER PREPAREDNESS

3.1. Incident Management System ("IMS")

A fundamental challenge of disaster preparedness activities for a utility is to accomplish the maximum amount of work in a constrained timeframe with limited resources available, working in an inherently dangerous environment. To meet this challenge, utilities require a management system that is distinct from a normal operating management model to effectively absorb the impact of disasters on their operations. The proposed enhancements / implementation of the Incident Management System ("IMS") and Incident Command System ("ICS") are proven approaches of managing emergency situations of any scale, adopted by a number of utilities in the United States (Florida Power & Light, ConEd, ComEd, Southern California, NiSource etc.)[2] as well as the U.S. Department of Homeland Security and other U.S. government agencies involved in managing natural disasters and other emergency events.

Toronto Hydro is aligned to best practices with respect to the current IMS and corresponding ICS. Toronto Hydro has developed a crisis management command structure used by the executive team and those in management. However, personnel who are relied upon to support that command structure typically follow normal operating procedures, and need to be trained on ICS/IMS frameworks to enable effective

[2] John Kullmann, "Utilities and the Incident Command System" Online: Electric Energy Online <http://www.electricenergyonline.com/show_article.php?mag=97&article=773>.

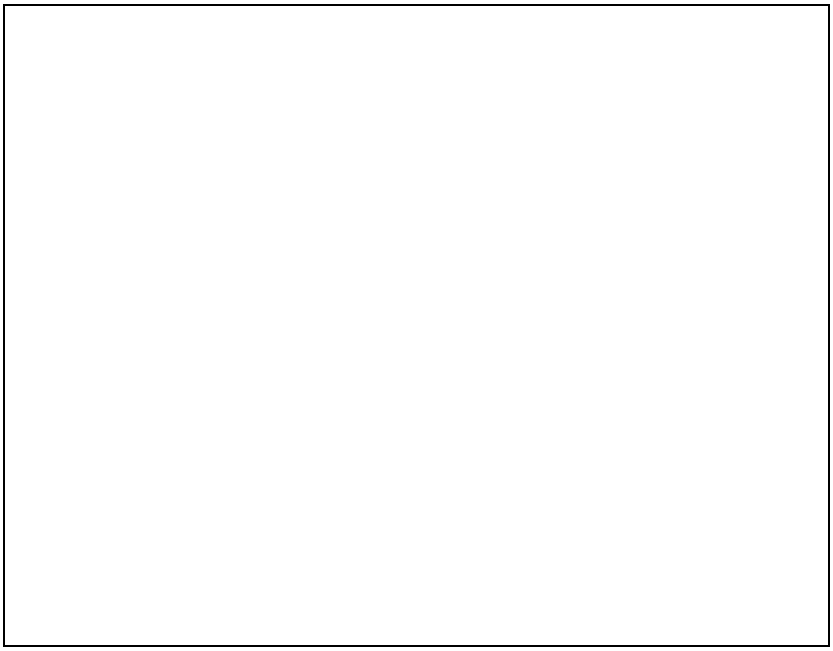
coordination of work execution. The expansion of the IMS framework across the organization is expected to enable the utility to manage emergencies more effectively. A comprehensive IMS framework also aligns with Toronto Hydro's continuous improvement cycle of Plan, Do, Check, Act[3] which responds to established emergency management standards and guidelines such as CSA Z1600, Emergency Management and Business Continuity and ISO 22301, Business Continuity Management.

Toronto Hydro currently has in place an overall framework for its existing Corporate Disaster Preparedness portfolio (as illustrated in Figure 3), which ensures compliance with the terms of its distribution license, but is primarily governance centric in its nature. This framework has been instrumental in establishing Toronto Hydro's Disaster Preparedness Steering Committee and a forum which oversees the development and progress of the utility's disaster preparedness activities.

Pending approval of the requested funding, Toronto Hydro seeks to fully develop its IMS by expanding the current framework into a management system specific to grid impacts. This entails identifying all the necessary grid operation-related elements of a disaster preparedness management system, as well as the necessary methodologies and processes for planning, implementing, executing and taking corrective action as described in the CSA and ISO standards. The contemplated migration will move the IMS away from the broad corporate view by developing the management framework elements specific to addressing grid-related issues. As noted in the Panel's findings, the current function of the corporate disaster framework enables visibility, but not the granular level of detail required to affect the optimal response to grid events. Figure 1 showcases the current state of IMS implementation at Toronto Hydro and identifies the areas of improvement for accomplishing more comprehensive IMS implementation.

[3] To learn more about this framework, refer to the Human Resources and Safety program at Exhibit 4B, Tab 2, Schedule 14.

The graph below (Figure 1) depicts the methodology and level of measure adoption currently developed at Toronto Hydro, showing the 2014 plan line in green along with the current state in black. As this is only depicting the Tier 1 functions (Figure 2) the corresponding graphs for Tier 2 and 3 would be currently at zero. Table 2 on the following page provides a high-level definition for each maturity level (1-5).



Green line shows the desired maturity state of the existing Corporate Disaster Preparedness Program

Black line shows the current maturity state of the existing Corporate Disaster Preparedness Program

Program maturity scale of 1 to 5 represents a quantitative score of increasing maturity from initial to strategic.

Figure 1: Current Corporate Disaster Preparedness Maturity

Table 2: Current Corporate Disaster Preparedness Maturity

1	2	3	4	5
Initial	Fragmented	Comprehensive	Integrated	Strategic
x Objectives, policies, a strategy and processes are absent	x Objectives and policies are somewhat undefined	x Some objectives, governance and oversight is defined	x Most relevant aspects have been defined	x Strong culture of Disaster Preparedness
x Disaster Preparedness is performed on an 'as needed basis'	x No coordination between business units	x Disaster Preparedness is hazard-specific and silo-ed in its coordination	x An 'all-hazards' approach has been adopted for Disaster Preparedness	x Disaster Preparedness is strategically 'all hazards' and complimented with hazard-specific plans
x Little to no accountability for preparing for disasters	x Activities are focused on reaction and response planning and actions	x Activities are focused on functional recovery after the fact	x Disaster Preparedness is integrated across business units	x Enterprise Risk and Disaster Preparedness is aligned
			x Activities are focused on continuity	x Activities are focused on building a resilient Toronto Hydro

3.2. Incident Command System

Once a disaster is triggered, the critical components of IMS framework (processes, plans, personnel) are activated to manage the incident. To ensure effective management of a crisis at hand, Toronto Hydro requires an appropriate management structure to oversee the effective and proper use personnel and resources. This structured is referred to as the Incident Command System ("ICS").

The ICS establishes a clear, yet flexible management hierarchy for the entity-wide approach to resolving disaster situations and managing its dedicated system and resources as illustrated in Figure 2 below. It is an intentional departure from a utility's normal

operating organizational hierarchy, which typically involves a vertical reporting chain of command not suited to making decisions under emergency circumstnaces. The ICS is an established best practice in the U.S.[4], and has also recently adopted by Ontario's emergency management coordinating body, the Office of the Fire Marshal and Emergency Management.

The ICS is an objective-based command structure which prescribes different roles and responsibilities for disaster responders to fulfill. The key benefit of ICS is once deployed, the organization shifts from operating as separate divisions to specific functions that strive to achieve a common objective set by the Incident Commander. Ultimately, this structure ensures all of the key "pieces" (functions) required to fix the problem are activated and working in synergy toward a common goal.

Operating under the ICS model empowers decision makers (Section Leads) to take the actions required to respond to the emergency, they, Incident Commander, who is charge of emergency response, oversee these actions. Operating under normal conditions (as separate divisions using regular reporting structures and responsibility) can cause delays in response and decision making.

[4] Grant Davies, Miki Deric, and Brooke Davies, "Emergency Response - Incident Command System" (2005) November/December Electric Perspectives at page 60, online: Electric Perspectives <http://daviescon.com/wp-content/uploads/2012/05/2005-11-EP-Emergency-Response-The-Incident-Command-System.pdf>.

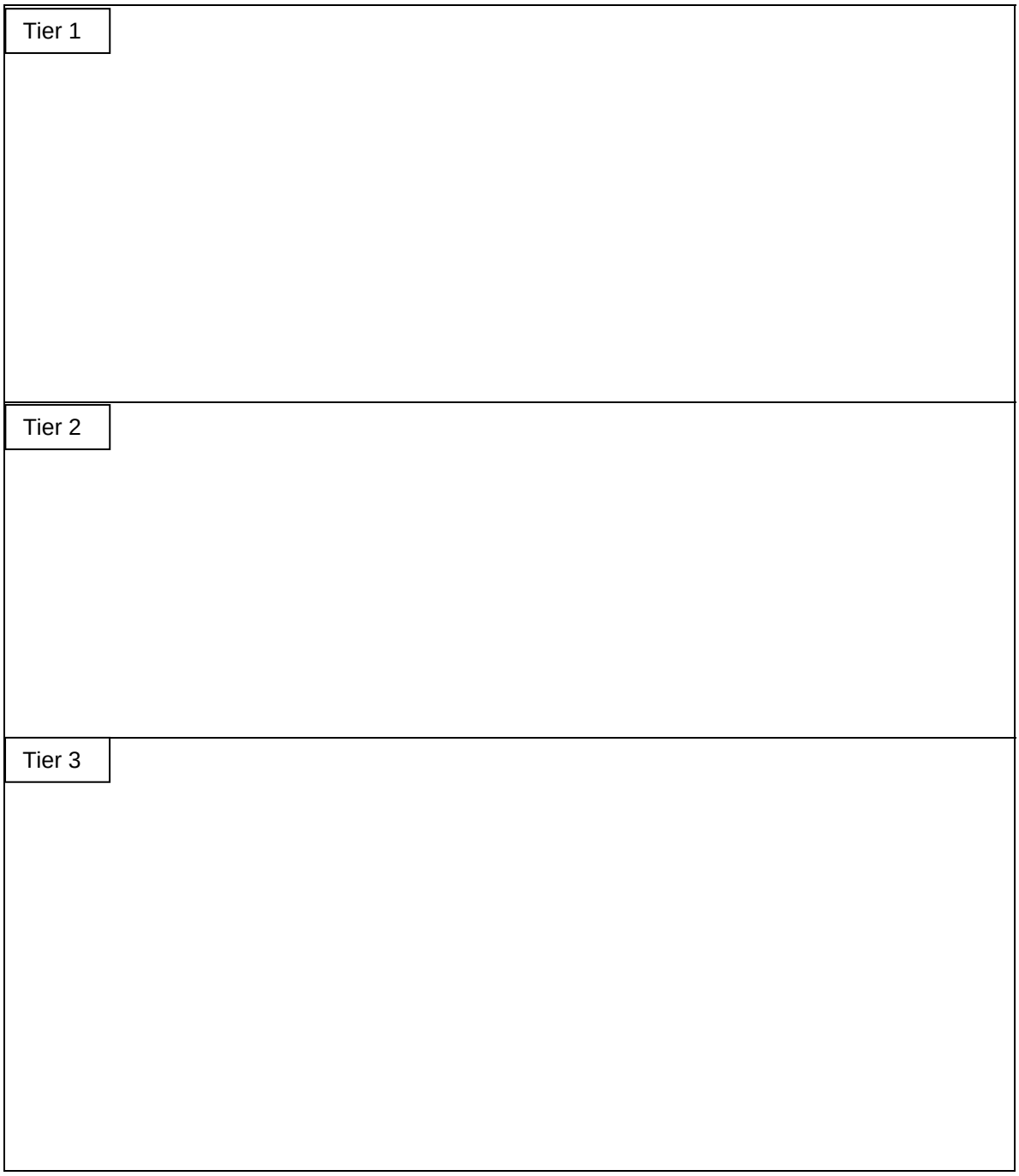


Figure 2: Example of Incident Command System. Source: FEMA

The implementation of this flexible management structure is expected to allow Toronto Hydro to commence resolution of contingencies faster and more effectively, by

empowering assigned decision makers to make critical decisions upon arrival on event site. This is done by prescribing specific roles and responsibilities that are required to manage any type of emergency event. ICS creates a hierarchy-based structure, allowing the Incident Commander and Section Leads to respond to the incident as needed. Reporting hierarchies applicable under normal conditions are not designed to manage disasters and may slow down the restoration efforts.

Beyond enabling Toronto Hydro to enhance decision making during an emergency, the ICS framework establishes clear accountability lines and defines standard communications protocols and common terminology between field crews and the control authority, and across the first responder teams themselves. This significantly improves work coordination across the affected area(s) and streamlines the process of obtaining and communicating interim status updates and decisions between the control centre and crews deployed in the field. As with the incident organizational structure itself, the normal communication protocols are not suitable under the ICS model, given the effectively different organizational structure and signoff/reporting relationships that are used under the normal circumstances. These communications protocols and special procedures apply to all parts of the utility's contingency response, including the control centre-field interface, and the sections/employees taking charge of the funds, facilities, equipment, human resources and customer communications. All issue-specific rules and operating procedures require extensive testing under simulated conditions as well as a sign-off from authorities that control each area under normal circumstances.

The concept of managing an emergency using the Incident Command System is not new to Toronto Hydro. At the executive level, the utility has developed the ICS framework for all command staff and section leads ("Tier 1" in Figure 3 below). At present, the second tier of ICS management, which covers the roles and responsibilities of those supporting the Section Leads, have not been developed or implemented. The same is true

for the third tier of ICS management, where the specific emergency roles and responsibilities of staff in the field, office staff who could be given alternate roles during contingency events have not yet been developed.

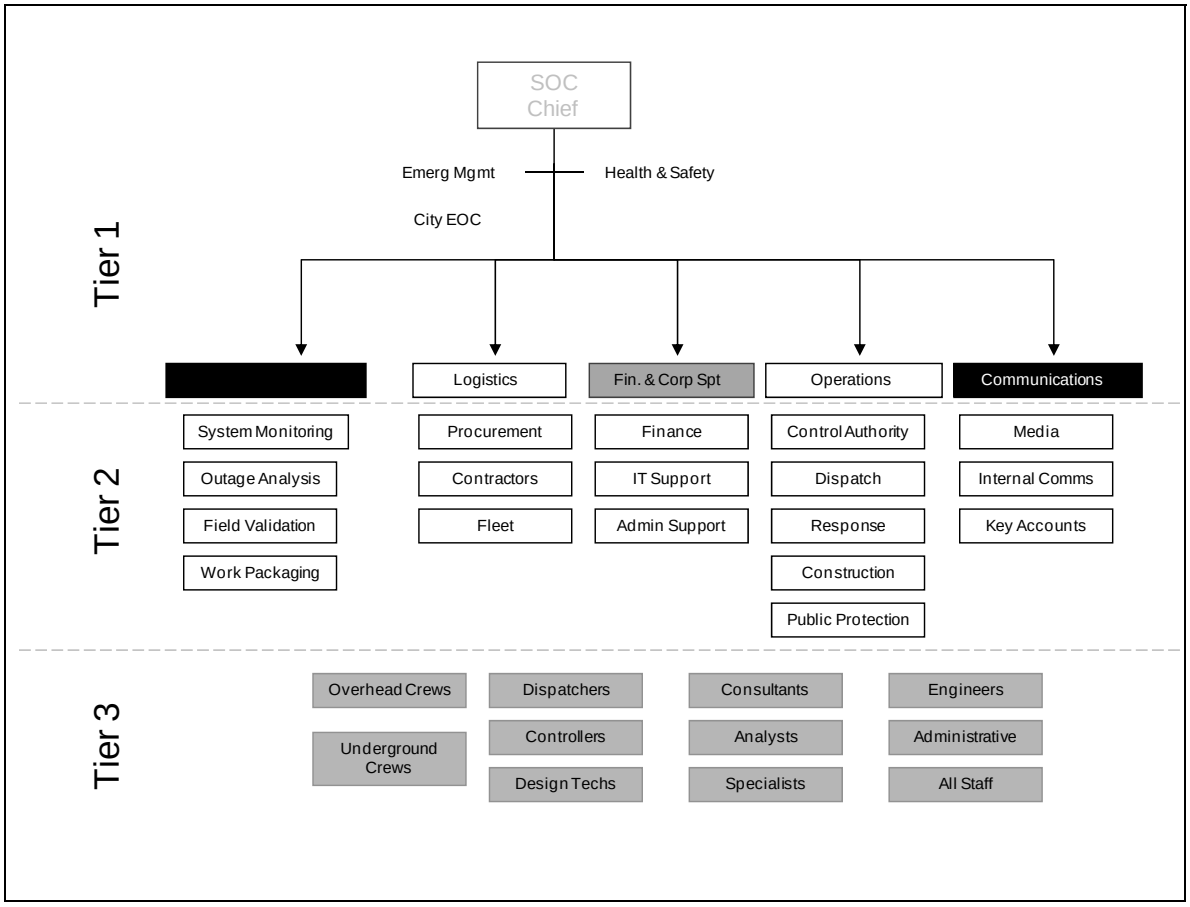


Figure 3: Toronto Hydro's Incident Command System

Accordingly, Toronto Hydro seeks funding for the development, detailing and implementation of its second and third tiers of the ICS framework. This development work entails defining roles and responsibilities, building processes, tools and systems, and enhancing methodologies to assist in improved response. Toronto Hydro envisions that at the completion of Tier 2 and 3 implementation, all employees will be assigned an

emergency role in Toronto Hydro's Incident Command System to ensure they are properly trained to competently fulfill their duties in the event of a disaster.

Once completed, Toronto Hydro expects to have readily available internal resources to fulfill emergency duties in the event of a disaster, thereby reducing the risk of resource shortages. Ultimately, Toronto Hydro plans to fully staff its incident command system to provide two resources for every position in the system, and three mutually exclusive shifts when around-the-clock disaster preparedness activation is necessary.

4. 2.2 DISTRIBUTION SYSTEM DISASTER PLANNING

4.1. Grid Scenario Analysis and Contingency Planning

At an operational (grid response) level, the utility has traditionally maintained three levels of grid emergencies which outline grid impact triggers and respective actions that the utility is allowed to take in order to restore power. While Toronto Hydro has experienced many level 1 and level 2 emergencies which it has managed effectively, the utility's response to the less frequent level 3 emergencies (owing in part to their infrequent nature and the utility's limited experience in addressing them), has shown areas for improvement, as highlighted by Independent Review Panel (the "Panel") for the December 2013 Ice Storm.

A key finding of the Panel was that Toronto Hydro does not have sufficient experience with significant grid disturbances, and lacks Level 3 emergency scenario development and preparation. For instance, larger U.S. utilities, with more experience in handling significant system contingencies, were found to have four or five levels of grid emergencies corresponding and the respective level of response. In order to correctly identify and develop plans for the appropriate level of response to severe disasters

impacting its grid, Toronto Hydro needs to undertake continual stress testing and scenario analysis on the impacts of events of varying nature and magnitude. At present, the utility does not possess the adequate funding or resources to undertake such scenario analysis, simulation and response framework development.

Apart from the onset of disaster events, Toronto Hydro is continually approached by municipal and provincial authorities as well as individual organizations hosting events in the City, to provide a level of assurance in the form of contingency plans for specific events such as the G20 in 2010 or PanAm Games and many others smaller-scale events that bring together thousands of participants. Each of these events is unique in nature, making their scope difficult to adapt to Toronto Hydro's existing grid emergency plans. At present, utility grid emergency plans are focused on sustaining large critical loads impacting the preservation of the provincial grid. However, when Toronto hosted the G20 meeting in 2010, it was obliged by the provincial and federal government to prepare plans and provide coordination in the event of power disruption. The same level of commitment is being required by provincial entities in preparation for the upcoming 2015 PanAm Games, along with similar requests for special preparedness for smaller events, such as major conventions hosted by the city.

Accordingly, Toronto Hydro seeks funding for the enhancement of event-specific grid emergency planning. This entails the improvement of emergency levels 2 and 3, and the development of additional levels of emergency response for significant system disturbances through simulating stressing scenarios on Toronto Hydro's grid emergency plans and protocols. Resources dedicated to this program area could be leveraged to oversee the number of event-specific contingency planning requests received on an annual basis. Improvements and enhancements towards increasing Toronto Hydro's grid emergency preparedness would add a stronger assurance for the IESO and government interests that Toronto Hydro is prepared to respond to major grid disasters.

4.2. Mutual Aid Planning

The scale and impact of emergency and disaster events faced by utilities may exceed the complement of resources available to respond to the disaster in a timely and effective manner, requiring utilities to seek external support from their peers. The exchange of crews, equipment, supplies or expertise between neighbouring utilities in times of emergency need is commonly referred to as mutual aid assistance.

Mutual aid assistance is highly beneficial for utilities for a number of reasons. First, understanding that large-scale emergencies affect any utility, mutual aid is a common understanding of goodwill between neighbouring utilities, which facilitates a cooperative spirit in determining arrangements that benefit all parties entering into the agreement. Second, from a financial perspective, mutual aid partners agree to provide all necessary sustenance, accommodation and appropriate compensation for visiting crews, with the understanding that the utility furnishing mutual aid is not doing so for profit. Third, a mutual aid arrangement between utilities will ensure ready access to the complete compliment of expertise, vehicles, equipment and supplies needed to restore power. However, as further described below, mutual aid assistance can carry operational challenges and requires a significant amount of planning and coordination to be leveraged safely and efficiently.

To ensure the safety of crews coming to assist Toronto Hydro during disasters, the utility needs to undertake significant research, negotiation and planning to facilitate mutual aid assistance and derive the maximum benefits of such arrangements. Jurisdiction-specific legislative and regulatory regimes, different operating standards and system configurations, can significantly limit the host utility's ability to take full advantage of the mutual aid assistance in a short timeframe. Operational complications associated with differences in safety practices, work protection code, construction standards and restoration practices, and lack of familiarity with the requesting utility's system often

results in mutual aid crews being assigned to other, non-critical tasks, which ultimately leads to longer restoration times and prevents the full utilization of highly qualified resources. While still providing critical relief, the difficulties that are often encountered with respect to the effective deployment of mutual aid assistance crews can lead to an increase in overall remediation costs.

There is no utility in Ontario that is sufficiently similar to Toronto Hydro, in large part because of the downtown underground secondary network which requires highly specialized utility workers, and the number of assets used on the system that are not widely deployed elsewhere in the province (i.e., Overhead Box Construction, PILC cable etc). In the event of a disaster requiring additional underground network expertise, Toronto Hydro must look towards utilities such as Con Ed in New York or Com Ed in Chicago (just as Con Ed approached Toronto Hydro during Hurricane Sandy in October 2012).

At present, the mutual aid arrangement in Ontario is informally led by Hydro One who groups local distribution companies into three proximity-based zones and facilitates the annual upkeep of contacts and a high-level estimate of available resources. Toronto Hydro is currently grouped in a zone with utilities such as Orangeville and Guelph Hydro, which are not comparable to Toronto Hydro's operations in either size or distribution system complexity. This system also does not account for large scale events (like the ice storm) that affect significant areas of Ontario beyond Toronto, further reducing the availability of mutual aid resources.

Accordingly, Toronto Hydro seeks funding for the development and implementation of a mutual aid program which better suits its needs and would explore targeted bi-lateral or multi-lateral mutual aid agreements with other utilities that can effectively respond to contingencies on its system. This includes developing a framework, negotiating

agreements, and developing plans and processes that would be scalable for the safe and efficient movement of crews and resources between Canadian and American utilities depending on the specific resource requirements during an emergency.

At present, Toronto Hydro's mutual aid program is in its nascent stages (specifically at Stage 1 as showcased in Figure 4). With appropriate funding, Toronto Hydro plans to further enhance its mutual aid program (initiated in partnership with ComEd in October 2013) to Stage 2. This would include all facets of Toronto Hydro requesting (intake) and furnishing (outbound) mutual aid assistance and would align the program with the recommendation of the Panel.

Key areas of mutual aid planning include: developing contracts, administrative planning, development and facilitation of safety training, establishing a standardized needs assessment, allocation and staging, logistics and resource plans, administrative reporting, stand down and release processes.

Criteria	Initiate	Interim	Vision
Mutual Aid Stage	1	2	3
Level of Commitment	Voluntary	Obligated*	Preparation Indicators*
Resource Requests	A la carte	Combo	Packages
Resource Output	Limited scope of work for responding resources	Moderate use of responding resources' full potential	Full utilization of responding resources full potential
Formality	Letter of Intent	Memorandum of Understanding	Mutual Aid Agreement

Figure 3: Toronto Hydro's Mutual Aid Stage Description and Criteria Used to Enable Functional Enablement without Completed Detailed Program.

On January 23, 2014, Toronto Hydro was appointed co-chair of the Canadian Electricity Association's ("CEA") National Mutual Aid Working Group, tasked with developing a

national standard for mutual aid assistance. This standard will entail common tools, agreements and plan formats to standardize and facilitate enhanced mutual aid assistance and planning across Canada. Collaboration with the CEA and partnering utilities on this project demonstrates Toronto Hydro's commitment to be more efficient by building on the existing national experience and expertise. Along with the CEA efforts, Toronto Hydro endeavours to join the Northeast Mutual Aid Group, alongside Hydro One and Hydro Quebec, adding further strength to this program.

5. TRAINING, EXERCISE AND TESTING

5.1. Training

Once the previously mentioned frameworks, systems and arrangements are developed, Toronto Hydro will need to develop specific training modules, schedules and sessions to impart these new frameworks onto the utility workforce. This is required to ensure that employees understand the emergency roles and communication protocols outlined in the management system and plans, and develop the appropriate competencies for meeting these new roles effectively.

At present, the training program is in its nascent stage and focuses mainly on the management level (Tier 1 of Figure 3) of the Incident Command System. Currently, efforts remain focused on the executive team as the resources required to develop and facilitate training are fully engaged by other projects. In addition, many of those filling the ICS roles do not work together under normal operations, making coordination more challenging during a real event.

Continual training and exercising of disaster roles and responsibilities is crucial for effective response during contingency events, as without repetition and continuous improvement of special skills and tasks they are often forgotten or not fully internalized.

To meet the sudden impacts caused by storms, Toronto Hydro requires a workforce sufficiently competent in both their primary responsibilities and their mandates under the disaster conditions and the alternate roles they may play if an emergency event materializes.

Larger multi-day emergencies such as the December 2013 ice storm require three rotating shifts to ensure responders are sufficiently rested to work safely and effectively and prevent burn-out. In order to facilitate such transitions between three shift rotations and an effective, continuous 24/7 operation, the ICS model needs to be fully staffed with three shifts that must all be equally competent in the ICS framework and the associated procedures.

Toronto Hydro seeks funding to provide training sessions on a proactive, continual basis for all staff identified as having a role in the proposed ICS framework. Since the ICS model entails a holistic command structure, each rotating shift is comprised of different levels of staff, fulfilling distinct functions. For example, each rotating shift may be comprised of strategic senior management, tactical supervisors and operational field crews. Accordingly, emergency training needs to be tailored for each level of response necessary in an emergency response, and need to be repeated with a periodic frequency to ensure retention and competence.

5.2. Exercising and Testing

At present, due to the lack of dedicated Disaster Preparedness Management resources, exercise, testing and auditing of current plans, procedures and work instructions is limited to several occurrences of limited scope each year. Exercising and testing is commonly reserved to scenario analysis or discussion based exercises, which provides an exploratory platform for participants, but does not go into the depth required to fully train personnel in an alternate role.

Mature exercise and testing programs are action-based, requiring participants to demonstrate their training and facilitate a benchmarking platform which is more advantageous in identifying strengths and weaknesses of tested systems and plans. To provide the assurance to the city and its customers that disaster preparedness initiatives are working as envisioned, plans and systems need to be rigorously tested on a continuous basis, while personnel undergo regular exercising to identify areas for improvement.

In addition to testing the Incident Command System, training and exercises will need to be developed around Grid Scenario Analysis and Contingency Planning. All issue-specific rules and operating procedures require extensive testing under simulated conditions.

Toronto Hydro seeks funding to develop a sound exercise and testing program within its disaster preparedness management system based on a framework of performance criteria as the indicator of its training success or failure. Since exercise and testing are intricately linked to training, all staff and systems receiving training must be exercised and tested with the same frequency. Funding is required to develop exercises and tests for all three tiers of Toronto Hydro's proposed ICS framework and the three rotating shifts. Complimenting these exercises and tests are requirements for facilitation, auditing and reporting tools, templates and expert evaluations. Once exercise or test reports are submitted, amendments to plans, procedures and systems need to be taken to close identified gaps, while more intricate exercises are required for the next round of testing to ensure the requisite rigour.

Another key component to providing quality assurance is the need to contract third party assessors to ensure that Toronto Hydro's processes are robust and effective. The discipline of

disaster preparedness or emergency management is relatively new and Toronto Hydro would benefit from periodical assessments by external experts to provide an unbiased perspective, recommendations and new ideas for continuous improvement. Accordingly, in addition to training program development and facilitation, Toronto Hydro requires funding to source auditors and emergency management consultants to periodically evaluate and provide recommendations as the disaster preparedness management program evolves.

6. PROGRAM COSTS

Toronto Hydro's proposed 2015 expenditures for this new and sustained program is $2.4 million.[5] The scope of work comprising the program involves program development, implementation, testing, internal control and audit work, and other functions associated with full-scale implementation of a new corporate-wide initiative. Given the scope of work and Toronto Hydro's plans to sufficiently implement this framework by the end of 2015, the internal resources currently available to the utility are insufficient to undertake the project of this magnitude. Comparisons to other utilities indicate that a utility of Toronto Hydro's size should have at least eight dedicated full time employees to manage all facets of a disaster and emergency management program. Con Edison of New York is the closest electric utility comparator in terms of system configuration for both overhead and underground system, and the nature of its service territory which provides power to key national, state and private enterprise customers within a densely urban populated area. Toronto Hydro is seeking to duplicate Con Edison's emergency management success on a scaled basis, by borrowing elements of its emergency management department's reporting hierarchy, such as dedicating emergency management professionals to developing contingency planning and operating frameworks across

[5] Toronto Hydro notes that it has incurred $0.9 million in related expenditures in 2011, but these costs have not been sustained throughout the period due to the funds being reallocated towards other areas of priority.

overhead, underground, sub-stations, preparedness, coordination, strategic emergency planning and business continuity management.

To the extent of its knowledge, Toronto Hydro is one of only four local distribution companies in Ontario who have a dedicated full time position for disaster preparedness/ emergency management/ business continuity (others being Hydro One, Hydro Ottawa and PowerStream). Owing to the limited number of these professionals in the Ontario distribution utilities sector, candidates who specialize in local power distribution may be difficult to identify and retain. In addition to regular program management and administrative activities, Toronto Hydro requires external auditing and expert advice to institute, proliferate, and monitor the implementation of the program.

Being a new program, there are no sustained historical expenditures associated with this operating area.

The following table provides a breakdown of proposed expenditures by main driver:

Table 3: Proposed Expenditures by Main Driver

Expenditure Area	2015
Full time staff	1.55
Contractors (part time staff)	0.2
Consulting	0.25
Training & Exercise cost	0.15
Audit	0.2
Total Program Cost	**2.4**

6.1. Expected Results

Once implemented and completed, the delivery of the Incident Management and Command System, Grid Scenario Plans, Mutual Aid Planning and its subsequent training and testing should result in a higher acceptance and skills retention across the

organization of employees' alternate (emergency) roles and responsibilities and the overall corporate emergency management system and protocols. More specifically, as the program matures, the utility expects to see the following results over the rate period:

- an enhanced Incident Management Program to ensure all critical pieces of an effective disaster preparedness program are developed and implemented;
- a stronger Incident Command System to manage emergencies efficiently, effectively using a standard approach for all management levels to enhance emergency response
- grid System emergency planning and scenario analysis to stress test the electrical grid and develop appropriate plans;
- a more rigorous system and plan to accommodate and utilize mutual aid resources, thus facilitating the reduction of power restoration times and its associated costs; and
- a rigorous training and exercise program to ensure all required personnel are regularly trained and exercised on their roles and responsibilities during emergency activation

The objective of enhancing the DPM Program is for Toronto Hydro to have a more extensive and rigorous emergency preparedness program. This is expected to result in improved planning in relation to extreme events and better coordination with partners and peers, and to overall, enhance Toronto Hydro's resiliency. An effective DPM program provides customer value by reducing the duration of power outages, and the associated risks and vulnerability during emergencies. To remain competitive in the global market, and to continue to attract businesses which are increasingly reliant on reliable electricity service under all circumstances, Canada, Ontario and Toronto need a disaster-resilient City.

Final Report

The Response of Toronto Hydro Electric System Limited to the December 2013 Ice Storm

June 19, 2014

Prepared for:
The Toronto Hydro Independent Review Panel
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1. Executive Summary

In early January 2014, Toronto Hydro System Limited (Toronto Hydro or the Company) executive management commissioned an Independent Review Panel (IRP) to review the Company's response to the 2013 Ice Storm. The intention of the review was to confirm emergency management practices that are working well and areas in need of improvement. Toronto Hydro retained Davies Consulting LLC, a leading management consulting firm with extensive experience in utility emergency response throughout North America, to conduct the assessment under the direction of the IRP. This Executive Summary to the IRP Final Report includes: a brief overview of the 2013 Ice Storm and Toronto Hydro's response; a description of the scope of the review; and highlights of the findings and recommendations of the Panel.

1.1. Synopsis of the 2013 Storm and Toronto Hydro's Response

On December 21 and 22, 2013, the Greater Toronto Area (GTA) was at the epicentre of a freezing rain event that brought between 20 and 30 millimetres of freezing precipitation – more than two year's worth – in two days. This severe ice storm resulted in 313,000 service interruptions (at peak) to Toronto Hydro customers. Approximately 57% (416,000) of the customers served by Toronto Hydro lost power at one point during the event, which ultimately affected more than one million City residents. Most of the damage was caused by tree limbs falling on power lines, either creating faults or breaking the lines. In addition to widespread power outages, the event caused extensive property damage and economic losses.

Toronto Hydro quickly mobilized its management team and called in available resources, which began restoration work by 8 a.m. on December 22, 2013, before the storm system departed the Company's service area. Power was restored to all customers who could receive service by the morning of January 2, 2014, 11 days after the restoration began. Toronto Hydro resumed normal operations on January 3, 2014. Approximately 98% of Toronto Hydro's core trade workers supported the restoration effort, aided by another 450 field workers (line and forestry) from contractors and ten other utilities, as well as the company management and

professional office staff. Notably there was only one recordable safety incident at Toronto Hydro over the course of the restoration and no deaths attributed to the storm.

Figure 1 shows the progress of Toronto Hydro's restoration after the 2013 Ice Storm, noting the following milestones:

1. Initial weather statements warning of a potential ice event;
2. Initial request for mutual assistance issued by Toronto Hydro;
3. Power restored to all critical facilities designated by the City Emergency Operations Centre (EOC);
4. Approximately 86% of all customers affected restored (72 hours from the start of restoration);
5. Approximately 90% of customers out at peak restored;
6. Approximately 99% of customers out at peak restored; and
7. All customers who can accept service restored.

Figure 1: 2013 Ice Storm Restoration Timeline with Key Milestones

When compared to the performance of other utilities conducting ice and snow storm restorations, Toronto Hydro's overall performance is well within the industry norm as shown in Figure 2.

Figure 2: Event Benchmark Comparison

Source: Davies Consulting Storm Response Benchmark Database, 2014

1.2. Review Scope and Approach

The organizing framework for the Toronto Hydro review is the widely used emergency management (EM) life cycle, as adapted to the utility environment. Figure 3 depicts this four phase cycle, anchored by a comprehensive incident communications strategy.

Figure 3: Utility Emergency Management Life Cycle

The review addressed nine areas of Toronto Hydro's response. Table 1 shows how they align to the utility emergency management life cycle.

Table 1: Alignment of Toronto Hydro Assessment Scope to Emergency Management Lifecycle

Emergency Management Life Cycle	Toronto Hydro Review Scope
Prepare	ƒ Emergency Planning and Preparedness
Respond and Recover (Restore)	ƒ Resource Acquisition and Allocation ƒ Damage Assessment and Restoration Planning ƒ Restoration Execution ƒ Information Systems and Technologies ƒ Tororto Hydro – City Coordiration
Mitigate	ƒ Vegetation Management and System Hardening/Resilience
Incident Communications	ƒ Communications – Customer Contact ƒ Communications – Other Stakeholders

The Davies Consulting team used a structured, comprehensive, principles based approach to conduct the 2013 Ice Storm Review. They interviewed nearly 80 stakeholders, received close to 100 public comments through Town Halls and email, reviewed relevant internal plans, reports and documentation, and considered pertinent City and Provincial regulations, policies, and emergency management practices. The approach taken by the team preserved the confidentiality of information provided by stakeholders and lead to findings and recommendations that were objective, data r centered, and informed by leading practice.

1.3. Summary of Findings and Recommendations

The review of Toronto Hydro's response to the 2013 Ice Storm revealed both well r executed emergency management practices and areas in need of improvement. The summary findings for each area evaluated, are:

- Toronto Hydro followed an Incident Command System based approach at the management level, but had not fully developed, trained, and exercised the approach across the Company;
- Customers could not obtain timely and accurate information about their outage status (including estimated time of restoration, or ETR) during the event;
- The Company's incident communication performance, with a defined media strategy and unity of message, met or exceeded industry best practices;
- The Company secured and deployed mutual assistance resources early in the restoration and executed the overall mutual assistance process generally well;

- The process for determining restoration priorities was in line with industry leading practices; however, the damage assessment process was not fully executed;
- While the restoration approach varied among the Local Command Centres, the overall restoration duration was similar to that of comparable events in the industry;
- Toronto Hydro has implemented some advanced operational and information technology systems, but has not fully integrated them to provide adequate restoration support and situational awareness; and
- The circuit based vegetation management preventive program is on a three year cycle which meets or exceeds industry best practice and follows industry pruning standards and City of Toronto by laws.

The IRP identified 25 recommendations for consideration by Toronto Hydro management. The following list is a summary of these recommendations by area evaluated:

- Update emergency response plans to align with vision and strategy, incorporate the documentation of key processes and procedures, and train response roles and structure;
- Improve situational awareness capabilities to enable development of accurate ETRs and facilitate focus on critical priorities;
- Develop capacity to provide customers timely access to report and obtain critical information related to their outages, during day to day, as well as large scale outages;
- Work with key stakeholders to identify, agree upon, and fund cost beneficial system hardening and resilience initiatives, including vegetation management and targeted conversion of line segments to underground construction;
- Educate customers and stakeholders to ensure that they understand their responsibilities and are better prepared and more fully informed when incidents occur (e.g., impacts requiring repair of damaged equipment on customer property);
- Codify the process for rapid access to and deployment of trained, certified, and equipped resources;
- Predefine restoration approaches that are scaled to outage levels and can be executed efficiently and safely;
- Update and further integrate key information and operational systems to provide real or near real time intelligence during major events; and

- Enhance collaboration between Toronto Hydro and the City to integrate outreach, messaging and education to improve citizen preparedness and awareness of major events.

1.4. Moving Forward

The 2013 Ice Storm was an unprecedented event that disrupted the lives of most Toronto residents and tested the mettle of the first responders, as well as the City and Toronto Hydro personnel involved in the recovery effort. Through a dedicated, coordinated, and intensive response, the community was safely restored to normalcy within a reasonable timeframe given the amount and type of damage suffered. Toronto Hydro performed the restoration in a manner consistent with industry norms. The Company's management and approach to the restoration was prudent, diligent, and safe. As expected with any large incident, the recovery from this ice storm also exposed several aspects of the emergency response that can be further improved.

In accordance with the commissioned scope of the Panel review, the recommendations presented in this report focus mainly on the improvements that Toronto Hydro can make to further enhance its ability to respond to future events that cause widespread power outages. Additionally, and notably, several of the recommended improvements call for closer cooperation among Toronto Hydro, the City of Toronto and the Province of Ontario to prepare the community for future major outage events. This report should serve as the starting point for a more sustained, coordinated effort among all of these parties.

2. Introduction

On December 21 and 22, 2013, a severe ice storm struck the greater Toronto area, resulting in approximately 313,000 service interruptions (at peak) to Toronto Hydro customers[1]. Approximately 57% (416,000) of the customers served by Toronto Hydro lost power at one point during the event, which ultimately affected more than one million city residents. In addition to widespread power outages, the event caused extensive property damage and economic losses. Toronto Hydro deployed approximately 1,250 field resources, including more than 400 from other utilities and contractors (i.e., off system) restored service to 75% of customers within 48 hours from the time the restoration began. Crews completed restoration of all customers who could accept power by January 2, 2014. Notably, there was only one recordable safety incident at Toronto Hydro over the course of the restoration and no deaths attributed to the storm.

2.1. Purpose, Governance, Scope

On January 9, 2014, Toronto Hydro executives held a press conference to brief the public on the Company's emergency preparedness planning, restoration approach and priorities, and communications strategy during the incident. Anthony Haines, President and CEO of Toronto Hydro, remarked that the 2013 Ice Storm was "the most disruptive incident we have faced." At that time, the Company announced its establishment of an independent panel to oversee a review of its response to the 2013 Ice Storm. The intention of the review was to confirm practices that are working well and to identify areas in need of improvement. The role of the Independent Review Panel (IRP) was to ensure the objectivity of the review and provide guidance and subject matter expertise. IRP members are:

- David J. McFadden, Panel Chair and Partner, Gowling Lafleur Henderson LLP;
- Joseph Pennachetti, City Manager, City of Toronto;
- Sean Conway, Visiting Fellow, Centre for Urban Energy – Ryerson University; and
- Carlos D. Torres, Vice President of Emergency Management, Consolidated Edison of New York, Inc.

Toronto Hydro retained Davies Consulting LLC, a leading management consulting firm with extensive experience in utility emergency response throughout North America, to conduct the review under the direction of the IRP. The effort began in late January 2014.

[1] The peak number of customer interruptions represents the highest number of customers who were interrupted at the same time. Since the event lasted for several days, additional customers lost power at different points in time, ultimately resulting in 416,000 customers experiencing an interruption during the Ice Storm.

The scope of the assessment included all aspects of the widely used emergency management (EM) life cycle, as adapted to the utility environment. Figure 3 depicts this four phase cycle, centered by a comprehensive incident communications strategy.

The main components assessed within each phase of the utility emergency management life cycle are:

- Preparedness
  - Organization and responsibility for emergency management
  - Emergency Response Plan structure and completeness
  - Emergency (or second) roles process
  - Emergency management training program
  - Exercises (table top and functional)
- Response and Recovery (Restoration)
  - Mobilization and level declaration
  - Resource acquisition and allocation
  - Response structure and roles/responsibilities
  - Logistics
  - Restoration strategy and execution efficiency
  - Situational awareness and damage assessment
  - Wires down and cut, clear and make safe process
  - Work planning and prioritization
  - Demobilization
- Incident Communication
  - Communication strategy
  - Estimated Time of Restoration (ETR) development, dissemination, and tracking
  - Key message development
  - One voice communication
  - Social media
  - Liaison program
  - Customer call centre
- Mitigation (Distribution Infrastructure Maintenance and Improvement)
  - Vegetation management
  - Pole inspection
  - Storm hardening
- Use of Supporting Technology Systems (Operational and Information)

2.2. Approach and Methodology

The Davies Consulting team conducting the assessment used a structured, comprehensive, principles based approach to evaluate Toronto Hydro's response to the

2013 Ice Storm. They interviewed nearly 80 stakeholders, received close to 100 public comments through Town Halls and email, reviewed relevant internal plans, reports, and documentations, and considered pertinent City and Provincial regulations, policies, and emergency management practices. Throughout the assessment process, the following core principles guided the work of the Davies Consulting team:

- Transparency – consultants conducting fact finding and analysis have full access to Company information and personnel;
- Inclusiveness – representatives of stakeholder groups have an opportunity to contribute through interviews, public town halls, and email feedback;
- Data centered analysis – findings and recommendations are substantiated by quantitative and qualitative data and original sources of data are used to the extent possible;
- Informed by leading practice – knowledge of industry leading practices is used to develop interview questions and to guide analysis; this knowledge is drawn from Davies Consulting's project work with more than 35 investor owned and municipal utilities, participation in industry associations, and proprietary research; and
- Confidentiality – source information provided by individual interviewees and interested parties is not shared outside Davies Consulting and findings are not attributable to individuals or groups.

Davies Consulting used the following methodology to conduct the assessment of Toronto Hydro:

1. Understand the impact of the storm on Toronto Hydro's system. Characterized the magnitude of the 2013 Ice Storm's impact on Toronto Hydro's distribution system, using weather reports, Toronto Hydro provided documentation, and interviews.
2. Collect pertinent data about Toronto Hydro's performance. In collaboration with Toronto Hydro management and the IRP, identified participants and other stakeholders in the 2013 Ice Storm emergency management and restoration process. Conducted interviews with a representative cross section including: Toronto Hydro management and front line personnel; Union leadership; City of Toronto employees; and City of Toronto elected leaders. Collected public feedback through three town hall meetings and via public email address (torontoicestorm@daviescon.com) for those who were not able to attend. Submitted approximately 50 data requests for operational, call centre, system, and other program data. Review documentation provided along with pertinent City and Provincial policies and regulations (e.g., electric safety code, building code, tree trimming standards).

3. Analyze data to develop findings and recommendations. Evaluated each aspect of Toronto Hydro's response, comparing Company performance against its plans and standards, industry standards, and leading practices. Compared aspects of Toronto Hydro's performance (e.g., restoration duration, cost) to those of other utilities using Davies Consulting proprietary Storm Response Benchmark Database, which is described later in this report. Formulated findings of strengths and opportunities for improvement. Developed actionable recommendations to address areas in need of improvement.
4. Develop final report. Prepared a comprehensive written report that described Toronto Hydro's emergency management and restoration performance, summarized leading or expected practice in each of the nine areas addressed within the scope of the review, and detailed the findings and recommendations for Toronto Hydro management consideration.

2.3. Evaluation Areas

The Davies Consulting review addressed nine areas of Toronto Hydro's emergency planning, preparedness, and response practices. The first eight of these areas relate to the emergency response life cycle as shown on Table 2. The ninth addresses the numerous and significant areas of overlap and integration that occur between Toronto Hydro and City responders when supporting the recovery of the community after an event like the 2013 Ice Storm.

Table 2: Alignment of Toronto Hydro Assessment Scope to Emergency Management Lifecycle

Emergency Management Life Cycle	Toronto Hydro Review Scope
Prepare	ƒ Emergency Planning and Preparedness
Respond and Recover (Restore)	ƒ Resource Acquisition and Allocation ƒ Damage Assessment and Restoration Planning ƒ Restoration Execution ƒ Information Systems and Technologies ƒ Tororto Hydro – City Coordiration
Mitigate	ƒ Vegetation Management and System Hardening/Resilience
Incident Communications	ƒ Communications – Customer Contact ƒ Communications – Other Stakeholders

3. Overview of Toronto Hydro System

Toronto Hydro began operation on May 2, 1911. Today, more than 100 years later, Toronto Hydro owns and operates $2.6 billion of capital assets comprised primarily of an electricity distribution system which delivers electricity to more than 730,000 customers located in the City of Toronto. It is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in the Province of Ontario.

Toronto Hydro is wholly owned by Toronto Hydro Corporation, a holding company incorporated under the Ontario Business Corporations Act in 1999 by the City of Toronto (the "Corporation"), its sole shareholder. In 1998, Bill 103 amalgamated six municipal electric utilities into one, nearly tripling Toronto Hydro's customer base to approximately 650,000 customers. Table 3 provides a snapshot of Toronto Hydro's distribution system characteristics and Figure 4 is a map of Toronto Hydro's service territory.

Table 3: Toronto Hydro System Statistics

Population	2.8 million
Customers	733,800
Service Territory Size	630 square kilometers (240 square miles)
Employees	1,570
Distribution	
ƒ Distribution circuits (number)	1,710
ƒ Overhead (miles)	15,000 km (9,321 miles)
ƒ Underground (miles)	11,200 km (6,959 miles)
ƒ Overhead transformers	60,650
ƒ Poles	175,400
ƒ Switches	16,000
Subsations	169 municipal stations/35 transmission stations (shared)
Meters (12/31/13)	648,000 distribution and 85,800 industrial/commercial

Figure 4: Toronto Hydro Service Territory

4. The December 2013 Ice Storm and Toronto Hydro's Response

On Thursday, December 19, 2013, Toronto Hydro began to track weather warnings from Environment Canada, indicating the probability of an ice event. Starting around 3:00 p.m. on Saturday, December 21, 2013, and into Sunday December 22, 2013, the Toronto Hydro service territory was at the epicentre of a freezing rain event that brought between 20 and 30 millimetres of freezing precipitation (more than two year's worth in two days)[2], resulting in significant ice accumulation on trees and power lines. The ice accumulation left roads and sidewalks slick and dangerous and knocked down trees and tree limbs across the region causing widespread power outages. In addition to wreaking havoc across the Greater Toronto Area, the storm crippled North American transportation at one of the busiest travel times of the year.

The surface map of the storm affected area, in Figure 5 below, shows the concentration of freezing rain over the Greater Toronto Area at the peak of the storm on Sunday December 22, 2013, at 6:00 a.m. (red color represents the freezing rain, while white/blue areas are snowfall). The freezing rain stopped around 9:00 p.m., on Sunday, December 22, 2014.

Figure 5: Surface Map of 2013 Ice Storm at Peak Intensity

Power outages started shortly after 8 p.m. on Saturday and peaked early on Sunday morning when 313,000 customers were without power. The remnants of the weather system continued through the morning of Monday, December 23, 2013, and the

[2] Source: Environment Canada

Company continued to experience additional outages as it began initial restoration. Ultimately, approximately 416,000 customers, or 57% of all Toronto Hydro customers, experienced service interruptions as a result of the Ice Storm, affecting more than one million Toronto residents. The majority of the damage was caused by tree limbs falling on power lines, either creating faults or breaking the lines.

Toronto Hydro quickly mobilized its management team and called in available resources, which began restoration work by 8 a.m. on December 22, 2013, when it was safe to work. Service was restored to all customers who could receive power by January 2, 2014, 11 days after the restoration began. Toronto Hydro resumed normal operations on January 3, 2014, after restoring the remaining customers who experienced damage on their property and required permits from the Electrical Safety Authority (ESA) to be reconnected to the grid. Approximately 98% of Toronto Hydro's core trade workers supported the restoration effort, aided by another 450 field workers (line and forestry) from contractors and 10 other utilities. Figure 6 below shows the restoration progress timeline with the following key milestones:

1. Initial weather statements warning of ice event;
2. Initial request for Mutual Assistance issued by Toronto Hydro;
3. Power restored to all critical facilities designated by the City Emergency Operations Centre (EOC);
4. Approximately 86% of all customers affected restored (72 hours from the start of restoration);
5. Approximately 90% of customers out at peak restored;
6. Approximately 99% of customers out at peak restored; and
7. All customers who can accept service restored.

Figure 6: 2013 Ice Storm Restoration Timeline with Key Milestones

As part of the review of Toronto Hydro's restoration effort during the 2013 Ice Storm, Davies Consulting compared the Company's response to other ice and snow storm restorations, using information from its confidential and proprietary Storm Response Benchmark Database.[3] Figure 7 depicts the restoration duration (on the X axis), percent of customers affected at peak (on the Y axis) and the total cost of restoration (indicated by the size of the bubble). When compared to other similar events, according to these metrics, Toronto Hydro's overall performance during the 2013 Ice Storm was within the industry norm.

[3] Davies Consulting began to develop its confidential and proprietary Storm Benchmark Database in 2003. The database currently contains key statistics from more than 95 major event responses by over 42 electric utilities across North America. While each event is unique and the comparisons among utilities have to be carefully evaluated, benchmarking can be valuable to identify areas where potential improvement opportunities exist.

Figure 7: Event Benchmark Comparison

5. Findings and Recommendations

5.1. Overview

The following sections describe the findings from the review and provide 25 recommendations to address opportunities for improvement. The findings and recommendations are grouped within the nine evaluation areas described in Section 2.3 of this report. The areas are presented in the following order: Emergency Planning and Preparedness; Resource Acquisition and Allocation; Damage Assessment and Planning; Restoration Execution; Communications – Customer Contact; Communications – Other Stakeholders; Information Systems and Technologies; Vegetation Management and System Hardening/Resiliency; and Toronto Hydro City Coordination.

Each finding of a strength and area of improvement is addressed in detail within each evaluation area. The following statements distill the key findings:

- Toronto Hydro followed an Incident Command System based approach at the management level, but had not fully developed, trained, and exercised the approach across the Company;
- Customers could not obtain timely and accurate information about their outage status (including estimated time of restoration or ETR) during the event;
- The incident communication process, with a defined media strategy and unity of message, was in line with industry leading practices;
- The Company secured and deployed mutual assistance resources early in the restoration and executed the overall mutual assistance process generally well;
- Restoration priorities were in line with industry practices; however, the damage assessment process was not fully executed;
- While the restoration approach varied among the Local Command Centres, the overall restoration duration was in line with similar events in the industry;
- Toronto Hydro has implemented some advanced operational and information technology systems, but has not fully integrated them to provide adequate restoration support and situational awareness; and
- The circuit based vegetation management preventive program is on a three year cycle which is in line with industry practices and follows industry pruning standards and City of Toronto by-laws.

Likewise, each recommendation is detailed within each evaluation area. The following list is a top line summary of the recommendations by area evaluated:

- Update emergency response plans to align with vision and strategy, incorporate the documentation of key processes and procedures, and train response roles and structure;
- Improve situational awareness capabilities to enable development of accurate ETRs and facilitate focus on critical priorities;
- Develop capacity to provide customers timely access to report and obtain critical information related to their outage, including blue sky and full scale major events;
- Work with key stakeholders to identify, agree upon, and fund cost beneficial system hardening and resilience initiatives, including vegetation management and targeted conversion of line segments to underground construction;
- Educate customers and stakeholders to ensure that they understand their responsibilities and are better prepared and more fully informed when incidents occur (e.g., impacts requiring repair of damaged equipment on customer premise);
- Codify the process for rapid access to and deployment of trained, certified, and equipped resources;
- Predefine restoration approaches that are scaled to outage levels and can be executed efficiently and safely;
- Update and further integrate key information and operational systems to provide real or near real time intelligence during major events; and
- Enhance collaboration between Toronto Hydro and the City to Integrate outreach, messaging and education to improve citizen preparedness and awareness of major events.

Appendix C provides a summary table of all of the findings (including strengths and opportunities for improvement) and recommendations organized by evaluation area.

For easy reference, each recommendation has an alpha numeric key associating it to one of the evaluation areas (e.g., EPP1, EPP2). The following table lists the reference key for each evaluation area.

Table 4: Recommendations Reference Keys

Reference Key	Evaluation Area
EPP	Emergency Planning and Preparedness
RA	Resource Acquisition and Allocation
DAP	Damage Assessment and Restoration Planning
RE	Restoration Execution
CCC	Communications – Customer Contact
COS	Communications – Other Stakeholders
IT	Information Systems and Technologies
VMS-H	Vegetation Management and System Hardening/Resiliency
TH–C	Toronto Hydro – City Coordination

5.2. Emergency Planning and Preparedness

Across the electric utility industry in North America, emergency management is receiving heightened attention. Over the last 10 years, weather related events have grown in frequency and magnitude, as illustrated by a number of recent catastrophic level storms (e.g., Hurricane Katrina, Hurricane Sandy, Hurricane Irene, the Alberta and Ontario floods of 2013, and the arctic blasts of early 2014). In addition to the weather events, there are growing concerns about and significant efforts to address other types of emergencies/hazards, such as cyber attacks, physical attacks, and pandemics. Recognizing that utilities play an essential role in community recovery once a major event occurs, utility leaders are making emergency management a core corporate competency, as illustrated in the Canadian Electrical Association 2013 Annual Report:

> "CEA member companies understand how important electricity is to virtually every aspect of the lives of Canadians, making emergency preparedness a critical business priority."

Leading practice utilities are strengthening emergency management by:

- Establishing an emergency management vision, guiding principles, and strategy;
- Incorporating the Incident Command System (ICS)[4];

[4] Incident Command System (ICS) is a standardized on-site management system designed to enable effective, efficient incident management by integrating a combination of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure.

The ICS is used to manage an incident or a non-emergency event, and can be used equally well for both small and large situations (Source: ICS Canada).

The Province of Ontario has developed the Incident Management System (IMS) that provides standardized organizational structures, functions, processes, and terminology for use at all levels of emergency response in Ontario. IMS addresses the need for coordinated responses to all types of incidents and is closely related to the Incident Command System (ICS). ICS is used by some first responders in Ontario and many first responders (wild land fire, search and rescue, etc.) across Canada.

- Developing a set of emergency response plans that are comprehensive, useable, scalable, and address all hazards;
- Designating formal emergency response roles and responsibilities, ideally managed within a central emergency management organization;
- Conducting annual system wide exercises designed to stress response processes and enable the Company to identify improvement opportunities prior to an actual event;
- Coordinating with local and state/provincial governments in planning and exercising efforts;
- Partnering with regulatory stakeholders to ensure that the emergency management organization and program is appropriately staffed and resourced; and
- Tying emergency management and preparedness to key performance indicators for staff.

The infusion of emergency management knowledge, skills, and discipline across an organization takes persistent leadership attention, significant investment, and dedicated time. It may take five or more years to fully develop plans, train staff, and exercise capabilities.

This assessment of Toronto Hydro's emergency management planning and preparedness capabilities in advance of the 2013 Ice Storm addressed the following:

- Adherence to ICS principles and practices;
- Emergency management planning;
- Emergency management organization and resourcing;
- Resourcing emergency roles;
- Emergency training and exercises; and
- Liaison/Coordination with external stakeholders (e.g., City of Toronto staff, elected officials, Provincial agencies, first responders).

5.2.1. Emergency Planning and Preparedness Findings

Since 2008, Toronto Hydro has had dedicated emergency planning staff, ranging between one and four full time equivalents (FTEs). Notably, Toronto Hydro centralized the corporate emergency management function in 2012, placing it within the Strategy and Risk Management Group. This group is responsible for the overall corporate

emergency preparedness (all hazards), including developing emergency response plans, facilitating table top simulations and functional exercises, training staff, benchmarking, and coordinating emergency management activities across the Company. The Grid Response Plan provides the framework for responding to major events; however, it does not include sufficient description of all key processes and procedures. Additionally, the Grid Response Plan defines three levels of emergencies which may not be sufficient to address a larger scale event.

Emergency Planning and Preparedness Strengths

1. Emergency response structure largely aligns with the Incident Command System, which is considered to be the industry leading practice in emergency response.

Toronto Hydro uses ICS[5] to manage all types of emergencies. The initial focus of Toronto Hydro's ICS implementation was to establish the Crisis Management Team and Incident Management Team roles and structure and train executives and managers who fill those roles in the Emergency Operations Centre (EOC) and System Operations Centre (SOC). This approach is consistent with comparably mature ICS programs at other utilities.

Toronto Hydro's ICS structure is described in the Company's Crisis Management Plan and Grid Disruption Plan. It closely aligns to the Canadian and Provincial ICS models (See Figure 8 and Figure 9).

Figure 8: Toronto Hydro Incident Command System Structure

[5] The Province of Ontario has developed the Incident Management System (IMS) that provides standardized organizational structures, functions, processes and terminology for use at all levels of emergency response in Ontario. IMS addresses the need for coordinated responses to all types of incidents and is closely related to the Incident Command System (ICS) ICS is used by some first responders in Ontario and many first responders (wild land fire, search and rescue, etc.) across Canada.

The Company's ICS structure includes most of the command staff roles such as Incident Commander, Communications (Public Information Officer), Environmental, Health and Safety Officer (Safety), and general staff roles (Operations, Planning, Logistics, and Administration Section Chiefs). There are two notable differences between the Toronto Hydro structure and the Canada/Ontario structure:

1. Toronto Hydro's Crisis Management Team includes a legal officer, a role common within a private company ICS; and
2. Omission of the liaison officer role.

At Toronto Hydro, the Corporate Disaster Preparedness (CDP) Advisor serves as the liaison officer, acting as the primary interface with the City of Toronto Office of Emergency Management. Lastly, the SOC Manager oversees system operations including all the work protection activities on the distribution system.

Figure 9: Canada and Ontario EM Incident Management System Structure

The Grid Disruption Plan, which governs the restoration of major electric distribution outages, also uses an ICS based response structure. Toronto Hydro used this plan to guide the 2013 Ice Storm restoration. While the roles in this plan have different titles than those defined by ICS, they address the same general staff functions (See Figure 10).

Figure 10 Figure 10: Toronto Hydro Grid Disruption Response Organization

2. Corporate Emergency Management organization is centralized and addresses all hazards.

Toronto Hydro has a standalone emergency management organization that addresses all hazards. Following an unfavorable rate case that resulted in management restructure in 2011/2012, Toronto Hydro downsized its group of full time emergency management professionals from four to one, centralized the function, and placed it within the Strategy and Enterprise Risk Management group. Previously, the organization with responsibility for emergency response was within the Electric Grid Operations group and its primary focus was on grid disruption events.

This move to establish a discrete emergency management function (managed outside of operations) is in line with practices of leading utilities. The separation of the traditional "storm response" group from operations helps to ensure that the focus is all hazards. In addition, this structure enables the group to better engage the entire corporation in a response, versus just the operations group.

Increasingly across the utility industry, the leader of this emergency management organization has the role of Director or Vice President, denoting the corporate importance of this function. The emergency management responsibilities typically include: maintenance and integration of emergency plans; risk management; weather tracking; training and exercises; modeling and analytics; business continuity planning; benchmarking with utilities and other industries and ICS implementation. Since the electric grid is the key asset of a utility, central emergency management groups often include a grid operations expert. Alternatively, they work closely with the grid emergency management lead in the electric delivery business unit.

3. Trained and exercised System Operations Centre (Command Centre) roles and responsibilities prior to the event.

Toronto Hydro has a training and exercise program for Senior Management Standby (SMS) – a group of on-call leaders, SOC staff and the Crisis Management Team (CMT). Toronto Hydro conducted the following training and exercises in 2013:

- Two CMT training sessions;
- Six Grid Disruption Plan training sessions with the SMS; and
- Six exercises:
  - Executives only;
  - Communications team only;
  - Executives and the support team;
  - Executives, support team, and the Independent Electricity Systems Operator (IESO) and North American Electric Reliability Council (NERC) Grid Exercise II (GridEx II);
  - Executives, SMS, and the City of Toronto OEM; and
  - The City of Toronto OEM only.

4. Pre-event weather monitoring process in place and used to support activation decisions.

Building accurate situational awareness is critical when preparing for or responding to emergencies. An important component is the weather forecast. In preparation for the December 2013, Toronto Hydro monitored weather information provided by Environment Canada, the government's source of weather and meteorological information. This effort began early in the week of December 16 and continued throughout the restoration.

On December 19, Toronto Hydro issued the following press release (See Figure 11) in which it warned of severe weather and noted the risk of potential and extended power outages.

Figure 11: December 19, 2013 Press Release

This approach to weather monitoring is in line with standard practices of utilities that do not have an in house meteorologist.

Emergency Planning and Preparedness Opportunities for Improvement

1. Emergency response plans provided an overall structure for response, but did not include detailed descriptions of key processes and all roles.

Toronto Hydro has two emergency response plans: a Crisis Management Plan and a Grid Disruption Plan (GDP).

The Crisis Management Plan describes how the senior executives work in a crisis. The Crisis Management Plan serves as a "core" plan overlaying the GDP, which many utilities describe as an "annex". The GDP "outlines the way in which decision makers use the additional powers and authority accessed through the declaration of a grid emergency."[6] It includes such information as emergency declaration procedures, emergency triggers and levels, coordination between the Crisis Management Team and System Operations Centre, and guidance for plan maintenance, along with checklists for SOC roles, and forms for high level damage assessment, objective setting, tactical planning, and stand down assessment. Toronto Hydro emergency response staff used the GDP during the 2013 Ice Storm.

The overall format of the GDP (core plan plus annexes) is reasonable for a newly constructed plan, but currently it does not include:

- Definition of key response processes (e.g., damage assessment, cut and clear, mutual assistance deployment);
- Different response strategies for varying incident levels;
- Sufficient detail about the response organization and roles below the SOC level (e.g., the Local Information Command Centres, or LICCs);

[6] Grid Disruption Plan, Toronto Hydro, October 28, 2013

- Checklists, forms, and job aids for response staff; and
- Communications protocols and processes, including stakeholder outreach/liaison.

2. Toronto Hydro characterizes grid incidents on a three level scale, which may not adequately address full scale events.

Toronto Hydro currently designates three levels of grid emergency in the GDP. As shown on Figure 12, the criteria used to establish the severity of an incident include: expected restoration duration, impact to customers and key accounts, the potential threat to public and employee safety, the expectation of environmental damage, and reputational impact. These emergency levels do not adequately address the complexity and potential impact of incidents where restoration times will exceed 72 hours.

Figure 12: Toronto Hydro Grid Emergency Levels

At the federal level in Canada, there are three emergency levels. In the United States, the standard in public sector emergency management is a five level scale. The U.S. utility sector is migrating to the five level standard as well. The City of Toronto uses a four level scale (0 3).

Many utilities have adopted a wider range of levels in order to better understand and communicate the scale and complexity of an incident. A more extensive scale is useful when trying to understand and communicate the implications of emergencies that last up to three days (as planned for at Toronto Hydro), incidents that last up to 10 days (as experienced in the 2013 Ice Storm), and incidents that last up to 30 days, as experienced by some Canadians in the aftermath of a 1998 ice storm.

3. Key restoration strategies and processes were not defined or understood at all levels of the Company with roles in the response.

The restoration strategy touches on all aspects of the response, including the restoration approach (circuit based, area based, order based)[7], call volume management, work order management, and the process to develop estimated time of restoration (ETR). The absence of a commonly known restoration strategy during the Ice Storm response caused the LICC managers to create their own strategies and processes. For example, managers in one LICC did not have sufficient training or experience in managing an incident of this scale and continued to apply an order based approach, while another LICC implemented circuit based restoration based on lessons learned from work in Long Island during Hurricane Sandy.

4. Many Toronto Hydro employees did not have a pre-assigned and trained role for major incidents.

Utilities that use ICS typically assign and provide training on a second set of duties to many employees who are not operationally qualified. These secondary duties, increasingly called emergency response roles, are activated when the magnitude of an incident requires a level of support that exceeds the capacity of the day-to-day operations staff. A person filling an emergency response role (or "storm role") often performs tasks during emergency conditions that are different from their "normal" work activities. Some examples of emergency roles are damage assessor, wires down guard, customer service representative, materials handler, and staging site manager.

Toronto Hydro did not have in place a systematic, comprehensive process for assigning and managing emergency response roles. Many employees didn't have a pre-assigned role, while some, who were pre-assigned roles such as LICC management and support, were unfamiliar or ill-suited to the job tasks – or didn't have access to necessary systems and locations.

A few areas that would have benefitted from more effective response role support during the 2013 Ice Storm were:

- Incident management;
- Damage assessment;
- Logistics support;
- Wires down guards;
- Work order management; and
- Crew support, including clearing debris in the field and supporting certified power line persons.

[7] Different restoration approaches are described under the section 5.5.1. of this report.

5. Toronto Hydro conducted exercises and training at the Command Centre level, but did not perform sufficient training and exercise in the Local Incident Command Centres.

Prior to the 2013 Ice Storm, the roles and responsibilities as well as processes at the LICCs were not widely trained and exercised. The approach to focus emergency response training at the central command level first is consistent with that of many other utilities that are implementing ICS and emergency management programs. It can, however, lead to some breakdown in execution if the company has not adequately trained personnel responsible for managing the decentralized operations being managed by the LICCs.

5.2.2. Emergency Planning and Preparedness Recommendations

EPP1. Reaffirm and communicate emergency management vision and strategy throughout all of Toronto Hydro.

Toronto Hydro executive leadership should affirm its belief that emergency management is a core competency of the Company. This can be achieved through a compelling vision statement and set of guiding principles that will drive the Company's response in the future. Executives should communicate these to the entire organization and incorporate them into the corporate emergency management plan. Nearly every Toronto Hydro staff member interviewed in this effort wanted to participate in improving the process. The emergency management vision and guiding principles should capture and "unify" this interest.

EPP2. Continue to inculcate the ICS based approach to emergency response.

- Expand the use of emergency response roles (i.e., second roles);
- Formalize the pre-event activation and communication process;
- Update the emergency levels to include worst case planning assumptions; and
- Expand the training and exercise program to the service centres.

The adoption of ICS is a cultural shift for any organization. It can take years for a company to move from espousing the principles of ICS to having front line personnel use it on a daily basis. Learning from the public sector's adoption of ICS over the course of several decades and the experiences of other utilities, the deployment of ICS is deemed successful only when the senior management, middle management, and front line personnel use it on a regular basis. In order to achieve the frequent, more "routine" use of ICS, Toronto Hydro should focus on formalizing the second roles process and broadening training and exercises to include more front line response staff.

Second Roles

A comprehensive second (or emergency response) roles process should include:

- Assigning an alternate set of duties to employees;
- Training and/or certifying employees to conduct those duties; and
- Providing them the opportunity to demonstrate competency through periodic exercises.

The effort should be conducted via collaboration between the emergency management organization, human resources, and Company operating groups.

Toronto Hydro should establish an "inventory" of second roles, documentation of the desired competencies (knowledge, skills, and abilities) or certifications desired for each, and a list of one or more staff members who fit the requirements. New employees should receive a second roles assignment upon hire, and current staff could receive assignments during the annual review process. Individual development plans should include metrics related to second roles. To start, Toronto Hydro could review current rosters to determine:

- Missing roles that should be added immediately (e.g., damage assessors, customer service representatives);
- How well the competencies of those currently assigned match with second role requirements; and
- Other internal sources of staff to fill roles (e.g., Finance, Human Resources).

Event Levels

Toronto Hydro should expand the emergency levels on the grid emergency scale it uses to address full scale incidents (e.g., Level 4 or greater). When determining the associated triggers to use, Toronto Hydro should consider developing several planning scenarios (bounding scenarios) including one that details a "worst case" incident. This "worst case" would likely exceed the 2013 Ice Storm in terms of damage, employee and customer impact, and public safety risk. Toronto Hydro should develop the hazard scenarios in consultation with the City and Provincial emergency managers to support closer integration of planning and response.

Training and Exercises

Toronto Hydro should extend its ICS roles and process training to staff in the Local Incident Command Centres at a minimum. This would include classroom or on line courses and periodic, planned exercises (table tops and functional) to reinforce and test capabilities. The training program should be put in place to support staff assigned to second roles, with refresher training offered annualy. Additionally, the Company should require all employees who could be engaged in emergency response to complete basic

ICS training (on line or classroom) and require staff filling key command roles to be ICS certified.

EPP 3 Enhance centralized emergency management group resources to support full implementation and sustainment of ICS and ongoing relationships with key stakeholders.

Toronto Hydro should maintain a centralized emergency management organization and continue to support on an all hazards approach to emergency management. The assignment of a Director or higher level executive to lead the group would indicate executive support of this role in driving emergency management discipline and capabilities across Toronto Hydro. The Company also should seek to increase the size of the organization. Ideally, it should include full time, dedicated staff responsible for such functions as grid operations emergency response, training and exercise, plan management, ICS implementation and sustainment, emergency management coordination with the City and regulators, and possibly strategy and analysis.

EPP 4 Add dedicated grid operations emergency management resources.

In order to support the expansion and implementation of the Grid Disruption Plan, Toronto Hydro should seek adequate funding to increase the number of resources dedicated to its centralized emergency management organization as well as a specific grid operations emergency management group. This grid operations emergency management group would be responsible for updating the Grid Response Plan, developing specific restoration processes, and designing training curriculum. It could report directly to the centralized organization and reside within the grid operations organization, or report to the Senior VP of grid operations with a dotted line reporting relationship to the centralized emergency management group. This dotted line relationship will ensure alignment between grid operations and emergency management vision, principles, and strategy.

EPP 5 Update the Emergency Response Plan to improve comprehensiveness and usability.

The Emergency Response Plan should retain the current, all hazards focus and should be enhanced to include roles and responsibilities of LICC and field response staff, especially during the grid disruption response. This effort will be substantial since it will include aligning key preparedness and response functions across the organization, documenting the processes (flow charts, forms, checklists) in the Emergency Response Plan, and identifying the roles and responsibilities of all who are responsible for executing them.

Toronto Hydro should focus first on updating function specific process descriptions for overhead and underground outages, and other related documentation in the Grid Disruption Plan. Eventually, the Emergency Response Plan should include other function specific and hazard specific annexes (e.g., pandemic, physical security attacks, and flooding).

5.3. Resource Acquisition and Allocation

When a major incident occurs, the readiness of a utility to secure and deploy sufficient resources (i.e., personnel and equipment) directly affects the safety, speed, and efficiency of restoration. Addressing a number of outages that is orders of magnitude higher than experienced day to day, is a complex task requiring significantly more skilled workers, proficient supervisors, specialized tools, gear, and materials. Some staffing needs may be met through redeployment of internal resources, for example, using engineers to conduct damage assessments. Current vendors may be able to expedite delivery of equipment and services, such as standard gauge wire, poles, and meals.

Responses to larger events, however, typically necessitate the use of mutual assistance to secure people and equipment. As noted by the Edison Electric Institute, the association that represents all United States (U.S.) shareholder-owned electric companies, "Mutual assistance is an essential part of the electric power industry's service restoration process and contingency planning." The recent series of widespread, devastating weather events bear this out:

- Tens of thousands of utility workers representing 80 utilities from across the U.S. and Canada were deployed during the response to Hurricane Sandy and Nor'easter Athena in October/November 2012;
- 30,000 utility workers responded to the June 2012 Derecho that hit the mid r Atlantic west to Ohio, including crews from Canada; and
- Nearly 50,000 line workers and crews, including crews from Canada, assisted n the restoration efforts in response to Hurricane Irene in August 2011[8].

The mutual assistance network is a voluntary partnership of electric utilities across North America that is committed to helping restore power whenever and wherever assistance is needed. Electric utilities impacted by a major outage event are able to increase the size of their workforce by 'borrowing' crews from other utilities.

In the U.S., the mutual assistance network, initiated decades ago, is organized into Regional Mutual Assistance Groups (RMAGs) that manage the voluntary agreements among electric utilities within the same region. Members initiate requests for restoration assistance through the RMAG, which then facilitates the process of identifying available crews, coordinates logistics, and locates specialized resources as needed (e.g., tree trimmers, call centre support). In addition to belonging to one or more RMAGs, most U.S. utilities also participate in a nationwide mutual assistance agreement through the Edison Electric Institute.

[8] Source: Edison Electric Institute

Members of the Canadian Electricity Association (CEA), the national forum and authoritative voice of the electrical industry in Canada, have been active in RMAGs within Canada and the U.S. A number of Canadian utilities are members of RMAGs, primarily the North Atlantic Mutual Assistance Group (NAMAG) which was formed in 2013 through a merger of three smaller RMAGs. In response to increasingly frequent and severe weather events that tax RMAG capabilities, the CEA convened a National Mutual Assistance Working Group (NWAWG) in February 2013. This group will serve as a forum for sharing leading practices and improving all aspects of coordinating cross-border mutual assistance.[9]

Other sources of personnel to meet outage restoration demands are organizations that supply contract personnel. Often utilities use contractors to fill blue sky roles (e.g., line crews, tree trimmers, call centre representatives), and may have agreements in place to draw upon additional resources in the event of an emergency. These kinds of agreements tend to be tailored to reflect the particular needs of the utility and capabilities of the contractor, whereas mutual assistance agreements are more standardized.

As resource procurement gears up, utilities need to have in place the essential infrastructure to support more personnel, such as equipment, materials, fuel, transportation, personal care (lodging, food, laundry, etc.), along with crew mobilization, supervision, and demobilization processes, and alternate work and crew staging sites. Leading practice is to pre-establish agreements with multiple vendors, or have "turn-key" contracts (i.e., where a vendor handles significant portions of logistical support). Pre-established plans and agreements provide for the "scaling" and specialization of resources needed to support response to all incident levels and hazards. It is important to note that contractor resources that are released by one utility to support restoration at another utility are considered a part of the mutual assistance process. They are allocated according to the agreements between or among the relevant RMAGs.

The assessment of Toronto Hydro's resource acquisition proficiency addressed the following:

- Resource acquisition strategy;
- Determination of types and quantities of resources needed for an efficient restoration;
- Procurement of off-system support, including mobilization criteria, process, and agreements;

[9] Canadian Electricity Association, Electricity Matters, January 2013.

- Procurement of equipment, materials, transportation and fuel, housing, feeding and care of crews, and all other logistical needs;
- On boarding process and procedures, including safety training;
- Deployment of off system resources such as work assignment, supervision, and coordination with internal crews; and
- Demobilization of resources, including criteria and processes.

5.3.1. Resource Acquisition and Allocation Findings

Nearly all of Toronto Hydro's core trade workers (98%), management and professional office staff, along with 450 mutual assistance field resources supported restoration following the 2013 Ice Storm. A wide range of crew types was used, including overhead line, underground line, forestry, construction, and trouble shooters. The Company sourced the supplemental crews through sustained contractors (who have agreements in place to provide support), other contractors, the City of Toronto, and mutual assistance from other utilities. Notably, this was the first time that Toronto Hydro had used mutual assistance. Ten utilities from within and outside the Province of Ontario supplied approximately 250 linemen.

The Company called upon existing relationships with its third party warehouse provider, an expediter, and corporate food service provider to quickly source and make available the equipment, materials, and meals to support the incoming and Toronto Hydro crews. The arrangements for people and the resources needed to support them were in place within 48 hours. These included the provision of flight transportation, trucks, equipment, lodging, and food for mutual assistance crews from Manitoba Hydro.

While the mutual assistance process worked well and accelerated the restoration process, most of the procedures were developed just in time. The current plan does not detail the mutual assistance process and procedures or include contracts with third r party vendors to accommodate a large influx of resources. Also, at the time of the event, Toronto Hydro did not belong to any of the U.S. RMAGs. The Company has since applied to join the Northern Atlantic Mutual Assistance Group (NAMAG).

Resource Acquisition and Allocation Strengths

1. Safely deployed the largest number of resources for any response in Toronto Hydro history.

Toronto Hydro management began to reach out to off system resources immediately, starting with an email to other utilities on December 22, 2013, at 3:40 p.m. In total, 10 utilities provided approximately 250 lineman and forestry workers. See Appendix B for a list of utilities that supplied mutual assistance. The total number of resources supporting restoration following the 2013 Ice Storm, including internal staff and field personnel, contractors, and mutual assistance, was nearly 1,400 – the largest number of any response conducted by Toronto Hydro.

During the course of the restoration, only one recordable safety incident occurred. A recordable is defined as an incident that causes a worker to miss work time. This statistic is noteworthy as the persistent ice and freezing temperatures following the storm made work locations (uneven surfaces, backyards, heavily canopied areas, locations requiring ladders to access) hazardous.

2. Developed and applied mutual assistance processes in real time that generally worked.

Toronto Hydro crews have provided mutual assistance to other utilities several times in recent years including restorations following Hurricane Irene (August 2011), the Derecho (June 2012), and Hurricane Sandy (October 2012). Many linemen also supported the lengthy restoration effort following the 1998 Quebec ice storm. While Toronto Hydro has experience offering mutual assistance, the first time the Company requested mutual assistance, was for the response to the 2013 Ice Storm.

Toronto Hydro executives and the Logistics Resource lead, who was responsible for mutual assistance intake and support processes, relied upon established relationships with other utility executives and agreements, practices, and processes in place to support daily operations to bring on and support mutual assistance providers. They were able to call upon current vendors to expedite materials and equipment deliveries, expand food services, and provide fuel. The logistics group also was able to quickly procure other services, such as lodging, when pre-existing agreements or processes did not exist.

Beginning on Sunday afternoon December 22, 2013, approximately 12 hours after the outages started and after the Company declared the Level 3 emergency, the Toronto Hydro Planning Section Chief initiated calls to other utilities within the Province of Ontario and in the neighbouring Province of Manitoba, to request line and forestry crews. This decision was based on the number of customers affected and the conditions in the field. The sustained contractor (a company with an agreement in place for daily construction work) was contacted at 4:00 a.m. on Sunday, December 22. It is important to note that some of the neighbouring utilities were impacted by the same event and were restoring their own systems and therefore not in the position to provide assistance to Toronto Hydro. Some of these companies eventually sent resources after they restored outages to their customers.

Mutual assistance crews (including some forestry crews) began to arrive on Tuesday, December 24. Contractor crews (ranging from 2-4 crews, with 3-6 members each) were on site by Sunday, December 22. Contractor provided forestry crews began work on Sunday, December 22, and forestry crews provided by the City of Toronto engaged on Tuesday, December 24.

After securing mutual assistance crews from external sources, Toronto Hydro staff from the Human Resources and Safety, Power Systems, and Operation Support Services

Divisions drew upon experiences from responding to other Level 3 incidents (e.g., Hurricane Sandy) to quickly develop the content for onboarding briefings to off-system mutual assistance and forestry crews.

Also, Toronto Hydro provided "bird dog" supervisory support to all but a few (later arriving) mutual assistance crews. Supervisors identified to fill these roles (approximately 60) were experienced in responding to emergency situations. They knew the number of resources needed and processes required to keep crews fully engaged in restoration (e.g., work protection clearances, access to tools and equipment, coordination with other crews, etc.).

3. Flew in, equipped, and deployed mutual assistance resources from Manitoba within 48 hours.

When feasible, mutual assistance crews arrive with their own equipment (e.g., trucks, specialized tools, clothing, etc.). In order to expedite their arrival, the 42-member contingent from Manitoba Hydro was flown to Toronto. This was the second largest number sent by a responding utility. Crew members arrived with their own personal protective equipment and tailboards. Toronto Hydro supplied everything else they needed to support the restoration. This included bucket and passenger trucks (for crews and supervisors), equipment, tools, materials, supplemental clothing, and additional safety equipment requested

Toronto Hydro transported, outfitted, and deployed all Manitoba crews and supervisors within two days of placing the call for assistance to Manitoba Hydro management. Toronto Hydro resource leads began to prepare on Monday, December 23, for the intake of the Manitoba Hydro workers. Crews were out and working by mid-day on December 25. This was a unique feat. By contrast, a number of utilities attempted to fly in crews from the West Coast during the Hurricane Sandy restoration, but ran into significant barriers and delays.

4. Conducted thorough mutual assistance on-boarding process and safety briefings.

Upon arrival, mutual assistance crews were transported and checked in to their respective hotels, conveyed to the LICC from which they would be dispatched, and given an extensive orientation briefing that addressed local safety rules and conditions, high-level work protection code information, and what to expect on the streets. Trades training staff from the Human Resources and Safety Division conducted 14 training sessions. The Manager of the Mutual Assistance LICC conducted 2 training sessions. In addition, each day, mutual assistance crews would receive safety briefings prior to being dispatched to work locations.

5. Strong collaboration between City and Toronto Hydro tree crews on restoration activities.

The City of Toronto Urban Forestry's top priority during the aftermath of the 2013 Ice Storm was to provide resources to Toronto Hydro to restore power. The City Director of

Forestry participated in daily planning conference calls that included Toronto Hydro executives, to review progress and identify needs. The City provided forestry crews directly to the LICCs, or to work locations, as directed by Toronto Hydro.

Resource Acquisition and Allocation Opportunities for Improvement

1. Mutual assistance processes and agreements with other utilities across Canada and North America were not formalized.

As a member of the CEA sponsored National Mutual Assistance Working Group (NMAWG), Toronto Hydro is engaged in discussions with other utilities across Canada, to establish a national mutual assistance agreement, share leading practices, and improve cross-border mutual assistance. Toronto Hydro also is awaiting approval of its application to join NAMAG. Going into the 2013 Ice Storm, the Company did not have written mutual assistance agreements in place with other utilities, nor did it belong to regional or national mutual assistance groups. For the 2013 Ice Storm response, Toronto Hydro obtained mutual assistance from other Canadian utilities through personal, peer to peer contacts.

This less formal approach worked in large part because other utilities were experienced in providing mutual assistance, could quickly agree to terms (e.g., right to leave if needed, billing for just expenses incurred), and had crews available. If the 2013 Ice Storm had been more widespread, it likely would have taken longer to secure the additional line and forestry resources to restore in a reasonable amount of time. Most North American utilities participate in one or more regional mutual assistance groups, and/or a nationwide mutual assistance agreement to mitigate the risk of not having inadequate numbers or types resources to execute a restoration safely and reasonably.

2. The process to acquire and coordinate the deployment of City forestry crews was not defined in advance.

The 2013 Ice Storm affected large portions of the tree canopy of the City of Toronto, in turn causing significant and prolonged outages for Toronto Hydro customers. The nature of the damage called for deployment of a significant number of forestry crews. On a blue sky day, Toronto Hydro typically uses between seven and eight contractor forestry crews and one Company forestry crew. In addition to the company contractors and crew, and the City forestry resources, approximately 200 forestry resources obtained through mutual assistance, executed tree cutting and clearing work, in support of the restoration.

Urban Forestry Operations of the City of Toronto was a logical source for this assistance. In the course of their work, City forestry crews communicate with Toronto Hydro every day, are familiar with the territory, and are local. Although Toronto Hydro and City Urban Forestry were participating in periodic discussions about emergency and work planning, they did not mutually define and document processes and guidelines for communicating strategic priorities, establishing work hours, assigning supervisory roles,

or sharing contractor supplied crews. The initial contact to "get crews on the road," along with the daily SOC calls worked well, but communication became less effective among the middle and field ranks.

3. Toronto Hydro has limited ability to accommodate a large influx of mutual assistance resources.

Ten utilities sent approximately 250 line personnel to support Toronto Hydro's Ice Storm restoration. As one manager interviewed observed, "This is the size of a small company." Utilities experienced in managing large numbers of mutual assistance workers typically have in place comprehensive plans, processes, and roles to support all aspects of crew management, including onboarding, lodging, food, laundry and other personal care, equipping, transporting, work assignment, supervision, and demobilization. During a response to a larger event, a significant number of host utility resources are needed for orientation/training, off system crew supervision, and logistical support.

Toronto Hydro's Grid Disruption Plan does not address mutual assistance specifically. In the absence of defined and trained procedures and roles, Toronto Hydro accommodated incoming mutual assistance crews through "just in time" assignment of internal staff who were able to draw upon personal experience and lessons learned providing mutual assistance to other utilities (e.g., during Hurricane Sandy and the 1998 Quebec ice storm). They were able to put together training and safety briefings, roster enough experienced tradespeople to serve as "bird dogs" for most mutual assistance crews, secure adequate lodging, and equip crews who arrived without trucks or other equipment.

While interviews with mutual assistance providers indicate that Toronto Hydro handled the additional resources well, the approach used may not scale to an even larger event. Virtually all available internal supervisory resources were used and there would have been a shortage of bucket and commercial vehicles had crews been flown in (in addition to the Manitoba Hydro crews).

4. The demobilization process for mutual assistance crews was not clearly defined.

Leading mutual assistance practices address the full life cycle of off system resource management, from acquisition through release. Determining when to wind down the use of mutual assistance crews can be difficult, especially when there are lasting effects (ongoing outages) from a storm, like Toronto Hydro experienced after this storm. The mutual assistane portion of an Emergency Response Plan should describe the process and criteria for releasing crews along with procedures, checklists, and forms for collecting equipment and conducting a formal check out. Mutual assistane agreements address demobilization guidelines and authorities as well.

Toronto Hydro management did not have a shared understanding of how and when to release mutual assistance crews. In the absence of clear direction, the utilities providing

mutual assistance resources determined when they would be leaving. In one case, the crews from one utility decided to leave, with Toronto Hydro's concurrence, and then were brought back from the airport to work another day.

5.3.2. Resource Acquisition Recommendations

RA-1 Adopt a resource management strategy that provides for deployment of all available resources, seamless integration and coordination of crews, and optimal supervisory span of control.

Building on the informal processes and relationships used to access mutual assistance during the 2013 Ice Storm, Toronto Hydro should formulate a resource strategy to support emergency response that addresses:

- All likely sources of mutual assistance;
- Numbers and types of resources needed for all incident levels; and
- Criteria for triggering mutual assistance requests.

As part of the emergency plan documentation, agreements should be put in place with utilities, contractors, and City agencies. The companion mutual assistance plan would:

- Detail the mutual assistance processes (i.e., mobilization, onboarding, care and feeding, equipping, deployment, supervision, demobilization);
- Establish roles and responsibilities and authorities;
- Provide criteria for demobilization and policies; and
- Include template and job aids (e.g., standard expense forms).

Also, the plan would specify the number of supervisors needed for "bird dog" and other oversight support to mutual assistance crews, along with a roster of qualified and trained internal and contractor staff.

- Establish mutual assistance process and agreements that encompass all potential sources of crews: regional, national, cross-border utilities, contractors, and City.

The mutual assistance strategy will distinguish types and sources of mutual assistance desired to support all levels and types of likely hazardous incidents. Primarly, this assistance will be limited to line and forestry crews, but could include other roles, like damage assessors and underground crews. Toronto Hydro should put in place written agreements with identified primary and backup providers.

With utilities, this may be done through joining one or more RMAGs (within Canada or including U.S. RMAGs), participating in the national mutual assistance agreement, or creating individual agreements. Toronto Hydro should continue to pursue membership

in NAMAG and explore joining other RMAGs in the United States, including the Great Lakes Mutual Assistance Group (GLMAG).

With City departments, Toronto Hydro should accelerate current discussions and include terms and expectations in the respective Company and City emergency response plans (or in a joint emergency response plan). With sustained and other contractors, Toronto Hydro should review current terms and add "scaling" requirements to ensure availability of resources when significantly more crews are needed.

- Document the process, with predefined decision criteria, to mobilize and demobilize mutual assistance.

Toronto Hydro's Emergency Response Plan should include documentation of all activities, decisions, roles, and infrastructure needed to support incoming mutual assistance. Since activating mutual assistance can be costly (i.e., as soon as the utility orders crews, and the crews start mobilizing and traveling, all the costs are borne by the requesting utility), it's important that Toronto Hydro establish specific, comprehensible criteria to guide the responsible parties to make timely, appropriate decisions. Criteria could include:

- Number of outage spots;
- Number of customers affected;
- Projected level of damage;
- Capacity to effectively deploy off-system resources;
- Availability of internal crews and supervision;
- Skills needed (e.g., forestry); and
- Public perception (e.g., Why are crews leaving when my power is off still?).

- Source and prepare supplemental supervisors to accommodate maximum crew scale-up.

As a corollary process to instituting second roles, Toronto Hydro should identify and train internal staff that are qualified to serve as mutual assistance crew "bird dogs" and/or supervisors. These additional supervisors may be needed if utilities providing mutual assistance are unable to send a suitable number. The size of the internal pool should be large enough to provide adequate span of control (1 to 2 crews for bird dogs; each with 5 to 7 bird dogs per supervisor). Sources of qualified personnel could be former crew supervisors currently employed in other positions, retirees, former tradespeople on modified assignments (due to medically documented reasons), and sustained contractors.

RA-2 Create a comprehensive, scalable logistics plan as part of the Emergency Response Plan.

A logistics plan describes the infrastructure and services needed to support restoration, particularly with regard to mutual assistance resources. The processes, agreements, and roles detailed in the plan should scale in accordance with the incident level. For example, a staging site may be needed in the wake of a large hurricane, or super storm, but not for a Level 3 ice storm.

Agreements with vendors should be negotiated in advance (at least in part) to ensure that vendors can plan accordingly. These discussions will provide valuable planning information to vendors, help Toronto Hydro assess vendor capability to support a large scale response, ensure that priority is given to Toronto Hydro, and uncover any issues or risks (e.g., potential materials shortages). Some utilities contract with vendors that provide "turnkey" support, taking care of virtually all logistical needs related to mutual assistance.

5.4. Damage Assessment and Restoration Planning

Effective planning and damage assessment are essential for a rapid and effective restoration. The information gathered through a damage assessment process provides the planning team with the insights necessary to:

- Determine the type and number of resources required to support the restoration;
- Create the most efficient restoration plan based on the extent and type of damage and available resources;
- Develop accurate restoration estimates (ETRs);
- Support daily work plan development and customer communications; and
- Identify safety issues/dangerous conditions.

The objective is to perform damage assessment as early as possible, often within the first two to three days after it is safe to begin work in the field. Assessments are usually conducted by feeder (circuit) according to a pre-established priority.

The information captured in the field is entered into the outage management system (OMS) and used by the Planning Section in the SOC to prioritize restoration work and develop ETRs. A large incident may necessitate more than one cycle of damage assessment:

- First, a quick, higher level scan to understand the amount and type of damage; and
- Second, a more thorough assessment to capture detailed damage information on each circuit, including the number of poles, wire spans, and equipment to be replaced at each specific location.

During major events, utilities use damage assessment teams, often referred to as patrollers, to evaluate damage before a line crew is dispatched to perform repairs. Damage assessors patrol circuits to identify trouble locations and assess the extent of the damage. They document what they find on a pre-developed form or a circuit map. Some of the more advanced utilities have implemented tools, such as tablets, that allow damage assessors to enter the information directly into a system linked to the GIS and OMS systems.

During day-to-day operations or minor events, line crews or "trouble crews" typically handle damage assessment, but additional resources are usually needed to conduct this process when a major event occurs. Other pre-qualified resources, such as engineers, designers, or retired linemen or supervisors may perform this role. Using other suitable personnel to conduct damage assessment allows trouble and line crews to focus exclusively on repairing the damage and restoring power.

In addition to conducting damage assessment, leading utilities have implemented a forensic analysis process to collect detailed information on specific equipment and structure failures. They use this data in statistical analyses to determine causes of outages during major events, which then supports subsequent analysis of different options to harden the distribution system for future events.

The review of Toronto Hydro's damage assessment and restoration planning competency addressed the following:

- Definition and execution of a damage assessment process;
- Capture and use of damage assessment data;
- Development of ETRs;
- Establishment and adherence to restoration priorities;
- Work planning practices; and
- Use of standard planning tools.

5.4.1. Damage Assessment and Restoration Planning Findings

Following the industry leading practice, Toronto Hydro established priorities early in the restoration and restored customer service in accordance with those priorities. The Company maintained focus through frequent Command Centre conference calls and communicating the specific priorities for the subsequent planning period. The overnight planning activities, however, were not conducted consistently by all of the LICCs.

Toronto Hydro used its "triage"[10] process to gather damage information. This process served other needs, apart from damage assessment, including evaluating the wire down locations being reported by the customers, crews and first responders, and making them safe for public and utility employees participating in the response. Toronto Hydro used underground crews, service crews, and designers (who are not directly involved in the physical restoration of the electric system) to conduct the triage process.

Toronto Hydro established restoration priorities early and restored customer service in accordance with those priorities. Response leads at the SOC and LICCs maintained focus on priorities through frequent Command Centre conference calls and communicating the specific priorities for the subsequent planning period.

Damage Assessment and Restoration Planning Strengths

1. Overall restoration priorities were in line with industry practices.

Toronto Hydro established and followed restoration priorities during the 2013 Ice Storm response that followed typical industry practices. These priorities were:

- Public safety (911 calls and live down wires);
- Critical customers (e.g., hospitals, water pumping stations, 911 call centres);
- Substation and feeder backbone restoration (i.e., portions of the system that provide service to large blocks of customers);
- Lateral sections of the circuits (i.e., branches of the circuit that are typically single phase lines that serve several streets in a neighbourhood); and
- Customer service drops (i.e., lines that connect the house to the overhead transformer and typically service one or two customers).

Since Toronto Hydro serves a densely populated urban area, its electric distribution system has a number of connection points between different circuits (i.e., circuit ties) that allow them to quickly restore service to a portion of customers by switching load from one feeder to another. The initial focus of restoration was to secure any known locations that could compromise public safety. The second priority was to restore customers designated as critical by the City of Toronto. The City identified this group by the morning of December 24, 2013.

The restoration continued by restoring feeder backbones, then laterals, and lastly, individual customer connections. It is important to understand that in order to keep

[10] "Triage" refers to the process developed by Toronto Hydro to conduct field evaluation of downed wire reports received from customers and either make the location safe or escalate it to a more appropriate resource. As a part of the process, the resources dispatched to the location gather data on the specific damage (e.g., pole, transformer, wire) to ensure that, subsequently, the right resources and the required equipment are dispatched to repair the damage

crews productive during a large restoration, some priorities are addressed in parallel. This is especially true during periods of transition between categories of priorities.

By following these priorities, which addressed larger blocks of customers first, Toronto Hydro was able to restore power to 86% of the customers who were out at peak within the 72 hours from the start of the field restoration (See Figure 13).

Figure 13: December 2013 Ice Storm Restoration

2. The Command Centre coordination calls (every three hours) provided useful information and maintained alignment of Local Incident Command Centres to restoration priorities.

Once the Command Centre (System Operations Centre) was activated on Sunday morning, December 22, 2014, the Incident Commander held coordination calls every three hours. The standard industry practice is to conduct these calls twice a day. Toronto Hydro chose to hold them more often given the degree of damage caused by the ice storm.

These calls were essential to maintaining response organization alignment to restoration priorities. They provided a platform for participants to share restoration progress updates and readjust plans for the subsequent planning period. The participants on the calls included the general staff within the Command Centre as well as the leads from the LICCs.

3. Some Local Incident Command Centres conducted planning activities overnight to facilitate work assignments and crew deployments for the subsequent shift.

A utility industry leading practice is to use the overnight shift to plan and organize assignments for the subsequent day shift. Conducting work planning at night affords the day shift managers and supervisors more time for crew support and for the extensive coordination with external stakeholders that typically occurs during the day. In addition, the restoration data from completed jobs is updated at the end of the day shift to provide the overnight shift planners with the most accurate job status information.

In some of the LICCs at Toronto Hydro, the lead established a process for planning the specific work for the next day, making crew assignments and creating job packets overnight. This practice aided the deployment of the day crews.

Damage Assessment and Restoration Planning Opportunities for Improvement

1. Lack of real, or near real time situational awareness of outages and work progress below the feeder level.

A critical element of a major event restoration process is maintaining an understanding of the current state of the system. This includes having real or near real time knowledge of the restoration status and field conditions, as well as any other information that can support decision making around priorities and resources. While Toronto Hydro could assess the outage status at the feeder level, primarily through its SCADA (remote control and dispatch analysis) system, the outage status below that level (e.g., street) and associated damage assessment information were not readily available throughout the event.

2. Damage Assessment process was not defined, documented, or consistently applied across the Local Incident Command Centres.

Toronto Hydro's triage process addresses portions of the damage assessment process but does not provide for the systematic evaluation of the system condition in the field, capture of infrastructure damage information, or timely provision of that information to other stakeholders (e.g., Planning Section, ETR developers, and Communications). The Grid Disruption Plan does not include a comprehensive, detailed damage assessment process. Lacking information about the process flow, roles and responsibilities, forms, checklists, and other job aids, some LICCs addressed elements of damage assessment as part of the triage process, or developed ad hoc guidance in real time.

3. Restoration estimates were not developed at various levels of specificity.

During an incident, the Restoration Planning section within the Central Command Centre is responsible for developing estimated times of restoration (ETRs) throughout the incident response. At the start of a restoration, while the damage assessment is in progress, utilities can provide this information at a high level only – a global ETR. As the restoration progresses planners can refine estimates, providing information at a

substation, circuit, or individual customer level. An ETR usually is the most critical piece of information to a customer. The Company did not have in place a systematic and documented process for creating accurate and timely ETRs at multiple levels of specificity (e.g., circuit, customer).

4. Work planning practices varied across Local Incident Command Centres.

The planning activities that took place at the LICCs included developing the work plan for the next period and creating associated work packets. These packets typically include print outs of the OMS outage record, a circuit map, and any damage information collected by the assessors. At Toronto Hydro, each LICC manager used an "individually developed" work planning process. Some generated assignments overnight and planned multiple jobs for the crews in advance, while others assigned new jobs to the crews as they completed their work.

5. The Central Command Centre and Local Incident Command Centres did not use standard planning tools.

A leading practice in the utility industry is to use standard forms to capture and consolidate planning information throughout an event. Using a common template accelerates information exchange and ensures that the same level of detail is captured and made available to all restoration participants. Toronto Hydro's Grid Disruption Plan does not reference specific tools and forms (e.g., Incident Action Plan) that the Planning Section should use to collect, consolidate, and share commonly used planning information.

5.4.2. Damage Assessment and Restoration Planning Recommendations

DAP1 Institute a damage assessment process that defines the required approach, procedures, and competencies to establish situational awareness and planning inputs within the specified timeframe (e.g., within 48 hours).

Toronto Hydro should set objectives for establishing overall situational awareness and conducting the initial damage assessment in major events. These objectives should include the timeframe within which the initial damage assessment will be completed and the level of information required to support key decisions. For example, for a Level 2 event, the global ETR should be made available within 24 hours and for a full scale event within 48 hours. Once it has established these objectives, the Company should work with selected stakeholders, such as the City, to identify the information required for each key decision throughout the event, then create a process and assign responsibilities for capturing that information in a timely and accurate manner.

Specific to damage assessment, within the current triage process, the Company should separate the wires down investigation component from the damage information gathering process. There should be a clearly defined, end to end processes for addressing both wires down and damage assessment with pre assigned responsibilities, data collection specifications, and required competencies and training. Also, the Company should determine the number of assessors required to complete the assessment within the pre defined timeframes and identify potential sources of qualified personnel, which can include third party contractors and mutual assistance.

- Build a stronger damage data reporting interface with OMS and alternate data capture processes and tools.

In addition to instituting the process for conducting damage assessment, Toronto Hydro should evaluate different options for automating the capture and integration of damage assessment field data. One example is providing tablets with GPS capabilities to assessors to use to identify specific equipment in the Company's GIS system.

DAP2 Develop a process to establish (calculate) timely and accurate ETRs

Most customers experiencing an extended outage want to be able to develop a coping plan. They need to have a reasonably accurate sense of how long they may be without refrigeration, heat, or air conditioning. This information is especially critical for vulnerable populations.

Toronto Hydro should develop a more rigorous process for developing ETRs throughout the course of an event. The Company should first understand stakeholder needs and then develop realistic goals for creating ETRs. Customers generally understand that in the aftermath of a particularly damaging event, like the 2013 Ice Storm or a major hurricane, a utility has to spend some time assessing the situation in order to provide reasonable restoration estimates. So, for example, the earliest time by which Toronto Hydro could provide an initial ETR may be within 48 hours in a full scale event.

Toronto Hydro should set specific thresholds for issuing the initial ETR (usually at the global level) as well as the timeframes for refining that estimate to more detailed levels (e.g., neighbourhood/sub station, circuit, individual customer) at different points of restoration and for different levels of events. Table 5 below provides an example of a tool the Company could develop to support the ETR process.

Table 5: Example of an ETR Timing Matrix

Storm Level	Level 1	Level 2	Leve 3	Level 4 or Greater
Definition	Estimated restorations of 8 hours or less	Estimated restorations of more than 8 & less than 24 hours	Estimated restorations of more than 24 hours & less than 3 days	Estimated restorations greater than 3 days
ETR Communication Guidelines	Individual specific ETR available at first call	Individual specific ETR available at first call	Post Assessment 12 hrs. – global 24 hrs. – county 36 hrs. – circuit 48 hrs. – individual	Post Assessment 24 hrs. – global 48 hrs. – county 72 hrs. – circuit 96 hrs. – individual
Coping Information	Specific information about local damage	Specific information about local damage	General information to begin with increasing granularity	General information to begin with increasing granularity

Also, the Company should assign responsibilities for developing and monitoring the ETR, so that any potentially expiring estimates are evaluated ahead of time and either addressed or adjusted in advance.

DAP 3 Establish standard work planning processes and procedures; train and exercise response personnel to drive consistency across central and local commands.

Toronto Hydro should develop, document, and communicate the process to be used for work planning during major events. This would include activities such as: identifying priorities, developing incident action plans, assigning work to the available field crews, and creating work packets. A set of standard forms and tools should accompany this process.

Also, the Company should detail the roles and responsibilities for this process, specify the requisite competencies, and pre-assign personnel to fill these roles during an incident. The Grid Disruption Plan should include process and role documentation along with the standard forms and other job aids. In order to ensure compliance with the new process, the emergency management group should develop and execute a training program, including a table top exercise, to provide adequate opportunities for staff to understand and practice their roles.

5.5. Restoration Execution

The keys to successful restoration are persistent attention to employee and public safety, sustained focus on restoration priorities, ability to decentralize restoration and avoid bottlenecks, and effectiveness of crew deployment throughout the event.

Preserving the safety of public and utility workers is the most important aspect of the restoration execution. Methods that utilities use to conduct restoration efforts safely include safety orientations for incoming crews, daily safety briefings at the start of each shift, and daily safety bulletins. Some utilities also have developed handbooks that provide an overview of their system configuration and typical hazards, which are used by off-system crews to familiarize themselves with the potential field conditions.

Effective restoration of large outage events often requires the use of off-system resources. This influx can create a workforce that is far larger in size than the one that carries out the day-to-day work. Efficient and safe deployment of such a large number of resources requires careful coordination, effective field management, and adequate pre-planning of the work.

In large events that affect significant portions of the system, utilities decentralize the restoration function and manage the work locally. The intention is to reduce bottlenecks, such as processing switching orders or dispatching crews. Since utilities have different switching procedures, it is important to carefully manage the transition to a decentralized model in order to ensure the safety of public and utility workers.

A restoration typically follows a set of agreed upon priorities, starting with the critical infrastructure first. In some cases, however, in order to re-energize certain essential facilities, utilities may have to restore less critical parts of the system first. For example, when restoring a hospital that is at the end of a circuit, crews may need to restore the substation, and main sections of the distribution circuits (i.e., feeders). As a result, a number of other customers who are not deemed to be part of the critical infrastructure would be restored along with the hospital.

As mentioned earlier, public safety is the number one priority during restoration, with handling downed wires and making the system safe a high priority that presents several challenges. Fallen overhead wires that are energized pose a public safety threat. It is difficult to differentiate electric wires from telecommunications wires, or evaluate if downed electric wires are energized. Therefore, a large number of downed wire locations throughout the service territory creates an urgent demand for restoration resources.

Since downed wire locations can often number in the thousands, utilities typically focus first on those locations that are reported though 911 emergency calls and where wires are visibly arcing, smoking, or on fire. At these locations, crews cut, clear, and make safe locations so that restoration crews can repair the damage according to the restoration priorities. The utilities use public campaigns and communications channels to educate the public on the dangers of approaching downed wires during major events.

Service lines that serve single residences or small groups of customers are frequently restored at the end of the event, resulting in a long "tail" on the restoration curve, with multiple days at the end spent restoring very small enclaves of customers. Some utilities

have service crews and electricians who are not qualified to work on primary voltage lines and an effective restoration practice is to deploy these resources early to begin restoration of the service drops, which are typically handled last, while line crews work on restoring primary lines.

The assessment of Toronto Hydro's restoration execution addressed the following:

- Safety performance;
- Restoration strategy and execution efficiency;
- Cut, clear, and make safe process;
- Wires down;
- Dispatch; and
- Coordination with external stakeholders (e.g., City, Province)

5.5.1. Restoration Execution Findings

When compared with similar events in the past, the overall customer restoration curve during the 2013 Ice Storm was in line with industry experience. The restoration curve shows the number of customers out over time throughout the restoration period and depicts the rate of restoration (See Figure 13). Since public and worker safety is paramount, it is important to note that Toronto Hydro safety performance during the 2013 Ice Storm restoration was excellent. There was only one recordable incident during the event.

In addition, the Company worked with the ESA to introduce flexibility depending on situation based on safety risk for reconnecting services to reduce the hardship by the customers. It also managed the work protection and special requests well to ensure that there were no unusual delays in restoring the customers. The single largest area of opportunity in the restoration process is the inconsistent coordination of the work across the Local Incident Command Centres, including adherence to restoration approach and use of standard dispatching practices.

Restoration Execution Strengths

1. Safety performance was excellent.

Among the approximately 1,250 field resources involved in the restoration over an 11 r day period, there was only one recordable incident. Typically, safety performance during major events is better than day to day safety performance. When compared to the performance of other utilities during similar events, however, Toronto Hydro's results rank among the best.

In order to ensure safe restoration, Toronto Hydro created an on boarding curriculum for the off system crews that included a comprehensive safety orientation. The supervisors held safety briefings at the start of each shift to update crews on safety

hazards and emphasize the need to follow safety procedures. In addition to the exceptional worker safety record during the restoration, there were no deaths in the greater Toronto area that were directly attributed to the 2013 Ice Storm. This is a notable outcome for all the City staff and first responders who came together to restore normalcy to the residents.

2. Dispatch functions were decentralized to Local Incident Command Centres early in the restoration process.

In line with leading industry practices, during major events Toronto Hydro separates its service territory into local areas that are managed through Local Incident Command Centres (LICCs). This provides the Company with the ability to decentralize the dispatch function, thereby reducing the potential for bottlenecks at the central dispatch location. Through decentralization, Toronto Hydro doubled the number of dispatchers during the 2013 Ice Storm. Most of these dispatchers were located in the LICCs and had access to the outage management system (OMS) and could perform dispatch functions in accordance with local restoration priorities at the time.

3. Coordination with the Electrical Safety Authority (ESA) to reconnect customer premises was adjusted during the event to reduce hardship.

Standard ESA guidelines for restoring service connections require the equipment on the customer premise to be safe in order to reconnect power. During major events, the mast with the meter head may be damaged (See Figure 14), requiring the customer to perform repairs before service can be restored. The work is typically performed by a qualified electrician hired directly by the customer.

Figure 14: Example of Mast Damage

When utility workers attempt to restore a service where they deem equipment on the customer premise to not to be in proper condition, they are directed by ESA regulation to disconnect the customer service. In the initial days of the 2013 Ice Storm response, Toronto Hydro crews found some instances where the customers had power but their equipment was not in proper condition and they were forced to disconnect customer services. The Company quickly realized that this would create an unnecessary burden on customers who didn't lose power. Toronto Hydro worked with the ESA to amend the process, creating a form for customers to sign acknowledging that they would repair their equipment within a certain period of time, so their service would not be disconnected. The new process worked well for the majority of customers, but has not been fully adopted for future events.

4. Special requests were handled within the pre-defined priority order.

During major restorations, utilities often receive requests from elected officials and other influential stakeholders to restore a specific customer or commercial premise sooner than the restoration strategy would dictate. As a result, responding to a special request could cause a utility to deviate from focusing on the priorities in the restoration plan. During the 2013 Ice Storm, members of the Toronto City Council and local government for the most part allowed Toronto Hydro to restore according to the pre-established priorities and only intervened when there were truly life-threatening emergencies. In those occasions when a special request was made that did not seem to

be warranted, Toronto Hydro executives stayed firm and did not deviate from the restoration strategy.

5. The work protection process did not cause unusually long delays in restoration.

According to interviews with the field crews from Toronto Hydro, there were some normal and expected delays in performing the work protection. The practice of work protection (i.e., "switching and tagging") provides clear guidelines under which a line crew can operate different devices that allow it to reconfigure the circuit and restore power to portions of customers more quickly as they repair the damage. This is an area of restoration where utilities typically encounter delays because a substantially larger number of switching requests from the field arrive at the central location (i.e., system control centre) at the same time. Sometimes, these delays can exceed one hour depending on the number of orders simultaneously requested which are handled by a relatively small group of qualified system operators. Toronto Hydro operators were able to issue switching orders within a reasonable amount of time without causing any delays beyond those that are typical for a restoration effort of this magnitude.

6. "Bird dogging" of mutual assistance crews worked well.

Off system crews that are brought in through mutual assistance often are not familiar with the local electric distribution system. A leading practice is for the host utility to provide them with a local resource to help with daily work needs (e.g., navigating the territory, coordinating work with other crews, ensuring the safety of the work site, accessing food). These resources, referred to as "bird dogs," are typically local company line workers and recent retirees who are familiar with the system and are trained to operate the switching devices in the field. Bird dogs may support one or more crews.

Toronto Hydro adopted the practice of providing bird dogs to many of the mutual assistance crews, particularly those arriving during the first few days of the restoration. They dealt with system control for work protection, completed customer premise paperwork, and facilitated work assignment, in coordination with dispatchers. Interviews with utilities providing mutual assistance indicate that Toronto Hydro executed the bird dog role proficiently.

Restoration Execution Opportunities for Improvement

1. Restoration approach was not consistent, varying between "order based" and "feeder based."

During major events utilities typically can use one of three restoration approaches: order based, area based, or circuit based. The choice of approach corresponds to the severity and amount of damage across the service territory. Figure 15 illustrates how a utility could apply these approaches across a range of incident levels.

Order based restorations are typically limited to small events, where the utility manages resources and work based on individual outage management system (OMS) orders. In

area based responses, a utility will decentralize crew and work management to regions or divisions. A central system operations group retains control over crews restoring feeder lockouts and responding to 911 calls, but all major restoration work is referred to the decentralized region. The regions prioritize work, identify resource needs, manage resources, and develop ETRs.

A circuit based approach is typically used in the highest level events (Level 3 and greater), where the widespread devastation requires complete rebuilding of the electric delivery infrastructure. In circuit based restorations, crews are assigned to rebuild an entire circuit or portions of a circuit. The circuit is usually isolated from the rest of the system to ensure that it does not become energized during the work. The field crews energize portions of the circuit as work is completed.

Figure 15: Restoration Approaches

Toronto Hydro does not have a formally defined process to transition among different restoration approaches. During the 2013 Ice Storm restoration, the Company used a circuit based approach to start, restoring the feeder sections of the circuits, and then used an order based approach once it moved into restoring lateral sections instead of restoring all of the remaining damage on that circuit. In this storm response it might have been more appropriate to use an area based approach and repair the damage in an entire area (i.e., substation). This might have minimized the travel time by multiple crews and enabled better coordination of work assignments. Lastly, the restoration approach varied slightly across the LICs.

2. Lack of full coordination among decentralized dispatch functions led to some inefficiency in crew deployment.

Restoration following a large, unplanned event, like the 2013 Ice Storm, requires a significant amount of ad hoc coordination. The reason for this is that initially, while the necessary resources are being mobilized, the amount and location of damage is largely

unknown. This caused the planning phase and the execution phase of the restoration to be carried out in parallel with some level of inefficient work execution. Emergency plans help to reduce these inefficiencies, but cannot completely eliminate them.

At the start of restoration, Toronto Hydro quickly decentralized its dispatch functions into the LICCs, which is in line with leading industry practice. It appears, however, that the dispatch process was not fully synchronized among the LICC dispatchers, central dispatch, and the supervisors who were working with mutual assistance and contractor crews. This resulted in some actual and perceived inefficiencies such as:

- Crews were dispatched to a location that had been restored already;
- Different types of crews would be dispatched to the same location to perform different aspects of the necessary repairs with a significant time lag in between;
- Customers didn't understand why crews left before restoring power; and
- Crews had to wait after completing a job to receive their next assignment from the dispatcher.

One challenge to the dispatch process was a delay in closing trouble tickets in the outage management system once crews completed the work. Most utilities experience this problem during an event the size of the 2013 Ice Storm. Field crews focus on restoring power as quickly as possible and tend to turn in their completed tickets at the end of the day instead of calling them in as repairs are completed.

3. Local Incident Command Centre structure (three geographic and two functional locations) added complexity to crew deployment and work coordination.

During the 2013 Ice Storm response, Toronto Hydro activated five LICCs. Three of the centres were responsible for Toronto Hydro crews restoring distinct geographic areas of the service territory:

- Monogram – western part of the service territory;
- Milner – eastern part of the territory; and
- Commissioners – the downtown area.

Two LICCs handled externally provided crews, with one for the mutual assistance crews and the other for contractor crews. The off-system resources (both contractors and mutual assistance crews) worked across the service territory, but dispatchers in each of the three geographically based LICCs did not have full visibility into all the off-system resource assignments and availability. This lessened their ability to fully coordinate the dispatch process

4. Restoration execution approaches were not followed consistently by all Local Incident Command Centres.

The SOC established the overall restoration strategy and monitored progress against priorities, but the LICCs applied different approaches to implement the strategy. For example, some of the LICCs used a feeder based restoration approach, while others applied an order based approach when responding to similar conditions. Since the level and type of damage may vary across a service territory, LICCs should have some flexibility to determine what approach best meets restoration objectives. The damage from the 2013 Ice Storm, however, was similar across the affected areas within Toronto Hydro's territory. This suggests that the LICCs should have been following the same restoration approach.

5. Toronto Hydro has different work protection processes than other utilities in the Province of Ontario, limiting the type of work that mutual assistance crews can perform.

Toronto Hydro's electric distribution system includes a large underground network that feeds most of the downtown area. This network provides reliable service to customers through redundancy of power sources (i.e., if one feeder is interrupted, the network will continue to operate without causing customer outages because other feeders will pick up the lost load). It also requires a unique set of skills to operate or demanding proficiencies that are different from those required to operate an overhead system. In addition, during amalgamation of the utilities operating in Toronto, the decision was made to adopt the switching and tagging (i.e., system protection) practices that were in place at that time on the legacy Toronto Hydro system, to provide continuity for the network system operation. As a result, Toronto Hydro's system protection practices are different from those of other utilities in the province.

The key differences are in the coding and coloring of signage that is used to mark the devices controlled by field personnel. These differences can be addressed during an emergency restoration through the provision of guidelines that allow external utility crews to isolate a section of the system and then use their own switching and tagging processes to restore that section. As Toronto Hydro did not have guidelines like these in place, it was not able to use the full capabilities of off system resources.

5.5.2. Restoration Execution Recommendations

RE-1 Predetermine best restoration approach for each emergency Level (e.g., 1 to 4).

Toronto Hydro should reassess the emergency level scale it currently uses to categorize major distribution outages and consider adding a Level 4 or greater event definition. The Company should then refine or establish criteria (with ranges) for activating the different levels of response. Activation criteria could include number of customers affected, number of trouble spots, and expected duration of restoration.

This refined definition and characterization of events should provide a clearer indication of the preferred restoration approach for each event level (e.g., order based, circuit based, or area based). The predetermined approaches should be used to drive consistency in restoration execution, but provide enough flexibility to accommodate meaningful differences in field conditions among the Local Incident Control Centres.

- Amend work protection and restoration guidelines to enable off-system crews to "take over" and restore portions of the system in a catastrophic outage.

The Company should consider amending its switching and tagging rules during major events to allow off-system crews to take over the control of portions of the system. While it is unreasonable to expect outside crews to learn local company procedures, a number of utilities have created processes to isolate parts of the system during major events, so mutual assistance resources can support more aspects of the restoration and control sections of the circuits without compromising safety.

- For each restoration approach, provide standard processes and procedures, and secure adequate resources to expedite dispatch work.

For each pre-established restoration approach, Toronto Hydro should identify the commensurate number of qualified dispatchers needed. The Grid Disruption Plan should include a description of the process, procedures and associated forms for assigning, tracking, and closing work during major events. The processes should address both centralized and decentralized dispatch functions.

REC 2 Eliminate centralized mutual assistance and contractor Local Incident Command Centres and encompass those resources within the three geographic LICCs.

Toronto Hydro should eliminate the centralized LICCs for mutual assistance and contractors to facilitate coordination of dispatch across the geographic LICCs. Once the restoration process is decentralized to LICCs, the off-system resources (mutual assistance and contractors) should be assigned to one of the three geographic LICCs based on the need (capabilites and numbers). At that point, the geographic LICCs would take control of the off-system resources and use them as required to restore outages within their portion of the system.

After a LICC has completed restoration or no longer needs certain types of crews (e.g., forestry), it can release them to another LICC. The process, criteria, and responsibility for assigning off-system resources should be clearly defined in the Grid Disruption Plan

5.6. Communications – Customer Contact

The ability of a utility to handle a significantly larger volume of customer calls during a major outage is essential to a successful restoration. During the first few days of a major storm, or other event causing widespread outages, incoming calls increased dramatically as compared to the expected daily volume. Although the Internet has provided

additional channels for customers to communicate with utilities during outages (e.g., email or website), many still want to talk to a representative, particularly during an extended outage.

It is critical that the utility have plans in place to satisfactorily address this spike in customer calls. These emergency response plans must be executed swiftly to minimize customer frustration, reduce the likelihood of repeat calls to resolve problems, and avoid complaints to regulators. Actions to handle the anticipated increase in calls could include:

- Training in house resources from outside the call centre, who have system access, to take outage calls;
- Contracting in advance with vendors to supply trained customer service representatives; and
- Establishing mutual assistance arrangements with other utility call centres.

Successful plans are usually anchored by effective interactive voice response (IVR) applications. These allow customers to self report outages and receive restoration information. Overflow telecommunications capacity for these systems can be provided through contracts with technology companies that specialize in providing utilities with IVR capacity, including interfaces to outage management systems.

An emergency plan for customer communication might also include a strategy to proactively reduce incoming calls. For example, outbound messaging (i.e., robo calls, texts, or emails) to individual customers about expected or actual outage status can eliminate numerous incoming calls. Providing additional channels of communication for customers can reduce call volume as well. Website, email, mobile, and texting applications allow customers to report outages and track outage status. Also, social media avenues (e.g., Twitter, Facebook) provide ways for customers to obtain information in lieu of calling

Utilities use a few different organizational models to conduct the function of answering outage calls from customers. For example, some utilities place the responsibility in the call centre which also handles business calls related to customer billing and other general inquiries. Others route customer calls related to outages to their dispatch function within field operations. Many use third party call centres for primary or supplemental support.

The assessment of Toronto Hydro's management of customer contact throughout the 2013 Ice Storm addressed the following:

- Availability of a plan to address the increased volume of calls from customers;
- Plan effectiveness and thoroughness of implementation;

- Availability of alternatives to speaking with a representative by which customers can report an outage or receive information about restoration;
- Process for reporting outages, including ease of use and clarity of navigation scripts; and
- Process for providing accurate and timely messages on all customer facing systems and applications.

5.6.1. Communications – Customer Contact Findings

The day to day responsibility for handling outage calls at Toronto Hydro resides in the Distribution Grid Management Division, specifically in the dispatch section of the Power System Planning & Logistics organization. All customer calls to the main customer number to report a power outage, wire down, or power quality problem are handled through the IVR. It directs them to "select 1," which allows a caller to self report an outage in the IVR, or enter the queue to speak with a dispatcher. A wire down or power quality call goes into the queue for the caller to speak directly to a dispatcher, as do calls that are not successfully completed in the outage application. The dispatch volume averages 135 calls per day during blue sky conditions.

When a major outage occurs, however, dispatch requests a specific number of resources from Customer Care to augment the dispatch team and help respond to incoming calls. This allows some of the dispatchers to be reassigned from handling incoming outage calls to dispatching field crews. Customer service representatives from the call centre and, as needed, from other areas of Customer Care, are assigned to answer emergency calls in 8 or 12 hour shifts, 24 hours a day.

Toronto Hydro experienced an unprecedented call volume during the 2013 Ice Storm. A total of 397,500 calls entered the IVR from the main customer phone number from December 21, 2013, through January 2, 2014. Of those, it is estimated that 374,200[11] were storm calls and 23,300 were non storm calls (i.e., 14,300 calls were directed to the residential and commercial queues and an estimated 9,000 calls were non storm calls to all other business functions within the Company). Just over one third of the total storm calls (127,800) were received the first full day of the storm on Sunday, December 22, 2013.

On December 22, 2013, the number of calls entering the dispatch queue was 947 times greater than the average of 135 received during normal operations. For the following

[11] Calls to areas of the Company other than dispatch and the residential/commercial queues were significantly higher than during normal operations. Toronto Hydro categorized the number of higher than expected calls as storm calls. The estimated number of storm calls likely is conservative because it does not include storm calls answered in the residential and commercial queues (other than those which were reported as being transferred from those queues to the dispatch queue).

five days the incoming storm calls averaged 40,800 (302 times the average number of calls handled in the dispatch queue during non-crisis times).

Communications – Customer Contact Strengths

1. The ability to use an external contract call centre as a back up call centre site.

Since 2007, the Toronto Hydro Customer Care organization has contracted with a local call centre outsourcer, to provide call handling and clerical services. The outsourcer agents answer calls to the residential queues weekdays between 8:00 a.m. and 4:30 p.m. The outsourcer's staff is trained to take all non outage residential calls, which represent the majority of calls to Toronto Hydro. The Toronto Hydro in-house call centre handles the more complex commercial calls.

Call volumes vary depending on the day of the week, time of the month, and holiday schedules. The highest call volumes typically occur on Mondays, at the beginning and end of each month, and the day following holidays. On a typical Monday near the beginning or end of the month, the outsourced call centre answers about 2,500 Toronto Hydro calls.

The contract with the outsourcer provides a potentially reliable source of additional staff to answer calls during times of major outages. Equipment is in place to route calls easily from the Company to outsourced call centre and some call centre staff are familiar with Toronto Hydro procedures. From the perspective of emergency management, there is another major advantage: geographic diversity. If an incident renders the Toronto Hydro call centre inaccessible, calls can be readily directed to a contractor site at another location.

2. The Key Accounts organization within Customer Care implemented an effective process to inform key and commercial accounts of outage status.

There is a group within Toronto Hydro responsible for managing the relationships with its "key" accounts. Key accounts are customers with consumption of 1 megawatt hours or higher annually (at one site or in aggregate). There are approximately 550 such accounts.

The key account managers serve as an access point into Toronto Hydro to help answer customer questions and facilitate solutions. The key accounts program includes a group of about 15 employees (the key accounts staff plus a group of employees and contractors from the Conservation Demand Management team), who provide on-call service to their key accounts during normal business hours. Each week, on a rotating basis, one person from the group is assigned to take calls outside of normal business hours.

During the 2013 Ice Storm, key account representatives worked 12-hour shifts to keep their customers advised of restoration efforts. This continued until January 2, 2014, when power was restored to all key accounts. In addition to providing extended call

coverage, key accounts sent daily group emails to customers with general information about Toronto Hydro's plans and progress. Key customers gave positive feedback about receiving this additional information.

Recognizing that other commercial customers (with usage below the key account threshold) had a similar need for restoration information during an outage, Customer Care had been developing a proactive commercial customer outage communications program in the months prior to the 2013 Ice Storm. Commercial customers received letters asking them to enroll in the program and provide an email address for outage communications. On December 20, 2013, the day before the storm, an email was sent to 4,500 customers who had enrolled, thanking them for registering and informing them the program would start in the spring.

When the ice storm hit the next day, Customer Care was able to initiate a "light" version of the planned program. It communicated general restoration information to the enrollees via group emails. Also, Customer Care set up an email inbox to allow two-way communication with these customers.

3. The control room, dispatch, call centre, and key accounts staff are co-located, enabling more effective information exchange.

At the time of the 2013 Ice Storm, the control room, dispatch, call centre, and key accounts functions were all located at the same facility. The proximity of controllers, dispatchers, customer service, and key accounts personnel provided for easier, quicker face-to-face communication. In-person communication is especially important during an emergency response, when key staff is focused on completing assigned tasks and may not have as much time to monitor the channels of communication they used during non-emergency times. The nearness to control and dispatch allowed key account managers more timely access to updates on restoration status, improving their responsiveness to customers. Likewise, Customer Care supervisors had access to dispatch to discuss individual customer situations.

Communications – Customer Contact Opportunities for Improvement

1. There was insufficient overflow capacity (system and staffing) to take outage calls, so that the majority of callers were not able to report or get information on outage status.

<u>Telephony Capacity</u>

The telephone system associated with the main customer phone number has eight T1 lines which are limited to 152 channels to match the number of IVR Integrated Voice Recognition ports. Thus 152 customers can be served concurrently. Some of the ports are dedicated to the IVR and others to the queues to be answered by representatives. If the number of calls into the main number exceeds this threshold (i.e., when all ports are in use) the customer will hear a fast busy signal. Toronto Hydro does not get

information regarding the number of customers who get fast busy signals, so the number of customers who heard busy signals during the 2013 Ice Storm is unknown.

To address the issue of telephone port constraints during high call volume periods, Toronto Hydro adjusts system parameters to play a message, referred to as the "initial high call volume message." Callers hear this message when volumes are greater than can be handled by the capacity of the system. This message is played as soon as customers enter the IVR system to inform them that the telephone system has reached its maximum usage. For example: "Thank you for calling Toronto Hydro. Please be advised that due to the large volume of outages across the city we cannot accept any non-emergency or power outage calls at this time." The intent is to reduce the number of customers getting a busy signal and inform callers Toronto Hydro is aware of the outage. This message varies depending on the situation and is updated as a restoration progresses.

Toronto Hydro did not have a plan in place to add telephone lines to accommodate the significant increase in call volume. So, during the 2013 Ice Storm, 117,800 customers (31% of storm callers) heard this initial high call volume message. The inability to complete a call to report an outage was one of the most common problems customers raised at the town halls and through email feedback.

IVR Outage Self-Service Application

When Toronto Hydro customers call to report outages, the initial IVR menu instructs them to select "1", which takes them down a path to report one of three things: an outage; wire down; or other power quality issue. The second menu instructs the caller to select "1" to report an outage and that selection puts the customer into the outage self-service application. (If the customer selects "2" for a wire down or selects "3" for a power quality issue, the call is put into the queue for a dispatcher.) The outage self-service IVR leads the caller through a process to provide the account number or address associated with the outage. Because the IVR outage application interfaces with the outage management system (OMS), when the customer successfully finishes providing the information required, a trouble ticket is automatically created in OMS.

If the IVR system cannot understand a customer's answers or there are other problems in the interaction, the call is transferred to the queue to speak to a representative. Of the 374,200 total storm calls, 13,800 (4%) were completed in the Company's self-serve outage application without the assistance of a representative. The Davies Consulting storm database contains company-reported self-service IVR outage statistics for eight major storms. Across all the storms, at least 50% of incoming calls were handled in self-service IVR outage applications. The completion rate in three of the storms exceeded 70%.

Comments from employees and customers pointed out features of the Toronto Hydro IVR that could be improved to improve its containment rate (i.e., the percentage of calls

successfully completed in the IVR without the assistance of a representative). For example, providing an account number is cumbersome and discourages some from trying to complete their outage in the automated system. Another is that the IVR voice recognition system does not distinguish accents well.

Staffing to Answer Calls

The Customer Care organization can draw from approximately 80 representatives to answer calls during periods of high volume. This number includes approximately 30 Toronto Hydro employees (those working in the in-house call centre and those who have rotated from the call centre into customer billing and collections functions) and 50 call centre staff. The full complement of available representatives (both internal and from outsourcer) was fully deployed until December 27, 2013.

Lack of prior training on handling outage calls caused some of the delay in deploying resources to answer calls. It precluded the use of a few Toronto Hydro employees during the 2013 Ice Storm because of union rules which restrict offering overtime to an employee who has no experience in the specific role. And, as noted previously, the outsourced call centre employees had not been trained to answer outage calls prior to this storm.

A few days into the 2013 Ice Storm, Toronto Hydro contacted the outsourced call centre for back up support to handle storm calls. The outsourcer provided 66 additional agents to take calls in the dispatch queue, including the pool of 50 noted above. Toronto Hydro staff provided training to the outsourced agents on how to answer customer questions and about which information to pass to their supervisors to enter tickets for new outages. The supervisors were given more detailed training and access to OMS Web Entry. Toronto Hydro did not have other agreements in place to access additional staff to handle the sharp increase in customer calls.

Of the total storm calls, 21,000 (5%) were handled by company representatives. By comparison, the Davies Consulting Storm Benchmark Database shows that in one major storm, 24% of the 1.1 million storm calls were answered by a pool of 350 employees from the affected company and its sister company. In another case, 31% of the 194,000 storm calls were answered by a pool of over 500 employees from the company's in-house and contracted call centres.

Dispatch Queue High Call Volume Message

A large number of customers who called when there was an available telephone port still heard a message that the Company could not receive any more calls at that time. Those callers experienced a high call volume message after their calls had been accepted by the IVR and they made a selection within the outage menu which put them into the dispatch queue. (If they selected "1" to report an outage and were not able to successfully complete the report in the self-service IVR, they were transferred to the

dispatch queue. Callers who selected "2" or "3" to report a wire down or other issue also were placed in the dispatch queue).

During normal operations when there are not many outages, the system is set to allow approximately 30 calls in the queue to dispatchers during business hours and 10 calls outside of business hours. Adjustments are made depending on the number of incoming calls and staff available to handle calls. After the maximum number of callers has entered the queue, the next customer hears a message that "no additional calls can be accepted at this time." Of the total callers that entered the dispatch queue during the 2013 Ice Storm, 136,000 (84% of callers entering the dispatch queue or 36% of all storm callers) received this message.

Abandoned Calls

During the 2013 Ice Storm, 20% of callers who were able to enter the outage queue to talk with a representative abandoned their calls while waiting. An abandoned call is one when the caller, after entering the queue to speak to a representative, hangs up before the call is answered. At Toronto Hydro, the percentage of abandoned calls is this number compared to the total calls entering the queue that do not receive a high call volume message

Although abandoned call goals vary among companies, a range of up to 5% or 6% is considered acceptable within the call centre industry, with a tolerance of up to 8% or even 10%. The Toronto Hydro call centre, for example, has a scorecard goal of 3% abandoned calls during non-emergency periods. The Davies Consulting Storm Benchmark Database includes data on abandoned calls for eight storms. For these storms, the percentage of abandoned calls is 12% or less.

Average Speed of Answer

Average Speed of Answer (ASA) is a call centre measure of the average number of seconds from the time a customer requests to be transferred to a representative to the time the representative answers the call. The overall average ASA for customers in the dispatch queue during the 2013 Ice Storm period was 7 minutes and 14 seconds.

Many different companies across a variety of industries use call centres. This variation makes it difficult to establish a "standard" ASA goal. A frequently seen company ASA goal is at or about 40 seconds, but this goal normally would not apply during an emergency. Davies Consulting has evaluated call centre performance for major storms at two utilities which accomplished 43 second and 62 second ASAs during major outages. At both those utilities, 50% or more of the incoming calls were successfully handled in the self-service outage IVR application and their in-house and outsource call centres provided a significantly larger pool of representatives to handle calls.

2. The Integrated Voice Recognition system was difficult to navigate, not intuitive, and did not effectively support customers who are non native English speakers.

As noted above, 14,000 (4%) of the total incoming outage calls were completed in the Company's self service outage application, as compared to other utilities with completion rates of 50% or more. Comparisons to other utilities and information gleaned from interviews with employees familiar with the IVR system indicate the following gaps:

- The outage IVR provided inaccurate information to many customers regarding the status of their outages. Large numbers of customers received false messages that their power had been restored causing confusion and frustration, as well as an increase in call volumes. Contributing factors were delays in closing outage tickets in the OMS and inadequate interface between the IVR and OMS.);
- The IVR's voice recognition system does not distinguish many of the accents associated with languages commonly spoken in the Toronto area causing callers to be bumped out of the self service outage application;
- The outage IVR initially asks for a customer's account number, which, if in hand, is cumbersome to enter. Often this discourages customers from trying to complete their outage reports in the automated system;
- The IVR does not provide a service order ("ticket") number to customers to confirm that an outage is recorded; and
- Once a customer selects the path to report an outage, there is no option to return to the previous menu if, for example, a mistake is made when entering an address. When something like this occurs, the customer must hang up and call back to start over.

3. Outage status information was inadequate and often inaccurate.

Dispatchers and customers service representatives answering outage calls often encountered weary, impatient, sometimes angry, customers. Many were frustrated from the necessity of calling multiple times before reaching a representative. As discussed above, large numbers received information from the IVR that power had been restored to their homes when, in fact, it was not.

In addition, customers received inaccurate information from the outage map on the Toronto Hydro website. This map is created using postal codes and is not fully integrated with OMS. As a result, it displayed erroneous information, driving customers to call the Company.

During any outage, and particularly during extended outages, customers may have to make decisions regarding their living arrangements and businesses. Fundamentally, they need to know when their power will be restored. When Toronto Hydro representatives answered customer calls, they had minimal information to satisfy customers' needs. Information regarding estimated restoration times was not available. For the most part,

dispatchers and customer service representatives had to use the Company's messaging from press releases and general communications to employees when speaking with customers.

When calls were escalated to supervisors, they could access dispatch to try to get more specific information. Although ETR information was not usually available, other information about what was happening in the field could be garnered to put together enough information to respond to the customer inquiries. Some of the representatives were physically located at workstations in dispatch and could also glean some additional information to use in conversations with customers.

4. Alternate paths to contact Toronto Hydro (e.g., email, web) were in place, but all were not monitored frequently enough.

In addition to calling, Toronto Hydro customers used three web based options to contact the Company during the 2013 Ice Storm:

- Free form email;
- Website contact form; and
- Website power outage reporting form.

Customers sent comments or inquiries using an unstructured format to the Company via contactus@torontohydro.com or a contact form provided on the corporate website (See Figure 16). The intended use of the contact form is for customer inquiries related to billing, other account information, and general questions. During the 2013 Ice Storm, however, the majority of contact forms (and free form emails) submitted were related to outages. Day to day, a dedicated team of three customer service representatives and/or student interns from the Toronto Hydro call centre respond to these inquiries.

During this storm, student interns responded to the emails and contact forms by scanning them for wire down or other safety concerns which merited priority reporting and outages not previously reported. They would create an outage ticket as indicated. The interns monitored the emails and contact forms only during normal business hours on non holiday workdays.

Figure 16: Web based Contact Form

The number of emails and contact forms forwarded to the Toronto Hydro call centre team for response from December 22, 2013, through January 2, 2014, was 2,028. Daily totals for those dates ranged from a low of 42 on January 1, to a peak of 392 on December 24. Normally, the team receives 80 to 120 account related emails per day on weekdays and 50 or fewer per day on weekends.

Customers also used the Toronto Hydro corporate website to report an outage using the form shown in Figure 17. The dispatch group is responsible for following up on the power outage reporting forms, which involves manually entering each form into OMS. Unlike many utilities today, Toronto Hydro has not developed an automatic interface from the form to OMS. During the 2013 Ice Storm, customers forwarded 106,000 outage reports using this form.

During the storm response, from time to time, dispatch supervisors would request a few representatives to review these forms and input outages not already reported to OMS. Resources were not assigned to regularly review the power outage reporting forms throughout the restoration.

Figure 17: Power Outage Reporting Form

5. Toronto Hydro does not provide mobile capability to report or track outages.

As the penetration of smart devices increases, so do customer expectations to receive information they need and want, at any time, and through the communication channel they prefer. In response, many companies have developed applications to allow their customers to do business with them more easily on cell phones and tablets. Many utilities (including Hydro One) offer free mobile applications that allow customers to report and check the status of power outages. Toronto Hydro does not have a mobile application and did not provide customers with the ability to report their outages through text messaging.

6. There was no capability to transfer Toronto Hydro related calls from the 311 call centre.

During the 2013 Ice Storm, some Toronto Hydro customers called the City of Toronto 311 call centre to report their outage or get restoration information. The call centre representatives had no information or procedures to use in order to help these customers. They had not been trained on the restoration process for widespread electricity outages, nor had they been made aware of the outage reporting form

available on the Toronto Hydro website. No technological interfaces (such as the capability to transfer calls to the Toronto Hydro call centre) were available between the two entities.

5.6.2. Communications – Customer Contact Recommendations

The volume of customer inquiries and the sustained need for outage status information resulting from the 2013 Ice Storm revealed gaps in emergency preparedness, insufficient scalability of telephony and staffing, and the need for additional and broader training. During widespread outages Toronto Hydro must be able to rely on technological solutions (self-service IVR and web based applications) to accurately handle the vast majority of customer contacts without the intervention of a representative. Specific recommendations to improve customer contact communications are:

CCC1. Secure capacity (people and technology) to support timely customer contact during an incident:

- Enhance the customer self-service IVR outage application to handle significantly more calls.

Toronto Hydro should invest in improving its self-service IVR outage application so that its performance during emergencies is in line with peer utilities. If Toronto Hydro customers had successfully completed 50% of incoming storm calls in the IVR, an additional 172,100 calls would have been satisfactorily completed.

In redesigning or replacing the application, Toronto Hydro should consider surveying other utilities with high containment rate systems to determine what changes and new features would be most effective. These could include:

- Upgrading the voice recognition technology to enable more customers to complete their transactions in the IVR;
- Deleting the request for an account number to identify the outage location;
- Providing options for a customer to return to the front of the outage IVR menu and/or other points in the interaction;
- Providing the customer a ticket or reference number to confirm that the outage has been recorded and to allow quicker, easier access to outage status information; and
- Correcting issues in the current interface to the OMS.

In concert with the technological enhancements, Toronto Hydro should adopt procedures to more frequently (in near real time) update restoration information in the OMS. With system improvements and implementation of those procedures, customers

calling for outage status could receive accurate information without the assistance of a representative.

- Secure sufficient capacity and surge capability during periods of extremely high call volume to eliminate busy signals.

Toronto Hydro should explore alternatives through either expanding the capacity of its IVR, or contracting with a third party high volume call processing company to ensure that the customers do not receive busy signals during full scale events. Call processing companies can provide a cost effective alternative to purchasing telephony capacity adequate to handle infrequent high call volumes. There are a number of services available from these companies, but most frequently utilities contract for additional capacity, so more customers can be handled concurrently through self service outage IVR. Utilities contracting with these companies have reduced or completely eliminated fast busy signals during full scale events

For example, a third party company specifically set up for outage communications provided additional telephone ports and using the client utility's IVR application, successfully handled over 233,000 of the 1.1 million calls the utility received during a recent major storm. On the peak call volume day in another storm, customers completed 19,800 calls in another utility's self service IVR using 21st Century Communications ports. In both cases, the outage reports were successfully interfaced to the utilities' OMS systems, providing customers with accurate outage status information.

The call transfer to the third party call processor is seamless for customers. Customers needing to report a wire down or talk to a representative for other purposes are transferred to the dispatch queue in the same way that they would be if their call was answered by telephony at the utility rather than at the third party call processor.

The use of a third party call processor to handle overflow calls, when paired with an improved Toronto Hydro self service outage IVR, could potentially eliminate the need for the initial high call volume message which was heard by 31% of storm callers during the ice storm.

- Identify and train customer representatives within Toronto Hydro and at outsourcer to service outage calls and website contacts during major incidents.

The Dispatch Group should analyze how many customer contact resources would be needed under various emergency scenarios and develop a plan in collaboration with Customer Care that would allow them to deploy the amount of resources needed to satisfactorily handle the maximum number of estimated calls and website contacts. The analysis should consider factors such as: how the crisis impacts the use of either the in r house or contract call centre facilities, telephony capacity, IVR containment rates for customers reporting outages and seeking outage status information, estimates of how

many customers will report outages using the website outage form and whether or not the outage form is interfaced to OMS.

Using this evaluation as a base, Toronto Hydro can determine how many trained resources will be needed at all times, and implement a training program and schedule to ensure this level of readiness. Training topics should include:

- The use of all automated systems involved in outage reporting at Toronto Hydro (self-service outage IVR, OMS, Web Access, the website outage form, the website outage map, and any other systems that may be developed in the future to allow customers to report outages or receive restoration information);
- Communicating ETRs to customers;
- Handling of difficult customers. (Toronto Hydro training staff might identify representatives who are able to better handle customers during a storm and ask them to role play handling calls.)
- Refresher courses; and
- Implement web based and mobile outage applications to support high volume self-service.

The outage information that customers report on the corporate power outage reporting forms does not automatically feed into the OMS. Each form completed by a customer must be manually entered to OMS. An on-line interface would reduce or eliminate the need for staff to input outage information during an emergency (and day to day). When an interface is developed, considerations should be given to providing a service order or ticket number to customers when they successfully submit a form, to assure them the outage had been recorded and provides a reference number.

The Company should also develop and implement mobile outage applications to provide customers the ability to report outages and track restoration status from their smart phones and tablets. This should reduce calls to representatives. Various utilities offer free applications that allow customers to report outages and find outage status. Some provide outage maps, searchable by address, which are updated with OMS information, as often as every 15 minutes. In a few cases, these applications provide cause, crew status, and estimated time of restoration (when it is known).

CCC2 Improve the process for ensuring accurate and uniform outage status messages across every mode of communication to customers (e.g., IVR, web, mobile application, low tech channels).

The previous recommendation suggests methods to improve outage status accuracy when customers use the self-service outage IVR. Many of the same programming and procedural changes for outage status accuracy should be applied to the outage form on www.torontohydro.com and to any mobile applications implemented in the future. The

keys to consistent accuracy are enhancing the automated interface with OMS and entering restoration information to OMS on a near real time basis.

A process also, should be put in place to provide field status information to dispatch and call centre staff. Implementation of recommendations elsewhere in this report to improve the ETR process are essential to providing representatives the information they need to properly serve customers during outages. Until those recommendations can be successfully implemented, dispatch and Customer Care need to develop a method by which more granular information regarding field activities can be communicated to all representatives answering calls and Internet inquiries.

CCC3 Employ outbound calling/texting to inform customers of outage status and other pertinent information.

Toronto Hydro uses outbound calling software to support the collection of Accounts Receivable. A leading practice employed by some utilities is to use this software to provide messaging to customers during storms. This application can push telephone calls to customers, with or without a representative attending the call. Outbound calling campaigns designed for outage purposes normally do not require interface with a representative.

The use of outbound calling before and during incidents could enhance the Company's effectiveness in meeting communications objectives. For example, some utilities use outbound calling to give customers pertinent information to better prepare for a forecasted major storm. Another common use is to message customers served by feeders that have been restored, telling them the Company has restored service in their area and asking them to confirm if they have or have not been restored.

Customer Care and Corporate Communcations staff should develop plans for the proactive use of outbound calling and texting during extended outages. Surveying other utilities regarding their use of outbound calling and texting technology might be useful in planning and designing campaigns. Those selected for implementation should be designed and tested to ensure timely execution when needed.

CCC4 Work with City of Toronto to evaluate options for using 311 capabilties.

The Toronto City 311 call centre and Toronto Hydro Customer Care staff have begun to discuss ways to improve the handling of outage related calls during an incident. Some ideas being discussed include providing outage communications updates to the 311 representatives on a regular basis during extended outages and training 311 representatives to complete website outage forms for customers who may not have access to the Internet during the outage. The evaluation should address:

- The capacity needed to meet anticipated call volumes at all incident levels;
- The knowledge and skills needed to support single call resolution;

- The potential impact on service levels to other City agencies and organizations that the 311 call centre serves; and
- Ways to automate communication between Toronto Hydro and the City during large scale incidents

5.7. Communications – Other Stakeholders

A utility's ability to effectively communicate to internal and external stakeholders during a major incident is equally as important as the efficiency of the physical restoration. In order to return the community back to "normalcy" in the shortest time possible, and maintain customer and stakeholder satisfaction during major power outages, a utility must:

- Demonstrate that it knows the customer is without power;
- Convey a sense of urgency about restoring power;
- Provide consistent and accurate information on restoration progress; and
- Provide customers with accurate and reasonable estimated times of restoration.

While the first and fourth points are addressed in the previous section of this report, this area of review focuses on the broader aspects of crisis communications during the 2013 Ice Storm, specifically answering the following questions:

- Have processes been put in place to ensure "one voice" communication during major events and are these processes followed?
- Was Toronto Hydro able to maintain a sense of control continually apprising its stakeholders of the restoration approach and progress?

During an event, the utility should designate a single individual who is responsible for communicating with the media and public, leaving the rest of the staff free to focus on the restoration. The content of the messages delivered during the restoration should be confined to helping stakeholders understand the prioritization and restoration process, issuing safety advisories, delivering progress updates, and providing ETRs. Introducing additional "voices" during a major restoration effort can lead to inconsistent, disjointed messaging. This can create confusion among customers and other stakeholders, which then must be addressed in a "clarification" effort which can draw resources away from restoration.

When incidents occur, leading utilities ensure that messages:

- Are consistent and effective across all communications channels;
- Reach the proper audiences; and
- Are understood by spokespersons and compliment overall communications objectives.

Toronto Hydro had the process in place to ensure that messages were consistent with the communications strategy (evaluated daily) and performed well in several channels of communication.

The review of Toronto Hydro's communications to other stakeholders throughout the 2013 Ice Storm restoration addressed the following:

- Communications strategy and roles;
- Execution of "one voice" communication;
- ETR process;
- Methods and modes of communication, including social media;
- Alignment of internal and external communications;
- Synchronization of messaging and communications processes with the City and Province; and
- Outreach to vulnerable populations.

5.7.1. Communications – Other Stakeholders Findings

Throughout the event, Toronto Hydro was able to maintain unity of message, demonstrate the level of understanding and control over the incident, and provide stakeholders with a clear understanding of the restoration priorities and progress. It is important to recognize that the strengths in the communication process to stakeholders were somewhat muted by the Company's shortcomings in providing customers with the ability to report their outages and receive updates on their status. See Section 5.6 for more details.

Toronto Hydro worked closely with City and Provincial officials to coordinate the messaging to the public and used social media to distribute the messages. Some customers did not have access to radio, TV, and social media, and the officials did not provide alternative sources of information such as town meetings, loudspeakers, or door hangers to reach these populations.

Communications – Other Stakeholders Strengths

1. As the face of the Company and the executive spokesperson, the CEO performed his role well.

When used, the executive spokesperson is the most visible and important role in incident and crisis communication. During the 2013 Ice Storm, the President and Chief Executive Officer (CEO) served as the primary spokesperson for the Company. As the face of the Company, he was present, on message, empathetic, transparent, and consistent in his external communication. Conducting upwards of 25 interviews between, December 19, 2013, and January 2, 2014, his messages were aligned with press release content, maintaining a sense of consistency that was received well by the stakeholders. The frequency and quality of communication provided by the executive spokesperson, given the information available about restoration status, was comparable to leading practice within the industry.

2. Proactive media campaign and consistent messaging (use of "one voice"), including coordination with the Systems Operations Centre, worked well.

Toronto Hydro presented a consistent message across all of its communication channels, aligning with the "one voice" concept, which is considered a leading practice. The Company also used a sound communication methodology, delivering messages crafted by the media and communications lead and approved by the incident commander. Toronto Hydro's communication department ensured that all communications channels disseminated consistent message content.

On the whole, messages were coordinated with and ultimately approved by the incident commander and were part of the daily discussion in the SOC and the Grid Emergency Report, a form of an incident action plan (IAP). This was accomplished through a communications meeting that occurred at 6 a.m. every day. During this meeting, the messages of the day were created in preparation for the 7 a.m. news cycle. The messages were updated throughout the day.

All internal and external communications stemmed from approved press releases that were distributed to the media. Once press releases were issued, communications staff used them to craft messages for different communications channels (e.g., press conferences, interviews, e-mails to key stakeholders) and employees were sent approved messages to ensure the entire Company was in alignment with respect to its response. The spokesperson was consistent in conveying the messages of the day throughout the event.

One area of criticism was that messaging on the first day of restoration created an expectation that the restoration would take 72 hours. An in-depth analysis of all the communication issued at the time, including the press conference footage, the media reports, and internal messaging and plans, has not revealed the source of this information. The Grid Emergency Report noted the key message on the first day was

that the restoration would take "at least 72 hours." Given that the Toronto Hydro emergency levels used 72 hours as the lower threshold for the largest events, it is understandable why the Company would consider messaging the 72 hour timeframe in the early stages of the response, before the damage assessment was completed.

3. Toronto Hydro was viewed as an effective partner in City and Provincial communications.

Toronto Hydro continuously communicated with the City of Toronto and made the Company spokesperson available for City press conferences. The level of effort to communicate jointly is a leading practice for a utility during major events and enabled Toronto Hydro to be seen as an effective partner with the City and Provincial governments. There were at least 15 press conferences between City Hall and Queen's Park that the CEO attended with City leaders. While the City and Toronto Hydro spoke about different aspects of the emergency, their messages were consistent and complementary.

Many citizens turned to the City Council for answers when Toronto Hydro could not provide them information through its own Call Centre. When the City Councillors became overwhelmed with inquiries, they turned to one of a few Toronto Hydro staff members. They were prolific communicators with the City Council, answering questions for the Councillors about the restoration. Throughout the interviews, participants repeatedly noted that Toronto Hydro was a strong and committed partner in communication to the public throughout the event.

4. Toronto Hydro used a variety of methods to reach the public, including social media.

Toronto Hydro used various communication channels to reach external stakeholder groups. These channels include broadcast media, print media, radio, social media, and the corporate website, as well as phone and email for some stakeholder groups. Social media proved to be the channel with the biggest growth and stakeholder engagement. Toronto Hydro's Facebook fan page garnered 3,000 new fans and over 6,000 unique comments while the Company's Twitter account accumulated approximately 24,000 new followers and 20,633 retweets during the 2013 Ice Storm. The number of retweets is a valuable metric as it indicates the value of the message to the subscriber as well as indicates the potential number of ultimate views. Figure 18 shows samples of Twitter messages posted during this storm.

Figure 18: Sample Twitter Messages

Communications – Other Stakeholders Opportunities for Improvement

1. Process for developing and issuing timely and accurate ETRs (estimated times of restoration) was not clearly defined.

Toronto Hydro did not have an effective process or the technology in place to provide estimated times of restoration consistently and automatically for the magnitude of outage that occurred as a result of the 2013 Ice Storm. Across the industry, ETRs are by far the most sought after piece of information when a utility experiences widespread outages. The processes at Toronto Hydro do not currently support the provision of ETRs outside of normal or blue sky day outages. While this is not uncommon in many other utilities, providing customers with an accurate and timely restoration estimate is becoming an expectation during major events.

On December 22, 2013 (the first day of restoration), one of the key messages from the System Operations Centre was that the restoration would last at least 72 hours. This estimate was translated into a restoration time of 72 hours, essentially omitting the 'at least' reference from the 72 hour restoration message. It was soon apparent that this ETR was not aligned with the key message of the day and it did not accurately reflect the level of damage or the effort that would be required to restore the damage. From that point on, Toronto Hydro wisely did not issue any other projections for restoration, because it did not have a strong process for developing and validating restoration estimates at the time of the event. As a result of this decision, customers were not provided any specific estimates of their outage durations.

2. Liaison roles with some stakeholder groups were not clearly defined.

Overall, Toronto Hydro's liaison presence was seen in a favorable light, but there was a slight disconnect in the expectations between the Company and the City Office of Emergency Management. Additionally, there were no clearly defined expectations and guidelines to address information and other assistance needed by the City Council members. Toronto Hydro did, however, manage critical restoration requests from the public sector very well. It responded promptly to building fires at Toronto Fire's request and was responsive to the Office of Emergency Management's critical infrastructure and public safety requests. Additionally, Toronto Hydro avoided 'special' requests for preferential restoration. The Company also provided Council members with three dedicated contact people who were very responsive, according to the interviews.

Toronto Hydro staffed liaison positions at the Office of Emergency Management, but the type of information that stakeholders needed and the level of interaction that they wanted from Toronto Hydro were not defined in advance. The operational liaison at the City Office of Emergency Management effectively maintained operational communication and solved emerging restoration priorities including City critical facilities that lost primary and back up generation. As the event progressed and Toronto Hydro was unable to provide its liaison to the OEM with actionable, operational information, the need for an executive presence increased. Because of that, the City OEM had to engage Toronto Hydro executives to resolve issues.

Due to shortcomings in Toronto Hydro's call centre, City of Toronto Councillors received an unexpected numbers of requests from citizens. Toronto Hydro corresponded with Councillors and their staff in approximately 7,000 emails and over 100 direct phone calls.

3. Messages were not always accessible to all stakeholders (e.g., customers with no access to TV, radio, or social media).

During an extended power outage, many customers lost access to habitually used information channels, such as radio, television, and social media. In addition, Toronto's population includes a significant portion of people who are not technology savvy and this, along with the inaccessibility of the call centre, left them with little or no information on outage status. During the 2013 Ice Storm, the Company did not provide sufficiently for alternative ways to communicate with the customers, such as town hall meetings, neighbourhood updates, loudspeaker messaging or door hangers.

5.7.2. Communications – Other Stakeholders Recommendations

COS1 Develop a process to communicate timely and accurate ETRs at different levels of specificity.

Toronto Hydro should update its entire estimated time of restoration (ETR) process to enable the automatic provision of estimates to customers. This process will require

Toronto Hydro to provide a realistic timeframe for restoration for varying levels or sizes of incidents to set expectations with its stakeholders. It should advise customers about the unavoidable limitations in ETR delivery immediately following a complex outage and create communication strategies around these limitations.

The Company should identify all potential channels for providing the ETR updates to various stakeholders and develop a process to ensure that the messaging is consistent and accurate across all venues. These channels should include non traditional ways of communicating to address the needs of those populations that are not technically savvy or do not have access to traditional media due to an extended outage.

COS2 In collaboration with the City of Toronto, develop an education program to improve stakeholder literacy of: restoration process, customer responsibility, and preparedness.

Toronto Hydro should work with the City of Toronto to develop a program and execute an education campaign about the power restoration process to the citizens of Toronto. Educating the population on personal preparedness and resiliency is the responsibility of the public emergency managers. Providing educational information on electric (and gas) utility restoration is the responsibility of the utility. Working together, Toronto's Office of Emergency Management and Toronto Hydro should determine how best to conduct joint or complementary personal preparedness education.

Toronto Hydro, in partnership with the City and Provincial Emergency Management organizations, should develop a public education program for external customer and stakeholder groups. The Canadian Electric Association may consider bringing together Hydro companies across Canada to create an education e in conjunction with national emergency management organizations. The annual program should educate customers on the following:

- Delivering electricity from the power plant to the meter in order to provide a general understanding of how the system works;
- Specifying what stakeholders are responsible for and what they should do before and during a Toronto Hydro response to an incident, including special needs customers, use of electricians to restore the damage on customer property, etc.;
- Responding to outages during blue sky days versus during an incident to illustrate the complexity of responding to a single outage and how the complexity changes when multiple outages occur;
- Understanding priorities and how they play a role in the manner in which Toronto Hydro responds to incidents; and
- Ensuring stakeholders are aware of what they need in order for their residence to accept service from Toronto Hydro.

A program like this would equip stakeholders with information that will help them set realistic expectations, so they can make informed decisions to protect their health, safety, and comfort during an outage.

COS3 Expand liaison role to address education, communication, and coordination with key community stakeholders (e.g., elected leaders, public safety) during major incidents.

One of the most critical responsibilities of the utility emergency manager is to create relationships with public and private sector emergency partners prior to an emergency. According to public safety professionals in the Toronto government, Toronto Hydro has recently improved its capabilities in the liaison role. This effort started at the beginning of 2013 and markedly improved during and after the July 2013 floods. Toronto Hydro should further improve its capability to provide the following:

- Operational information to City of Toronto (OEM, police and fire, transportation);
- An avenue to review restoration priorities in real time;
- Executive level interface in the most demanding responses;
- An ability to embed and coordinate Toronto Hydro assets with City public safety and public works assets, and vice versa, during a response;
- A process for coordinating public communication and leveraging each other's communication channels;
- Pre-established guidelines for handling special requests; and
- Appropriate interface/liaison to City Councillors to arm them with the unified message and support other specific information and outreach needs.

COS4 Formalize process for developing, approving, and disseminating key messages.

Toronto Hydro's communications team was deliberate in ensuring that the press releases issued to the media were the basis of information used to develop all other external and employee communications. Some of the processes used to support the messaging process were developed "just in time." Toronto Hydro should document the process for developing key messages and potentially enhance it further, based on any lessons learned. This documentation should become a part of the Emergency Management Plan going forward. For example, the process should capture the following:

- All of the internal and external stakeholder touch points;
- The most appropriate channels to disseminate information to those internal and external stakeholders;
- Commonly requested information for each touch point;

- Specific roles for the message development team, including responsibilities for message development and approval;
- Process map depicting a step by step message development and approval process; and
- Pre-scripted messages in the key languages used by the residents of the Greater Toronto Area.

Documenting these processes and procedures will ensure the consistent use of messaging during major events and consistency in the training of new team members in preparation for an event.

5.8. Information Systems and Technologies

The role of the information and operational technologies in major events is two fold. They provide incident managers with the ability to identify, process, and comprehend critical restoration information (e.g., customers out, location of outages, devices that have operated, location of crews) in order to establish "situational awareness" and provide data and intelligence to inform restoration decision making. The level of deployment and integration of these systems and tools can directly affect the incident response team's ability to make timely and informed command and control decisions at the strategic, operational, and tactical level.

The operational and information technology systems commonly used by utilities during major events are:

- Outage management system (OMS);
- Geographic Information System (GIS);
- Customer Information System (CIS);
- Supervisory Control and Data Acquisition system (SCADA);
- Integrated voice response system (IVR);
- Mobile Data System (MDS);
- Automated metering infrastructure (AMI, smart meters); and
- Radio communications, web sites and web-enabled applications.

The integration of the different systems provides the utility with an end to end ability to manage outages. For example, when a customer calls a customer service representative (CSR) or the IVR to report a power outage, a trouble ticket is produced in OMS that represents that individual customer's outage. As additional notifications are received from the IVR or other CSRs indicating more customer outages in the same area as the initial call, OMS will use algorithms to determine what upstream device (e.g., fuse, recloser, or breaker) operated to interrupt service to the entire group of customers.

OMS will then create an outage ticket for that specific device. In companies with MDS, dispatchers send the trouble tickets to trouble or line crews' MDS terminal. In utilities without MDS, a dispatcher will typically radio the ticket information to the crew and the crew will then initiate a paper ticket process to provide the required information to clear the ticket from OMS.

The OMS plays a critical role in the end to end process. It captures, evaluates, and tracks the status of outages across the service territory. It integrates with the IVR system and CIS to generate outage records for individual customers tracks group calls related to outages, and generates outage tickets for repair. It links to the GIS system provides information about electric distribution system connectivity, and generates reports on the status of outages across the system for further analysis.

During major events, there is an exponential increase in the number of people interfacing with the OMS and the number of transactions that OMS has to handle. This level of activity often creates the risk of a system slow down or shut down when the number of transactions approach or exceed the capacity of the system.

GIS is used to enhance a utility's ability to track assets, develop circuit maps, and, in some cases, view tree canopy in relation to the system's equipment and assets.

MDS aids the development of situational awareness and operational decision making. MDS terminals installed in line trucks provide GPS and trouble spot information and enable restoration crews to interface directly with work management systems, OMS, and dispatchers to streamline execution of operational decisions. MDS can be used to capture damage assessment information, or as a tool to better communicate ETRs from crews in the field to customers. A drawback is the cost to outfit an entire vehicle fleet. Currently, all of the grid response vehicles and supervisors at Toronto Hydro have installed MDS terminals on their vehicles. In addition, meter technicians and inspectors use handheld mobile units.

SCADA systems provide an understanding of the scope of the outages and allow operators to remotely open and close devices in the field. This improves reliability on a day to day basis and can be used early in a large event response to re energize those circuits that have ties to other feeders that have not been affected by the outage. This remote restoration can result in faster restoration of some customers. SCADA also provides support throughout a restoration by allowing the system operators to remotely switch circuits as repairs are made.

Since the early 21st century, utilities have been adopting and implementing advanced metering infrastructure (AMI), also known as smart meters. These systems provide utilities with the ability to carry out two way communication with meters, and can be used to "ping" a meter (i.e., send a signal) to determine whether there is power at the premise. While this is a functionality that the smart meters provide, the primary objective in installing AMI was to support energy efficiency initiatives and enable

customers to manage their energy usage. As a result, most of the AMI systems are not capable of conducting mass surveys ("pings") of customer meters to provide immediate status of the outages.

The IVR and CIS are described in Section 5.6 Communications – Customer Contact.

The assessment of the Toronto Hydro information systems and technologies used to support the 2013 Ice Storm restoration encompassed the following:

- Systems scalability;
- Systems integration;
- Availability of critical data (e.g., for accurate situational awareness, ETRs);
- Accommodation of new users;
- Use of mobile based technologies; and
- Alternatives when technology is down/unavailable.

5.8.1. Information Systems and Technology Findings

Like most other utilities, Toronto Hydro has implemented and integrated each of the systems described above, to support day to day operations. Generally, they support blue sky day operations and smaller outage events (i.e., Level 1 or 2) with great proficiency. The volume of transactions and interfaces generated by the 2013 Ice Storm, stressed the capacity of the system, pushing some portions of the technology infrastructure to their limits.

Information Systems and Technology Strengths

1. One of the early adopters of smart meter technology.

In 2006, Toronto Hydro was one of the first utilities in North America to deploy smart meter technology, called Automated Metering Infrastructure (AMI). As a part of an Ontario Energy Board (OEB) initiative to improve energy efficiency, regulators provided funding for the Company to install the AMI infrastructure. Today, there are 648,000 retail customer and 85,800 industrial/commercial smart meters on Toronto Hydro's system. This extensive smart meter network provides Toronto Hydro with the ability to remotely outages. Since energy efficiency was the primary objective for AMI, the system is not set up to support a large scale restoration. For example, the current system uses a manual process to ping each meter, requiring excessive time to determine the status of an outage for a group of customers (e.g., an entire circuit).

2. An extensive Supervisory Control and Data Acquisition (SCADA) system with 85,000 control points on more than 4,000 devices.

Over the years, Toronto Hydro has implemented an extensive SCADA system with connectivity to more than 90% of its distribution circuit breakers. Approximately 140

circuit breakers on the 4kV system do not have SCADA controls. As a result, Toronto Hydro's SCADA system provides relatively strong penetration of the devices for an overhead system of its size and construction.

This allows Toronto Hydro to perform remote sensing and control of devices on the electrical distribution system. During an event like the 2013 Ice Storm, the SCADA system was used to initially determine the number of feeder lock outs (i.e., circuits that were completely out of power) and perform remote switching and restoration operations. These resulted in some portion of customers being restored within the first 24 hours from when the event started. Since the SCADA system feeds information into the Outage Management System (OMS), the outage tickets associated with the circuit lockouts were created immediately for field review and restoration.

3. Mobile Data Terminals available in a portion of Toronto Hydro vehicles.

Approximately 20% of Toronto Hydro trucks used during the 2013 Ice Storm restoration and were equipped with full MDS terminals and another 30% had mobile connectivity. These mobile units, typically laptops located in each vehicle with cellular technology and automatic vehicle locating technology (AVL) or Global Positioning Satellite (GPS) Technology, allow the crews to receive, accept, update, and close outage tickets from their truck and provide a more timely status of each outage in the OMS. At the same time, GPS location provides the dispatchers with real time visibility into crew locations so that they can assign work to the crews that are closest to the outage.

Information Systems and Technology Opportunities for Improvement

1. OMS hardware and interfaces were not scalable to handle the number of concurrent users during the 2013 Ice Storm.

Toronto Hydro's OMS license can accommodate 33 concurrent users, which provides enough bandwidth to operate the system on a blue sky day and during Level 1 and 2 outage events. Per the Emergency Response Plan, during the 2013 Ice Storm, Toronto Hydro decentralized the dispatch function to local incident command centres to more efficiently manage the restoration work. As a result, the volume of concurrent transactions exceeded the capacity of the system and caused a brief outage.

In addition, the version of the OMS system that was implemented does not include the web interface for managing basic transactions. The current OMS was designed for use by "super users" – staff who need broader access to system functions to conduct their daily work. In addition to enabling basic OMS transactions, such as opening and closing outage tickets, assigning ETRs for individual customers, and running basic outage status reports, this "super user" interface provides the ability to make changes to the connectivity model, 'un nest' outages that the OMS has logically tied to a single device, and purge incorrectly created outage tickets. Super users access OMS through a more sophisticated interface that typically requires training and significant on the job experience to master. A more basic interface for managing the outage tickets and

running basic reports would require much less training and use less bandwidth than the "super user" version.

2. Groups of smart meters could not be pinged quickly to determine the outage status and a portion of them do not have "last gasp" technology.

As mentioned earlier, Toronto Hydro was one of the early adopters of AMI technology comprising the smart meter hardware, software, and communication network. At the time the AMI system was installed, the primary purpose was to support energy efficiency initiatives through the provision of highly reliable consumption usage readings, so that customers can better manage their energy usage. While smart meters can be used to identify or verify outages, the existing system allows for serial communication (one meter at a time) only, which is done through a highly manual process. This process does not support effective (near real time) "pinging" of meters to assist in identifying "nested" outages.

In addition to this limited capability to provide outage status on a large scale, approximately two thirds of Toronto Hydro's smart meters do not have "last gasp technology." This technology sends an automatic notification to the OMS the moment an outage occurs on the meter and enables the OMS to match premises with outages.

3. The GIS system does not have fully accurate connectivity at the meter level.

Similar to leading electric utilities, Toronto Hydro has an integrated GIS system that provides connectivity of its electric network from the substation breaker level through the customer meter. Currently, the accuracy of meter connectivity to the correct transformer is approximately 85% in the core of the City (legacy Toronto Hydro service territory) and 95% across the rest of the system. While maintaining 100% accuracy of meter connectivity may not be achievable, because of the frequent changes in system configuration, the current level of accuracy does not provide the Company with the ability to ensure accurate prediction of the outage levels and customer counts, especially during major events.

4. Lack of connectivity among different information technology systems caused inaccuracy of outage status information available to customers.

Leading utilities have integrated their main IT and OT systems to automatically collect key outage information, analyze the data, and provide status updates to customers through a variety of channels (e.g., web site, text, mobile app, outage map, IVR). Toronto Hydro systems are integrated to a level that provides sufficient support for day r to day operations. In a large scale event, however, the level of manual intervention required to process information and transactions prevents Toronto Hydro from providing timely and accurate information to customers regarding their outage status.

5.8.2. Information Systems and Technology Recommendations

IT 1. Include IT/OT technologies that provide real or near real time intelligence in the technology strategic roadmap.

As Toronto Hydro updates its strategic roadmap for IT/OT systems and invests in new technologies could support larger scale restorations, it should:

- Identify what information is needed by Toronto Hydro decision makers, customers, and key stakeholders like the City of Toronto Office of Emergency Management, first responders, public safety agencies, and other public officials during an large scale, complex restoration;
- Update and automate, where indicated, the processes that support the delivery of this information to those groups; and
- Identify alternatives to support communicaton and information management when systems are down or unavailable.

Toronto Hydro should develop cost estimates for the priorities confirmed through the road mapping projects. There could be new systems or enhancements to current systems.

- Expand mobile platforms for operational communication (e.g., mobile data terminals, mobile platforms for damage assessment).

Toronto Hydro should expand the use of mobile technology to all crews to further automate the exchange of information between the field and command centres. Providing more smart devices supported by a back-end software system that is integrated with OMS and GIS would allow field personnel to enter damage information, receive work orders remotely, estimate restoration times, and close work orders in a timely manner, with minimal human intervention in the command and control centres.

- Evaluate enhancements to smart meter technologies to improve situational awareness during large scale outage.

With the advancement of smart metering technology and the communications network, Toronto Hydro should continue with its plan to replace the data collectors, which will expedite the ability to "ping" groups of meters. Also the Company should investigate the costs of upgrading the meters that currently don't have the "last gasp" technology.

- Upgrade the outage management system (OMS) and create an OMS lite (thin client or web based) version to support decentralized command and control.

The OMS at Toronto Hydro, including hardware, software, servers, and other associated infrastructure, should accommodate different types of users (super users, users with "read only" needs) and a larger number of concurrent users. Enhancements to consider include:

- Implementing a more current version of the OMS software;
- Arranging access to provisional licensing to support a short term uptick of users; and
- Providing a scaled down version of OMS for non superusers.

The access to this version could be through a terminal or it can be web based.

- Ensure that primary data systems (i.e., GIS, OMS, CIS, outage map) integrate to provide key data for customers and decision makers

Toronto Hydro should assess the current system architecture, particularly integration points between key operational systems (e.g., OMS, GIS) and information systems (e.g., CIS, website). The Company should address the interface point between main systems where information links are slow, where needed information isn't available to provide an accurate portrayal of system or outage status, or where critical information isn't accessible at all. Once critical gaps are known, Toronto Hydro should identify and include needed enhancements on the technology roadmap.

5.9. Vegetation Management and System Hardening/ Resilience

The increased frequency of severity of weather events, along with changing expectations and lower tolerance for long duration outages by customers, have spurred utilities to explore ways to improve storm performance of their distribution systems (durability and resilience). Durability[12] refers to the ability of the system to withstand the impacts of storms without damage and includes materials or equipment that resist damage, the arrangement of existing equipment to resist or avoid damage, and technologies that help protect the system from damage. Resilience[13] is defined as the ability to continue to operate despite damage to some parts of the distribution system. It encompasses the configuration of system components to reduce the numbers of outages, reconfiguration of the system to maintain service, and application of system resources to continue service to customers while the electric system is restored. Some commonly used durability and resilience enhancement techniques include:

- Improving the strength of poles and structures;
- Burying overhead lines;

[12] Edison Electric Institute (EEI) defines hardening as those activities that: "improve the durability and stability of infrastructure to withstand the impacts of severe weather events with minimal damage," Before and After the Storm, March 2013.

[13] The Edison Electric Institute also defines resilience as those "measures (that) do not prevent damage; rather they enable facilities to continue operating despite damage and/or promote a rapid return to normal operations," Before and After the Storm, March 2013.

- Enhancing flexibility of the electric system through circuit ties and system automation; and
- Increasing vegetation clearances around power lines.

System Hardening/Resilience

Most system hardening initiatives span multiple years, involving sequential cycles of investment to yield improvement. Leading utilities have worked with their key stakeholders (in particular, regulators) to identify the best options, evaluate the costs and benefits for each option, determine the optimal portfolio of projects to enhance the durability and resilience of their distribution systems, and ultimately secure funding for this work. There is no standard approach within the utility industry to evaluate the costs and benefits associated with hardening options, but the three most commonly used methodologies are: probability based; relative comparison; and recent event baseline.

Each of these methods requires the use of a set of assumptions that can be supported by historical data if it is available. It's a challenge for utilities to have enough actual data to fully assess the benefits of each hardening option. There are not many major events, the impact of each event can vary substantially, and utilities have tended to focus resources on restoration activities, rather than data gathering.

Converting Overhead Lines to Underground

Over the past decade and immediately after a major event that causes extensive power outages, customers, regulators, legislators, and other external stakeholders tend to express interest in the conversion of overhead distribution facilities to underground construction. Underground facilities reduce, if not eliminate, the risk of failure due to high wind, falling trees, and ice accumulation. On the other hand, they are more exposed than overhead lines to other hazards such as heat and flooding. Damage related to heat and flooding often requires more time and higher cost to restore.

In addition to the potentially higher cost of underground restorations, all of the studies that have been commissioned by different regulators and state legislators across the U.S. have deemed widespread "undergrounding" to be cost prohibitive. Some of the preliminary estimates for converting the remaining overhead infrastructure (approximately 58% of circuit lines) at Toronto Hydro to underground range from $11 or $16 billion dollars. Another concern is that the actual conversion process inconveniences property owners and creates aesthetic issues – yard excavation, driveway removal and replacement, damage to tree root systems, and pad mount transformers placed on customers' property.

As an alternative to implementing large conversions, some utilities have converted selected overhead circuits or sections of circuits to improve the reliability of service to critical infrastructure facilities. These include hospitals, water filtration plants, 911 call centres, etc. Usually sections that are targeted for conversion to underground are

located in heavily treed areas, in backlots with difficult access, and areas that are not prone to flooding.

Vegetation Management

Vegetation is typically the single largest culprit of outages during major events. Trees and limbs tend to fall into distribution lines and take down wire and equipment, including poles, creating interruptions to customers service. Most utilities clear vegetation around lines, typically using a predefined cycle. Trees and limbs that cause outages in major events tend to fall in from outside the typical clearances or rights of way (ROW).

Some utilities have expanded their vegetation management programs to increase clearance specifications, remove overhangs, and take out hazard trees from outside the ROW. Aggressive VM programs can reduce damage during major events, but are difficult to execute since they require access and approvals by property owners. It is important to note that most of the utilities do not trim around service drops.[14] This is usually the responsibility of a property owner. Most of the utility vegetation management work is outsourced to contractors who specialize in maintaining line clearance for utilities.

Also, VM programs often must comply with external regulations, particularly when utilities serve urban areas with dense tree canopy. The arboriculture industry pruning standard defines proper pruning techniques to ensure that any pruning does not negatively affect the health of the tree. Workers must follow these standards when maintaining vegetation around distribution lines. In addition, many municipalities, and some neighbourhoods, have specific requirements to protect their tree canopy. These may prescribe the amount of clearance around a line, how to remove dying or deceased trees, and sometimes even access to trees that are on private property.

Pole Maintenance

In addition to investing in vegetation management, most utilities conduct periodic wood pole inspection and replacement programs. The inspection cycles typically range from 8 to 15 years and include a combination of visual, sounding, ground line, and boring methods for assessing the integrity of wood poles. The poles which do not pass the test are stratified by priority (i.e., When do they need to be replaced based on their condition?) and replaced within a predefined target period.

Utility hardening programs usually must comply with externally imposed policies and guidelines, too. For example, in order to ensure the safety of electric utility construction, utilities adhere to electric safety codes which establish guidelines for pole loading based on historic weather patterns by geographic area. They are expressed in terms of the

[14] A service drop is an overhead electrical line running from a utility pole to a customer's building or other premises. It is the point where electric utilities provide power to their customers.

minimum wind speeds and ice loading that the structures are expected to withstand. Utilities are expected to follow these guidelines to ensure that their construction standards and structures, including wood poles, meet loading standards at the time of installation.

The review of Toronto Hydro's vegetation management and system hardening and resilience programs addressed the following:

- Program scope and management;
- Conformance to industry standards and performance as compared to leading practices;
- Adherence to local by-laws; and
- Resiliency building approaches and methods

5.9.1. Vegetation Management and System Hardening/Resilience Findings

The damage that Toronto Hydro experienced during the 2013 Ice Storm was mostly caused by tree limbs falling on distribution lines and breaking the conductors. During the entire storm, the Company had to replace only 17 out of approximately 101,000 wood poles on its distribution system. Given the small fraction of poles that were broken during the ice storm and the well defined wood pole inspection and replacement program in place, it can be concluded that the strength and integrity of the Company's wood pole plant did not contribute to the number of outages experienced during this storm and may have actually prevented a larger amount of damage. As a part of the Company's asset management effort, Toronto Hydro conducts a Planned Wood Pole Inspection program (PWPI) on a 10 year cycle.

Throughout the Company's history, Toronto Hydro has maintained clearances around its power lines using different methods and programs. In 2008, Toronto Hydro renegotiated its vegetation management contract and established a three year, circuit r based cycle for maintaining clearances across its system, which is an industry leading practice. The current VM program follows the CSA and ANSI standards as well as City of Toronto Line Clearance Guidelines[15].

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[15] Canadian Standard Association (CSA) C22.3 No. 1 r10
- Flashover distance for AC System Conductors to trees

ANSI A300 – Standard Practices for Tree Care Operations
- Recommended standard by the International Society of Arboriculture (ISA) and the Tree Care Industry Association (TCIA)

City By-Laws – City of Toronto Forestry Cycle Pruning Guidelines
- 15 cm (0.5 ft.) clearance from house service
- 30 cm (1 ft.) clearance from secondary conductors
- 90 cm (3 ft.) clearance from primary conductors

In 2008, Toronto Hydro conducted a study to explore different system hardening options. As a result of that study, the Company began to implement several hardening efforts including but not limited to better pole guying,[16] stronger insulators, and fiberglass brackets for pole line equipment support.[17] It is important to note that over the past 30 years, Toronto Hydro has been installing underground systems in all new developments. This has been a standard industry practice, with developers bearing a portion of the cost.

Vegetation Management and System Hardening/Resilience Strengths

1. Toronto Hydro has been following a circuit based trimming program since 2008 and adheres to accepted industry and City of Toronto pruning standards.

In 2008 the Company re-negotiated its VM program and implemented a circuit based approach. The approach used until then was grid based, focused on clearing distribution lines by geographic areas (i.e., sections of the City) irrespective of the electric system configuration. The circuit based approach focuses the yearly VM spending on circuits where it will provide the best reliability improvement while ensuring that the system is still maintained in adherence with the accepted industry and City of Toronto pruning standards. Similar to most utilities, the Company does not trim around service drops.

2. Vegetation management preventive maintenance program is in line with industry practices (i.e., three year cycle).

The duration of the vegetation trim cycle for an electric distribution utility depends on a number of factors, such as tree species, local by-laws, customer priorities, and the electric system configuration. The cycle for line clearances typically ranges between three and seven years on the distribution system. Toronto Hydro maintains its circuit clearances on a three year average cycle, meaning that circuits are pruned every two to five years, depending on their reliability performance. This VM preventive cycle is often considered a leading industry practice.

3. Over the past six years, Toronto Hydro has maintained a consistent scope of the vegetation management program (e.g., clearances, miles completed) while reducing the cost of the program.

As mentioned earlier, most utility vegetation management work is conducted by outside contractors that specialize in electric line clearance. Toronto Hydro uses an outside contractor for all preventive trimming. It has retained one vegetation management crew in-house that focuses on customer requests and corrective maintenance work. There is a certified arborist in-house.

[16] Includes installing a tensioned wire on poles, designed to add stability to a free-standing structure.
[17] Fiberglass brackets are not subject to as much decay as the wood brackets.

When Toronto Hydro transitioned from the area based to circuit based approach in 2008, it requested bids from outside contractors. The Company was able to reduce the overall cost of the program while continuing to maintain the same clearances (in line with industry and City of Toronto standards) on a three year average cycle. This strategy reduced the costs of the overall program while providing the same (or better) day to day reliability.

Figure 19 depicts Toronto Hydro's vegetation related reliability on a blue sky day over the period 2003 through 2013. The red line represents the System Average Interruption Frequency Index (SAIFI) and the blue line shows the total number of outages caused by trees. SAIFI is a standard industry metric used to evaluate the reliability performance and it represents the number of interruptions that an average customer would have in a 12 month period. The calculations do not include major outage event days, but they do include outages related to annual weather patterns and smaller events, which cause the fluctuations in performance from year to year. Despite these fluctuations, statistics indicate that the vegetation related reliability performance has remained constant or slightly improved for Toronto Hydro since the implementation of the changes to the contract in 2008.

Figure 19: Toronto Hydro Vegetation Related Outages and SAIFI (2003-2013)

4. Toronto Hydro's wood pole program is in line with industry leading practice.

For more than 15 years, Toronto Hydro has been conducting a PWPI program on a 10 year cycle. The work is performed by contractors specializing in this field. The program

includes a two step assessment (visual and sounding assessment and a bore test)[18] with standard remediation alternatives for wood poles that do not pass the inspection. The Company has established timeframes within which the rejected poles have to be addressed. The cycle and scope of the Company's PWPI program are in line with industry leading practices.

Vegetation Management and System Hardening/Resilience Opportunities for Improvement

1. City of Toronto line clearance by laws are defined for blue sky reliability, not for preventing outages during major incidents.

With the recent increase in frequency of major weather events across North America, the City of Toronto line clearance guidelines may not provide for an adequate balance between tree canopy objectives and the need for larger clearances to reduce the risk of widespread, prolonged power outages. The current clearance guidelines provide for a 3' clearance around primary lines and 1' around secondary wires. These are not sufficient to protect the lines during major weather incidents, whether they are related to ice, wind, heavy snow, or wind.

2. Coordination of clearing efforts with City vegetation management crews during an incident and day to day.

Toronto Hydro crews focus on power line clearance only, and City crews focus on parks and street side tree maintenance. While the scope and primary objectives of their daily work differ), Company and City forestry crews often work together during major events to restore power to City residents. During the 2013 Ice Storm, Toronto Hydro and the City did not have a standard process to communicate the availability of City forestry resources and expected working hours each day, a procedure to transfer control of the crews to Toronto Hydro, or a consistent approach for requesting and assigning crews.

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[18] The first step always is a visual and sounding assessment of the pole. The pole is inspected for external signs of decay, feathering, through checks, mechanical damage, insect infestation, etc. A hammer is also used to strike the pole from the ground level up to eight feet above; the sound characteristics of the hammer blow help determine if there are internal cavities caused by decay. This is done on all wood poles. For poles less than 20 years old, a visual and sounding inspection is adequate to confirm the integrity of the pole (barring observed defects).

The second step is a bore test or a resistograph test. This is performed on poles older than 20 years, and on any other poles that are suspected to have an internal defect, even if they are less than 20 years old. For the bore test, a 13mm diameter bit is used to bore into the pole on a 45 degree angle, at ground level. The resultant shavings are examined for signs of decay and then the hole is plugged. An alternate technology to the bore test is a resistograph test, in which a 2mm diameter drill bit connected to a measuring instrument is used to drill into the pole. The resultant graph showing drill position and power consumption can be analyzed to identify internal cavities. The advantage of the resistograph test is that it leaves only a very small hole in the pole that does not require plugging.

5.9.2. Vegetation Management and System Hardening/Resilience Recommendations

VMSH 1 Evaluate all viable options to improve distribution system resilience during major weather events, including converting lines to underground for sections of circuits where it will enhance the reliability of services to critical infrastructure and facilities.

Toronto Hydro should conduct an in depth study to identify and evaluate options for enhancing the distribution system resilience during major weather events. The study should quantify the value and costs associated with each alternative and identify the best combination of projects to improve system performance during these incidents. The Company will need to work with the City of Toronto to identify mutually acceptable and cost effective options related to increasing vegetation management clearances around power lines.

Initiatives that the Company should consider include, but are not limited to:

- Increase right of way width or removal of "overhang" (aggressive vegetation management);
- Install breakaway disconnects on the pole side of the service lines;
- Increase structure loading to withstand high wind and ice;
- Replace small conductors;
- Improve circuit sectionalization to provide more flexibility;
- Convert overhead back lot to underground, or move to the front lot (street side);
- Upgrade overhead structures/circuits to heavy loading standard;
- Convert overhead lateral (tap) lines to underground;
- Convert entire overhead circuits to underground; and
- Develop micro grids.

These measures, including the conversion of overhead lines to underground, can enhance the reliability of services during major weather events (e.g., ice, wind, hurricane) to critical infrastructure and facilities such as hospitals, water filtration plants, and 911 call centres.

VMSH 2 Gain support from key stakeholders on the level of resilience required and related funding.

The costs associated with improving distribution system resilience are significant. In order to implement the improvements identified in the study, Toronto Hydro should work with the Ontario Electricity Board, the City of Toronto, and other stakeholder groups to gain agreement on the level of resilience desired – and the amount of

investment required. Once there is a shared understanding of the target level of resiliency and the costs associated to achieve it, stakeholders will need to agree to a cost recovery mechanism.

5.10. Toronto Hydro / City Coordination

Over the course of the assessment, stakeholder interviews and public comments[19] revealed various aspects of emergency management at the community level that could benefit from a closer collaboration between Toronto Hydro and the City of Toronto. The Independent Review Panel requested Davies Consulting to review and make recommendations for areas where joint efforts between Toronto Hydro and the City could improve emergency preparedness and response. These include:

- Personal preparedness – advance planning undertaken by individual citizens or groups of citizens to be able to meet basic living needs during an extended power outage. This could include having: a several day supply of food, water, and household supplies; alternative living arrangements; an evacuation plan; clothing and blankets to withstand lack of heat; a battery powered radio; a back up supply of medication and other critical health supplies; and (possibly) a back up generator.
- Communication when technology is "down" – disseminating coping information (e.g., restoration priorities and status, availability of city services, safety messages) when channels powered by electricity are not available (i.e., Internet, television, cell phone, radio).
- Support for vulnerable populations – availability of assistance for groups of residents who have limited ability to cope during an emergency, including the economically disadvantaged, the uninsured, low income children, the elderly, the homeless, those with serious health conditions, and the mentally impaired.
- Shelters / warming centres – locations made available by the City that provide alternative housing, a place to re charge devices, and access to heat.
- Planning and communication of restoration priorities – joint identification of critical facilities to re energize first and messaging of priorities to the public throughout the restoration.
- Explanation of customer responsibility for electrical equipment repairs on their premise – clearer definition and communication of the obligation of the homeowner/dweller, as established by the Ontario Electrical Safety Authority, to fix equipment on his/her property, such as standpipes, so that customers can arrange for repairs early in the event.

[19] See Appendix D for a summary of public comments.

- Explanation of building codes – standards maintained by Toronto Building that enable or hamper ingress or egress within high rise buildings and provide for emergency power supply.
- Use of 311 call centre for back up support – feasibility of using the City of Toronto facility to handle overflow calls for Toronto Hydro during an emergency.
- Coordination of urban forestation policies and plans – mindful of the needs for reliable and more resilient electricity distribution system, joint consideration of City, Toronto Hydro, and other key stakeholders when developing standards and procedures to manage the urban tree canopy and forestation efforts.
- Emergency response coordination (police, fire, other) – maintaining frequent, if not continuous, contact between Toronto Hydro and first responders during major power outages.

5.10.1. Toronto Hydro – City Coordination Findings

City of Toronto staff and public officials interviewed, uniformly noted how well Toronto Hydro responded to the 2013 Ice Storm given the extreme cold, hazardous working conditions, and extensive, tree related damage. Both Toronto Hydro and the City of Toronto recognized that this was a community recovery, as well as customer restoration effort. They were able to accomplish both through an effective collaboration over the course of the event to coordinate restoration priorities, public communicaton, forestry, and outreach.

The ways in which Toronto Hydro was able to work effectively with the City include:

- Identification of critical load priorities – The City and Toronto Hydro had in place a pre-determined list of critical facilities to be restored first and Toronto Hydro's restoration plans aligned with these priorities. Toronto Hydro participated on daily planning calls with the City and other stakeholders where it provided updates on restoration process.
- Sharing of vegetation management resources – Toronto Hydro needed a number of additional forestry resources to address the tree-related damage to the system. In addition to the Company contractors who supplied additional resources, the City of Toronto provided many City forestry crews to support the effort.
- Public communication – Toronto Hydro executives and staff supported the communication efforts of the City of Toronto through participation in daily press conferences, attendance at Provincial meetings, and responding to the thousands of emails received by Councillors.

5.10.2. Toronto Hydro – City Coordination Recommendations

THC1 Strengthen emergency management coordination between City of Toronto and Toronto Hydro.

- Identify and monitor vulnerable and special medical needs populations.

Public comments received at three town hall meetings and through emails to torontoicestorm@daviescon.com indicate that residents may not understand that outreach and support to vulnerable populations is a responsibility of the City of Toronto, not Toronto Hydro. Toronto Hydro does maintain a list of customers who, because of medical needs, would be in a life threatening situation in the event of a power outage. Customers voluntarily provide this information to the Company. The Company uses the information provided to alert effected customers of planned outages. In case of emergency, Toronto Hydro shares this information to the City for follow up.

As a central and visible participant in the community recovery after a major event, Toronto Hydro should consider offering additional communications and outreach support to the City. Balancing the requirement to maintain privacy of customer information with the need to ensure the safety and health of customers, Toronto Hydro should consider ways to use its customer database and knowledge of its external liaisons and other employees who routinely interface with the public, to assist the City in reaching those most in need.

Toronto Hydro could use its communication channels (e.g., website, social media) to support outreach to vulnerable groups during an event (i.e., "check in on your neighbour," locations of shelters and warming centres). Prior to an event, Toronto Hydro could include reminders in personal preparedness communications directed to populations who need more support. Also, the City and elected officials should consider targeted outreach to high rise building owners and neighbourhood associations to encourage them to check in on neighbours and tenants during an emergency.

- Educate customers/citizens about emergency preparedness.

In areas where major events, are infrequent, it's easy for people to have little knowledge of or have become complacent about emergency preparedness. The respective websites of both Toronto Hydro and the City of Toronto include tips and guidelines to help customers and citizens better cope when power is out. An example is a checklist for a 72 hour emergency kit. Both should consider supplementing this "passive" source of information with a more active outreach campaign, such as public service announcements on radio and television, bill inserts, announcements on community on line bulletin boards, participation at town meetings, and providing mobile applications. Also, Councillors' communications may be a useful channel to reinforce the importance of personal emergency readiness.

- Conduct joint planning, training, and exercises.

Leading practice utilities ensure that their emergency management strategy, plans, training programs and exercises are closely aligned with those of key, external stakeholders, especially local governments. During a major event, utility workers function as first responders, necessitating a seamless coordination with local emergency management organizations, police, and fire/rescue professionals. This requires cooperative planning, agreement on planning scenarios, and joint participation in functional exercises. The City of Toronto and Toronto Hydro should continue and consider increasing the frequency of current planning discussions. They should agree to planning scenarios (i.e., the type and severity of incident), share and vet emergency plans, and schedule joint exercises to test readiness.

THC2 In collaboration with the City of Toronto (Urban Forestry), update related urban forestry plans to ensure adequate line clearances to withstand major events.

In urban areas with dense tree canopy, like the Greater Toronto area, there are often competing objectives between increasing the number of trees and decreasing the number of vegetation related outages. Toronto Hydro forestry crews adhere to standards set forth by the CSA, ANSI, and the City of Toronto, which do not provide for sufficient clearances to reduce the likelihood of tree related outages during incidents like the 2013 Ice Storm. The City of Toronto urban forestry team should work closely with the Toronto Hydro staff to update the Urban Forestry Plan to ensure that the reliability of customer service is incorporated in the plan.

THC3 Request the Province to require all new and existing buildings to have adequate back up generation within the next 10 years.

The Provincial building code that regulates emergency power supply for buildings is "intended to accommodate the safe evacuation of occupants within the building in case of a fire emergency and assist in firefighting operations in case of a fire emergency."[20] The regulation does not address the provision of emergency power supply for essential needs (e.g., refrigeration, heat, phone service) during an extended outage. Many of the public comments expressed concern for the safety and health of family, friends, neighbours, and elderly people who had limited ability to leave their high rise residences. The IRP recommends that the Provincial government consider a requirement for all new and existing building to provide a means for back up power for a longer period of time. This will allow for the safe evacuation of and access to vulnerable populations that live in high rise buildings.

[20] Briefing Note, Chief Building Official, Toronto Building, July 11, 2013

6. Moving Forward

The 2013 Ice Storm was an unprecedented event that disrupted the lives of most Toronto residents and tested the mettle of the first responders, as well as the City and Toronto Hydro personnel involved in the recovery effort. Through a dedicated, coordinated, and intensive response, the community was safely restored to normalcy within a reasonable timeframe given the amount and type of damage suffered. Toronto Hydro executed the restoration in a manner consistent with industry practices. The Company's management and approach to the restoration was prudent, diligent, and safe. As expected with any large incident, the recovery from this ice storm also exposed several aspects of the emergency response that can be further improved.

In accordance with the commissioned scope of the panel review, the recommendations presented in this report focus mainly on the improvements that Toronto Hydro can make to further enhance its ability to respond to future events that cause widespread power outages. Additionally, and notably, there are several areas, primarily described in Section 5.10 Toronto Hydro City Coordination, where heightened attention from and cooperation among Toronto Hydro, the City of Toronto, and the Province of Ontario can improve the community's capability to better cope with and manage the response to a large scale event in the future. This report should serve as the starting point for a more sustained, coordinated effort among all of these parties, the outcome of which will be meaningful improvement in community preparedness for future major outage events.

Appendix A: Glossary of Terms

Term	Description
Bird Dog	A local utility resource dedicated to helping off r system/mutual assistance crews with daily work needs (e.g., navigating the territory, coordinating work with other crews, ensuring the safety of the work site, accessing food). These resources are typically local company line workers and recent retirees who are familiar with the system and are trained to operate the switching devices in the field. Bird dogs may support one or more crews.
Backbone	The main three phase portion of a distribution circuit that is connected directly to the substation circuit breaker. All load in a circuit is served either directly from the backbone or from three, two and single phase lines (laterals) tapped off the backbone.
Blue Sky	Refers to day to day, normal operations
Canadian Electric Association (CEA)	The industry association for Canadian electric utilities.
Circuit	A continuous flow of electricity from a source to a load or loads. In utility distribution, a circuit is the main (usually 3 phase) line and all three, two, and single phase sections (laterals) served by a single substation circuit breaker.
Circuit sectionalization	The practice used by utilities to break an electric circuit into sections that can be isolated from the rest of the circuit in case of an outage to protect all of the customers from getting an outage as a result. This also allows the utility to switch the source of power to the circuit from one feeder or substation to another during an outage, if another source is available.
Damage Assessment	The process for systematically collecting damage information in the field to support the restoration planning, resource acquisition, and development of restoration estimates.
EHS Officer	Environmental, Health, and Safety Officer
Estimated Time of	An estimate of the restoration time. The ETR can be

Appendix A: Glossary of Terms

Term	Description
Restoration (ETR)	provided at multiple levels, including global, regional, neighbourhood/substation, circuit, and individual customer.
Functional Exercise	A functional exercise simulates an emergency in the most realistic manner possible short of moving real people and equipment to an actual site. As the name suggests, its goal is to test or evaluate the capability of one or more functions in the context of an emergency event.
Incident Command System (ICS)	A standardized, on-site management system designed to enable effective, efficient incident management by integrating a combination of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure. ICS is used to manage an incident or a non-emergency event, and can be used equally well for both small and large incidents.
Last Gasp Technology	When the smart meter loses power, it records state information to flash memory or sends out a wireless signal that it has lost power—the meter's "last gasp." Not all smart meters on Toronto Hydro's system have this technology.
Lateral	A three, two or single phase section off the main line (backbone) of the circuit, constructed to extend to loads that are not directly in the path of the main line. Laterals are typically connected to the main line through fuses or reclosers.
Mutual Assistance	The process by which electric utilities provide resources to each other to support major restoration efforts. This process is unique to the industry and is crucial for responding to large emergencies since no single utility has adequate resources to quickly restore normalcy after full scale events.
Off-System Resources/Crews	Individuals who do not work on Toronto Hydro system day to day but who are deployed by their company (a contractor or another utility) to support the restoration effort. Once the restoration is completed, these resources return to their home company.
Pole Guying	The practice of installing one or more tensioned wires on poles designed to add stability to a free standing

Appendix A: Glossary of Terms

Term	Description
	structure so that it can withstand higher speed winds without blowing over.
Service Drop	An overhead electrical line running from a utility pole to a customer's building or other premises. It is the point where electric utilities provide power to their customers.
Smart Meter	Usually a digital device that records consumption of electric energy in intervals of an hour or less and communicates that information, at least daily, back to the utility for monitoring and billing purposes. Smart meters enable two way communication between the meter and the central system.
Storm Hardening	Activities that a utility may undertake to improve the durability and stability of infrastructure to withstand the impacts of severe weather events with minimal damage
System Operations Centre (SOC)	A facility that houses system operators and data management system, providing real time status and the ability to remotely operate the distribution system The Incident Management Team at Toronto Hydro uses an SOC during major events.
Tabletop Exercise	A tabletop exercise simulates an emergency situation in an informal, stress free environment. The participants – usualy the decision makers during an emergency – gather around a table to discuss general problems and procedures in the context of an emergency scenario. The focus is on training and familiarization with roles, procedures, or responsibilities. An advantage of a tabletop exercise is that it can allow people to test a hypothetical situation without causing disruption in the community.
Triage Process	Process used by Toronto Hydro during storms to verify the downed wire reports received from customers. The "triage" crew determines if the wire is live, makes the location safe by grounding it if possible, or collects the data and refers the job to the appropriate resource to resolve.
Vegetation Management (VM)	Refers to the cyclical and reactive program for maintaining trees and tree limbs at a safe distance from the distribution power lines. A VM program is

Appendix A: Glossary of Terms

Term	Description
	guided by a set of industry standards and local City by laws as well as the electric distribution company guidelines.

Appendix B: Utility Mutual Assistance Providers

The following 10 utilities provided mutual assistance to Toronto Hydro during the restoration of power outages caused by the 2013 Ice Storm:

- Brant Hydro;
- Entegrus;
- Enwin;
- Horizon;
- Hydro One;
- Manitoba Hydro;
- Norfolk Hydro;
- Ottawa Hydro;
- Sault Saint Marie PUC; and
- Sudbury Hydro.

Appendix C: Summary of Findings and Recommendations

Evaluation Areas	Findings		Recommendation
	Strengths	Opportunities for Improvement	
Emergency Planning and Preparedness	1. Emergency response structure largely aligns with the Incident Command System, which is considered to be the industry leading practice in emergency response.	1. Emergency response plans provided an overall structure for response, but did not include detailed descriptions of key processes and all roles.	EPP-1: Reaffirm and communicate emergency management vision and strategy throughout all of Toronto Hydro.
	2. Corporate Emergency Management organization is centralized and addresses all hazards.	2. Toronto Hydro characterizes grid incidents on a three level scale, which may not address full scale events adequately.	EPP-2: Continue to inculcate the ICS-based approach to emergency response.
	3. Trained and exercised System Operations Centre (Command Centre) roles and responsibilities prior to the event.	3. Key restoration strategies and processes were not defined or understood at all levels of the company with roles in the response.	EPP-3: Enhance centralized Emergency Management group resources to support full implementation and sustainment of ICS and ongoing relationships with key stakeholders.
	4. Pre-event weather monitoring process in place and used to support activation decisions.	4. Many Toronto Hydro employees did not have a pre-assigned and trained role for major incidents.	EPP-4: Add dedicated grid operations emergency management resources
		5. Toronto Hydro conducted exercises and training at the Command Centre level, but did not perform sufficient training and exercise in the Local Incident Command Centres.	EPP-5: Update the Emergency Response Plan to improve comprehensiveness and usability.

Appendix C: Summary of Findings and Recommendations

Evaluation Areas	Findings		Recommendation
	Strengths	Opportunities for Improvement	
Resource Acquisition and Allocation	1. Safely deployed the largest number of resources for any response in Toronto Hydro history.	1. Mutual assistance processes and agreements with other utilities across Canada and North America were not formalized.	RA1: Adopt a resource management strategy that provides for: deployment of all available resources, seamless integration and coordination of crews, and optimal supervisory span of control.
	2. Developed and applied mutual assistance processes in real time that generally worked.	2. The process to acquire and coordinate the deployment of City forestry crews was not defined in advance.	RA2: Create a comprehensive, scalable, logistics plan as part of the Emergency Response Plan.
	3. Flew in, equipped, and deployed mutual assistance resources from Manitoba within 48 hours.	3. Toronto Hydro has limited ability to accommodate a large influx of mutual assistance resources	
	4. Conducted thorough mutual assistance on boarding process and safety briefings.	4. The demobilization process for mutual assistance crews was not clearly defined.	
	5. Strong collaboration between City and Toronto Hydro tree crews on restoration activities.		
Damage Assessment and Restoration Planning	1. Overall restoration priorities were in line with industry practices.	1. Lack of real, or near real time situational awareness of outages and work progress below the feeder level.	DAP1: Institute a damage assessment process that defines the required approach, procedures, and competencies to establish situational awareness and planning inputs within the specified timeframe (e.g., within 48 hours).

Evaluation Areas	Findings		Recommendation
	Strengths	Opportunities for Improvement	
	2. The Command Centre coordination calls (every three hours) provided useful information and maintained alignment of Local Incident Command Centres to restoration priorities.	2. Damage Assessment process was not defined, documented, or consistently applied across the Local Incident Command Centres.	DAP2: Develop a process to establish (calculate) timely and accurate ETRs.
	3. Some Local Incident Command Centres conducted planning activities overnight to facilitate work assignments and crew deployments for the subsequent shift.	3. Restoration estimates were not developed at various levels of specificity.	DAP3: Establish standard work planning processes and procedures; train and exercise response personnel to drive consistency across central and local commands.
		4. Work planning practices varied across Local Incident Command Centres.	
		5. The Central Command Centre and Local Incident Command Centres did not use standard planning tools.	
Restoration Execution	1. Safety performance was excellent.	1. Restoration approach was not consistent, varying between "order r based" and "feeder based."	RE1: Predetermine best restoration approach for each emergency Level (e.g. 1 - 4).
	2. Dispatch functions were decentralized to Local Incident Command Centres early in the restoration process.	2. Lack of full coordination among decentralized dispatch functions led to some inefficiency in crew deployment.	RE2: Eliminate centralized mutual assistance and contractor LICCs and encompass those resources within the three, geographic LICCs.
	3. Coordination with the Electrical Safety Authority (ESA) to reconnect customer premises was adjusted during the event to reduce hardship.	3. Local Command Centre structure (three geographic and two functional locations) added complexity to crew deployment and work coordination.	

Evaluation Areas	Findings		Recommendation
	Strengths	Opportunities for Improvement	
	4. Special requests were handled within the pre-defined priority order.	4. Restoration execution approaches were not followed consistenly by all Local Incident Command Centres.	
	5. The work protection process did not cause unusually long delays in restoration.	5. Toronto Hydro has different work protection processes than other utilities in the Province of Ontario, limiting the type of work that mutual assistance crews can perform.	
	6. "Bird dogging" of mutual assistance crews worked well.		
Communications or Customer Contact	1. The ability to use an external contract call centre as a back up call centre site.	1. There was insufficient overflow capacity (system and staffing) to take outage calls, so that the majority of callers were not able to report or get information on outage status	CCC1: Secure capacity (people and technology) to support timely customer contact during an incident.
	2. The Key Accounts organization within Customer Care implemented an effective process to inform key and commercial accounts of outage status.	2. The Integrated Voice Recognition (IVR) system was difficult to navigate, not intuitive, and did not effectively support customers who are non-native English speakers.	CCC2: Improve the process for ensuring accurate and uniform outage status messages across every mode of communication to customers (e.g., IVR, web, mobile application, low tech channels).
	3. The control room, dispatch, call centre, and key accounts staff are co-located, enabling more effective information exchange.	3. Outage status information was inadequate and often inaccurate.	CCC3: Employ outbound calling/texting to inform customers of outage status and other pertinent information.

Evaluation Areas	Findings		Recommendation
	Strengths	Opportunities for Improvement	
		4. Alternate paths to contact Toronto Hydro (e.g., email, web) were in place, but all were not monitored frequently enough.	CCC-4: Work with City of Toronto to evaluate options for using 311 capabilities.
		5. Toronto Hydro does not provide mobile capability to report or track outages.	
		6. There was no capability to transfer Toronto Hydro related calls from the 311 call centre.	
Communications or Other Stakeholders	1. As the face of the company and the executive spokesperson, the CEO performed his role well.	1. Process for developing and issuing timely and accurate ETRs was not clearly defined.	COS-1: Develop a process to communicate timely and accurate ETR at different levels of specificity.
	2. Proactive media campaign and consistent messaging (use of "one voice"), including coordination with the Systems Operations Centre, worked well.	2. Liaison roles with some stakeholder groups were not clearly defined.	COS-2: In collaboration with the City of Toronto, develop an education program to improve stakeholder literacy of: restoration process, customer responsibility, and preparedness.
	3. Toronto Hydro was viewed as an effective partner in City and Provincial communications.	3. Messages were not always accessible to all stakeholders (e.g., customers with no access to TV, radio, or social media).	COS-3: Expand liaison role to address education, communication, and coordination with key community stakeholders (e.g., elected leaders, public safety) during major incidents.
	4. Toronto Hydro used a variety of methods to reach the public, including		COS-4: Formalize process for developing, approving, and

Evaluation Areas	Findings		Recommendation
	Strengths	Opportunities for Improvement	
	social media.		disseminating key messages.
Information Systems and Technologies	1. One of the early adopters of smart meter technology.	1. OMS hardware and interfaces were not scalable to handle the number of concurrent users during the 2013 Ice Storm.	IT 1: Include IT/OT technologies that provide real time or near real time intelligence in the technology strategic roadmap.
	2. An extensive Supervisory Control and Data Acquisition (SCADA) system with 85,000 control points on over 4,000 devices.	2. Groups of smart meters could not be pinged quickly to determine the outage status and a portion of them do not have "last gasp" technology.	
	3. Mobile Data Terminals available in a portion of Toronto Hydro vehicles.	3. The GIS system does not have fully accurate connectivity at the meter level.	
		4. Lack of connectivity among different information technology systems caused inaccuracy of outage status information available to customers.	
Vegetation Management and System Hardening/ Resilience	1. Toronto Hydro has been following a circuit based trimming program since 2008 and adheres to accepted industry and City of Toronto pruning standards.	1. City of Toronto line clearance by r laws are defined for blue sky reliability, not for preventing outages during major incidents.	VMSH 1: Evaluate all viable options to improve distribution system resilience during major weather everts, including converting lines to underground for sections of circuits where it will enhance the reliability of services to critical infrastructure and facilities.

Evaluation Areas	Findings		Recommendation
	Strengths	Opportunities for Improvement	
	2. Vegetation management preventive maintenance program is in line with industry practices (i.e., three year cycle).	2. Coordination of clearing efforts with City vegetation management crews during an incident and day to day.	VMSH 2: Gain support from key stakeholders on the level of resilience required and related funding.
	3. Over the past six years Toronto Hydro has maintained a consistent scope of the vegetation management program (e.g., clearance: miles complete) while reducing the cost of the program.		
	4. Toronto Hydro's wood pole program is in line with industry leading practice.		
Toronto Hydro / City Coordination			THC 1: Strengthen emergency management coordination between City of Toronto and Toronto Hydro.
			THC 2: In collaboration with the City of Toronto (Urban Forestry), update related urban forestry plans to ensure adequate line clearances to withstand major events.
			THC 3: Request the Province to require all new and existing buildings to have adequate back-up generation within the next 10 years.

Appendix D: Summary of Public Comments

An objective of the Independent Review Panel (IRP or Panel) was to consider feedback, insights and suggestions from representatives of each stakeholder group affected by the Ice Storm. Along with collecting input from Toronto Hydro employees, City and Provincial staff, first responders, and other parties involved with the recovery, the Panel invited input from Toronto residents and business owners on Toronto Hydro's preparation for and response to the December 2013 Ice Storm. Citizens had an opportunity to provide verbal or written comments at a town hall meeting, or email feedback via a dedicated address monitored solely by Davies Consulting.

Approximately 50 people in total, attended the town hall meetings, coordinated by the City of Toronto and held on Thursday March 6, from 7:00 p.m. to 9:30 p.m. at the following locations:

- North York Civic Centre, 5100 Yonge Street, Council Chamber
- Etobicoke Civic Centre, 399 The West Mall, Council Chamber
- Scarborough Civic Centre, 150 Borough Drive, Council Chamber

IRP members moderated each meeting, with the assistance of a Davies Consulting team member. Each attendee who wished to address the Panel had the opportunity to do so either verbally, or by submitting written comments. Representatives from Toronto Hydro were not present at the meetings, so that Torontonians could speak freely.

Over 80 comments were submitted via torontoicestorm@daviesconsulting.com, between February 27, 2013, and March 31, 2013, the period for public comment. Davies Consulting monitored this email address daily. Team members collated and reviewed these comments, along with those received at the Town Halls.

The prevalent themes from the public comments were:

- Praise about the efforts of the Toronto Hydro linemen, commending them for their performance under adverse conditions;
- Poor or inaccurate communication to the public, including: inaccurate or not available estimated times of restoration (ETRs); incorrect restoration information given by call centre representatives; inability to see outage information in general (e.g., maps); lack of information about restoration priorities; and limited access to messages when technology was down (e.g., no internet, radio or television);
- Limited to no access to call center, including prolonged inability to reach a representative by phone; long wait times if able to connect; lack of information on the website; and limited on line alternatives to report outages and receive updates;

- Tree trimming and pruning, including the adequacy of clearances and vegetation management budget; and
- Communication and outreach to vulnerable populations, including: prior identification of those with critical needs; direct outreach to vulnerable populations after an event; provisions for back-up power to high-rise buildings; and clearer communication of locations of warming centres and shelters.

The Panel considered the comments and suggestions offered by the public as it developed the findings and recommendations presented in this report.

CONTROL CENTRE OPERATIONS

1. SUMMARY

Table 1: Control Centre Operations Program Costs ($ Millions)

	2011	2012	2013	2014	2015
Total	8.4	8.3	8.9	8.2	8.4

Toronto Hydro's Control Centre program helps to ensure the safe and reliable operation of the utility's distribution grid through real-time system control and monitoring activities carried out from a single location. The control centre coordinates the necessary system switching and restoration work needed to mitigate the impact of emergency outages, enables load transfers for capital and maintenance work, and monitors the flow of electricity across Toronto Hydro's distribution plant.

The control centre maintains Toronto Hydro's visibility into its distribution asset performance via a digital network enabled for both voice and data communication. Using radio and telecommunications mediums, the network provides an uninterrupted flow of vital information that allows Toronto Hydro to perform real-time control activities and gain situational awareness if unexpected contingencies occur. Beyond the real-time utilization, Toronto Hydro stores the collected system condition data for future use in system planning activities and to maintain legal compliance.

The cornerstone of the control centre's monitoring and control capabilities is the Supervisory Control and Data Acquisition ("SCADA") technology, deployed extensively throughout Toronto Hydro's 27.6 kV, 13.8 kV, and 4kV stations & feeders. The SCADA system enables Toronto Hydro to remotely read asset condition, system status and receive other pertinent information such as status of equipment or loading on distribution feeders that allows it to make real-time operational decisions. The control centre also plays a

critical role in facilitating Toronto Hydro's crews and contractors conducting their work in a safe environment.

2. PROGRAM DESCRIPTION

Under normal operating conditions, the control centre plans for and coordinates execution of switching/load transfer work required to balance system loading, perform capital construction and maintenance work, and oversees the procedures that enable Toronto Hydro's crews to safely approach and work on the utility's distribution plant. These activities involve complex research and intricate planning work, and require up-to-date information on system performance in the affected areas, as well as constant communication with the field. During the times between contingency events, Toronto Hydro also investigates the causes of certain past outages to identify potential trends and devise the means of addressing any similar situations more effectively going forward.

During the major contingency events caused by adverse weather or extreme heat, Toronto Hydro's control centre prioritizes, oversees and enables the execution of service restoration work, coordinates the utility's response to the Police, Fire and Ambulance ("PFA") calls, and works with Hydro One and the Independent Electricity System Operator ("IESO") to ensure safe and reliable operation of the provincial electricity grid.

Figure 1: Toronto Hydro Control Room display and operating area.

The staffing complement of Toronto Hydro's control centre includes power system controllers that monitor system performance and coordinate the switching work, and engineers, technicians and clerical employees that analyze grid performance data and ensure that control centre asset information records are up to date. Performing this work requires competent 24/7 oversight of system operation and a broad range of technical skills and experience, which are in high demand in today's labour marketplace.

In line with the main functional responsibilities noted above, the Control Centre program consists of one segment, which is in turn comprised of two primary areas described in further detail below:

- Control Centre Operations; and
- Grid Performance Analysis and Support.

2.1. Control Centre Operations

Control Centre operations activities include real-time system performance monitoring, system risk analysis and execution of switching and load transfer work as is required to enable service restoration during outages, and performance of scheduled and reactive capital and maintenance work. The control centre oversees all equipment related to the 35 Hydro One supply points, down to the street-level primary feeders normally energized at 4 kV, 13.8 kV, or 27.6 kV.

The scope and complexity of tasks performed by control centre operators have been significantly aided by the expansion and sophistication of the supporting technology over the past decade. The increase in SCADA capabilities (Feeder Automation and Intelligent Electronic Devices ("IEDs")), along with the introduction of the Network Management Systems (Distribution Management System & Outage Management System) have broadened the scope and quality of information available to controllers and allowed for the streamlining and harmonization of the standard operating procedures. These process efficiencies have allowed the control room to meet the increasing level of demand without substantially expanding its staffing complement or lowering of its service levels.

Under normal operating conditions[1], control centre operators work to prepare and execute "Orders to Operate" safety documents ("OTOs"), which enables planned capital and maintenance work for the utility's crews. Each OTO is comprised of a list of switching instructions that enable operations crews to safely transfer customer load and/or establish suitable work protection over a specified range of system devices.

Depending on an area of the city, time of day, season and area system configuration, the scope of the OTOs instructions can range from 15 steps to over 150. Absent this centrally managed planning and execution process, individual crews would not have

[1] "Normal Operations Conditions" is defined as any time when the utility is not experiencing an emergency event exceeding ordinary resourcing levels.

sufficient visibility of the system conditions and location of other crews, potentially placing workers and the public at risk. The centralized management of the OTO framework enables utility crews to work in accordance with applicable safety legislation and protects the security of supply to Toronto Hydro customers. Crucial in this process is the constant flow and analysis of incoming system data as the controllers relay on accurate data in all forms to help direct and support decisions and actions for the field crews.

Other regular work in the control room includes issuing "Hold Off's". These are safety documents that modify protection systems and record the location of workers within the direct proximity of electrical equipment (e.g., in a cable chamber) to ensure that no other activities that may impact their safety or operation of equipment take place until their work is completed. Inaccurately recorded and processed Hold Offs can place worker safety and proper system operation at risk should an incident occur in the physical or electrical proximity to the work site.

Accordingly, preparing the OTOs and processing each Hold-Off requires a significant amount of training and experience that can only be obtained by operating a system of Toronto Hydro's scale and complexity.

Since both the Hold-Offs and the OTOs are necessary to enable safe and efficient execution of the utility's capital work program, their numbers have been increasing in line with the capital work ramp-up. Toronto Hydro has managed this increase while maintaining the control centre staffing levels by effectively leveraging its information technology capabilities described above.

Table 2 depicts the numbers of Hold-Offs, OTOs and past outage event investigations that Toronto Hydro completed over the 2011-2013 period. While the number of activities

has generally increased, Toronto Hydro has managed to process these requests with a generally declining staffing complement.

Table 2: Historical Control Centre Performance Statistics and Staffing Levels

	2011	2012	2013
OTOs	2,571	2,479	3,016
Hold Offs	27,265	19,370	25,200
Outage Investigations	12,394	12,319	18,641
Total Operating Activities	42,230	34,168	46,857
Control Centre FTEs	45	48	41
Activities per FTE	**938**	**712**	**1,143**

To ensure continuous improvement in service delivery under normal system conditions, Toronto Hydro tracks a number of additional performance statistics, including Idle Time, Time to Issue Hold-Offs, and Percentage of Work Deferred due to System Constraints. Over the Historical Period (2011-2013), Toronto Hydro has seen the improvement on each of these metrics.

During abnormal system events, typically caused by storm activity or heat stress to the distribution assets, the control centre coordinates Toronto Hydro's response to system contingencies. Given the size of Toronto Hydro's 1,700-feeder system, control centre oversight helps coordinate response to customer outages in a safe and efficient manner. Control room operators prioritize, coordinate and control all restoration activities in accordance with pre-determined emergency procedures. All PFA calls related to accidents involving electrical plant are also routed directly through the control centre.

The information received and processed by the control centre during outages also helps Toronto Hydro inform their employees and customers about the nature and magnitude of adverse events and the progress of restoration work. This function is particularly

important in light of increased media interest in all outage events and growing customer expectations for up-to-the-minute updates through a variety of social media channels.

Given that Toronto Hydro's load represents approximately 18% of Ontario's total electricity demand, the control centre also plays a critical role in assisting Hydro One and the IESO to manage the safe and reliable operation of the provincial electricity grid during province-wide contingency events, by quickly and efficiently executing the orders from the upstream network operators.

2.1.1. Grid Performance Analysis and Support

Supporting the work of system controllers are engineers, technicians and clerical support workers analyse grid performance and support the upkeep and modification of system information. Toronto Hydro's distribution grid is in the state of perpetual change, as new customers regularly connect to the system and capital projects consistently change system capacity or configuration. To ensure that the control centre can access the most current information, the Grid Performance Analysis and Support function updates the system records on a regular basis. This work helps to protect Toronto Hydro crews and customers from exposure to unsafe conditions and ensures that switching and other control centre-mandated activities achieve planned results without compromising system integrity and reliability.

The Grid Performance Analysis function also reviews the Interruption Tracking Information System ("ITIS") data to determine the causes of system failures and aggregate related failures to cost trends. The results of this work enable Toronto Hydro to conduct further engineering studies and develop mitigating strategies to improve system safety and customer reliability. In addition to providing the inputs for asset management planning processes, Toronto Hydro compiles system performance statistics

such as System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") for the regulatory and other reporting purposes.

The Grid Performance Analysis and Support section also oversees the activities related to maintaining, improving and modifying Toronto Hydro's SCADA system to maintain cyber security and facilitate system operation efficiency. All SCADA employees are trained engineers and technicians that possess specific skill sets in SCADA or Industrial Control Systems work. Their efforts facilitate remote system monitoring and control, and help ensure that decisions and orders from the control centre are executed quickly and efficiently. When Toronto Hydro installs new system monitoring and control equipment, it relies on SCADA engineers to configure and enable these devices to work seamlessly with the existing equipment and applications.

The SCADA system consists of three distinct sections:

- The Control Room Software and Hardware collates and displays all the information obtained from the field;
- The Communications Mediums such as fibre cable and wireless infrastructure transfer the data from the field to the control room; and
- The Field Monitoring Devices attached to Toronto Hydro plant collect real-time asset performance information.

Figure 2: SCADA display of a typical Toronto Hydro network vault.

Another key responsibility that rests with the Grid Performance Analysis and Support function are continuous updates to the control centre's live network model. This work is critical to ensure that system controllers are aware of the latest conditions affecting the sub-components of Toronto Hydro's distribution system when they devise the plans for system restoration.

The Grid Performance Analysis group is also responsible for the operational planning and outage coordination with both the IESO and Hydro One to ensure that both can carry out their operating and capital activities without causing adverse effects on the Toronto Hydro system. The work load in this area is increasing with the work for the 2015 Pan Am & Parapan American Games along with a significant capital and maintenance activities planned by Hydro One.

As Toronto Hydro's system continues to grow and evolve, the Grid Performance Analysis and Support function is becoming more complex and critical to system operation both under the normal conditions and system contingencies. Recent intensification of the utility's capital work program, along with increased scrutiny from Toronto Hydro's customers and media means that Toronto Hydro increasingly performs more support tasks without the corresponding increase in headcount. Similar to the Control Centre function, Toronto Hydro has managed to avoid further staffing increases by investing in technology that streamlines the operational processes and ensuring that program employees are cross-trained in all control centre-related functions.

The density and complexity of Toronto Hydro's urban system place significant expectations on the skills and experience of Toronto Hydro's Control Centre staff. New recruits, irrespective of educational backgrounds and/or experience, require several years to substantially familiarize themselves with Toronto Hydro's system. The configuration of Toronto Hydro's distribution network, characterized by complex feeder interaction and limited visibility into upstream Hydro One supply points and customer-owned equipment, requires significant training. Accordingly, to facilitate the ongoing generational turnover without exposing its system to additional operational and safety risks, Toronto Hydro continues to invest in training programs that ensure that new system controllers and data engineers and technicians can make optimal decisions under the normal conditions and during severe weather events. To achieve the desired levels of competence and experience, all new recruits participate in a comprehensive apprenticeship program that gradually exposes them to increasingly complex operating tasks that comprise the typical workload of Toronto Hydro's control centre.

2.1.2. Program Costs

Table 3: Control Center Operations Program Costs ($ Millions)

	2011	2012	2013	2014	2015
Total	8.4	8.3	8.9	8.2	8.4

2.1.3. 2011-2012

2012 expenditures were $0.1 million lower than 2011 levels due to a reduction in payroll costs. This decrease was partially offset by re-allocation of information technology expenditures associated with SCADA support function into the utility's IT program; the function, and associated costs, included the licensing of the software systems that support the SCADA and Power System Analysis employee. The offset was also based on an increase in associated costs driven by hiring of new apprentices to facilitate timely and efficient knowledge transfer due to anticipated retirements, along with normal inflationary increases.

2.1.4. 2012-2013

The $0.6 million increase in 2013 relative to 2012 was driven by a further increase in apprentices and supervisory staff.

2.1.5. 2013-2014

The projected 2014 Bridge Year expenditure is $0.7 million lower than 2013 levels due to staffing attrition through retirements, resulting in several unfilled positions.

Over the Historical and Bridge years (2011-2014), Toronto Hydro focused on the following activities to enhance the competency, flexibility and sustainability of its Control Centre program:

- conducting educational programs to increase staff cross-functional competence and enable more flexible staffing arrangements, including knowledge retention and documentation;
- increasing staff numbers on longer shifts to enable larger work throughput without reducing safety;
- planning for future staff turnover due to retirements by ensuring that newly hired employees undergoing the apprenticeship program overlap with those projected to retire in the short- or medium-term, for facilitating knowledge transfer.

2.1.6. Test Year Costs

The forecast costs for the 2015 Test Year are $8.4 million, which represents an increase of $0.2 million above the 2014 Bridge year costs. This increase is associated with normal inflationary pressures and the collective bargaining agreement provisions.

The proposed level of spending helps to ensure the safe and efficient operation of Toronto Hydro's evolving electricity system, by improving control centre staffing flexibility and increased system monitoring and re-configuration necessitated by the volume of proposed capital and maintenance work programs. Any funding reductions from the proposed levels could affect customer reliability, by limiting both the quality and volume of maintenance or system improvements that could be enabled by the control room processing capabilities.

The impact of expenditure reductions could also extend into reliability. Abnormal system configurations, if not properly processed and supervised, can cause undue restoration delays or overloads on remaining equipment. Any funding reductions could also increase the exposure for Toronto Hydro's crews and customers to safety risks as more work would be expected from the control room staff, with less time to ensure the required double checks and safety tools are kept up to date.

The continued 24/7 management of the system by Toronto Hydro as contemplated under the current proposed budget facilitates safe and reliable system operation and quick mitigation of any potential operating risks. Any service level reductions could also extend the operating risk to the bulk electricity system, as Toronto Hydro controllers work closely with their Hydro One and IESO counterparts to facilitate proper management of the upstream transmission system. This work entails enabling control of the system in emergency conditions, controlling Toronto Hydro crews to respond to the IESO or Hydro One, and enabling system configurations that can facilitate restoration or risk reduction to the bulk power system.

The Grid Analysis and Support expenditures contribute to the Control Room's flexibility and ability to monitor and understand changing system conditions, which, among other things, facilitate proper asset utilization by managing loading levels and other related functions. Any funding reductions could affect the operating efficiency and safety of Toronto Hydro customers and employees, through reduced ability to process and integrate the data on changing system configuration in a timely manner, manage the complexity of the dynamic system without impacting the controller time and understanding the asset impact of actions based on engineering analysis.

The scope and volume of work for support functions is in line with other utilities within Ontario and North America that have large SCADA and Distribution and Outage Management systems and rely on large sets of data for accuracy and efficiency.

CUSTOMER-DRIVEN WORK PROGRAM

1. SUMMARY

Table 1: Customer-Driven Work Program Expenditures ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Customer Driven Work	6.0	5.9	7.0	8.2	10.1

The Customer Driven Work program oversees the execution of activities driven by requests from existing and future customers relating to connection of premises and equipment to Toronto Hydro's system and maintenance of those assets. Specific activities encompassed within this program include planning, engineering and design, and field work required to safely and efficiently facilitate the following processes, each representing a discrete segment described in more detail below:

- design costs associated with customer connection requests related to unrealized new development or renovation projects;
- provision of plant locates to enable safe excavation and sub-surface exploration activities in the City of Toronto; and
- customer-owned equipment maintenance or modification work.

A subset of the activities captured within the Customer-Driven Work program and the resulting costs are driven by legislative and regulatory requirements.[1]

While Toronto Hydro is obligated to undertake the work comprising the Customer-Driven Work program, the utility manages these costs through a number of initiatives,

[1] These include the Electricity Act, 1998, the Distribution System Code (DSC), the Ontario Underground Infrastructure Notification System Act, 2012 (One Call Act), the Construction Projects Regulation O. Reg 213/91 and legislation governing the fire prevention and detection activities.

described below, in order to mitigate ratepayer impact. The following table provides an overview of the historical (2011-2013), bridge (2014) and test year (2015) costs of the program by individual segments:

Table 2: Historical, Bridge and Test Year Expenditures by Segment ($Million)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Customer Connections	1.9	1.7	2.6	2.9	2.6
Damage Prevention	2.8	2.3	1.6	2.9	4.7
Vault Access, Customer Isolation, Deconstruction and Disconnection	1.2	1.9	2.8	2.4	2.8
Total Customer-Driven Work	**6.0**	**5.9**	**7.0**	**8.2**	**10.1**

2. PROGRAM DESCRIPTION

2.1. Customer Connections Segment

The Customer Connections segment is driven by customer requests for connections to Toronto Hydro's distribution system. Serving one of the fastest growing cities in North America, Toronto Hydro receives high volumes of requests to connect new residential developments or businesses each year. These requests vary in location, load requirements and the complexity of underlying planning or construction work.

Toronto Hydro is obligated to connect a customer to its system if that customer and the associated connection complies with all requirements outlined in the Distribution System Code ("DSC") and the utility's Conditions of Service, subject to any applicable limitations. Customer connections can be in the form of a basic connection, or a connection that requires expansion work, as outlined in the Offer to Connect. In order to accommodate a new connection request, Toronto Hydro must undertake a number of activities, further described below.

Following a formal receipt of a connection request, Toronto Hydro works with prospective customers to develop an appropriate connection design, calculate the up-front customer connection deposit (as required by the DSC) and establish a mutually satisfactory construction schedule. In a number of cases, such as when an industrial customer or a large residential development seeks connection in capacity-constrained areas, Toronto Hydro must research and design the optimal means of system expansion to accommodate customer requests. Given the high density of Toronto's urban core, capacity limitations at many of the utility's Transformer and Municipal Stations ("TS" and "MS", respectively) and spatial restrictions of existing underground or overhead easements exist. As a result, highly skilled and experienced engineering and design staff is required to complete the requisite expansion and design work.

Given the current pace of Toronto's growth and the volume of large connection requests, Toronto Hydro identifies and addresses areas where insufficient connection capacity exists or is projected to materialize in the near or medium term. Accordingly, another dimension of customer connection work involves the proactive identification of existing and anticipated capacity constraints through analysis of development plans prepared by provincial and municipal agencies and private development firms. Toronto Hydro incorporates the results of this analytical work into its load forecasts and its system upgrade and expansion plans.

In parallel with connection expansion planning and design activities, Toronto Hydro is required to integrate the anticipated work with the utility's planned construction activities to ensure that the scope, nature and timing of connection work do not adversely affect the utility's planned work program. To achieve this integration, Toronto Hydro takes into account planned connection work and the availability of the utility's internal and external labour resources, coordinates planned switching and outage schedules and secures the necessary work permits. Where possible, Toronto Hydro also strives to identify and leverage any potential synergies between connection work and other planned construction activities undertaken by the utility, other utilities or municipal and provincial government agencies.

In accommodating new connections in high growth areas, Toronto Hydro must often consider highly complex and expensive means of satisfying customer connection requirements. An illustrative example of these challenges is the case of new condominium developments at Bremner Boulevard and York St. In spite of their physical proximity to Windsor TS, these buildings are being connected to Terauley TS located near Bay and Dundas due to connection capacity limitations at Windsor TS. This sub-optimal, but currently unavoidable connection arrangement, results in higher costs from the planning, design and construction perspectives.

Throughout the duration of connection planning and design activities, Toronto Hydro maintains frequent communication with prospective customers to effectively manage their expectations and accommodate evolving requirements or concerns where possible. If planned or ongoing connection work may temporarily affect service quality, reliability or otherwise disrupt existing Toronto Hydro customers, the utility endeavours to ensure that affected customers receive timely notifications of such limitations and are able to provide their input with respect to the scheduling of planned activities.

The utility recovers eligible costs associated with planning and execution of connection work from the requesting customers in accordance with the DSC and other relevant Ontario Energy Board ("OEB") and internal policies. The remainder of the costs is either capitalized or recovered through operating costs as described below.

A common source of a portion of connection related operating costs is instances where investigative or design work is stranded due to the customer failing to execute an offer to connect with Toronto Hydro. In this instance, Toronto Hydro responds to customer inquiries by providing preliminary cost estimates prior to the initiation of a detailed design in accordance with the DSC. In the event that the customer does not execute the offer to connect, Toronto Hydro is unable to recover its costs.

Operational work that supports customer connections also comes in the form of demand-billable transactions, which are connections associated with temporary service requests. Toronto Hydro provides firm quotations for these transactions, with any variance between actual costs of completing the project and the terms of a firm connection offer recovered through operating expenditures. Finally, operating costs related to customer connection work also include program support costs such as tools and equipment, uniforms, information technology, vehicle and occupancy costs.

Toronto Hydro measures the success of its customer connections function by tracking the OEB-mandated connection timelines for customers above and below the 750V connection threshold, the results of which are available on the utility's Regulatory Scorecard and the OEB Yearbooks of Distributors.

2.1.1. Segment Costs

The following table presents segment actual and bridge operating costs for the 2011-2014 period:

Table 3: Customer Connections Segment Expenditures ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Customer Connections	1.9	1.7	2.6	2.9	2.6

From 2011 to 2013, operating expenditures increased by over 37%. Operating expenditures related to this segment are related to the number and complexity of service connections received, and can vary from year to year based on the volume and nature of requests in a given year. In preparing preliminary cost estimates, due to the current state of the system, complex planning and design work is often necessary, particularly in connection-constrained locations. These complexities lead to longer lead times, and high connection costs, which results in a higher likelihood of connection projects being stranded due to the circumstances outside of the utility's control.

2.1.2. Test Year Segment Costs

Operating expenditures are forecasted to decrease from $2.9 million in 2014 to $2.6 million in 2015. Accommodating customer connection requests is a condition of Toronto Hydro's distribution licence. Given that the work underlying customer connection-related operating expenditures is driven by prospective customer requests, Toronto Hydro attempts to address them as expediently as possible.

The proposed test year costs are driven by the volumes of accommodated and anticipated connection requests, and the complexity of the underlying planning and design work, performance of which is a condition of Toronto Hydro's distribution licence.

2.2. Damage Prevention Segment

The Damage Prevention segment consists of governance, oversight, and execution of work to ensure public safety and prevent potential damage to Toronto Hydro's equipment during work performed in the vicinity of the utility's overhead and underground assets. The specific activities comprising the segment include work to identify the locations of Toronto Hydro's underground infrastructure prior to excavating activities (commonly referred to as "cable locates") and supply of insulated line covers for customer work conducted in the vicinity of overhead lines.

2.2.1. Cable Locating

Prior to excavation, Ontario homeowners or contractors may use the Ontario One Call service to confirm that the work area does not contain any buried utility infrastructure. Toronto Hydro participates in the One Call program, and is responsible for the service costs associated with requests pertaining to its service territory.

Beyond leveraging the One Call contact centre capabilities, the utility outsources the cable locating function to a third party provider who processes incoming requests and identifies the location of Toronto Hydro's underground infrastructure on the properties in question. This process assists in preventing damage to the utility's civil and electrical plant, reduces the risk of unplanned outages, and facilitates the safety of Toronto Hydro's customers and of the parties performing the excavation work.

The public and contractors are not charged for the use of the Ontario One Call service in order to encourage the widespread adoption of this service, which benefits public safety and prevents costly damages to underground utility infrastructure. In contrast, as a registered user of the service, Toronto Hydro is obligated to pay Ontario One Call for the call centre services it provides. The following table outlines the number of requests

received by Ontario One Call in Toronto Hydro's territory and the associated costs of the service:

Table 4: Ontario One Call Customer Request Volumes & Costs

Year	Number of Requests	Cost	Average Cost per Request
2011	105,019	$ 0.2M	$ 1.85
2012	126,172	$ 0.2M	$ 1.81
2013	148,454	$ 0.3M	$ 1.81

Toronto Hydro expects that with the introduction of the Ontario Underground Infrastructure Notification System Act, 2012[2] and increased public awareness, the volumes of requests will continue to increase. The following table outlines the volumes of locate requests and the associated third party costs that Toronto Hydro incurred from 2011 to 2013:

Table 5: Third Party Locates Provider Volumes & Costs

Year	Number of Locates	Cost	Average Cost per Locate
2011	99,725	$ 1.5M	$ 15.20
2012	99,097	$ 1.5M	$ 15.41
2013	118,035	$ 1.6M	$ 13.26

The cost of an individual locate differs depending on the nature of work requested and the associated timeline for its execution. There are three types of locate requests, namely Regular Locates, Emergency Locates during business hours, and Emergency Locates outside of business hours.

Toronto Hydro has been using external locates services provider for the past 15 years. However, prior to 2011, it also maintained dedicated internal resources to provide a

[2] S.O. 2012, c. 4. ["Ontario Infrastructure Notification System Act"]

portion of this service. These employees have now been either re-assigned to other activities or have left the utility through attrition. Toronto Hydro estimates that the total cost of an average locate performed by an internal employee prior to 2011 ranged from $50-$75. Since the time when Toronto Hydro contracted out locates in 2011, the utility has realized significant cost efficiencies by implementing an externally executed work program that the utility oversees and audits for quality control.

Using external locate service providers is now industry standard, as, to the utility's knowledge, the City of Toronto, and most other utilities and telecommunications companies have adopted this practice. Taking advantage of economies of scale, external locates providers can perform the required work at significantly lower costs, while having access to resources to perform emergency work as needed.

Segment activities also include planning and execution of Alternate Locate Agreements ("ALAs"), which prevent delays of the receipt of Ontario One Call service by large excavation companies. ALAs are primarily established for excavations that utilize Hydrovac technology, or for shallow depth excavation (typically less than 0.35 meters deep). With an established agreement, an excavation utility is assigned a blanket locate and an excavator identification number. These agreements enable Toronto Hydro and excavation companies to remain in compliance with applicable legislation.

Prior to excavating, the utility may call Ontario One Call service and provide this number to obtain immediate approval to excavate. As such, customers are able to bypass the standard five-day turnaround time for the receipt of the service, thereby resulting in more productive and efficient use of time. In addition, Toronto Hydro is able to save the costs associated with completing the locate. The ALAs result in fewer customer complaints, require less coordination and oversight from Toronto Hydro, and lead to cost reductions for Toronto Hydro and its customers.

Over the past few years the number of locates and damage investigations have substantially increased in parallel with the overall growth of Toronto Hydro's capital work and general construction activities in the utility's service territory. Increased construction activities generate additional work to update, expand or correct the utility's asset records.

2.2.2. Overhead Line Covers

The last component of the damage prevention segment is the oversight of the installation of protective power line covers. In accordance with the Construction Projects Regulation,[3] it is a contractor's responsibility to ensure that people and equipment at work sites maintain a safe distance from power lines. When requested, a Toronto Hydro authorized contractor safely installs and removes power line covers. Toronto Hydro audits the contractor practices and undertakes the inspections of covers themselves.

2.2.3. Segment Costs

The following table presents the Historic (2011-2013), Bridge (2014) and Test Year (2015) costs associated with the Damage Prevention segment :

Table 6: Damage Prevention Segment Expenditures ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Damage Prevention	2.8	2.3	1.6	2.9	4.7

[3] O. Reg 213/91, made under the Occupational Health and Safety Act, R.S.O. 1990, C. O.1 ["Construction Projects Regulation"].

From 2011 to 2013 there was a steady decrease in operating expenditures as a result of efficiencies and staff attrition. It should be noted that although the cost of the Ontario One Call Service and the Third Party locate provider was $1.9 million in 2013, the actual operating expenditure was $1.6 million. This variance was as a result of a one-time credit issued by the third party locate provider to rectify administrative errors regarding services rendered in previous years. In 2014, Toronto Hydro anticipates that the trend of increased volume will continue, and thus forecasts that the 2014 costs will be $2.9 million.

As discussed above, Toronto Hydro anticipates an increased volume of requests for locates as the contractor community and general public become more aware of the Ontario One Call process and due to increased development and construction in the City of Toronto. The increase is evident in the following table:

Table 7: Historical Locates Requests and Work Requirements (2011 – 2013)

Year	Number of Requests	% Change	Number of Locates	% of Requests resulting in Locates
2011	105,019	-	99,725	95%
2012	126,172	+20%	99,097	79%
2013	148,454	+18%	118,035	80%

As shown in the table above, during the 2011-2013 period, the percentage of requests resulting in locates has reduced by approximately 15%, which is attributed to the introduction of ALAs where individual locates are performed by requestors directly.

In the future, beyond continued utilization of the cost-effective external locates service, Toronto Hydro plans to increase the utilization of ALAs with parties that undertake large volume of construction activities in order to better manage its locate costs and the

resulting impact on ratepayers. To date, Toronto Hydro has implemented 23 such agreements in place since the program's inception in 2011. The utility estimates that the ALA framework saved Toronto Hydro and its ratepayers approximately $0.5 million in 2013. Despite the increase in ALAs and the associated savings, the increased awareness of Ontario One Call and the services they provide is expected to result in higher levels of requests than historically seen, leading to the projected costs of $2.9 million in 2014.

2.2.4. Test Year Segment Costs

Toronto Hydro anticipates that locate volumes will continue rising through 2014 and 2015. However, the majority of the Test Year increase ($1.7 million) is associated with the work related to assets that were formerly part of the City of Toronto's street lighting system.[4] The utility expects to continue seeking out opportunities for the additional ALA establishment as a means of controlling costs. The expenditures associated with the locate function are non-discretionary, as the service is mandated by provincial legislation and the volume of work is directly linked to the number customer requests. In addition to ensuring compliance with legislative requirements, locates provide value by helping prevent Toronto Hydro's distribution plant from being damaged, mitigating the risk of excavation-related outages and facilitating the safety of the utility's personnel and general public.

Toronto Hydro manages the cost of this activity by using the services of a third-party provider and by taking steps to proliferate the adoption of ALAs across the construction community. Moreover, to help ensure the ongoing adequacy and cost-effectiveness of the external service provider arrangement, Toronto Hydro periodically audits its partners' performance.

[4] As discussed in Exhibit 2A, Tab 5, Schedule 1, Toronto Hydro proposes to allocate a portion of the revenue received by TH Energy from the City of Toronto for street lighting maintenance and operation to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

Through other damage prevention functions (e.g. providing advice to system planners and external contractors on the location of active and idle underground assets), Toronto Hydro minimizes safety risks for its crews and reduces the number of work stoppages related to unexpected findings in the field. Finally, periodic updates of Toronto Hydro's underground plant records based on field findings facilitate effective future planning and reduce the likelihood of future excavation-related incidents.

2.3. Vault Access, Customer Isolations, Deconstructions and Disconnections Segment

The work comprising this segment enables Toronto Hydro's commercial, industrial and residential condominium customers to safely perform periodic maintenance activities on their (customer-owned) civil infrastructure and other equipment, and facilitates temporary or permanent disconnection of these facilities from the grid.

Toronto Hydro provides eligible customers with one complementary vault entry and a single isolation per year to promote regular maintenance of customer-owned facilities and equipment and to facilitate early identification of emerging issues. In certain cases, and as detailed below, Toronto Hydro will deconstruct a connection or disconnect a customer from the grid at the request of the customer.

2.3.1. Vault Access

Toronto Hydro's Conditions of Service stipulate that customers are responsible for supplying, maintaining, repairing and otherwise modifying all civil assets located on their property, and any civil infrastructure located on public road allowances that serves non-metered connections. The scope of applicable infrastructure includes poles, cable chambers, transformer rooms, transformer vaults, handwells, junction boxes and other equipment housing or supporting Toronto Hydro's connection assets. Most commonly,

however, customer equipment access activities involve transformer vaults located on customer property. In the interest of public safety, Toronto Hydro places locks on transformer vault doors, helping to ensure that only qualified personnel have access to these rooms and the high-voltage electrical equipment they contain. From time to time, Toronto Hydro customers require access to vaults for periodic maintenance and inspections, or to perform repairs identified as necessary during prior site visits.

There are over 4,500 customer-owned vaults in Toronto Hydro's service territory that contain electrical plant owned by the utility. Each vault is required to contain fire detection equipment, which must be inspected annually in accordance with the applicable legislative requirements. During vault inspections, qualified Toronto Hydro staff must be on hand for safety purposes and to prevent damage to the utility's assets. When Toronto Hydro identifies structural deficiencies with the vault or a problem with the access door, it provides the customer with a completed Customer Advice Form ("CAF"), which explains the nature of the deficiencies and recommends corrective steps.

As stated above, Toronto Hydro provides each qualifying customer with one transformer vault entry per year at no cost to the customer. The costs of any subsequent entries inside the vault are recovered from requesting customers.

2.3.2. Customer Isolations

Customer isolation work (i.e. temporary disconnection of customer equipment from Toronto Hydro's distribution grid) allows customers to perform inspection, maintenance, repairs or replacement to their electrical equipment. As with vault access, Toronto Hydro provides eligible customers with a single isolation per year free of charge in order to encourage the maintenance of equipment, including testing and maintenance of fire detectors in the vaults. In addition to facilitating maintenance work, customer isolations

ensure the safety of customers, as working in the vicinity of energized assets puts them at potential risk of contact with energized equipment.

During customer activities enabled through isolation, Toronto Hydro personnel must remain on hand to ensure that all applicable safety procedures are followed and that equipment integrity is preserved. To facilitate the execution of this work in a cost-effective manner, Toronto Hydro typically assigns these tasks to certified lines personnel that are performing accommodated duties due to a prior injury or other related considerations. In this manner, Toronto Hydro is able to leverage the skills and experience of accommodated workers while respecting their physical restrictions.

2.3.3. Deconstruction and Disconnections

Toronto Hydro typically carries out service disconnections and deconstruction of the associated equipment in response to customer requests. Under certain circumstances, such as in cases where the utility discovers an instance of an unauthorized use of power, the utility carries out the disconnection work as described in Exhibit 4A, Tab 2, Schedule 13.

The utility recovers the costs of normal disconnection and deconstruction work for Residential and small General Service (Class 1 and Class 2) customers through rates, as these costs are assumed at the time of economic evaluation of customer connection requests. An exception are the cases where existing Class 1 or 2 customer premises are being re-developed or expanded, in which cases Toronto Hydro recovers the costs directly from the requesting customers. For larger customers (Classes 3 and 4), Toronto Hydro recovers the costs of disconnection and deconstruction work directly from the requesting customers.

Irrespective of recovery methods, the costs of deconstruction and disconnection work vary significantly depending on service type and the specific scope of work. Toronto Hydro's practices with respect to the determination of disconnection/demolition costs are listed in the Conditions of Service document.

2.3.4. Segment Costs

The following table presents the historical (2011-2013), bridge (2014) and test year (2015) costs associated with this segment:

Table 8: Vault Access, Deconstruction & Disconnection Expenditures ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Vault Access, Customer Isolations and Disconnections	1.2	1.9	2.8	2.4	2.8

Toronto Hydro's operating expenditures for this segment increased by almost $1.0 million from 2012 to 2013. This increase is mainly attributable with the expansion of the Vault Access program, driven by Toronto Hydro's efforts to increase customer awareness of the importance of regular vault inspections. These activities resulted in a larger uptake of the complimentary vault access services, leading to incrementally higher expenditures.

2.3.5. Test Year Segment Costs

The 2015 Test Year operating expenditures are expected to increase from $2.4 million in 2014 to $2.8 million in 2015 due to an increase in volume of vault access and customer isolation requests. Toronto Hydro's vault access and customer isolation segment aims to promote regular maintenance of customer-owned equipment and helps to ensure personnel safety when performing this work. As previously mentioned, the cost of the

segment in a given year is directly linked to the number of customer requests that Toronto Hydro receives for vault entry and isolation.

By providing customers periodic access to their transformer vaults under professional supervision, Toronto Hydro facilitates the timely identification of any emerging structural or safety risks, thereby reducing the likelihood and/or the potential effect of incidents that could have otherwise materialized in the absence of such inspections.

Toronto Hydro manages vault access and customer isolation activities by assigning them, to the degree possible, to field workers already scheduled for other work. The funds requested for this segment are necessary because any reduction in funding could put public safety at risk and could ultimately result in higher costs for both Toronto Hydro and its customers, if the utility is required to remedy issues and incidences arising from insufficient or irregular maintenance of customer-owned vaults.

OPERATIONS SUPPORT – PLANNING PROGRAM

1. PROGRAM SUMMARY

Table 1: Operations Support Planning Program Expenditures ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Planning	9.0	9.0	11.5	10.3	12.9

/C

Toronto Hydro's Planning program encompasses a broad range of asset management work to support of reliable operation of the utility's electricity distribution system, performed by qualified and experienced engineers, technologists and support staff. The scope of work comprising the program includes materials and standards research, system planning and design, forecasting of customer and system needs, reliability planning, and enabling the integration of new technologies into the utility's system. The key outputs of the program are plans for capital and maintenance activities aimed at maintaining and/or improving performance of Toronto Hydro's distribution system. While an eligible portion of these costs is capitalized, the remaining costs are recovered through the operational expenditures.

As discussed throughout this application, the rigour and complexity of Toronto Hydro's asset planning and management processes have matured and gained sophistication over the time of Toronto Hydro's amalgamated existence. The enablers behind this continuous improvement are Toronto Hydro's staff, systems and processes funded through the Planning Program.

2. PROGRAM DESCRIPTION

The Planning program encompasses the full range of functions supporting Toronto Hydro's asset management work and coordination with other programs, most notably

Work Execution and Work Program Management and Support (Exhibit 4A, Tab 2, Schedules 8 and 9, respectively). As noted above, the program is staffed predominantly with experienced engineers and technologists possessing extensive knowledge of the utility's diverse and evolving asset base and unique system configuration. With the intensification of Toronto Hydro's capital program in the last several years, the Planning program has been relied on heavily to investigate, analyze and produce an increasingly complex and comprehensive capital and maintenance plans.

The Planning program consists of three segments:

- System Planning and Records Management
- Grid Solutions and Electric Vehicles; and
- Standards and Policies.

The System Planning and Records Management segment includes the functional areas responsible for system capacity and generation planning, maintenance planning and reliability and capital investment planning. Supporting the planning activities, and also included in this segment, is the records management function responsible for supporting the planners by maintaining and updating the utility's extensive asset records and related applications.

The Grid Solutions and Electric Vehicles segment undertakes research and planning aimed at modernization and enhancement of the utility's distribution system through integration and proliferation of Smart Grid technologies.

Finally, the Standards and Policies segment includes the functions responsible for the development and maintenance of Toronto Hydro's construction standards, and specific technological and construction standards.

Table 2 provides a detailed breakdown of the Planning program expenditures by segment.

Table 2: Operations Support – Planning Program Expenditures by Segment ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test	
Planning and Records Management	5.5	5.7	8.8	6.6	8.7	/C
Grid Solutions & EV's	0.8	0.7	0.5	1.2	1.5	
Standards & Policies	2.7	2.7	2.2	2.5	2.7	
Total	**9.0**	**9.0**	**11.5**	**10.3**	**12.9**	/C

The activities included in each of these segments are described in further detail below.

3. SYSTEM PLANNING AND RECORDS MANAGEMENT SEGMENT

The System Planning and Records Management segment is comprised of four functional areas: Investment and Reliability Planning, Maintenance Planning, Capacity and Generation Planning, and Records Management. These four functional areas work together to coordinate the execution of analytical work underlying the utility's asset management strategy, that underpins Toronto Hydro's Distribution System Plan ("DSP).[1]

3.1. Investment & Reliability Planning

The Investment and Reliability Planning function monitors the utility's reliability performance, develops of system-wide and targeted strategies to maintain and/or improve

[1] Exhibit 2B.

reliable performance of the utility's asset base, and prepares Toronto Hydro's Distribution System Plan ("DSP").

Reliability planning involves the analysis of power outage data from the distribution system to identify performance patterns and trends related to specific types of equipment or geographical areas. In conducting this work, Toronto Hydro relies on a number of applications, including the Interruption Tracking Information System ("ITIS") – an internally developed application that analyses the data collected through the utility's Outage Management System ("OMS"). The use of the ITIS tool enables Toronto Hydro to conduct a detailed analysis of outage events and identify the worst performing parts of Toronto Hydro's system and the customers disproportionately affected by system outages. The analytical work performed by the Reliability and Investment planning function underlies capital programs such as the Worst Performing Feeder ("WPF") program described in Exhibit 2B, E6.21.

In addition to analyzing the current state of system reliability, the Reliability and Investment Planning function also develops reliability forecasts on the basis of planned capital investments and maintenance activities. This enables Toronto Hydro to identify and monitor the achievement of this crucial outcome of system planning and investment. The results of Toronto Hydro's reliability forecast for the 2015-2019 period based on the utility's Distribution System Plan are provided in Exhibit 2B, C2.1.3.

General Investment planning entails a feeder-by-feeder analysis and determination of specific assets that require replacement, refurbishment or other forms of intervention, to ensure continued system safety and reliability of the utility's distribution system. In performing this work, Toronto Hydro relies on the reliability analysis as described above, taking further steps to localize the feeders and assets experiencing particular problems. Using the insights obtained through detailed reliability analysis, Toronto Hydro explores

feasible mitigation options to determine the final solutions to specific issues. If the preferred solution for a particular issue is a capital investment, Toronto Hydro creates a scope of work that is added to the utility's investment plan. In performing this work, the utility relies on a number of comprehensive asset management tools, including the Geospatially Enable Asset Registry ("GEAR"), and the Feeder Investment Model ("FIM"). [2]

Finally, the Investment and Reliability Planning function is responsible for the development of Toronto Hydro's evidence in support of its proposed capital investments for the purposes of regulatory filings. The engineers and technologists comprising this functional area have been instrumental in the development of Toronto Hydro's evidence for the current application, the 2012-2014 Incremental Capital Module ("ICM") filing and previous applications concerning capital work plans.

3.2. Maintenance Planning

The Maintenance Planning functional area oversees the analysis and preparation of Toronto Hydro's maintenance plans and schedules for all components of its distribution system. This work entails performing Reliability Centred Maintenance ("RCM") analysis for each asset class, analyzing historical failure data, and ensuring identified deficiencies are remedied. In addition, the Maintenance Planning function assists Toronto Hydro in preparing documentation for and analysing the results of competitive tenders for procurement of maintenance contractor services. The maintenance planning work is critical to ensure the safe and reliable operation of system assets and optimize the time at which operational and capital investment is needed.

[2] Exhibit 2B, Section D.

3.3. Capacity and Generation Planning

This functional area is responsible for planning both the future load requirements of the distribution system driven by customer growth, and requisite connection capacity to accommodate current and forecasted levels of distributed generation ("DG") in Toronto Hydro's service area. The integration of connection and generation demand planning into a single functional area allows Toronto Hydro to capitalize on key planning synergies, such as foregoing and/or deferring the need for load growth-enabling investments in the areas with forecasted DG connections, or facilitating cost-effective load transfers between transformer stations.

The capacity planning work requires constant monitoring of changing system characteristics, such as feeder and transformer station loadings, short circuit levels and system performance measures. Combining this system performance data with past system demand trends and known requests for connection of load and generation facilities, Toronto Hydro produces a seven annual system demand forecast on a rolling five-year basis. Given the nature of its mandate, the capacity and generation planning function is Toronto Hydro's technical liaison with the Ontario Power Authority ("OPA") on all matters related to the distributed generation programs (e.g., Feed-in-Tarriff ("FIT") and MicroFIT), and regional planning undertakings. When required, the capacity planning personnel also provide input in the area of load growth and short circuit forecasting requirements to Toronto Hydro other planning functions.

3.4. Records Management

The Records Management function is responsible for the maintenance and upkeep of digital records of Toronto Hydro's distribution. Given that the system capacity and configuration is constantly evolving due to new customer connections, equipment failures, retirements and additions, maintaining an up-to-date system of records is crucial to enable efficient and effective system planning and operation. Toronto Hydro also

maintains records of its distribution asset inspections pursuant to the Electrical Distribution Safety Regulation.[3] When Toronto Hydro installs new assets in its distribution system, either on a planned or a reactive basis, the records of installation and inspection are sent to the records management group, either in paper or electronic form, to verify that Toronto Hydro asset management processes have been followed with respect to that installation.

The records management function also plays a crucial role in ensuring the quality and accuracy of data used in Toronto Hydro's asset planning and management applications such as GEAR and the FIM, ensuring that the investment and operational decisions are based on the optimal information. Failure to verify the accuracy of information such as feeder and asset construction configurations could lead to safety risks for people working on Toronto Hydro's system.

3.5. Segment Costs

Table 3 displays Toronto Hydro's Historical (2011-2013), Bridge (2014) and Test Year (2015) costs for the Planning and Records Management Segment.

Table 3: Planning and Records Management Segment Expenditures ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Planning And Records Management	5.5	5.7	8.8	6.6	8.7

/C

Segment expenditures have generally increased year-over-year at a significantly lower pace than the volume of Toronto Hydro's capital expenditures, and at a pace similar to that of the maintenance work program that this segment supports.

[3] Ontario Regulation 22/04, made under the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A ["Electrical Distribution Safety Regulation].

3.6. Test Year Segment Costs

The 2015 Test Year expenditures for the Planning segment are $9.0 million, or $0.3 million higher than the projected 2014 costs. Once baseline plans are developed for the 2015 to 2019 period, continuous refinements will be required as new system requirements emerge and work execution progresses.

To help manage planning expenditures, Toronto Hydro utilises a number of contract employees and students that assist the utility's engineers in performing their analytical tasks. The utility expects to continue this practice throughout the 2015-2019 rate period.

4. GRID SOLUTIONS AND ELECTRIC VEHICLES SEGMENT

This segment is responsible for the research and development of innovation projects within Toronto Hydro's distribution system, in response to the government policy requirements, the emerging system needs, and technological innovations that can enhance the effectiveness and cost efficiency of grid operation.

The work conducted under the Grid Solutions segment can be classified into the following categories:

1) Grid Monitoring;
2) Distributed Intelligence;
3) Electric Vehicles; and
4) Active Demand Response.

The Grid Monitoring work entails management, maintenance and enhancement of Toronto Hydro's existing system monitoring assets, support of data management tools, and investigation of solutions for monitoring the utility's underground distribution assets. The key benefit of this work for Toronto Hydro is the improved visibility into the

performance of its distribution assets, which enhances the utility's ability to make operational and strategic decisions regarding its assets. This, in turn, facilitates further reliability improvements (for both momentary and sustained outages), leading to improvements in customer satisfaction.

The Distributed Intelligence work involves the collection and analysis of local data on performance of distributed generation ("DG") assets, and investigation of potential means of controlling distributed generation resources and implementation of micro-grids within Toronto Hydro's service territory, which would be supplied in part by distributed energy resources. A project that is currently underway is the analysis of potential implementation of a micro grid at the Exhibition Place. Key benefits of this program are improved visibility and control capability of feeders connected to DG resources, and improved system reliability due to integrated control of distributed generation resources. This research work is expected to provide Toronto Hydro with another tool for the cost-effective management of system constraints.

Under the Electric Vehicle ("EV") program, Toronto Hydro is studying the effect of potential proliferation of EVs throughout the utility's service territory. This work is primarily accomplished through collection and analysis of customer vehicle charging data. The insights obtained through this research work are expected to enable the utility to make the optimal decisions in terms of the supply and control infrastructure that may be required in the future to enable EV charging in different areas of Toronto.

The Active Demand Response work involves the investigation of advanced solutions for local demand response programs. The ability to actively manage local demand is expected to provide Toronto Hydro operating flexibility which may help defer costly capital investments without compromising reliability.[4]

[4] Exhibit 2B, E7.10

4.1. Segment Costs

Table 4 provides the Historical (2011), Bridge (2014) and Test Year (2015) expenditures for the Grid Solutions and Electric Vehicles segment.

Table 4: Grid Solutions and EVs Segment Expenditures ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Grid Solutions & EVs	0.8	0.7	0.5	1.2	1.5

Segment expenditures have increased due to the continue increase of renewable DG resources connecting to Toronto Hydro's system, and the evolution of the government's Smart Grid policy. While the majority of the work conducted under this segment is geared towards the future evolution of the utility's distribution system, Toronto Hydro submits that this work constitutes a prudent investment that is expected to allow the utility to keep pace with a rapidly evolving technological landscape of EVs, Smart Grid and renewable generation. Because Toronto Hydro's system was designed and constructed before these technologies became available, developments in these areas can have significant effect on the utility's system and must be monitored closely.

4.2. Test Year Costs

Toronto Hydro's test year forecast for the Grid Solutions and EV segment is $1.5 million, which represents an increase of $0.3 million above the 2014 projection. The increase is largely driven by the changing nature of the segment's activities over the recent years. Whereas a significant portion of the work performed in 2011-2013 historical years was directed at specific capital projects (and thus eligible for capitalization), the segment's work thus far in 2014 and anticipated for the 2015-2019 timeframe is more directed towards the research and development activities.

Analysis of performance data on items such as distributed generation interconnections and electric vehicle charging stations is important to understand both the immediate needs of and long term impacts on the distribution system. This analysis is also important to understand the exact requirements and system impacts of new technologies, such as the micro grid contemplated for installation at the Exhibition Place.

Absent the requested funding, Toronto Hydro's capability to research and investigate the implementation of emerging technologies that support customer choice and control, power system flexibility and adaptive infrastructure will be significantly challenged. In addition, funding reductions from the proposed levels would threaten Toronto Hydro's ability to support externally funded projects, such as those supported by the Ontario Government's Smart Grid Fund and the ecoEnergy Innovation Initiative, which represent cost effective means of achieving the key initiatives.

5. STANDARDS AND POLICIES SEGMENT

The Standards and Policies Segment is responsible for the development of all construction standards and other specifications for the electrical and civil construction work that occurs in Toronto Hydro's service territory. This work is driven in large part by the specification of the Electrical Distribution Safety Regulation,[5] which requires distributors to create standard design drawings and specifications for all equipment comprising the distribution system. The resulting drawings provide detailed specifications as to the type and configuration of equipment installed in Toronto Hydro's distribution system, to facilitate public and worker safety, as well as the reliable operation of the utility's distribution system.

[5] Supranote 3.

The work performed under the Standards and Policies segment is of particular importance in light of the circumstances of Toronto Hydro's amalgamation in 1998, when six neighbouring distributors with varying asset management practices, construction standards and equipment types were merged into a single organization. Over the years since the utility's amalgamation, the segment has standardized the construction standards in a manner that balances the diversity of legacy assets with the objectives of safety and operational efficiency. Certain aspects of this work continue to date, including the finalization of Nomenclature Standardization work described in Toronto Hydro's Review of Past Productivity[6] and working with the Supply Chain program[7] to coordinate the retirement of certain legacy or non-standard materials or equipment in the manner that maximizes the utility of remaining available stock.

The Standards and Policies segment also plays a key role in facilitating effective response to contingency events, by identifying the type and quantities of certain materials and equipment that are critical for the continuous operation of the company's distribution system. As described in the Supply Chain program,[8] the inventory items identified by the Standards Segment are segregated from general stock for specific use in reactive situations. The cooperation between the Standards and the Supply Chain programs also involves providing the input to the strategic sourcing work to identify the optimal suppliers of materials and equipment.

5.1. Segment Costs

Table 5 provides the Historical (2011), Bridge (2014) and Test Year (2015) expenditures for the Standards and Policies segment.

[6] Exhibit 1B, Tab 3 Schedule 5, Appendix A.
[7] Exhibit 4A, Tab 2, Schedule 12.
[8] Exhibit 4A, Tab 2, Schedule 12.

Table 5: Standards and Policies Segment Expenditures ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Standards & Policies	2.7	2.7	2.2	2.5	2.7

Segment expenditures have generally been stable throughout the period, with the 2015 Test Years forecasts matching the 2011 and 2012 historical actuals.

5.2. Test Year Segment Costs

As shown in the Table above, the Test Year segment costs for the Standards and Policies Segment are forecast to be $2.7 million, which represents an increase of $0.2 million above the 2014 projection. The incremental increase from the Bridge Year levels is driven by the need to support the development of new equipment specifications and standards for equipment proposed in the DSP application, such as reclosers as described in the Overhead Momentary Reductions program in the DSP.[9]

As Toronto Hydro continues to explore the use of new technologies in its distribution system to achieve reliability improvements, gain operational efficiencies and reduce overall operating costs, the Standards and Policies expenditures are necessary to ensure that the utility's distribution system continues to grow and evolve in a consistent and efficient manner, utilizing the uniform standards that reflect the best practices and optimal materials.

[9] Exhibit 2B, E7.4

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WORK EXECUTION MANAGEMENT AND SUPPORT PROGRAM

1. SUMMARY

Table 1: Work Execution Management and Support Program Expenditures ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Work Execution Management and Support	5.0	5.5	5.6	5.8	6.1

The Work Execution Management and Support Program oversees the balancing of Toronto Hydro's planned capital and maintenance work programs with available labour resources, and manages changes that arise as a result of operational complexities faced by front line crews. The program also provides auxiliary support services to ensure successful delivery of the planned work, including:

- Securing City of Toronto work permits;
- Engaging and collecting input from customers in the vicinity of the projects;
- Tracking project progress and labour resource utilization;
- Facilitating consistency in project forecasting and management of related practices; and
- Providing general administrative support to project managers.

This centralized function enables Toronto Hydro to facilitate optimal utilization of available resources, proactively identify and mitigate emerging risks, keep its customers informed of planned and ongoing work in their neighbourhoods, as well as coordinate and track the multitude of projects across the utility's service territory. The work comprising this segment is distinct from activities captured in the Work Execution

program,[1] which is primarily focused on oversight, training and other expenditures incurred in the process of actual work execution that are not attributable to a specific capital or maintenance project or program.

The activities comprising this program are grouped into two general categories and are discussed in more detail below:

- Work Execution Management; and
- Work Execution Support.

2. PROGRAM DESCRIPTION

2.1. Work Execution Management

Each year, Toronto Hydro undertakes hundreds of discrete capital and maintenance projects to replace, refurbish or otherwise modify its aging asset base, address emerging safety issues, accommodate new customers, and ensure that equipment is in a proper working order. Prior to setting out to do this work, the utility undertakes extensive planning efforts to ensure that its work plans for the current and future years match the availability of physical resources required to complete the program. Beyond matching resources to projects, Toronto Hydro works to facilitate all available resources being optimally utilized to facilitate cost efficiency and eliminate avoidable costs or other redundancies. Coordination, execution and verification of this planning and management work is the responsibility of the Work Execution Management staff.

The program staff work with Toronto Hydro's asset managers, designers, crew leaders, control centre and human resources staff to produce a resource-balanced work program execution plan, grounded in forecasted volumes and types of capital and maintenance

[1] Exhibit 4A, Schedule 2, Tab 9.

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projects. In developing this plan, Toronto Hydro analyzes the scale, scope and location of each project, and estimates the requisite number of hours and type of resources (e.g., civil, electrical, other specialized skills) based on the past information from similar projects, general trends, anticipated efficiencies and other available data. The utility then checks the resulting project labour requirements against the available labour schedules and makes the appropriate resource allocations to discrete projects. Once the individual project-based analysis is complete, the combined program (i.e., a collection of individual projects) is reviewed against the available resources and other relevant reference information on an aggregate level, to identify any inconsistencies, deficiencies or suboptimal resource utilization trends.

Toronto Hydro also works with other utilities and City of Toronto planners to coordinate the planned Toronto Hydro work with the anticipated work of these entities. The objective of this effort is to maximize available synergies, prevent potential conflicts and reduce the potential disruption of construction projects on Toronto Hydro's customers.

Underlying each resource-balanced plan is a set data and assumptions, based on past experience, forecasted resource availability, known risks and constraints, and other key planning criteria. Toronto Hydro monitors the work program execution and makes necessary adjustments to plans based on factors such as known complexities and emerging external constraints faced by field crews. As such, the resource-balanced plans undergo periodic amendments and re-forecasts to ensure that resource utilization matches the reality of field conditions in the mature and complex urban setting that Toronto Hydro operates in. The effect of each individual change requires assessment on the overall program level to ensure that the utility meets its overall work program objectives by the end of each year.

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In addition to maintaining the program-wide resource balance, Toronto Hydro tracks the status of each individual project comprising the work program. While tracking the project execution progress, Toronto Hydro also seeks to proactively identify anticipated or emerging risks that may impact the successful delivery of the work program, and then develops the appropriate mitigation strategies. Performing this work requires understanding of resource allocation management, schedule management, and project/program management. Accordingly, the program predominantly employs individuals with professional Project/Program Management designations and experience in design/construction work delivery.

The centralized Work Program Management function facilitates a coordinated approach to executing the projects and programs identified by engineering staff (i.e., Asset Management), while ensuring that design/construction resources are kept optimally busy. This allows Toronto Hydro to fulfill its program commitments to its customers, the Ontario Energy Board ("OEB") (as required), and other relevant stakeholders in a manner that supports value-for-money regarding capital and maintenance activities.

2.2. Work Execution Support

Timely and cost-effective execution of capital and maintenance projects requires comprehensive logistical support to anticipate and address the administrative requirements, secure permits, manage stakeholder expectations and facilitate execution efficiency. These, and other related functions comprise the mandate of Toronto Hydro's Work Execution Support program.

A subset of program staff works to facilitate timely issuance of City of Toronto permits required to cut into or otherwise modify city sidewalks and roadways in order to enable the execution of civil and electrical construction work. In a given year, Toronto Hydro requires multiple and roadway work permits. Securing timely and accurate approvals for

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this work involves coordination with Toronto Hydro engineers, designers and City officials to ensure that all relevant documentation is prepared in accordance with Municipal Consent Requirement for the Installation of Plant Within City of Toronto Streets ("MCR"). At times, issues management activities such as planned municipal (or other agency) work unknown to Toronto Hydro requires the original project scopes and timing to be modified, thus necessitating further coordination efforts on the part of Work Execution Support functional area.

Work Execution Support functional area also oversees the engagement of Toronto Hydro customers affected by the planned and ongoing work in the vicinity of their residences or places of business. Timely and effective communication with customers affected by the utility's work program assists Toronto Hydro in managing the expectations of local residents, and to the degree possible, accommodating their requests regarding manner of execution or final appearance of modified equipment and facilities.

Another critical function provided by the Work Execution Support program is timekeeping and general administrative support services. The timekeeping work entails monitoring and recording the labour efforts expanded by crews and engineering/design personnel on certain projects in order to facilitate tracking of project costs. The data collected through the time-keeping function allows Toronto Hydro to gain additional insights into the work execution patterns, identify trends and where necessary, adjust future planning and resource-allocation assumptions to better reflect the reality of the field conditions and drive further operational efficiencies. The administrative support includes general back-office support to project/program management and construction employees to facilitate project execution efficiency and effective use of staff's time.

Finally, the Work Execution Support function provides oversight and governance over the project and program management practices applicable to Toronto Hydro's capital and

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maintenance work programs. This function facilitates consistency of forecasting, risk identification, and progress tracking for all applicable projects/programs. Given the number and variety of projects and programs that comprise Toronto Hydro's capital and maintenance work program, the governance function is critical to ensure the integrity and accuracy of the utility's resource-balanced work plans, as well as the work plans and financial forecasts Toronto Hydro submits to the OEB, its shareholder and other neighbouring utilities. In addition to providing oversight, this function is also responsible for designing and amending procedural documents and project management tools that adhere to industry standards and best practices.

3. PROGRAM COSTS

Table 2 provides the Historical (2011-2013), Bridge (2014) and Test Year (2015) costs for the Work Execution Management and Support Program.

Table 2: Work Program Execution Management and Support Expenditures ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Work Execution Management and Support	5.0	5.5	5.6	5.8	6.1

The 2012 operating expenditures were $0.5 million higher than 2011 due to lower-than-expected labour recovery as result of reduced capital spending from the previously planned levels.

The 2013 expenditures were $0.1million higher than 2012 due to inflationary adjustments and mid-year establishment and consequent staffing of the:

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- **x** Maintenance Management Office ("MMO") to ensure the maintenance program is successfully forecasted, resource balanced, executed and reported, while delivery risks are proactively identified and mitigated.
- x Program Delivery Improvement & Governance ("PDIG") to provide governance through creation of new Program Management procedures, processes and tools for monitoring compliance.

The 2014 expenditures are anticipated to be $0.2 million higher than 2013 due to inflationary adjustments and further development and staffing of MMO and PDIG to meet the previously mentioned mandates.

As demonstrated in the Table 3 below, the Capital and Preventative and Predictive Maintenance programs are expected to grow by about 31% and 18%, respectively, from the Historical to the Bridge period. At the same time operating costs of the Work Execution Management and Support program, which is directly proportional to the size of the work program, are forecasted to grow by only 16% during the same period. This demonstrates Toronto Hydro's focus on continuous improvement and identifying operational efficiencies.

Table 3: Relationship between Program Costs and Capital and Preventative/ Predictive Maintenance Expenditures ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Total Capital Expenditures	445.5	288.0	445.7	582.7	523.6
Preventative and Predictive Maintenance	13.7	16.0	12.8	16.1	20.1
Work Execution Management and	5.0	5.5	5.6	5.8	6.1

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	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Support Program (WESP)					
% WEMS of Capital and P&P Maintenance.	1.1%	1.8%	1.2%	1.0%	1.1%

3.1. Test Year Costs

2015 operating costs are forecast at $6.1 million, which represents an increase of $0.3 million over 2014 projections. This increase is primarily due to inflationary adjustments as well as filling in staffing vacancies to support the growth of the capital and maintenance work program.

The Work Execution Management and Support Program is a critical part of Toronto Hydro's operations. It allows the utility's work plans to be grounded in a balanced and optimal utilization of labour resources and up-to-date information about the utility's operating conditions. Through this program, Toronto Hydro is able to keep track of and manage the impact of daily changes that are inherent in operating a utility in a large, complex and mature urban environment.[2] Program monitoring and work plan modification activities that are part of this program are a component of the utility's continuous improvement efforts, as the underlying analytical work provides Toronto Hydro with insights that inform future approaches.

The day-to-day project tracking and management efforts enable Toronto Hydro to quickly and accurately track the status of the ongoing projects, thereby facilitating identification and mitigation of risks, leveraging of potential synergies, and supporting alignment with work program objectives.

[2] For more information about these challenges, refer to Exhibit 1B, Tab 2, Schedule 4, Appendix A.

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A subset of program functions, most notably the permit facilitation and customer communication activities, are mandated by the municipal and OEB requirements. Beyond the external requirements to provide these services, Toronto Hydro derives significant operational value from timely and accurate permit completion and proactive project-specific communication with affected customers, as this work reduces the possibility of unanticipated work stoppages due to permitting issues or customer concerns.

Absent the program governance described above, Toronto Hydro's work plans would face increased risks of inconsistencies, improper assumptions, and suboptimal workforce allocation. These risks would in turn tend to undermine optimal resource allocation, negatively affecting customer experience, and compromising the value of the work to ratepayers and the utility.

Reductions to this program would also adversely affect Toronto Hydro's ability to accurately forecast the execution of its work programs, and to accommodate on-going changes to facilitate optimal utilization of resources. Similarly, reductions in this program would negatively impact work execution support functions such as timely availability of City permits and customer engagement/communication.

OPERATIONS SUPPORT – WORK PROGRAM EXECUTION

1. SUMMARY

Table 1: Work Program Execution Program Expenditures ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Work Program Execution	14.9	13.8	13.0	14.3	15.2

The activities comprising the Work Program Execution program entail the oversight, administrative training, and other functions performed in the process of actual execution of Toronto Hydro's capital and maintenance work programs, which are not eligible for capitalization in accordance with Toronto Hydro's policies and applicable accounting standards, and are not attributable to any specific maintenance programs or projects. Other expenses captured in this program include the costs of coordinating the capital and maintenance work performed by external contractor crews.

2. PROGRAM DESCRIPTION

As stated above, the Work Execution program encompasses the costs of oversight, support, coordination and training activities related to the physical execution Toronto Hydro's capital and maintenance programs. This includes the functions related to coordination and support of external contractors executing a portion of Toronto Hydro's capital and maintenance programs, activities included in the work performed by the utility's internal construction crews, and the operation of transformer and municipal stations. Among the specific cost drivers captured within this program are expenditures related to Toronto Hydro's workplace safety training program, the costs of purchase and issuance of small tools and other day-to-day elements, supervisory time not allocated

to core projects or functions, as well as the cost of training the utility's skilled trades apprentices. Given their nature, the expenditures are distinct from those captured in Toronto Hydro's Work Program Execution Management and Support program,[1] which captures activities related to project management and logistical support of discrete projects performed by internal crews.

The program includes the following three segments:

- Contractor Administration;
- Internal Work Execution; and
- Stations

Table 2 displays the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for each of the segments comprising the Work Execution Program.

Table 2: Work Program Execution Program Expenditures by Segment
($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Contractor Administration	0.8	0.4	2.1	2.1	1.8
Internal Work Execution	11.6	10.4	7.9	8.8	10.3
Stations	2.4	3.0	3.0	3.4	3.0
Total	**14.9**	**13.8**	**13.0**	**14.3**	**15.2**

The remainder of this schedule provides further detail of the activities captured within each of the segments.

[1] Exhibit 4A, Tab 2, Schedule 8.

3. CONTRACTOR ADMINISTARTION SEGMENT

The segment comprises the administration of capital and maintenance work performed by external contractors retained to provide flexible and cost-effective execution of Toronto Hydro's annual work programs, which in recent years has amounted to about $100 million. The contractor administration function represents the point of contact between Toronto Hydro and the contractors, and includes the administration and evaluation of competitive tenders for contractor services, execution and oversight of the ensuing contracts and administrative support of the specific projects assigned to contractor crews, including but not limited to:

- job package development and issuance;
- liaising with system planners to address specific design matters;
- field issues management;
- ordering of materials;
- facilitating changing of project scopes;
- monitoring contractor safety practices;
- invoicing and receipting; and
- inspection of newly constructed assets.

The work undertaken under this program entails internal coordination with Toronto Hydro's Planning[2], Legal[3] and Work Execution Management[4] programs to facilitate efficient completion of requisite work, such as facilitation of change requests to project scopes based on the field findings, or changes to the supplier delivery timelines necessitated by the progress of contractor-executed work.

Beginning in 2013, the scope of the segment oversight was expanded to include the contracted maintenance activities, in addition to capital construction. The use of

[2] Exhibit 4A, Tab 2, Schedule 7.
[3] Exhibit 4A, Tab 2, Schedule 18.
[4] Exhibit 4A, Tab 2, Schedule 8.

contracted resources allows Toronto Hydro scalability, flexibility and cost effectiveness in work program execution, given the year-over-year fluctuations in the nature and volumes of the utility's work program.

3.1. Segment Costs

Table 3 below presents the historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Contractor Administration segment.

Table 3: Contractor Administration Segment Expenditures ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Contractor Administration	0.8	0.4	2.1	2.1	1.8

Segment expenditures have fluctuated consistent with the volume of Toronto Hydro's capital work and the ensuing requirements. As noted above, the cost increases in 2013 are also partially attributable to the expansion of the segment's scope of responsibility to include the administration of the externally executed maintenance work.

3.2. Test Year Segment Costs

The 2015 Test Year costs for the Contractor Administration segment are $1.8 million, which represents a decrease of $0.3 million from 2014 bridge year forecast. As noted above, a significant cost increase in this program starting in 2013 was driven by the expansion of the segment's mandate to facilitate the externally executed maintenance work (e.g. underground vault, cable chamber and transformer inspections), leading to an increase in the associated support costs as well. The anticipated cost reduction in 2015 is driven by planned improvement in cost assignment, ensuring time spent working on specific jobs is fully charged to those jobs as opposed to the general operating expenditures.

4. INTERNAL WORK EXECUTION SEGMENT

This segment includes the administrative support and training costs associated with construction work performed by Toronto Hydro's internal construction crews. Among the costs included in this segment are project-specific planning, logistics, tracking, small tools issuance, administrative support of managers/supervisors, office-related expenditures, as well as supervisory time not directly attributable to any specific capital program or project.

Another major cost driver within the internal work execution segment are expenditures related to the comprehensive and ongoing safety training for the utility's construction crews. As described in more detail in the Human Resources and Safety program ("HR & Safety"),[5] employee health and safety are among the primary considerations at Toronto Hydro, as evidenced by the utility's adoption of industry-leading environment, health and safety ("EHS") standards, and reduction in its Total Recordable Injury Frequency ("TRIF") and other workplace health and safety indicators.

Underlying the utility's commitment to health and safety, is the extensive safety awareness and training work conducted throughout the year for all Toronto Hydro construction crews. Toronto Hydro certified tradespersons and apprentices participate in between 4.5 to nine days of EHS training per year (depending on trade), the costs of which are in part reflected in this segment. The extensive EHS training is geared towards providing the employees with requisite tools and knowledge to perform their work safely and efficiently, thereby maximizing the value of their work for the utility and its customers.

Finally, the Internal Work execution segment also includes a portion of (non-capitalized) expenditures associated with capital construction work performed by Toronto Hydro's

[5] Exhibit 4A, Tab 2, Schedule 14.

skilled trades apprentices. As discussed in more detail in Exhibit 4A, Tab 4, Schedule 3, Toronto Hydro's apprenticeship program is key to addressing the aging workforce challenge that the utility faces in the next five to ten years, as 25 to 50% of the workforce is expected to be eligible for retirement.[6] Due to the complexity of Toronto Hydro's system and the number of legacy assets that are largely unique to the utility in the Ontario context (e.g., Paper-Insulated Lead-Covered cable, Box Construction), apprentices are required to complete several years of theoretical and practical training to gain the requisite skills and knowledge that is required to work on Toronto Hydro's system safely and efficiently.

4.1. Segment Costs

Table 4 presents the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Internal Work Execution segment.

Table 4: Internal Work Execution Segment Expenditures ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Internal Work Execution	11.6	10.4	7.9	8.8	10.3

The significant decline in expenditures over the 2012 to 2014 years is attributable to two main factors:

- Transfer of resources from Internal Work Execution to the Contractor Administration segment described above, reducing the costs of this segment while simultaneously increasing the costs of the Contractor Administration portfolio
- Significant reduction in apprentice training relative to the 2011 levels

Certified and skilled trades are critical resource in the execution of Toronto Hydro's capital and maintenance programs, which are necessary to maintain the safety and reliability of the distribution system. To maintain a sufficient complement of these key

[6] For more information, also refer to Exhibit 4A, Tab 2, Schedule 14.

positions, in light of the retirements that the utility expects to encounter over the 2015-2019 rate period and thereafter, Toronto Hydro must invest in its apprenticeship training programs.

4.2. Test Year Segment Costs

The 2015 Test Year costs for the Work Execution segment is $10.3 million, which represents an increase of $1.5 million above the projected Bridge Year expenditures. This increase is driven by the need for a sustained investment in apprenticeship training programs. As explained in Exhibit 4A, Tab 4, Schedule 3, apprenticeship programs are a key aspect of Toronto Hydro's workforce renewal strategy. These programs are required to ensure a stable complement of certified skilled trades to execute capital and operational work programs during the 2015-2019 period and beyond, and to facilitate a smooth generational turnover in light of the significant levels of retirement (25% to 50%) that the utility anticipates over the next five to ten years.

5. STATIONS SEGMENT

The Stations segment includes the planning, training and supervisory costs associated with maintenance and capital work on Toronto Hydro's 21 Transformer and Municipal Stations, and the associated protection and control infrastructure that are not attributable to any specific stations projects or programs. These expenditures arise in the process of planning, design coordination and oversight of a variety of activities that encompass the station-related work. This segment also includes costs associated with instructors for stations apprentice training. Currently, over half of the total tradespersons within the stations groups are apprentices.

5.1. Segment Costs

Table 5 presents the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Stations segment.

Table 5: Stations Segment Expenditures ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Stations	2.4	3.0	3.0	3.4	3.0

5.2. Test Year Segment Costs

The 2015 Test Year Stations segment cost $3.0 million, consistent with 2012 and 2013 levels, and $0.4 million lower than 2014 Bridge Year projections.

FLEET AND EQUIPMENT SERVICES PROGRAM

1. SUMMARY

Table 1: Fleet and Equipment Services Program Costs ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Fleet & Equipment	8.7	8.6	8.7	8.4	8.9

The Fleet and Equipment Services ("FES") program encompasses the procurement, maintenance and disposal of Toronto Hydro vehicles, associated equipment, and employee personal protective gear/equipment. It is also responsible for ensuring that certain safety equipment and implements are tested and repaired in accordance with occupational health and safety requirements and other applicable standards. Comprehensive and timely delivery of these services facilitates Toronto Hydro's ability to carry out its electricity distribution activities in a safe, reliable, and expedient manner.

2. PROGRAM DESCRIPTION

The program and the associated budgets are subdivided into two segments, namely:

- Equipment Services; and
- Lab Services.

The Equipment Services segment is comprised of services that oversee that Toronto Hydro's 660 vehicles and the associated equipment remain in good working order, are optimally utilized, and are safe for both the Toronto Hydro employees operating them and the general public they share roads with. This includes procurement, maintenance, and administration of vehicle use using a combination of internal and external resources to reduce safety risks and facilitate value-for-money. Over the 2011-2013 historical

period, Toronto Hydro implemented a number of fleet-related productivity and efficiency-enhancing programs, which allowed the segment expenditures to remain generally flat over the more recent years.

Toronto Hydro plans to continue implementing further productivity and efficiency-enhancing initiatives to manage the maintenance costs, driven in large part by the planned volumes of fleet-related capital expenditures.[1]

The activities comprising the Lab Services segment are an important component of Toronto Hydro's strong health and safety performance. This includes regular testing of employee Personal Protective Equipment ("PPE") and the repair of confined space gas monitors which assist in protecting Toronto Hydro crews working in underground vaults and cable chambers from being exposed to harmful gases. Lab Services segment expenditures also include the cost of repairs and tests for transformer network protection relays. The segment's expenditures have increased over the historical period due to the 2012 restructuring and outsourcing of some activities formerly performed in-house.

3. EQUIPMENT SERVICES SEGMENT

The Equipment Services segment covers activities related to maintenance, repair and management of Toronto Hydro's vehicles and related equipment. The nature and frequency of vehicle maintenance activities are driven by the Ontario Ministry of Transportation requirements, vehicle manufacturer standards and specifications, safety testing requirements for vehicle-mounted equipment, Ministry of Labour standards, and vehicle warranty specifications.

[1] Exhibit 2B, E8.1

As of April 30, 2014, Toronto Hydro's fleet is composed of 660 units including cars, pickups, bucket trucks and other utility units such as sweepers, backhoes and forklifts.

All vehicles and equipment undergo periodic preventative maintenance, scheduled on the basis of time elapsed or distance travelled since the last inspection. Toronto Hydro performs the majority of this work in-house, typically inspecting each unit and the equipment mounted on it at least once a year, or as provided by manufacturer specifications or other relevant standard and regulations. In 2013, Toronto Hydro completed over 2,500 preventative maintenance jobs, totalling 7,200 hours of labour.

Toronto Hydro generally employs the services of external vendors for certain types of work, including:

- work that would expose Toronto Hydro employees to greater physical risk – such as vehicle suspension work;
- work that does not require the technical expertise of a licensed mechanic such as tire replacement;
- work requiring specific skills or credentials that Toronto Hydro Fleet employees do not posses, such as aerial lift dielectric testing; and
- work using equipment not owned by, or not readily accessible by the utility such as vehicle emissions testing.

Toronto Hydro also secures select services by way of competitive multi-year tenders, with respect to a number of fleet related activities including:

- parts procurement and management;
- fuel procurement and delivery;
- commercial gas station fuel card services;
- GPS system licensing and technical support;
- tire replacement and repair service; and

- vehicle towing services.

The Requests for Proposal ("RFPs") to procure these services and the subsequent RFP evaluation frameworks are structured to minimize overall maintenance and administration costs, reduce vehicle downtime, and ensure predictable service levels over the length of the contract.

3.1. Segment Costs

Table 2 presents the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Equipment Services segment.

Table 2: Table 2: Equipment Services Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015Test
Equipment Services	8.0	8.0	8.1	7.8	8.3

3.2. 2011-2014

Toronto Hydro's 2012 and 2013 actual Equipment Services expenditures were essentially flat versus 2011 actuals, with minor cost increases resulting from normal inflationary pressures and the terms of the utility's collective agreements, offset by efficiencies from the initiatives described below.

Toronto Hydro forecasts its 2014 Bridge Year expenditures to be $0.3M lower than the 2013 actuals, due to lower payroll costs, and an anticipated reduction in parts purchases as vehicles are refreshed through 2013 and 2014.

Since 2011,Toronto Hydro has implemented several productivity and efficiency initiatives that helped the utility manage fleet cost levels. These initiatives include:

- Unit Reduction – Toronto Hydro removed 79 vehicles from its fleet in 2011 to 2013, and expects to remove another seven by the end of 2014. This has been enabled by operational efficiencies elsewhere within the utility that subsequently reduced Toronto Hydro's transportation requirements.
- GPS Implementation – In 2010, Toronto Hydro equipped all of its vehicles with GPS telemetry units. Knowledge of each vehicle's exact location and electronic data query capabilities improved preventative maintenance attainment rates and reduced labour requirements for performance tracking (kilometres, engine hours etc).
- Vehicle Sharing – In 2011, Toronto Hydro undertook a small vehicle sharing pilot study for a single division, leading to increased vehicle utilization and reduction of dedicated vehicles by five units. The program is currently being expanded to large vehicles used throughout the organization.
- Maintenance Optimization – Starting in 2014, the utility extended the regular maintenance cycle for its light vehicles, thereby reducing requisite labour requirements, and aligning maintenance cycles with manufacturer recommendations.
- External Service RFPs – In 2013, Toronto Hydro held tenders for bulk fuel purchases, truck-to-truck diesel fuel delivery, and fuel card services. The resulting contracts are expected to generate additional savings in the above-noted areas.
- Activity Outsourcing – Toronto Hydro engaged a number of external vendors to support its fleet management functions, including consignment-based parts management and distribution, vehicle decommissioning and vehicle licence procurement and monitoring.

3.3. Test Year Segment Costs

Test Year expenditures are targeted to increase by $0.5 million from the projected 2014 Bridge Year expenditures. In addition to normal inflationary pressures, this increase is primarily due to a $0.2 million contractual labour cost increase and a $0.1 million increase in re-allocation of carrying costs for vehicles being used in the vehicle sharing program.

Over the 2015 Test Year and beyond, Toronto Hydro expects to manage equipment services segment increases through several productivity and efficiency initiatives described below:

- Vehicle Replacement Times – in 2013, Toronto Hydro commissioned a comprehensive vehicle Life Cycle Analysis ("LCA") study, the findings of which are expected to allow the utility to realize operational efficiencies going forward.
- Vehicle Sharing Expansion – the utility expects that the planned expansion of the previously described program will result in further vehicle count reductions, leading to maintenance efficiencies and faster restoration of identified failures.
- Incremental RFPs – Toronto Hydro plans to issue competitive tenders for towing, tire supply and maintenance, and PSG services. The utility expects that these tenders will result in proposals offering service improvements and competitive pricing.

Fleet and Equipment Services activities are a foundational component of basic utility operations, as they facilitate Toronto Hydro vehicles being able to adequately support system maintenance and capital investment initiatives, and help to ensure that the utility's vehicles are safe, reliable, and deliver consistent performance. The proposed Equipment Services Test Year expenditures supports the provision of labour, replacement parts, fuel, services, and administration required to execute these activities. To enhance the value of these services, Toronto Hydro has taken a number of steps to improve the efficiency of its

program delivery; these initiatives have had a positive effect on containing the utility's Test Year forecasts in light of increasing cost pressures associated with supporting Toronto Hydro's capital and maintenance programs.

Segment expenditures are generally driven by preventative maintenance and repair requirements identified by field staff. A reduction from the proposed level of spending may result in the following adverse consequences:

- Safety Risks – A reduction in segment expenditures could lead to reduction of frequency or scope of maintenance activities. Longer intervals between maintenance work could increase the possibility of defects going undetected, thus increasing the safety risk to Toronto Hydro employees and the general public.
- Reliability Risks – Reduction in maintenance levels could lead to increased vehicle downtime due to higher field failures, or an increase in the number of reported vehicle defects requiring vehicles to be taken out of service. Ultimately, fleet availability and vehicle or motored equipment failure while on a reactive call could adversely affect Toronto Hydro's ability to deliver timely service to the public and result in prolonged outages.
- Shop Productivity Impact – Reduction in regular maintenance could result in longer and more complex repairs thereby prolonging the time it takes for vehicles to be returned to service when failures are identified.

4. LAB SERVICES SEGMENT

The Lab Services segment supports the acquisition, certification and testing of safety tools, implements, and PPE worn by Toronto Hydro's field crews. The expenditures comprising this segment include:

- cost of procurement, cleaning, inspection, and electrical testing of rubber gloves;

- repair and calibration of network system protection relays;
- repair, calibration and technical support of confined space gas monitors;
- collection of test data of all insulating material tested within the lab; and
- cost of testing equipment maintenance and membership fees to sustain the lab's North American Independent Laboratories ("NAIL") certification.

Services performed by the equipment testing laboratory are important to the safety of the utility field crews performing work on Toronto Hydro's distribution system. Compromised insulating material or improperly functioning gas detectors while in use in Toronto Hydro's network vaults and cable chambers can expose these employees to significant potential safety risks. In addition, improperly functioning or untested and uncertified system protection relays could result in a protection failure or the disabling of power transformers, compromising grid integrity and overall system reliability.

As previously stated, rubber glove and gas monitor use are a legislative requirement for the utility's electrical distribution activities. The availability and the integrity of both types of implements are essential to facilitating the safety of Toronto Hydro employees. It is important that the employees performing the testing and certification work are appropriately skilled regarding both testing and repair procedures, as applicable. Employees repairing and certifying gas monitors and relays possess specific training and certification pertinent to the products and equipment that they process. Experience performing these functions is a key element of the lab technician's role. The current lab staffing complement possesses aggregate incumbent experience of almost 70 years.

4.1. Segment Costs

Table 2 presents the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Lab Services segment.

Table 3: Laboratory Services Expenditures ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Lab Services	0.7	0.6	0.6	0.6	0.6

As shown in the Table 3, the segment costs have decreased since 2011 by approximately $0.1 million. The primary cost reductions between 2011 and 2012 were achieved through reduction of the lab staffing complement and outsourcing of the following services:

- Manufacturing, repair, and annual certification of portable grounding devices;
- Repairs and certification of manual equipment used by overhead linepersons; and
- Cleaning and certification of rubber electrical line covers.

Segment costs were largely flat 2012 through 2013, and are projected to remain flat through both bridge and test years, primarily due to attrition and reduction in the scope of work expected to offset the normal inflationary pressures and collective agreement provisions.

4.2. Test Year Segment Costs

The 2015 segment expenditures are expected to remain in line with 2012 through 2014 bridge levels, with normal inflationary cost increases offset by the reduction in the scope of work performed in-house.

The activities performed by the Lab Services program are non-discretionary for the purposes of normal utility operations at Toronto Hydro. The used and periodic testing of rubber gloves in the performance of live line electrical work is mandated by law. Rubber gloves are considered personal protective equipment, and are worn to protect a worker from potential exposure to live equipment. The lab must perform a periodic 30-60 day washing, visual inspection and electrical testing of all in-service rubber gloves to facilitate Toronto Hydro employees performing live line electrical work safely.

The use and periodic testing of gas monitors is also a legislative requirement. Toronto Hydro's gas monitors are used to test air quality/toxicity both prior to entering and while working in a confined space, such as an underground vault or a cable chamber. Toronto Hydro performs repair work on the monitors as required to ensure that they function as specified by the manufacturer, and completes all repairs and calibration of malfunctioning units. Without access to functioning gas monitors when required, Toronto Hydro employees would not be able to enter confined spaces as needed to carry out their system maintenance and capital investment work.

Network protector relays are protective devices used to trigger a power transformer network protector when power is detected to be flowing in the reverse direction. The protector in turn disconnects the transformer from the secondary network to protect the stability and reliability of the network, as well as to prevent backward flowing current from moving from the secondary network towards the primary feeders. The electro-mechanical relays used by Toronto Hydro and serviced by the lab are no longer in production, and the Toronto Hydro Lab is currently the only Toronto Hydro-approved provider of repair and certification services. Absent this service, Toronto Hydro power transformer protectors requiring these relays would not function, compromising the stability and reliability of the network. For this reason, the services provided in this program are critical for ongoing, reliable, and continuous operation of some of Toronto Hydro's network transformers, as well as the integrity of the grid connected to them.

Reductions to the proposed level of spending would affect the Laboratory's ability to complete testing and procure materials for complete certification and repair of all PPE and equipment serviced by the lab.

FACILITIES MANAGEMENT PROGRAM

1. SUMMARY

Table 1: Facilities Management Program Expenditures ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Facilities Management Program	24.6	23.5	24.2	27.2	27.5

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Toronto Hydro's Facilities Management program delivers the workspace and property management services that enable the utility's employees to perform their work in optimally configured surroundings, and maintain the safety, operability and structural integrity of Toronto Hydro's station buildings. The program centralizes functions related to property management, including custodial services, security, utilities and communications, lease and rental agreement management, and other functions directed at maintaining and keeping the utility's facilities in good working order and in compliance with applicable legislation and regulations.

2. PROGRAM DESCRIPTION

Toronto Hydro's current building footprint consists of seven office buildings and 215 stations located throughout Toronto on more than 6,000,000 square-feet of property. All these buildings and stations are in various states of repair and range in age from historic sites built in the 19th century to new buildings built in the 1990s. Each property serves a unique purpose and needs to be maintained and serviced to meet standards mandated by legislative and regulatory requirements, to comply with Toronto Hydro's environment, health and safety policies, as well as facilitate Toronto Hydro's functions related to distributing electricity.

Operating and maintenance requirements for facilities reflect the results of evaluations conducted by a combination of internal experts, independent architectural and engineering firms, and original manufacturer equipment specifications. Toronto Hydro works to ensure that this technical information is translated into actionable capital and maintenance work plans and is ultimately executed within the appropriate timeframes.

A subset of facilities maintenance work is driven by local and provincial government safety accessibility, emergency preparedness and environmental regulations. These include:

- Emergency generator maintenance;
- Eye wash stations inspections;
- Fire suppression certifications and inspections;
- Lifting device inspections and certifications;
- Waste audits; and
- Designated substance surveys.

Failure to comply with government regulations can result in temporary equipment lock out and/or fines, which may lead to costly interruptions to regular business activities that can ultimately affect Toronto Hydro's customers.

In addition to the externally mandated work, Toronto Hydro's Facilities Program oversees the provision of services for Toronto Hydro buildings and stations which include the following:

- Routine Maintenance – ventilation unit and generator testing, grease trap clearing;
- Preventive Maintenance – daily inspections of lights, elevators, emergency exits;

- **Office Services** – custodial work, paper shredding, furniture moves and alterations;
- **Property Maintenance** – snow removal, landscaping, storm sewer clearing;
- **Security** – guards, surveillance equipment maintenance, access card services; and
- **Environmental Services** – recycling services, regulated first aid kit disposal.

Starting in 2014, Toronto Hydro consolidated the management of the above and related services under a single Facilities Management Operation ("FMO") function, performed by a third-party provider. This arrangement effectively creates a "one-window" approach for all facilities-related enquiries from utility staff and facilitates effective coordination of work. The implementation of a unified contract coordination function through the FMO is an expenditure driver for the 2014 Bridge and 2015 Test Year, as discussed in more detail below.

The remainder of the Facilities Management program expenditures cover administration of Toronto Hydro's lease and rental agreements, provision and inventory services of building maintenance tools and equipment, cost of managing utility and communication services, and property taxes.

In accordance with the above-noted activities, the Facilities Management program is comprised of three segments; the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures of each segment are summarized in Table 2 below.

Table 2: Facilities Management Program Expenditures by Segment ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Facilities Maintenance Services	11.9	10.0	10.4	13.0	13.5
Rentals & Leases	4.4	5.0	5.0	5.2	5.2

/C

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test	
Utilities & Communications	2.2	2.1	2.4	2.6	2.4	/C
Property Taxes	6.1	6.5	6.4	6.5	6.2	/C
Total Facilities	**24.6**	**23.5**	**24.2**	**27.2**	**27.5**	/C

3. FACILITIES MAINTENANCE SERVICES SEGMENT

Toronto Hydro's facilities maintenance segment relies on a combination of internal resources and more than 100 vendors to perform the necessary tasks and services to maintain its properties, including offices, work centres and buildings housing the utility's Transformer and Municipal stations ("TS" and "MS", respectively).

The building and property maintenance segment covers a broad range of daily, monthly and annual maintenance activities driven by internal health and safety policies, findings of internal and external engineering studies, stipulations of local and provincial legislation, and industry best practices. The focus of this program is to provide Toronto Hydro employees with a safe work environment that encourages effective and efficient execution of their duties, as well as to ensure that all owned and leased properties and buildings, including stations, are structurally sound and facility employee and public safety.

Facilities personnel possess a range of diverse skill sets and professional designations, including Building System Technicians, certified electricians, heating ventilating and air conditioning ("HVAC") technicians, welders and other similar trades certifications and training. This range of skills and expertise allows Toronto Hydro to ensure proactive and reactive identification and resolution of any issues that may affect the company's workforce and operation of its structures. Toronto Hydro's attention to regular

preventative maintenance of its office buildings and work centres contributes to the utility's safety record.

Toronto Hydro utilizes internal resources to complete preventative, corrective and reactive maintenance activities in the utility's office buildings and work centres. This includes work related to lighting, plumbing, heating, ventilation and air conditioning systems that require periodic inspections and repairs to ensure service quality and continuity.

Preventative maintenance entails routine inspections and tasks to ensure that equipment, systems and their respective components are fully operational. This includes activities such as periodic inspections of magnetic locks on all of Toronto Hydro's emergency exits, to prevent unauthorized entry and release when a fire alarm is activated. Through routine preventative inspections Toronto identifies those systems and objects requiring corrective work, ensuring that any malfunctions are proactively rectified. Toronto Hydro performs over 1,600 preventative maintenance checks a month to ensure that all office buildings and work centres are fully operable and safe.

Reactive facilities maintenance work involves responses to reports and requests to address any specific problems that materialize from time to time. Examples of reactive work include repairs of broken lights, adjustments of building temperatures to meet the requirements of the Occupational Health and Safety Act[1], and repairs to parking gates. For large-scale reactive activities or tasks requiring specialized skills, Toronto Hydro retains the services of external contractors.

Prior to 2014, Toronto Hydro managed over 100 individual contracts with providers of external services, ranging from regular custodial work to specialized support such as

[1] R.S.O. 1990, c. O.1 ("Occupational Health and Safety Act").

elevator maintenance, fire suppression systems inspection, or mechanized lifting and crane device repairs. In 2014, Toronto Hydro took steps to consolidate the management of its external contract services under a single contract with an external Facilities Management Operator ("FMO"). The FMO provider is responsible for procuring, scheduling, and tracking the contract services that Toronto Hydro formerly sourced on an individual basis.

Through the FMO, Toronto Hydro now manages and administers a single external facilities contract, passing the bulk of administrative work to the FMO, who sub-contracts the individual services. This arrangement significantly streamlines the process for Toronto Hydro's procurement and accounts payable functions, by eliminating the need for creation and processing of a large number of tenders, purchase orders, and invoices. Beyond the administrative efficiencies, external contract consolidation allows Toronto Hydro to leverage the size of the FMO in order to obtain more competitive prices and increase the efficiency of responding to unforeseen work requirements.

Beyond the administrative efficiencies and volume-based savings, the FMO arrangement offers Toronto Hydro a number of services that were not available internally prior to external services consolidation. These include:

- a 24-hour one-window call center for facility emergencies and requests;
- an asset database that links work orders to Toronto Hydro's assets such as generators, cranes and elevators. This facilitates asset management efficiency and simplifies compliance with the requirements of the International Organization of Standardization ("ISO").
- a Central Maintenance Management System ("CMMS") that automatically schedules preventative work. System data can be queried to produce custom reports that help Toronto Hydro plan capital projects more effectively.

These services provide Toronto Hydro with the means to react to issues sooner, track data on reoccurring problems in a systematic manner, and formulate improved facilities capital expenditure plans. This is a significant efficiency improvement over the previous arrangement, where building and equipment maintenance records were housed in separate paper-based binders located at each facility, requiring significant manual effort to consolidate information for the purpose of work planning and execution.

Moreover, prior to the introduction of a consolidated FMO, the Facilities program had to administer large volumes of individual purchase orders, contract tenders, and receipting and invoicing documents. Locating the appropriate contact for a particular service request and processing payments was significantly more resource-intensive, leading to service delays and occasional payment processing errors. These issues have now been addressed through introduction of a streamlined one-window facilities management approach.

3.1. Segment Costs

Toronto Hydro's Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures are summarized in Table 3. These costs include both internal and external work, vehicle cost and other related expenses. The main drivers for year-over-year cost variance included organizational restructuring activities, outsourcing expenses, and seasonal expenditures that vary depending on weather conditions.

Table 3: Facilities Maintenance Services Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Facilities Maintenance Services	11.9	10.0	10.4	13.0	13.5

/C

3.2. 2011-2012

The $1.9 million decrease in 2012 expenditures from the 2011 levels is primarily related to the 2012 restructuring program administered throughout the utility, lower snow removal expenditures due to a warmer winter, partially offset by normal inflationary increases.

3.3. 2012-2013

The $0.4 million increase in expenditures from 2012 to 2013 was largely driven by normal inflationary pressures and higher variable seasonal expenditures such as snow removal.

3.4. 2013-2014

The $2.6 million increase in costs from 2013 to the projected 2014 Bridge Year levels is related to normal inflationary pressures and the introduction of the Facilities Management Office outsourcing arrangement, which has significantly increased the scope of facilities services available at Toronto Hydro, while streamlining a number of internal processes and reducing the general administrative burden.

3.5. Test Year Segment Costs

The $0.5 million increase in the maintenance service cost from the Bridge Year to the Test Year forecasted expenditures is driven by normal material and labour inflationary pressures (e.g., parts and supplies, labour, and vehicle costs), costs of incremental activities identified through FMO's analysis and the expenditures associated with the management of buildings housing Transformer and Municipal stations, and maintenance expenditures associated with Copeland Transformer Station (TS). These costs are partially offset by anticipated savings from the proposed Operational Centre Consolidation Program, discussed in Exhibit 2B, E8.2.

/C

/C

/C

Facilities maintenance activities facilitate safe and efficient operation and functional integrity of Toronto Hydro's buildings, work centres and station civil infrastructure. The work comprising this segment aids in Toronto Hydro employees performing their duties

in well-maintained and optimally configured surroundings, assisting productivity and timely execution of day-to-day functions that comprise Toronto Hydro's mandate. A subset of Toronto Hydro's maintenance work is required by the federal, provincial and municipal laws.

Timely maintenance of key facilities equipment such as ventilation, fire suppression, elevation and lifting devices facilitates service continuity by preventing equipment outages or mandatory "lock-downs" as a result of unsuccessful inspections or audits. This, in turn, enables Toronto Hydro to perform its key functions, thus maintaining service availability and continuity relied upon by the utility's customers.

The recently implemented FMO model allows Toronto Hydro to drive further process efficiencies while expanding the range of available services that benefit the utility and its customers. Moreover, the maintenance management system underlying the FMO arrangement allows Toronto Hydro to automatically generate up-to-date expenditure reports at any point in time, enabling quick identification of any emerging trends in expenditures or problem areas. Over the longer timeframe, the FMO arrangement provides Toronto Hydro with flexibility with respect to future staffing levels.

Any reduction in funding levels would result in curtailments of the scope, frequency and timeliness of maintenance activities. This could, in turn, create situations where safety issues or equipment malfunctions are not identified and rectified in a timely manner, thus imposing potential safety risks to Toronto Hydro's employees or compromising the utility's ability to perform its key functions due to equipment malfunctions.

4. RENTALS AND LEASES SEGMENT

Toronto Hydro's rentals and leases costs are related to the utility's existing or planned agreements with owners and/or managers of properties occupied by Toronto Hydro's office buildings and work centres.

4.1. Segment Costs

Table 4 details Historical (2011-2013), Bridge (2014) and Test Year (2015) costs of the Rentals and Leases segment.

Table 4: Rentals and Leases Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Rentals and Leases	4.4	5.0	5.0	5.2	5.2

4.2. 2011-2012

The rentals and leases costs increased by 14% between 2011 and 2012 due to the termination of the lease inducement period for two of Toronto Hydro's office buildings that end in mid 2012. The inducement, which resulted in a reduction in monthly rental payments, accounts for approximately $0.4 million increase in 2012. In addition, Toronto Hydro began to lease another property from January 2012 and renewed two existing lease agreements, in December 2011 and August 2012, respectively.

4.3. 2012-2013

Toronto Hydro's rentals and leases expenditure remained largely flat between 2012 and 2013. Although there was an increase in the direct cost of the leases, as stipulated by the contracts for the lease and rental agreements, these costs were offset by the credit received from one of Toronto Hydro's landlords due to discovery of overpayment over the 2010-2012 period.

4.4. 2013-2014

The $0.2 million increase in rentals and lease costs between 2013 and 2014 is driven by cost increase contract provisions. Toronto Hydro does not project that there will be any termination of lease inducement period, credit to cost due to over payment in previous years or any other variables impacting rentals and lease costs in 2014.

4.5. Test Year Segment Costs

Toronto Hydro's Test Year segment costs are projected to remain flat between the 2014 Bridge and 2015 Test Year, with the normal contractual cost increases partially offset by anticipated staffing attrition. The utility's rentals and leases expenditures are driven by needs for sufficient, properly configured and cost-effective office and work centre space. The utility attempts to minimize its rental and leasing expenditures by working with commercial property brokerage companies to assist Toronto Hydro in securing the appropriate space at fair market value and otherwise suitable contractual arrangements.[2]

5. UTILITIES AND TELECOMMUNICATIONS SEGMENT

The Utilities and Telecommunications segment encompasses the costs of providing water, electricity, natural gas and related services to Toronto Hydro's office buildings, work centres and transformer and municipal stations. The utility's costs for this segment are driven by the costs it is charged by service providers. Beyond service rate increases, the year-over-year cost variances are affected by fluctuations in weather, such as extremely hot summers that increase electricity consumption or cooler-than-normal winters that result in higher heating expenditures.

[2] Toronto Hydro acknowledges that as a part of its proposed Operational Centre Consolidation Strategy, (Exhibit 2B, E8.2), contemplates expiration of the lease arrangements on two of the existing buildings during the term of the CIR plan.

Toronto Hydro works to manage its utilities costs by progressively improving the energy efficiency of its facilities. To facilitate consistent implementation of energy efficiency standards, Toronto Hydro has developed standards that outline the relevant energy, water and gas efficiency criteria that the utility's new and renovated work spaces adhere to. Consistent with its standards, Toronto Hydro has upgraded a large portion of its shared spaces with energy efficient lights, where it is economical to do so. The utility is also working to gradually convert its bathrooms to low-flow technologies.

Similar to utilities, telecommunications are another key component of the Facilities program expenditures. Desk phones, cell phones, internet access and other wireless communication equipment and services are vital tools for the day-to-day operations at Toronto Hydro. Beyond the typical business enablers, communications services and infrastructure enable the utility's security systems to communicate with command posts via fibre-optics or wireless networks, and allow service vehicles to have constant communication with dispatchers and the control room.

5.1. Segment Costs

Table 5 presents the Historical (2011-2013), Bridge (2014) and Test Year (2015) costs relating to Utilities and Telecommunications.

Table 5: Utilities and Telecommunications Segment Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Utilities & Telecommunications	2.2	2.1	2.4	2.6	2.4

/C

Utilities and Telecommunications costs have increased during the 2011 to 2014 period by approximately eight percent, driven by utility rate increases and general increase in

aggregate utilities demand driven by employee needs, partially offset by the results of work to improve Toronto Hydro's utilities consumption efficiency.

5.2. Test Year Segment Costs

Toronto Hydro's Utilities and Telecommunication segment expenditures for the 2015 Test Year are expected to decrease by $0.2 million relative to the 2014 Bridge Year, due to the anticipated savings from the Operational Centre Consolidation Program[3], which are projected to offset the normal inflationary pressures for the year, along with the incremental expenditures associated with Copeland TS. /C

Utilities and Telecommunications are essential business tools and commodities driven by circumstances largely outside of Toronto Hydro's control. As noted above, Toronto Hydro works to continuously improve its energy and efficiency performance by progressively upgrading the equipment standards used across its facilities where it is economic to do so. These improvements allow Toronto Hydro to partially control the pace and scale of its utilities expenditures.

6. PROPERTY TAXES SEGMENT

Property taxes are imposed on the basis of the amount of property owned by Toronto Hydro, the municipal tax rates and any applicable credits. With more than 6,000,000 square feet of property in Toronto, property taxes are a significant expense for Toronto Hydro. Historically, the property taxes in Toronto have increased at a rate of three percent per year. Toronto Hydro expects a similar trend to continue through the Test Year and beyond, which is reflected in the utility's forecasts.

[3] Exhibit 2B, E8.2

6.1. Segment Costs

Table 6 presents the Historical (2011-2013), Bridge (2014) and Test Year (2015) costs relating to Property Taxes.

Table 6: Property Taxes Segment Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Property Taxes	6.1	6.5	6.4	6.5	6.2

6.2. 2011-2012

In determining property tax for the year, Toronto Hydro estimates the cost and accrues it for the year. At year end, an adjustment is done in order to show the actual cost of property tax. In 2012, the Municipal Property Assessment Corporation ("MPAC") conducted their four year assessment cycle, where all Ontario properties were assessed to determine the true value of the properties for calculating property tax. On average, the value of the properties increased by 22 percent, which will be phased in over a four-year period. This helps explain the sudden 7 percent increase from 2011 - 2012.

6.3. 2012-2013

The 2013 decrease relative to 2012 reflects the sale of some of Toronto Hydro's properties and a property tax rate deduction, which further reduced the segment costs.

6.4. 2013-2014

The projected 2014 increase reflects the historical property tax rate increase of three percent Toronto has experienced over the past several years.

6.5. Test Year Segment Costs

Despite the anticipated three percent annual increase of property tax, property tax cost for the Test year is forecasted to be $0.3 million lower than in the Bridge year, due to the fact

that Toronto Hydro intends to sell two office buildings as a part of the proposed Operational Centre Consolidation Program.[4] The anticipated savings are expected to offset the incremental costs associated with Copeland TS As Toronto Hydro continues to renew and otherwise improve its existing infrastructure, the utility's property taxes are expected to increase over the 2015-2019 rate period. Where relevant, Toronto Hydro plans to continue working with MPAC to ensure that property valuations properly reflect the state and fair market value of Toronto Hydro's real estate asset base, thereby managing this cost component for the benefit of the utility's ratepayers.

/C

[4] Refer to the Operational Centers Consolidation Program at Exhibit 2B, E8.3

SUPPLY CHAIN SERVICES

1. SUMMARY

Table 1: Supply Chain Services Program Expenditures ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Supply Chain Services Program	7.1	6.6	9.0	10.3	9.9

The Supply Chain Services program supports the execution of Toronto Hydro's asset management plans and other operating programs that rely on procurement and warehousing activities. The overarching goal of the program is to facilitate timely and cost-effective acquisition of services, materials and equipment at the requisite quality, while also maintaining an amount of inventory to support uninterrupted work execution and manage materials handling costs. Each year, the program facilitates the procurement, warehousing and distribution of $80-$90 million in assets, as well as execution of an average of 145 contracts with a total value of about $230 million.

The Supply Chain Services program consists of one segment comprised of two interrelated functional areas, namely:

- Demand and Acquisition Services; and
- Warehouse and Logistics.

The Demand and Acquisition Services function facilitates the requisite equipment, materials and services being available to Toronto Hydro within the specified timelines and at the optimal cost. This is enabled through strategic sourcing of materials, market trend analysis and benchmarking, proactive inventory management, and performance-based collaboration with vendors. In performing these functions, the Demand and

Acquisition Services monitors the efficiency and effectiveness of the existing processes, and introduce process-based or technological innovations where warranted.

The Warehouse and Logistics function facilitates coordinated, cost-effective and timely receiving, stocking and distribution of materials and equipment required to implement Toronto Hydro's capital and maintenance work programs. In 2012, Toronto Hydro implemented a new Warehouse Management System ("WMS") which utilizes barcode technology, allowing more accurate and efficient performance of receiving, picking and staging activities than prior to the system's introduction. The WMS system has also enabled Toronto Hydro to perform its warehousing functions effectively in spite of the 20% reduction in staff following the 2012 restructuring program.

In an effort to enable the current scale of Toronto Hydro's capital program in a flexible and sustainable manner, in 2013 the utility engaged a Third Party Logistics ("3PL") warehousing services provider. The 3PL provider uses Toronto Hydro's WMS software and provides services at competitive market rates. Since the contractual arrangement is based on the actual volumes of work performed by the 3PL supplier, it provides Toronto Hydro with desired scalability in the face of uncertain work program levels and/or any emerging work requirements such as government policy changes or other unforeseen events. The 3PL arrangement is also a key driver in Toronto Hydro's plans to reduce its internal warehouse space over the 2015-2019 timeframe. Further details regarding this service model are provided below.

Table 1 above provides the total Historic (2011-2013), Bridge (2014) and Test Year (2015) costs of Toronto Hydro's Supply Chain Services program. Overall, the cost variance is explained by utility reorganization activities, warehouse efficiency and sustainability initiatives, and normal changes in operational circumstances. A more detailed discussion of program cost variances is provided in the sections that follow.

For the purposes of internal cost recovery, Toronto Hydro allocates the applicable portions of these costs across its operating programs and specific capital projects using the inventory on-cost rate. The utility calculates the annual rate by dividing the applicable Supply Chain program costs over the anticipated cost of materials supplying that year's capital and maintenance work program. The resulting rate (%) is then added to the materials charged to the capital and maintenance projects. Over the 2011-2014 timeframe, Toronto Hydro's on-cost rate has remained relatively flat, fluctuating between 12% and 14%.

The remainder of this schedule describes in further detail the two functions comprising the Supply Chain Services program, and details the key drivers behind the changes in the Historical, Bridge and Test Year expenditures.

2. PROGRAM DESCRIPTION

2.1. Demand and Acquisition Services

The Demand and Acquisition Services function provides delivery of goods and services to support Toronto Hydro's capital and maintenance work programs, and enables the utility's day-to-day operations. Work in Toronto Hydro's Demand and Acquisition Services function demands an extensive set of supply chain and electricity industry-specific skills, including understanding of the competitive bid process, in-depth knowledge of quantitative analysis and inventory management tools, familiarity with changing electricity system equipment standards, as well as advanced negotiation and communication skills. All current employees possess over a decade of supply chain-related work experience, with 40% having attained, or being in the process of completing the Supply Chain Management Professional ("SCMP") designation.

The scope of Acquisition Services activities entails sourcing of reputable and reliable suppliers, monitoring their performance to ensure that they meet their contractual obligations, and generating the Purchase Orders that underlie each agreement. Working with the various parts of the utility's operations, Acquisition Services leads the competitive bid generation and evaluation processes, and conducts market benchmarking to identify emerging industry trends and locate suitable suppliers.

Toronto Hydro bases competitive bid selection decisions on pre-established selection criteria that balance the quantitative and qualitative aspects of each desired proposal developed in collaboration with client business units. Once a supplier is identified, Toronto Hydro develops the contract terms and conditions relevant to the goods or services provided. Acquisition Services monitors supplier performance through collaboration with departments, and/or regular meetings and performance reporting with suppliers themselves.

To formalize vendor performance monitoring, in 2011 Toronto Hydro launched a Supplier Alliance vendor relationship management program with key providers of wire, cable, transformers and switches, and other products that account for about 80% of the utility's equipment and materials spend. The cornerstone of the program is the Vendor Scorecard, which is closely monitored and discussed at periodic vendor meetings. Commencing 2015, Toronto Hydro plans to expand the vendor relationship program to suppliers providing other forms of goods and services, for example providers of software/hardware..

Toronto Hydro operates in a dynamic environment, where supplier or manufacturer mergers, acquisitions and closures can affect market segment competition, or minimize the availability of some products. These natural market fluctuations can complicate the

utility's ability to procure the requisite materials, and require constant market activities monitoring and proactive vendor relationship management. An illustrative example of this issue is the Paper-Insulated Lead-Covered ("PILC") cable, which makes up about 1,300 kilometres of Toronto Hydro's aging underground distribution system. Today, PILC cable is only available from one supplier in North America, which necessitates close collaboration with the supplier and strategically negotiated contractual terms to ensure continuation of supply.

Beyond the supplier identification, management and materials procurement, the Supply and Acquisition function manages inventory levels in Toronto Hydro's warehouses in support of the utility's capital and maintenance programs. This involves reviewing historic use trends and known work projects to develop planned work requirement forecasts and supplier orders.

In addition to facilitating the planned work execution, the Demand and Acquisition program oversees materials and equipment stock coverage for the potential reactive work driven by adverse weather, system contingencies and other unforeseen events. To facilitate efficient and expedient execution of reactive work, Toronto Hydro establishes minimum and maximum inventory settings for each warehouse location and determines appropriate material re-order points and quantities that trigger purchase order generation as inventories are gradually depleted by use. Late shipments that can affect stock availability for either planned or reactive requirements are expedited with suppliers, and best delivery dates are ascertained and communicated to warehouses and requesting areas of the utility.

A significant challenge to execution of the Supply Chain program is presented by storm response activities, the nature and magnitude of which are difficult to predict and plan for. The volumes of certain materials, such as overhead wire and associated hardware

required in the aftermath of major storms often exceed all normal inventory levels, contingency stocks held by vendors, and forecasted reactive work requirements.

When major weather events occur, Toronto Hydro works with suppliers to immediately acquire all materials necessary to support power restoration activities. During the recent December 2013 ice storm, for example, the utility worked with its key vendors to expedite significant amounts of additional equipment, tools, and safety supplies from vendors. Toronto Hydro is not aware of any material delays in restoration caused by lack of required materials and equipment.

Acquisition Services also works with the Standards and Policies segment of the Operations Support – Planning program[1] at Toronto Hydro to identify certain materials and equipment that are crucial to the ongoing operation of the distribution network. Once identified, agreed-upon inventory items are flagged as critical spares and segregated from general stock for specific use in reactive situations. Examples of such equipment include various models and vintages of pad mounted switchgear and transformers. Where materials and equipment at the end of their useful lives are replaced with alternatives built to newer technical standards, Toronto Hydro times the inventory replacement so that the existing stock of the obsolete parts may be used up to minimize any residual inventory. In certain cases, Toronto Hydro may also return remaining quantities of the obsolete equipment to the supplier, or sell them for scrap.

Since 2008, the Demand and Acquisition Services segment has seen a 10% personnel reduction, while improving the customer service offers to the user programs. Areas of improvement include better alignment of planning assumptions through assignment of dedicated team members to each user department. Through these processes, Toronto Hydro has, among other things, improved its quality of competitive bid documents, and

[1] Exhibit 4A, Tab 2, Schedule 7.

reduction of the completion timelines for the competitive bid process. Process and coordination improvements have generally reduced the timelines for competitive bid preparation activities, with some recent processes taking up to 40% less time than in the past. The efficiencies gained as result of faster project completion allow for timely start to new projects and earlier transition to suppliers that offer potentially lower pricing, or otherwise provide a better value proposition.

2.2. Warehouse and Logistics

The Warehousing and Logistics function ensures the receiving, stocking, and issuance of all inventory materials for Toronto Hydro's capital construction and maintenance requirements. Field crews receive the requisite equipment and materials from one of four warehouse locations strategically situated across the city, including a recently added location managed by a third-party supplier, discussed in more detail below. The typical activities of the Warehousing and Logistics function include:

- unloading, visually inspecting, receiving, and storing materials and supplies from vendor vehicles for earliest availability for issuance to crews;
- picking, staging, and loading electric distribution material onto crew vehicles to allow them speedy exit from the work centre at the beginning of each work day;
- delivering and distributing requisite materials to and from job sites and between warehouses to facilitate faster and more efficient materials distribution;
- issuing miscellaneous (over-the-counter) items such as tools, clothing and safety equipment to crews so they continue to have the mandatory safety equipment and necessary tools to perform work;
- handling excess materials returned from the field upon work completion, such as partial cable reels which can be re-entered into inventory and issued to other jobs;
- arranging for field equipment slated for repairs or replacement to be returned to vendors and suppliers;

- establishing and maintaining appropriate minimum and maximum inventory levels at each warehouse to assure appropriate product mix is available to support the type of work being conducted by the crews serviced by each work centre; and
- performing daily inventory cycle count activities to facilitate the accuracy of Toronto Hydro's financial reporting, and reconcile physical inventory on the shelf with the Acquisition Services records.

In recent years, Toronto Hydro has worked to improve the service provided by the warehousing function to Toronto Hydro crews and contractors, through initiatives that optimize the staffing levels and warehouse space. These initiatives and their benefits are outlined below.

In May 2012, Toronto Hydro implemented a new WMS. This software and hardware solution utilizes barcode technology and provides real-time visibility of inventory position, adding efficiency to the receiving and picking functions. Warehouse transactions can be centrally prioritized and assigned to warehouse staff by queuing tasks to the employees' hand-held barcode guns. Tasks such as receiving, picking, and cycle counting can be carried out by the scanning of product bar coding now affixed to all incoming materials. This technological improvement significantly speeds up the previously manual tasks of keying in the entries for every incoming packing slip, outgoing picking slip, or cycle count entry. The use of this technology allows the warehouse to continue to provide and improve expected service levels to Toronto Hydro crews despite the 20% staff reduction through the 2012 restructuring program. As shown in Figure 1, Toronto Hydro has substantially improved its rate of fulfillment of crew materials and equipment orders on time and in full ("OTIF").

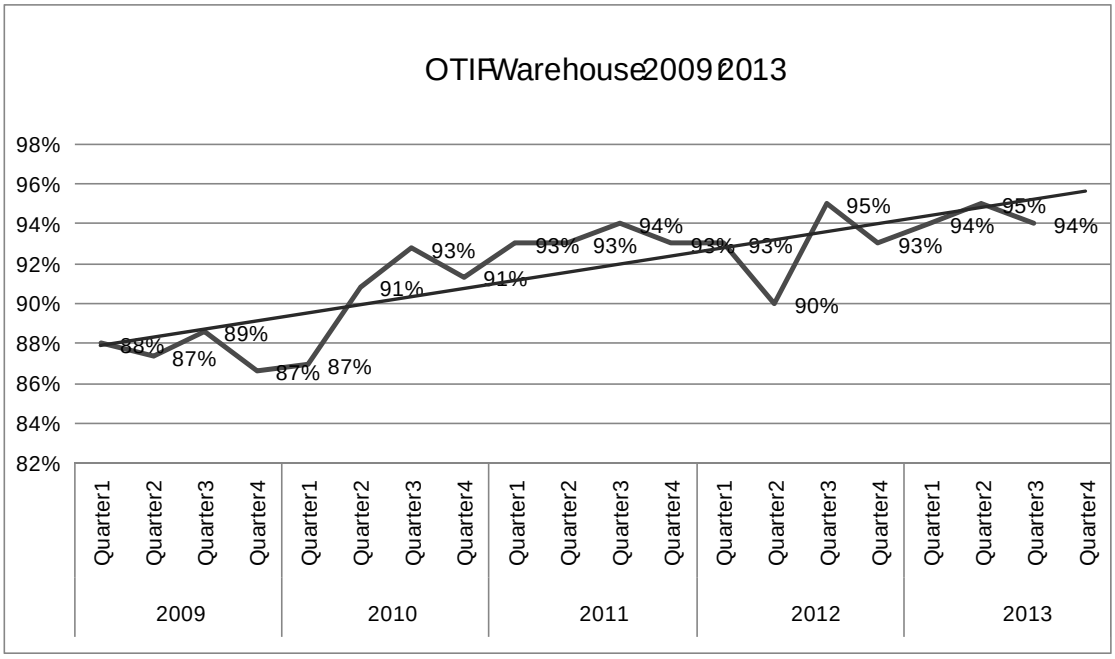


Figure 1: Warehouse Fulfillment Improvement

Commencing April 2013, Toronto Hydro also contracted a Third Party Logistics ("3PL") provider to operate a fourth warehouse located just north of the city, as an addition to the three existing work centres. Using the same WMS software as Toronto Hydro's warehouses, the 3PL provider handles incoming supplier deliveries, issues all materials for the planned work program, and distributes all materials used by Toronto Hydro's electrical contractors. The 3PL provider also replenishes stock to the three Toronto Hydro warehouse locations.

The three internal warehouses stage the goods for crew pick-up and focus on emergency reactive demand, replenishment of tools and safety items, and administration of the previously described critical spares program. They also receive and process the equipment returned from the field slated for inventory re-entry or repairs. The internal warehouses no longer handle equipment transfers across the work centres, which frees up

warehouse vehicles to replenish materials directly to job sites. This allows the crews to remain at the site instead of returning to the warehouse to pick up any materials needed to complete the work.

While the 3PL provider has assumed a significant portion of Toronto Hydro's warehousing duties, the internal work centres continue to play a key operational role by facilitating prompt materials issuance to the crews departing from the three work centres, and facilitating timely response to reactive requirements. By being able to pick up materials at the warehouses located in the different areas of the city, Toronto Hydro crews are able to get to their job sites much faster, thus enabling more efficient execution of planned work and faster power restoration timelines during reactive assignments.

In 2011 and 2012, Toronto Hydro assessed that additional space was needed. Given the fact that additional space was needed, Toronto Hydro considered three options:

- Option 1 – Maximize use of existing warehouse space and hire any needed additional staff to handle the higher inventory throughput;
- Option 2 – Lease a fourth Toronto Hydro-operated warehouse and hire additional staff as necessary;
- Option 3 – Outsource the additional space and labour to a 3PL provider.

Analysis of the three options led to the conclusions summarized below.

- Option 1 ("status quo") did not provide adequate space for the projected volumes of materials and supplies.
- Option 2 (incremental expansion of in-house warehousing capabilities) would support the additional throughput requirements, but would result in the incremental lease costs, and added equipment handling and labour costs. The option did not allow for scalability of labour costs in the event of material capital

and maintenance work program changes, particularly if they fluctuated based on funding levels, or the mix between electrical and civil projects.

- Option 3 (outsource the incremental work to a 3PL provider) allowed Toronto Hydro to reap the benefits of additional storage space at lower labour costs. Importantly, the throughput-based pricing model of the contemplated 3PL arrangement represented a scalable solution that could be expanded or reduced based on changing capital and maintenance plan requirements.

Based on these considerations, Toronto Hydro decided to pursue Option 3. The outsourcing arrangement allowed Toronto Hydro the flexibility in striking a balance between 3PL and Toronto Hydro resources to support the expected throughput levels.

The total value of materials and equipment throughput is expected to increase by 27% from 2011 to 2015. For the same period, the aggregate 3PL and internal labour costs has or is expected to rise by 28%, as compared to an increase of 31% if the 3PL approach was not pursued and Toronto Hydro procured additional warehousing facilities internally and hired additional staff.

Toronto Hydro closely manages its 3PL relationship through tools that include statistics on the number and timing adherence of pickups, receipts, and transfers. Moreover, the 3PL provider is also expected to maintain the accuracy of stock at its location, which is subject to periodic and random audits by Toronto Hydro.

The cost of Warehouse and Logistics function and a portion of the Acquisition and Demand Services function are recovered initially through the materials on-cost rate, applied to the value of the goods issued to jobs for specific projects, and ultimately

reflected in the projects' overall capital costs.[2] Despite increased operating costs associated with the engagement of a 3PL provider, which was necessary to accommodate the increased materials requirements, the above operating costs have grown at a pace similar to that of materials/commodities issued through the four warehouses. Consequently, the on-cost rates over the historic period have remained relatively flat, as depicted in Table 2, thereby managing the effect of supply chain costs on the utility's capital work program.

Table 2: On-Cost Rate (2011-2015)

Year	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
On-Cost Rate	12%	13%	12%	14%	12%

3. PROGRAM COSTS

Toronto Hydro's Supply Chain expenditures since 2011 have been predominantly affected by four drivers: 1) labour costs, 2) fluctuations of transformer rebates, 3) inventory write-off levels and 4) the introduction of a third party logistics provider.

Table 3: Supply Chain Program Costs ($ Millions)

($M)	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Total	7.1	6.6	9.0	10.3	9.9

3.1. 2011-2012

The $0.5 million reduction in expenditures between the 2011 and 2012 was primarily driven by a 20% reduction of warehouse staff following restructuring in 2012. The effect of the restructuring was partially offset by an increase in inventory write offs and

[2] As previously described, Toronto Hydro calculates an annual rate by dividing the applicable Supply Chain program costs over the anticipated cost of materials supplying that year's capital and maintenance work program. The resulting rate (%) is then added to the materials charged to the capital and maintenance projects.

reduction of transformer rebates received in 2012 compared to 2011. Transformer rebates are earned based on the volume of transformers purchased each year.

There were fewer transformers purchased in 2012, resulting in the reduction of rebates earned. The increased level of obsolete equipment write-offs was a result of a one-time inventory cleanup as the final stage of a warehouse reorganization following the implementation of the WMS capability.

3.2. 2012-2013

The $2.4 million increase in 2013 over the 2012 expenditures is due to the increase in external contracting costs driven by the engagement of a 3PL in April 2013, necessitated by incremental warehousing capacity requirements, which was more cost-effectively secured through an outsourcing arrangement. This increase is partially offset by the normalization of the inventory write-off levels relative to the one-time increase experienced in 2012, and the increase in transformer rebates compared to the year prior.

3.3. 2013-2014

The 2014 projected expenditures reflect an increase of $1.3 million versus 2013 due to the difference between the expected 2014 full year charges associated with 3PL services, as compared to only three quarters of its activities in 2013. This is partially offset by decreased labour costs following partial year recognition of retirements and organizational restructuring activities.

Since 2011, Toronto Hydro implemented a number of initiatives to enhance the efficiency and productivity of its Supply Chain program, thus improving service levels and managing the pace and scale of cost increases. For example, the utility took steps to reduce the time and resources spent on non-value added activities. This includes the

recent automation of low-value inventory purchase orders for items such as pole line hardware, small tools and consumable supplies. Instead of requiring human intervention, the inventory replenishment system now features an automated functionality that generates new purchase orders when stock levels reach a pre-determined threshold. This and other similar process improvements allow Toronto Hydro to devote more time to strategically significant activities such as vendor management and market analysis for competitive bid opportunities, while keeping expenditure levels flat or driving net reductions.

In order to drive service improvements from its inventory suppliers, in 2010 Toronto Hydro set out to formalize the monitoring of supplier performance by measuring the adherence of supplier deliveries to terms of their respective contracts. The measurement looked at whether deliveries of specific items were made in full (100% of expected product shipped), and arrived within three days of expected due date. For an order segment to be considered on time and in full, both the quantity and timing of the delivery have to meet their respective threshold stipulations.

Since the supplier performance management program's inception, Toronto Hydro narrowed the number of days in which deliveries were allowed to arrive early. Suppliers are now permitted to deliver no more than five days earlier than expected due date. This prevents suppliers from shipping materials at month- or year-end without prior approval from Toronto Hydro. The restriction helps Toronto Hydro keep its inventory values and associated carrying costs in check. Despite the narrower delivery window, the percentage of orders arriving orders on time and in full ("OTIF") continues to improve, as shown in Table 4.

Table 4: Supplier Delivery Performance

Year	2009	2010	2011	2012	2013	2014YTD
OTIF	80%	85%	92%	93%	94%	94%

Throughout the remainder of 2014, Acquisition Services plans to continue to look for opportunities to improve processes and to act opportunities to reduce costs. Among these process improvements is the new eProcurement application available starting July 2014, which offers three inter-connected modules.

- Spend Analytics: The tool's reporting functionality will automatically analyze total goods and services spend data, allowing for easier identification of spend trends and subsequent development of competitive bid strategies to pursue further savings.
- Competitive Bid Generation and Repository: The tool provides a work flow for competitive bid event creation and a repository for the documents generated, as well as a reference for supplier contact information, reducing the time taken to prepare and issue competitive bid activity.
- Contract Generation Repository: The tool simplifies the management of supplier contracts by providing a single point of reference. It also provides contract expiry alerts which will allow for appropriate time to formulate future sourcing strategies.

The goal of using the tool is to generate savings and other value propositions from competitive bid activity where synergies that have not been previously identified. For example, the tool will allow for easy identification of vendors used across multiple departments for similar work, creating opportunities for cross-functional work and ensuing savings and process efficiencies.

Similar to the Acquisitions and Demand process improvements, Toronto Hydro has implemented initiatives to improve service efficiency and cost effectiveness in the Warehouse and Logistics area that will continue to provide benefits to the utility and customers in the form of productivity improvements created by the optimization of resources.

3.4. Test Year Program Costs

The projected $0.4 million decrease between 2014 Bridge and the 2015 Test Year is driven by the reduction of labour costs and 3PL cost reductions. Toronto Hydro anticipates the decrease in labour costs as a result of projected 2015 attrition of several positions through retirements that Toronto Hydro does not intend to replace as part of this program. Moreover, the 3PL costs are expected to decrease due to the costing model that provides for lower service rates as the throughput value increases.

There are no anticipated increases expected for Demand and Acquisitions Services in 2015, other than inflationary increases and labour costs.

The services provided by the Supply Chain program are at the core of any electric utility's operation. The strategic sourcing, market and analysis and warehousing and logistics work comprising the program provides Toronto Hydro with materials, tools, services and implements required to perform day-to-date operating activities and efficiently execute the utility's capital and maintenance work programs.

Toronto Hydro's operating model balances the use of internal resources and outsourcing arrangements to deliver high service level at an optimal cost for the benefit of ratepayers. As detailed in the previous sections, the utility's Supply Chain expenditures have increased at a pace similar to the cost increases of materials that the program procures, stores and distributes.

Moreover, and as evidenced throughout this schedule, a number of technological and process efficiencies implemented over the past four years allow Toronto Hydro to perform its supply chain functions at higher service rates while at the same time reducing its staffing complement. The scalable nature of the utility's 3PL model further assists Toronto Hydro in reasonably accommodating fluctuations in its work program without incurring sustained incremental capital and operating costs.

Any material reductions of Supply Chain program funding from the proposed 2015 levels could mean that Toronto Hydro is not able to execute its capital and maintenance work programs as planned. Absent a proper and adequately supported warehouse function, stock could be misplaced, issued incorrectly, or damaged. The availability of approved products, upon demand, is essential to the operation of an electrical distributing utility.

Fundamental to the requirement for a centralized Supply Chain department is the need to retain a staffing complement that can execute the activities supporting the implementation of the utility's Procurement Policy[3] in an accurate and expedient manner. The level of required due diligence would be lost without this centralized function which could affect the quality of vendor selection. Toronto Hydro could also be exposed to sub-par vendor performance and risk availability of stock for both planned and reactive requirements without an ongoing vendor management program.

[3] Exhibit 4A, Tab 3, Schedule 2.

CUSTOMER CARE PROGRAM

1. SUMMARY

Table 1: Customer Care Program Expenditures ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Customer Care	41.9	37.5	39.7	42.2	46.1

The Customer Care program entails the activities and services directed at facilitating the needs of Toronto Hydro's 730,000 customers, including customer communications and relationship management, billing, metering and collections activities. Providing excellence in customer service is at the core of Toronto Hydro's corporate philosophy, and the utility is consistently seeking new ways to foster meaningful two-way communication, expand the range of service offerings to meet unique customer needs, and improve service convenience, and integrate new technological advancements to drive service level improvements and capitalize on available efficiencies.

2. PROGRAM DESCRIPTION

The Customer Care program is comprised of four segments covering most dimensions of direct interaction between the utility and its customers and/or work required to support this interaction. The segments are:

- Billing, Remittance and Meter Data Management segment which covers activities such as the reading of customer meters, upkeep and upgrades of the associated infrastructure, management of data, and preparation and processing of customer bills;

- Collections segment which entails the complete cycle of activities related to Toronto Hydro's efforts to collect the funds associated with unpaid customer accounts;
- Customer Relationship Management segment which oversees the utility's interaction with its current and future customers; and
- Communications and Public Affairs segment which captures activities related to the utility's community outreach, media relations, municipal government interaction and other aspects of public communications work performed by Toronto Hydro.

Table 2 provides the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for each of the four segments. Descriptions of the activities comprising each segment and details about the associated costs are provided in the sections that follow.

Table 2: Customer Care Program Expenditures by Segment ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Billing, Remittance & Meter Data Management	14.5	13.7	14.6	16.4	18.7
Collections	12.3	8.9	11.1	12.2	13.1
Customer Relationship Management	12.1	11.5	10.1	10.4	11.3
Communications & Public Affairs	3.0	3.3	4.0	3.1	3.0
Total	**41.9**	**37.5**	**39.7**	**42.2**	**46.1**

3. BILLING, REMITTANCE AND METER DATA MANAGEMENT SEGMENT

The Billing, Remittance, and Meter Data Management segment oversees the reading of electricity meters, validation and management of meter data, preparation of customer bills, and processing of payments. Toronto Hydro's customers receive their bills in regular intervals (either monthly or bi-monthly), based on accurate metering data and in compliance with applicable legislative and regulatory requirements for metering, billing, payment processing and retail settlement activities.

Over the historical period, Toronto Hydro has enhanced its automatic meter data collection and verification capabilities, broadened the scope of available bill delivery and payment options, and devised a number of customized processes to enable the billing and administration of payments for customer-owned micro-generation facilities. To manage segment cost increases and facilitate the introduction of new technological and procedural improvements, the utility outsources a number of its information processing functions and continues expanding its offering of online and self-serve tools.

The Billing, Remittance, and Meter Data Management segment is at the core of Toronto Hydro's "meter-to-cash" process that oversees conversion and verification of customer consumption data and other billable activities into customer bills, facilitating the accuracy of bills, and processing of the ensuing customer payments. Every year, Toronto Hydro issues about 5.1 million bills to approximately 730,000 customers. Over 600,000 of the utility's customers are billed on a bi-monthly basis, with the balance receiving their bills every month. In performing this work, Toronto Hydro attempts to provide its customers with a variety of billing and payment options that respond to their particular needs and preferences, while also supporting the utility in realizing processing efficiencies and facilitating faster receipt of customer payments. The automated nature of the majority of

the utility's data collection and verification processes facilitates bills issued to customers being both timely and accurate.

3.1. Metering and Data Management

As of December 31, 2013, Toronto Hydro had approximately 734,000 installed meters, of which approximately 696,000 are read remotely on a daily basis. The remaining 37,000 meters are manually read. The automated meter data is retrieved by one of the three major data collection systems and is then validated, estimated and edited for billing purposes. Each major data collection system serves different meter types/customer classes and requires specialized skills to maintain acceptable data collection hardware and standards.

The expansion of automated meter data collection and verification has reduced the number of residential and small commercial bills issued with estimated readings to less than 1%. Prior to system automation (2002-2006), manual meter reading resulted in estimation of 7.6% of customer bills, a combined four-year average of all residential and commercial customers. Automating the data collection of residential meters also allows customers to view and extract their hourly electricity consumption on Toronto Hydro's Time of Use ("TOU") web portal and use a customized energy management tool to control their costs. An online application is also available to larger industrial and commercial customers to allow for the download of interval data from the electricity meters at their facility.

As the practice of remote meter reading is now entrenched, Toronto Hydro is working to further maximize the efficiency of data collection by modernizing collection systems, enhancing the communication networks and improving system processing capabilities to increase the amount of meter data that is retrieved automatically.

Throughout 2014, Toronto Hydro expects to further reduce the number of manual readings to 20,000 meters, primarily through enhancements of data collection and processing capabilities for the commercial customers.

In addition to metered customers, Toronto Hydro has approximately 11,700 Unmetered Scattered Load ("USL") connections, which includes service to telephone booths, bus shelters, cable television boosters, traffic and park lighting, and signs. These unmetered devices consume a consistent amount of electricity from month to month and the ensuing bills are based on mutually agreed-upon load assumptions. The Billing, Remittance and Meter Data Management segment is responsible for keeping an up-to-date list of all service locations and updating usage calculations when customers make changes. To ensure USL billing accuracy, Toronto Hydro periodically conducts random field audits and reconciliation exercises with its customers.

3.2. Billing and Payment Services

The utility offers its customers several options for billing delivery method, including standard paper-based bills, e-bills and ePost billing services. For customers with specific accessibility needs, Toronto Hydro facilitates additional accommodation options, including bills with an option to increase font size, and audio playback options. To date, approximately 73,000 of Toronto Hydro customers receive their bills on line using e-billing options, which facilitates cost savings for the utility and provides convenience and accessibility for customers. Given the recent increase of Canada Post rates, Toronto Hydro is undertaking a proactive outreach campaign encouraging customers to adopt the electronic modes of receiving their bills as a means of controlling costs.

In addition to issuing electricity bills, the segment facilitates preparation and issuance of other customer bills for non-electricity services, such as customer-driven projects and costs resulting from certain claims proceeding.

The on-going implementation of the Green Energy and Green Economy Act, 2009[1] created additional complexity for Toronto Hydro by requiring a configurable and adaptable process to manage unique billing configurations for customers with embedded renewable electricity generators. To successfully provide appropriate levels of service to these customers, Toronto Hydro devised a number of new tools and processes to manage non-standard set-ups, process billing and credit/refund calculations, and resolve any associated customer issues or concerns.

The utility tracks and processes customer-move information so that correct meter data can be obtained, account holders are identified, first bills and final bills are addressed correctly and issued without delay. In 2013 alone Toronto Hydro processed over 130,000 customer moves, which amounts to almost 20% of the utility's total customer base. To streamline the administration of customer moves Toronto Hydro offers an online move portal, where customers can quickly provide the pertinent information which is subsequently processed by the utilitys Customer Care and Billing ("CC&B") system.

Toronto Hydro provides its customers with multiple bill payment options, including:

- Remittance via mailed cheque;
- Bank teller payment;
- Pre-authorized debit;
- Online and Telephone banking;
- Electronic funds transfer;
- Western Union;
- Moneygram; and
- Credit cards for customers facing disconnection.

[1] S.O. 2009, C.12. ["GEGEA"]

To maximize cash flow and minimize bad debt, Toronto Hydro encourages customers to adopt a pre-authorized payment plan. Approximately 160,000 Toronto Hydro customers pay their bills using a pre-authorized payment plan. Enabling this option requires the utility to monitor and update customer bank account information, and keep this information secure, as customers enrol, drop or make changes to their respective plan. Customers may also choose to smooth their payments through a budget billing process that allows for equal payments on a monthly basis with an annual reconciliation.

Another key dimension of the segment's activities is the ongoing communication and coordination with electricity retailers to ensure that necessary legal agreements are in place prior to customer account set-up, and that day-to-day retailer transactions and regular payments are processed quickly and efficiently.

To ensure proper functionality and compliance to relevant legislative and regulatory requirements of all elements of the meter-to-cash process, Toronto Hydro maintains a system of internal controls for both the existing and new systems and processes. Toronto Hydro reviews all key processes on an annual basis to ensure that adequate controls are in place and the procedures in use remain valid and comply with applicable financial, legislative and regulatory requirements.

3.3. Segment Costs

Table 3 provides Toronto Hydro's Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Billing, Remittance and Meter Data Management segment.

Table 3: Billing, Remittance and Meter Data Management Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Billing, Remittance and Meter Data Management	14.5	13.7	14.6	16.4	18.7

3.4. 2011-2012

Segment costs decreased by $0.8 million between 2011 and 2012 primarily owing to:

- $0.8 million decrease in labour cost as the additional resources needed for implementing the Customer Information System ("CIS") project in 2011 was no longer required in 2012; a reduction in full-time clerical staff was achieved due to increased outsourcing;
- $0.3 million increase in postage, bill printing, paper stock and envelopes;
- $0.4 million decrease in manual meter reading costs as additional meters became remotely read;
- $0.2 million decrease in costs associated with the installation and remote meter reading of Suite Meters; and
- $0.3 million increase in the accounting provision for bad debt costs for non-electricity service due to an increased risk of collecting.

3.5. 2012-2013

The $0.9 million increase in operating costs from 2012 to 2013 is primarily driven by:

- $1.2 million increase for labour due to normal internal inflationary pressures, and for Meter Data Management to accommodate increasing clerical labour requirements resulting from new smart meters, and an increase in field staff requirements to service meters and communication networks;
- $0.5 million increase due to a re-allocation of outsourcing expenditure management from the Customer Relationship Management segment;
- $0.2 million increase to cover postage increases, bill printing, paper stock and envelopes and payment processing services; and,
- $1.0 million decrease in the accounting provision for bad debt costs for non-electricity services due to an improvement in billing and collection processes.

3.6. 2013-2014

The 2014 Bridge Year costs are projected to increase by $1.8 million relative to the 2013. The cost increase is attributable to the following factors:

- $0.6 million increase in labour costs due to normal internal inflationary labour cost increases and reallocation of staff from other segments to accommodate the increase in the volume of fieldwork activities to support remote meter data collection activities;
- $0.5 million increase to cover increased Canada Post rates , bill printing, paper stock and envelopes and payment processing;
- $0.3 million increase in clerical work outsourcing costs; and
- $0.4 million increase resulting from an accounting provision adjustment for bad debt costs in 2013.

To manage its billing costs over the Historical period, Toronto Hydro outsourced several clerical tasks associated with Billing, Remittance and Meter Data Management to a third party in 2012. The activities include pre-authorized payment enrolments, credit transfers, billing adjustments, meter reading and billing exceptions, and meter and account set up for suite meters.

3.7. Test Year Segment Costs

The projected increase in operating costs from 2014 to 2015 is $2.3 million, is driven by the following anticipated factors:

- $1.1 million driven by normal inflationary labour cost increases and the need to support the deployment and maintenance of additional technology upgrade projects to support meter reading and infrastructure renewal;
- $0.7 million increase to address a significant Canada Post rate increase;

- $0.3 million for an increase in the provision for bad debt for non-electricity services; and
- $0.2 million increase in outsourced meter reading costs.

Meter Data Management, Billing and Remittance segment costs are expected to continue to experience upward pressure due to the anticipated volumes of customer base increases and changing customer demands. To alleviate these anticipated cost pressures, Toronto Hydro plans to continue controlling operational expenses by seeking to optimize the use of outsourced labour and encouraging customers to use the convenience and lower cost of online, self-serve and paperless channels to view their billing information and make payments. Toronto Hydro intends to continue enhancing the current suite of payment channel offerings to ensure timely customer payments and provide appropriate levels of customer choice.

Meter data management, billing, and remittance is a core function of an electricity utility as it includes the elements of the meter to cash process. Significant changes in metering technology and pricing structures over the last several years required Toronto Hydro to implement a number of changes to its meter and billing infrastructure along with the processes underlying the segment. Given that Toronto Hydro was an early adopter of emerging technology, ongoing work to optimize the utility's operations needs to continue throughout the 2015-2019 rate period as the technology and communications infrastructure becomes increasingly complex and sophisticated, and maintenance requirements increase with further technological proliferation.

Accurate capturing of revenue and an optimized cash flow are dependent on the accuracy and timeliness of bills issuance and payment processing. Any limitations to the utility's ability to effectively manage key technology systems, optimize business processes and

retain skilled resources owing to budget reductions could result in significant corporate financial risk, and negatively impact customer satisfaction levels.

4. COLLECTIONS SEGMENT

The Collections segment is responsible for tracking, contacting and collection of unpaid customer accounts. The segment's functions are based on regulatory requirements, as well as Toronto Hydro's objectives, industry best practices and guidelines for managing overdue accounts. Toronto Hydro's collections guidelines procedures meet all Ontario Energy Board ("OEB") and other relevant requirements pertaining to revenue collection and are designed to minimize the amount of bad debt expenses incurred by the utility, while providing customers with multiple options to rectify outstanding accounts.

For a utility with approximately 730,000 customers and over 130,000 customer moves annually, the collections function plays a key role in enabling Toronto Hydro to receive required revenue while minimizing bad debt expenditures. Effective collections help minimize the effect that bad debts have on other customers. To support collection activities, Toronto Hydro has dedicated collections customer service representatives ("CSRs") during business hours, and provides 24/7 access to collections information through an Interactive Voice Response ("IVR") system and an online portal. The IVR and online technology assists customers with their account management enquiries by providing updated account balances, payment option information, bill amount predictors and other related tools.

Toronto Hydro's collections CSRs are additionally trained in collections-specific legislation, regulations and municipal by-laws, outstanding arrears repayment strategies, commercial disconnect processes, and the Companies' Creditors Arrangement Act[2] ("CCAA") and

[2] R.S.C., 1985, c. C-36. ["CCAA"]

Bankruptcy procedures. Collections staff also possess all information related to Toronto Hydro's Low Income Energy Assistance Program ("LEAP")[3] and liaise as needed with the utility's social services partners to oversee program administration.

To facilitate stable and predictable cash flows and manage emerging arrears, Toronto Hydro proactively mails overdue payment reminder letters and places reminder phone calls to its customers, with an average of 350,000 letters and 173,000 phone calls placed each year. To manage the costs of these high-volume activities while maintaining the efficiency and timeliness of reminders, Toronto Hydro deploys automated systems for both letter writing and phone call placement.

In the event that regular reminders are unsuccessful, Toronto Hydro initiates a series of severance activities. This involves annually creating over 98,000 service orders to the utility's field collection contractor and internal field staff that deliver ten-day disconnection notices, making approximately 27,000 disconnection notice calls, and ultimately disconnecting about 9,000 accounts per year for non-payment. In many cases, the disconnection work requires the assistance of a bailiff. Toronto Hydro's field collections agents collect approximately $6.1 million in outstanding payments per year while delivering ten-day disconnection notices or when attending the premise to perform the disconnection.

To encourage timely payments, proactively identify at-risk accounts and otherwise facilitate the collection of outstanding payments, Toronto Hydro undertakes a range of specific activities, including:

- applying late payment fees to encourage on-time payments;
- managing and monitoring about 20,000 commercial accounts with security deposits and overseeing the annual process of deposit refunds;

[3] Exhibit 4A, Tab 2, Schedule 19.

- preparing and sending over 18,000 inactive unpaid accounts per year to external collection agencies for follow up and collection;
- implementing arrears payment arrangements to assist customers with rectifying their outstanding balances;
- overseeing administration of low income programs (e.g., LEAP); and
- performing write-off activities.

In addition to work with individual customer accounts, Toronto Hydro aggregates all outstanding payment/arrears information in a single financial report to reconcile the information with the accounting bad debt provision. Through this process Toronto Hydro reviews all aged accounts receivable balances, bankrupt accounts and accounts that are considered to be "at risk" to determine the utility's estimated bad debt exposure. The utility carefully monitors the bad debt trends so that corrective action can be taken as appropriate.

To allow regulatory compliance and to promote the procedural efficiency of new and existing collections activities, Toronto Hydro maintains a framework of internal controls. These controls are designed to ensure that major processes like the collection of accounts and bad debt write-offs follow well-defined steps. Toronto Hydro reviews existing key processes and proposed new processes on an ad hoc basis to help ensure that adequate controls are in place and procedures in use remain valid.

4.1. Segment Costs

Table 4 presents Toronto Hydro's Historic (2011-2013), Bridge (2014) and Test Year (2015) costs relating to the Collections segment.

Table 4: Collections Segment Costs ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Collections	12.3	8.9	11.1	12.2	13.1

Year-over-year collections management expenditures can be substantially influenced by the accounting provisions rules for bad debt provision, based on the applicable forecast methodology.

Between 2011 and 2014, actual operating costs remained fairly flat, with large year-over-year variances due to accounting adjustments to reduce or increase the provision for bad debt allowance. Operating cost increases that were attributable to normal inflationary labour cost increases and an increased ratio of field collections work performed in-house were offset by operating cost decreases accomplished by altering the ratio of in-house clerical resources versus third-party service provider. Ratios between in-house and third party providers for both field and clerical work were adjusted to optimize service quality while controlling costs.

4.2. 2011-2012

The operating costs decreased by $3.4 million from 2011 to 2012 due to the following:

- $0.8 million reduction in labour cost associated with substantial completion of Toronto Hydro's Customer Information System ("CIS") project in 2011, as well as a reduction in full-time clerical staff due to increased outsourcing;
- $2.9 million decrease in bad debt costs due to an accounting adjustment to reduce an over provision in the bad debt allowance; and
- $0.3 million increase in collection agency costs offsetting the above decrease due to a temporary interruption in certain business processes during the CIS conversion in 2011, which led to two year's worth of delinquent accounts being sent to collection agencies in 2012.

4.3. 2012-2013

The $2.2 million increase in operating costs from 2012 to 2013 was driven by :

- $0.2 million increase in labour costs for normal internal inflationary labour cost increases, and an increase in the use of internal field resources for severance activities;
- $1 million for an increase in the accounting provision for bad debt costs due to growth in customer base, average bill amounts, and other formulaic impacts;
- $0.7 million increase through allocation of outsourced clerical resource costs from the Customer Relationship budget to the Collections budget; and
- $0.3 million increase to cover the expansion of outsourced collection activities to control bad debt expenses.

4.4. 2013-2014

The increase in operating costs between 2013 and 2014 is projected to be $1.1 million, which includes the following components:

- $1.8 million increase in labour costs for normal internal inflationary cost increases, contracted services driven by new billing rules and applicable code amendments, and allocation of internal field staff to severance activities;
- $0.2 million decrease in the use of third party field service providers to perform severance activities; and
- $0.5 million decrease in the provision for bad debt cost anticipated from improved collection processes and the associated accounting adjustment.

4.5. Test Year Segment Costs

Toronto Hydro's forecast 2015 Test Year Collections expenditures of $13.1 million, are $0.9 million above the Bridge Year expenditures. The projected increase is primarily driven by the following factors:

- $0.5 million increase in the accounting provision for bad debt costs due to growth in customer base and average bill amounts, along with other inflationary impacts;

- $0.4 million increase for normal internal inflationary labour costs, fulfillment of staffing complement, and an increase in costs associated with collections field work.

The Collections segment is intended to exert control over what could, if left unchecked, result in substantial customer account arrears and uncollectable billed amounts which would ultimately create upward pressure on rates. While enabling the utility to prudently manage the collection of revenue, the Collections segment also is also designed to minimize financial hardship and avoid disruption of power to Toronto Hydro's most vulnerable customers, using both OEB regulated programs and Toronto Hydro internal processes.

To contain costs related to these activities, Toronto Hydro leverages technology and automation to efficiently manage high-volume activities, engages cost effective third-party providers, implements quality programs, and identifies and manages short interval controls to measure and manage results, and makes adjustments to collections strategies to leverage new technologies or support changing economic, regulatory, legislative or business conditions.

5. CUSTOMER RELATIONSHIP MANAGEMENT SEGMENT

The Customer Relationship Management segment oversees Toronto Hydro's interactions with current and future customers, and builds trusted relationships by engaging customers at the right time, with the right information, and through the right channel to better meet their needs. The segment's main objectives are to deliver customer value by providing efficient and timely response to all inquiries, building awareness of available programs, and educating customers on how to better manage their electricity usage.

The segment encompasses key facets of Toronto Hydro's interaction with its customer base, including the following functional areas: Contact Centre; Request Escalations; Key Accounts; Customer Experience; and Quality Assurance.

Toronto Hydro's specific procedures and programs in each of the functional areas comprising the Customer Relationship Management segment are designed to meet customer needs and improve operational efficiencies identified through the tracking and analysis of inbound customer enquiries, transactional surveys, focus groups, and other means of soliciting customer feedback.

In addition to providing customer-facing services, the segment also includes a project development function, tasked with designing and overseeing the work of critical technology projects, process optimization and performance management developed through ongoing process analysis, optimization and measurement activities.

5.1. Customer Contact Centre

The contact centre is the primary functional area of the Customer Relationship Management segment. The contact centre receives and responds to approximately 100,000 written inquiries and 596,000 telephone calls per year. Toronto Hydro's customers approach the contact centre to inquire about a broad spectrum of topics involving most aspects of Toronto Hydro's business. Common subjects include:

- updating and confirming customer records to reflect changes in customer information, such as move-ins and move-outs;
- verifying information and providing explanations about account management, billing, payment options, consumption, power quality, and collections;
- responding to inquiries regarding Time-of-Use ("TOU") billing, and assisting customers with the TOU web tool that provides load profile information and energy management advice; and

- directing customer calls to the appropriate department or employee through Toronto Hydro's main switchboard.

In performing this work, Toronto Hydro closely monitors the quality and efficiency of its customer contact activities using a combination of OEB-mandated and internally developed measures and metrics. Overall, Toronto Hydro performs well against the OEB's performance targets in the areas of telephone and written response, consistently exceeding the required service standards.[4] On average, over the 2011-2013 timeframe, the contact centre answered 77 percent of calls within 30 seconds, and responded to 92 percent of written inquiries within ten days.

5.2. Escalations and Special Investigations

The Escalations and Special Investigations area supports the contact centre. Escalations receives and resolves specific customer concerns that require additional review. The most frequently occurring issues relate to billing and collections, including those related to rate changes and energy consumption. The Escalations and Special Investigations function receives its requests through a variety of channels:

- approximately 440 customer issues annually are escalated through the call centre during daily operations;
- another 220 are received each year through Toronto Hydro's Office of the President; and
- about 75 requests are received annually directly from the OEB.

The Escalations and Special Investigations function is responsible for managing these volumes, and can deploy field resources to investigate power quality or billing issues that require a site visit. In 2013, the area resolved 98% of escalated customer inquiries within ten business days or less.

[4] Exhibit 2A, Tab 10, Schedule 1.

The Customer Relationship Management segment also investigates instances of potential unauthorized use of power. When Toronto Hydro suspects an instance of unauthorized power use it deploys field resources to conduct a site visit. If the site visit confirms unauthorized use of power, Toronto Hydro advises the affected customers to correct the issue within a prescribed period. A subsequent site visit is conducted to confirm that the unauthorized use of power no longer exists and, if required, a corrected bill is issued. This process minimizes the costs associated with potential revenue losses that are otherwise borne by all ratepayers.

From 2011 to 2013, Toronto Hydro uncovered 113 instances of unauthorized use of power, including 52 marijuana grow house operations. In all instances Toronto Hydro took steps to stop the unauthorized use of power and to collect the lost revenue.

5.3. Key Accounts

Another crucial activity area in the Customer Relationship Management segment is the Key Accounts function, which works proactively with large business customers in the Commercial and Industrial ("C&I") sector on matters such as planned outage notification and coordination, Global Adjustment settlement notification, load profile and rates analysis, and power quality and energy management.

The Key Accounts function also responds to issues raised by C&I customers and acts as a liaison to move customer issues forward with other segments within Toronto Hydro. Some of Key Accounts' functions include:

- meeting with customers to resolve billing issues, coordinate planned outages and connect customers with Toronto Hydro's Conservation and Demand Management (CDM) program offerings to explore opportunities for potential consumption efficiencies;
- providing business-specific updates during unplanned outages;

- communicating through channels such as social media, newsletters, and association outreach, educational and sector specific information;
- acting as a single point of contact within Toronto Hydro to facilitate and coordinate work related to large C&I customers; and
- building and maintaining positive relationships with Toronto's business community.

5.4. Customer Experience

To deliver timely, effective and comprehensive customer-facing activities and internal service practices, the Customer Experience area manages customer research, traditional and digital outreach efforts, through media, collateral (brochures, bill inserts and newsletters), direct mail, website, social media, mobile and e-mail outreach for residential and business customers. Customer research activities allow Toronto Hydro to gain insights into how current services, processes and communications align with customer views and experiences, and identify opportunities for improvement.

Using the feedback received through customer research and outreach, Toronto Hydro launched a customized self-service portal (MyTorontoHydro) in 2012, which offers an automated move-in/move-out processing capability, pre-authorized payment enrolment, the ability to view bill and payment history, and individual unit consumption information for landlords. The adoption of this service was promoted through traditional and digital outreach campaigns, with approximately 76,000 customers registered as of May 2014.

Toronto Hydro's on-line services were further enhanced in 2013 through the introduction of a mobile web application that provides customers with energy management information, a bill comparison function, and alerts to help manage electricity costs.

By the end of 2014, Toronto Hydro plans to consolidate all of its on-line service offerings (ebills, MyTorontoHydro, TOU portal) into one interface, to provide customers a single sign-on experience, thereby improving usability and uptake. Additional offerings will continue to be incorporated based on customer research and identified opportunities to increase efficiency. This includes offering MyTorontoHydro account management services to commercial customers and a fully automated new customer move-in process.

Over time, direct-to-customer communication efforts have increased due to the on-going changes in the government and regulatory policy affecting Ontario's electricity market, including new rate structures, technologies and service offerings. In a similar manner, the scope and volume of customer communication has grown to increase the adoption of Toronto Hydro's online and paperless service offerings, thereby decreasing expenditures associated with customer call handling and increasing customer choice and convenience. Proactive communications through bill inserts, newsletters and digital messaging helps build customer awareness and understanding of key aspects of the sector, increases the uptake of on-line services, and reduces the volume of interactions with the Contact Centre. This improves the efficiency and the effectiveness of maintaining customer relationships while also delivering operational gains.

Finally, the Quality Assurance function manages the development and distribution of issue-specific training materials for internal and external resources. It is also engaged in knowledge and service quality management, analyzing first call resolution ("FCR") results, conducting post-call customer surveys, and identifying training gaps as well as process and technology improvement opportunities. The function is also responsible for maintaining an intranet tool that provides staff with information on current policies, procedures, and regulatory changes to better service customers.

5.5. Segment Costs

Table 5 presents Toronto Hydro's Historic (2011-2013), Bridge (2014) and Test Year (2015) costs relating to the Customer Relationship Management Segment.

Table 5: Customer Relationship Management Segment Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Customer Relationship Management	12.1	11.5	10.1	10.4	11.3

5.6. 2011-2013

Toronto Hydro's Customer Relationship Management costs have declined over the 2011 to 2013 period as a result of process improvements and the implementation of a new business model in 2012. Leveraging the utility's customer feedback and research, the new model includes the expansion of self-service online tools, outsourcing of routine customer contact and clerical tasks, and division of segmented customer class-specific services, such as Key Accounts. A portion of the 2012-2013 decrease is attributed to a re-allocation of outsourcing expenditure management of billing related clerical tasks to the Billing segment. The resulting outsourcing arrangement is more cost effective and allows Toronto Hydro to maintain service quality standards during periods of elevated call volumes.

5.7. 2013-2014

The projected increase in operating costs from 2013 actuals to the 2014 Bridge Year is $0.3 million, driven by the renegotiation of the outsourcing contract's terms and fee structure, along with the normal inflationary labour cost increase. The resulting increase is partially offset by the further outsourcing of clerical tasks.

5.8. Test Year Segment Costs

The projected increase in operating costs from 2014 to 2015 is $0.9 million. The following factors have been identified as the likely primary drivers of this projected increase:

- $0.2 million for additional customer communications work related to new electricity rates, emergency preparedness and power outage information, new energy management tools and increasing awareness of the available self-service tools;
- $0.5 million for resources required to support technology projects related to system updates necessary to meet regulated obligations, deploy new on-line service offerings based on customer feedback, including those related to power outage communications, and manage the pace of customer growth-driven expenditures, and the expansion of fully automated customer transactions;
- $0.1 million due to the normal inflationary labour cost increase;
- $0.1 million to engage customers on opportunities to improve Toronto Hydro's service delivery options, and fulfill regulatory requirements.

Customer Relationship Management expenditures enable Toronto Hydro to maintain an ongoing dialogue and collaborative relationship with its customer base, responding to emerging needs and facilitating continuous improvement. Toronto Hydro has achieved significant cost efficiency gains since 2011, by combining customer class-based targeted services delivered by internal staff with third-party outsourcing activities and the expansion of online self-service tools. Importantly, the utility achieved these cost efficiencies while maintaining and/or improving its internally instituted, and externally mandated, service quality standards.

Any reduction in segment expenditures below the proposed levels would likely result in negative consequences, such as customers experiencing longer wait times to resolve their

inquiries, potentially leading to erosion of service level standards. Segment cost reductions would also negatively affect customer experience and satisfaction, as Toronto Hydro would need to reduce service delivery options to meet budgetary constraints.

6. COMMUNICATIONS AND PUBLIC AFFAIRS SEGMENT

The Communications and Public Affairs segment delivers high-quality, practical and timely information about Toronto Hydro's operations and programs to the general public and other interested parties. The segment's scope includes public and stakeholder relations, community outreach, media relations, concerns directed to the Office of the President, emergency communications, municipal government relations and annual reporting.

During the 2015-2019 period, Toronto Hydro aims to strengthen its collaborative relationships with various parties and stakeholders through the Communications and Public Affairs segment.

To perform the activities comprising the segment, Toronto Hydro utilizes a number of communication channels, including:

- engagements with local media;
- contact with local business improvement organizations, community groups and ratepayer associations;
- Toronto Hydro owned channels such as the utility's website,
- social media, including Twitter and Facebook;
- proactive outreach to City Councillors, the Mayor's office and City staff; and
- community events.

Effective and timely communication provides a valuable service to customers and other stakeholders, by increasing their awareness about various matters of interest such as the location and the anticipated restoration of outages, capital projects, and emergency preparedness. By communicating key information proactively, stakeholders and customers may also have fewer reasons to contact Toronto Hydro, which avoids operating costs elsewhere.

6.1. Community Relations

Toronto Hydro maintains productive relationships with public interest groups and agencies involved in commerce, social services, environmental protection and education.

The utility strives to provide timely and local updates and seek feedback on a range of planned and ongoing capital construction projects, environmental assessment proceedings, maintenance activities, and other related matters. Providing continuous updates and responding to emerging issues allows Toronto Hydro to increase stakeholder awareness and manage expectations regarding the impacts of the utility's activities on local communities and commerce.

Stakeholder outreach commonly takes the form of one-on-one contact with customers, community town hall meetings, special information sessions and a variety of online content. Using a variety of communication channels allows Toronto Hydro to engage customers with varying needs, concerns and preferences, with the goal of giving appropriate attention to all customer segments.

The community relations function also supports the utility's most vulnerable customers through the administration of the Low-Income Energy Assistance Program ("LEAP")[5] which helps eligible customers manage their bill payments and re-payment of arrears.

[5] Exhibit 4A, Tab 2, Schedule 19.

Toronto Hydro actively promotes the program using various communications' channels such as posters, e-newsletters to United Way agencies, face-to-face at community outreach events, and through news releases.

6.2. Media Relations

The media are an important conduit between Toronto Hydro and its customers and other stakeholders. The segment's media relations function proactively communicates accurate and timely information about power outages, electrical safety, consumer issues and local investments in the distribution system. Throughout the duration of major outages, communications staff remains in contact with media outlets until the service is restored. Media representatives receive up-to-date information on suspected outage causes, likely duration, and if necessary, appropriate measures to be taken for public safety and protection of Toronto Hydro's and customer-owned equipment. These efforts help disseminate key information to customers at the time when they are most likely to be looking for it.

Dedicated media relations personnel engage reporters directly on all matters, which allows the dispatched crews and other employees to proceed with their work without interruption. Media Relations officers and government relations staff provide timely information to local and provincial emergency management personnel, city councillors and social service agencies that may require such information in order to take appropriate action in the interests of public safety. During the December 2013 ice storm Toronto Hydro staff issued 28 news releases, tended to more than 1,000 tweets, and conducted approximately 1,500 interviews with mainstream media.

6.3. Municipal Government Relations

Building, maintaining and enhancing relationships with municipal government is critical to Toronto Hydro's ability to serve its customers and stakeholders. To facilitate this

function, Toronto Hydro routinely meets with City councillors and City staff on a range of ongoing and emerging issues, and oversees a proactive councillor engagement process to disseminate project information on a ward-by-ward basis.

The media relations function also handles constituent correspondence and concerns relayed by city councillors to the Office of the President. The most frequent concerns involve customers' inquiries regarding street lighting and power outage-related issues. During the December 2013 ice storm, Toronto Hydro staff responded to approximately 7,000 information enquiries from city councillors.

6.4. Segment Costs

Table 6 presents Toronto Hydro's Historical (2011-2013), Bridge (2014) and Test Year (2015) costs relating to the Communications and Public Affairs segment.

Table 6: Communications and Public Affairs Segment Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Communications and Public Affairs	3.0	3.3	4.0	3.1	3.0

6.5. 2011-2013

Between 2011 and 2013 Communications and Public Affairs segment costs increased due to one-time restructuring costs and normal inflationary pressures.

6.6. 2013-2014

The reduction in the 2014 Bridge Year relative to 2013 is due to one-time costs associated with organizational restructuring activities within the Public Affairs segment, as well as Toronto Hydro's efforts to find efficiencies in delivering this segment. To contain its costs over the historical period the utility reduced the use of outside consultants, opting to "insource" a larger portion of communications-related work. An

example of in-sourcing activities include the design, production and publication of annual reports, which are now fully produced in-house. Further cost efficiencies were achieved by limiting the amount of paper-based documentation in favour of online modes of content delivery.

6.7. Test Year Segment Costs

The proposed 2015 Test Year costs are consistent with the projected 2014 expenditures, with a minor reduction driven by the increased realization of efficiencies such as in-sourcing and limiting paper-based document distribution noted above. As described above, the utility took steps to manage the costs of delivering this segement; the outcome of these initiatives is that the proposed 2015 Test Year expenditures are equal to or lower than the 2011-2013 actuals, despite inflationary pressures and other related factors.

The proposed Test Year expenditures allow Toronto Hydro to effectively communicate with its diverse customer base about complex electricity sector issues and developments. They are also necessary to enable Toronto Hydro to maintain a productive dialogue with its customers and other affected stakeholders on all matters related to the utility's operations in the community. Building and maintaining strong relationships with its key stakeholders is important because it allows Toronto Hydro to effectively plan and coordinate the execution of its work program, and to reduce the likelihood of unanticipated developments that can affect project timelines and costs.

HUMAN RESOURCES & SAFETY

1. SUMMARY

Table 1: Human Resource and Safety Program Costs ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
HR & Safety	13.7	13.2	15.3	15.3	16.1

The primary objectives of the Human Resources and Safety ("HR & Safety") program are to ensure that:

- Toronto Hydro's current and future human resource complement meets the utility's evolving needs in a cost-effective and sustainable manner;
- employees possess the tools, skills, resources and support to execute the utility's capital plans and operational programs safely, reliably, responsibly and efficiently; and
- the utility consistently achieves its operational, financial and other key performance results.

The HR & Safety program meets these objectives through the provision of broad human resource management services to Toronto Hydro, including: environment, health and safety management; employee and labour relations; compensation and benefits management; performance and change management; employee communications; organization design and job design; recruitment; employee orientation; and training and development.

Toronto Hydro's HR & Safety program delivers these outcomes within the utility's complex operating environment which is characterized by unique and highly specialized operating requirements, organized labour dynamics, and aging workforce.

2. PROGRAM DESCRIPTION

The HR & Safety program consists of the following three segments:

1) Environment, Health & Safety
2) Human Resources Services and Employee Relations
3) Talent Management and Organizational Development

Toronto Hydro operates in a mature and densely urban environment, many aspects of which are unique or substantially different in scale and nature from other Ontario electricity distributors. Some of these factors include the following:

- a complex and rapidly evolving 1,600-feeder distribution system that includes an asset-intensive downtown distribution network;
- a mature and diverse grid infrastructure featuring legacy assets requiring specialized skills (e.g., box construction and Paper Insulated Led-Covered ("PILC") cable);
- unique safety challenges associated with high motor vehicle incident frequency, and widespread presence of designated substances in buildings and infrastructure; and
- large volumes of third-party initiated work in an urban environment characterized by spatial limitations and municipal ordnances restricting available work hours.

These factors, and other related conditions, characterize Toronto Hydro's service territory, and present significant challenges to the utility's HR & Safety program. The conditions in which the utility operates demand the development and maintenance of unique health and safety rules, provision of comprehensive training and apprenticeship programs to new and existing employees, and execution of targeted talent identification, succession planning and recruitment activities. Proactive, timely and cost-effective execution of these and related functions, influenced by unique considerations affecting the utility, represent the mandate of Toronto Hydro's HR & Safety program.

At the core of the HR & Safety program is a fundamental commitment to maintaining and continuously improving a robust and effective environment, health and safety management system ("EHSMS"). This focus manifests itself in a wide variety of programs, projects and resources deployed throughout the organization that prioritize and promote employee safety and wellness in every aspect of their lives, foster optimal working conditions to increase job satisfaction, facilitate productivity, and promote innovation, while also accommodating any specific needs or quickly responding to emerging trends.

Toronto Hydro's emphasis on health, safety and environment is best understood in light of the utility's history when the health, safety and environment-centered management systems were either absent or sub-optimally deployed. The summary below illustrates the key differences in outcomes between past approaches, and the current systems that Toronto Hydro has adopted since 2007. These systems include the EHSMS framework that Toronto Hydro adopted in 2007; OHSAS 18001[1] and ISO 14001[2], which the utility adopted in 2010; and formal certification of an operational management system in February 2013.

- Between 1942 and 1992, Toronto Hydro's legacy companies (pre-amalgamation) experienced a workplace fatality approximately every two-and-a-half years. There has not been a fatality at Toronto Hydro since 1992.
- In the last 14 years, the Workplace Safety and Insurance Board ("WSIB") allowed seven claims for premature death related to occupational asbestos exposure at Toronto Hydro. In each case, the instances of exposure occurred many years ago, prior to proper management systems being put in place. Asbestos management systems were put into place starting in 1990 with the introduction of the Asbestos

[1] Occupational Health and Safety Assessment Series ("OHSAS") 18001.
[2] International Organization for Standardization ("ISO") 14001.

Regulation[3] coming into effect. Toronto Hydro now has effective controls in place to protect its workers from asbestos and other designated substances.

- Between 1999 and 2005 Toronto Hydro workers experienced 22 permanent shoulder injuries; the lifetime cost of each is conservatively estimated to be $1 million. Professional ergonomic analysis of these injuries and implementation of effective controls has reduced shoulder injuries by 70% since 2005. The last shoulder injury resulting in a permanent disability occurred in 2011.

As a result of occupational health and safety programs and services that it has put in place, the utility benefits from having some of the lowest WSIB rates in the relevant industry sector. Toronto Hydro is currently in the WSIB rate group 835 (Oil, Power, and Water Distribution) and pays a premium of $1.07 per $100 of payroll. This is one of the lowest rates that the WSIB charges employers, and given the variety and magnitude of potential risks faced by Toronto Hydro's employees, the rate is a testament to the effectiveness of the utility's safety management programs.

For comparison purposes, utilities included in the rate 830 (power and telecommunication lines) pay a rate of $4.45 per $100 payroll. If Toronto Hydro and its peers in the rate 835 group had a similar injury and illness history as those in the rate 830 group, Toronto Hydro's annual premium to the WSIB would increase from $1.483 million (2013) to $6.167 million. The difference of $4.7 million in avoided operating expenditures is driven entirely by the comprehensiveness and proactive nature of the safety programs managed by the industry sector which belongs to the 835 rate group.

Beyond the avoided WSIB payment premium, the HR & Safety program has, and continues to achieve, tangible results in a number of areas. For example, since 2008

[3] Ontario Regulation 278/05, made under the Occupational Health and Safety Act, R.S.O. 1990, c. O.1 [the "Asbestos Regulation"]

Toronto Hydro achieved notable improvements with respect to the following key safety indicators:

- an 89% decrease (10.95 vs. 1.16) in Lost Time Injury Severity (LTIS);
- a 56% decrease (5.19 vs. 2.26) in Total Recordable Injury Frequency (TRIF);
- a 57% decrease (86 to 37) in the number of WSIB claims;
- a 79% (4,813 to 1,004) decrease in Restricted Work Days; and
- an 88% ($0.4 million to $0.05 million) decrease in WSIB New Experimental Experience Rating ("NEER") costs, and ensuing WSIB rebate of almost $0.3 million in recognition of substantially lower NEER costs over the last four years than expected by the program.

Toronto Hydro has also achieved significant reductions in employee absenteeism levels, specifically a 45% reduction in the rate of absenteeism from 2008 to 2013, resulting in a lower than the average rate in the utility according to Statistics Canada.[4]

The HR & Safety program has also been instrumental to the achievement of notable results with respect to the restructuring and reorganization of the utility's job functions. For example, since 2007, Toronto Hydro consolidated 41 job classifications into ten, and in 2012, the utility undertook eight major reorganizations and reviewed approximately 40 jobs. These activities enable Toronto Hydro to consider and introduce methods to adapt and modify job functions in order to facilitate performance level and productivity improvements, succession planning, and career development.

These and other accomplishments detailed throughout the remainder of this schedule are attributable to the ongoing collaboration between the HR & Safety program and the utility's other programs, aimed at establishing or refining processes and initiatives and

[4] Statistics Canada, Absence rates of full-time employees, by sex and North American Industry Classification System (NAICS), Canada, annual, online: Statistics Canada <http://www5.statcan.gc.ca/cansim/a26?lang=eng&id=2790030&p2=17>.

adopting international standards and best practices. As a cornerstone of Toronto Hydro's HR & Safety program, continuous improvement is supported by regular self-assessment efforts through external reviews and performance measurement.

Absent the effective administration and implementation of the HR & Safety programs, projects and services comprising the program's mandate, it is more likely that Toronto Hydro's employees would be exposed to unacceptable levels of risk of injuries and illness, reduced productivity levels, and operational decisions of reactive nature. These and other related risks could, in turn, increase the utility's costs and negatively impact the achievement of key operating objectives.

The remainder of this schedule will provide further details as to the scope, nature and value propositions of the functions and activities in each of the three segments.

3. ENVIRONMENT, HEALTH, AND SAFETY SEGMENT

Toronto Hydro's functions comprising the environment, health and safety ("EHS") segment are integrated with the utility's strategic planning and execution of operational and capital work programs. The segment's overarching objective is to ensure that Toronto Hydro adheres to legislative and regulatory requirements and best practices relating to occupational health and safety, workers compensation, environmental protection, and sustainability. The segment oversees execution of operational activities, preparation of plans and delivery of targeted initiatives, while adhering to the applicable internal and external reporting requirements.

Continuous monitoring and analysis of the utility's performance in environment, health, safety, and sustainability matters allows Toronto Hydro to proactively identify and

manage related risks, evaluate the effectiveness of existing practices, and facilitates compliance with statutory requirements and industry best practices.

Toronto Hydro has an obligation, pursuant to s. 4.6.1 of the Distribution System Code[5] ("DSC"), to follow good utility practices in operating and maintaining the distribution system and to abide by safety rules and regulations that apply to routine utility work, including but not limited to the Occupational Health & Safety Act ("OHSA").[6] The EHSMS and related activities performed as part of this segment are instrumental to ensuring that the utility complies with this critical obligation. Consistent with Toronto Hydro's service obligations, the work performed within this segment is carried out 24 hours a day, 7 days a week.

In addition to the utility's focus on health and safety, Toronto Hydro promotes sustainable development to integrate social and environmental responsibility into the utility's core values, culture and practices. The key functions and activities that comprise the EHS segment are summarized below.

3.1. Environmental Health and Safety Management System (EHSMS)

Toronto Hydro operates an integrated EHSMS, as opposed to having two separate environmental and safety functions, or distinguishing between these responsibilities by job design and any associated regulations.

The integrated EHSMS framework improves the efficiency and effectiveness of this segment through the joint delivery of common activities such as inspections, audits, reporting, investigations, annual planning, training, and management review meetings. It also facilitates Toronto Hydro's compliance with sections 4.6.3 to 4.6.5 of the DSC which require distributors to:

[5] Ontario Energy Board, *Distribution System Code*, (Toronto: Ontario Energy Board, 2013).
[6] R.S.O. 1990, c. O.1. ["OHSA"]

- implement an industry recognized health and safety program that includes training and regularly conducted audits (s. 4.6.3),
- remedy any problems that a distributor identifies as part of the audit as soon as possible or in accordance with the distributor's health and safety program (s. 4.6.4); and,
- put in place documented program supporting procedures and appropriate training to ensure compliance with environmental regulations and indicate a proactive approach to environmental damage avoidance (s. 4.6.5).

Toronto Hydro's decision to adopt an integrated EHSMS model was based on the results of a benchmarking study of EHS management systems conducted in 2010. The study concluded that organizations with the most effective EHS programs and best EHS results deployed integrated environmental, health and safety programs. Further research indicated that the most rigorous, demanding and effective governing EHS standards are the International Organization for Standardization ("ISO") 14001 and the Occupational Health and Safety Assessment Series ("OHSAS") 18001.[7]

Toronto Hydro found these standards to be the most comprehensive in the industry for the following reasons:

- they are the most widely recognized international standards;
- they form the basis for other crucial safety management standards (e.g., CSA Z1000, ANSI Z10)
- they were written to complement each other and to facilitate integration under a single management system; and
- compliance is verified by auditors governed by the Standards Council of Canada.

[7] ISO 14000 standards relate to environmental management. They help organizations (i) minimize the ways in which their operations negatively affect the environment, (ii) comply with legal, regulatory, and other environment-related requirements, and (iii) continually improve in the above. OHSAS 18001 is a standard for occupational health and safety management systems that is broadly recognized and adopted.

Toronto Hydro completed the implementation of an integrated EHSMS in 2011 and was subsequently certified by a third-party auditor as meeting the requirements of ISO 14001 and OHSAS 18001 in 2012.

Prior to integration of the environment, health and safety management functions into a single system, Toronto Hydro participated in a safety management program known as ZeroQuest® administered by the (then) Electrical Utility Safety Association (now the Infra-Structure Health and Safety Association).

The EHSMS provides a mechanism for early detection and mitigation of risks to achieving the corporate objectives relating to health, safety and environmental performance. In addition, the EHSMS is consistent with the risk management model adopted by Toronto Hydro under ISO 31000, as discussed in Exhibit 1C, Tab 3, Schedule 1, and dovetails with other management systems that allow for proactive planning, monitoring, reporting, and responding.

3.2. EHS Framework

Toronto Hydro's commitment to effective risk management, continual improvement and operational efficiency is demonstrated by the certification of its EHSMS with ISO 14001 and OHSAS 18001. Both ISO 14001 and OHSAS 18001 establish a framework based on the Plan–Do–Check–Act cycle, (also known as the Deming cycle), which is illustrated in Figure 1 below. Toronto Hydro plans, organizes and coordinates all EHS activities in accordance with this framework, which can be summarized as follows:

- Plan: Establish the objectives and processes necessary to deliver results in accordance with the Environmental and Health & Safety Policies.
- Do: Implement the processes.
- Check: Monitor and measure processes against the policies, objectives, targets, legal and other requirements, and report the results.
- Act: Take actions to continually improve performance of the management system.

Figure 1: Deming Cycle

Step 1: PLAN

The planning portion of the cycle begins with a number of key tasks including an audit of the EHS management system, and review of incident investigation findings and trends, applicable and proposed legislation, occupational health and safety ("OHS") hazards and risks, and past EHS performance relative to established goals, objectives and benchmarks. Based on this data and other considerations that may be put forth by management, the utility develops an annual plan.

Step 2: DO

The EHS segment consultants implement the annual plan through a number of activities, including:

- developing or amending EHS procedures and programs, associated training materials, and education and awareness communication materials;
- conducting a variety of tests and assessments such as industrial hygiene testing, ergonomic assessments, reviewing new equipment for the potential EHS risks and

benefits prior to entering the workplace, and assessing the layout of facilities to ensure the safety of the future occupants;

- collecting and analyzing performance data for corporate, divisional and departmental performance monitoring, as well as benchmarking activities;
- preparing reports to government agencies and other interested parties; and
- providing guidance to business units to ensure effective implementation of new or amended EHS procedures, and support them in the pursuit of their EHS goals and objectives.

Step 3: CHECK

This part of the cycle includes inspections, audits, investigations and the maintenance of records to verify: 1) the implementation of the operational controls, 2) the timely completion of planned work, 3) the achievement of objectives and targets, and 4) that operations are conducted safely.

- Inspections: On average, Toronto Hydro's managers, directors and front line supervisors conduct approximately 15,000 inspections per year. The EHS works with the relevant programs to develop inspection comprehensive checklists provide coaching and training for conducting effective inspections, analyze the inspection data and prepare reports for performance management and benchmarking. Since 2011, Toronto Hydro's inspection processes have been expanded to include environmental matters such as spill reports. In addition, the utility refined the safety inspection process in 2012 to shift the focus on behaviour, rather than physical conditions. The key to this process is to identify and acknowledge positive safety behaviours.
- Audits: EHS conducts audits to ensure compliance with EHS legislation and established procedures, provide assurance to management that EHS-related activities are properly managed and verify that adequate controls are in place to mitigate identified risks.

- Incident Investigations: While the focus of audits and inspections is to prevent incidents from occurring in the first place, investigations focus on determining the root cause and implementing permanent corrective actions to prevent incidents from re-occurring. Incidents reported and investigated include near misses, occupational injuries and illness, motor vehicle accidents and environmental spills.
- Performance Indicators: As required by ISO 14001 and OHSAS 18001, the EHS segment tracks and reports on a variety of performance indicators that gauge the effectiveness of the EHS management system. This helps ensure that costs are controlled and productivity is not negatively affected through excessive waste, injuries, illness, fines, legal fees, increased WSIB premiums, and property damage. The measures tracked include occupational safety performance indicators such as lost time frequency, severity, total recordable injury frequency, restricted work days, WSIB costs, and motor vehicle incidents, as well as environmental indicators relating to spills, hazardous and non-hazardous waste, greenhouse gasses released, energy conservation, and waste manifest compliance. Tracking the utility's performance against these outcomes, and taking appropriate proactive or corrective steps in response to these outcomes, facilitates continuous improvement at Toronto Hydro.

Step 4: ACT

The EHSMS requires Toronto Hydro to take actions based on the observations and findings of the checking component noted above, with the objective of ensuring that adequate controls are in place to mitigate risks, and that opportunities for continual improvement are pursued. The actions could include: 1) modifying the physical conditions; 2) amending existing procedures or training requirements; or 3) introducing new equipment, tools, processes, procedures and communicating these through education and awareness. In some cases the action can be completed immediately, while

in other circumstances actions require the establishment of multi-year objectives, targets and programs. If required, such objectives, targets and programs typically become part of the next year's planning component.

3.3. Occupational Health and Safety Activities

The EHS team develops, monitors and maintains occupational health programs that involve both proactive and reactive testing for ergonomics, indoor air quality, noise, vibration, lighting, thermal stress and designated substances, including any associated biological monitoring where warranted or required through legislation. These programs ensure the long-term health and wellness of the utility's critical workforce. In 2013, approximately 480 EHS related tests and/or assessments were conducted.

When required or appropriate, the EHS team issues EHS Bulletins to inform employees about hazards, or simply to remind everyone of safe working practices. Examples of EHS Bulletin topics include recall notices from suppliers, newly identified hazards, and personal protective equipment safety reminders.

Safety meetings are another important venue for sharing of information about safety. EHS contributes to this process, by gathering statistics and information, and preparing materials to be shared with and communicated to employees at monthly safety meetings.

In accordance with s. 4.6.2 of the DSC, Toronto Hydro and/or its EHS professionals are members of numerous industry-specific, recognized health and safety organizations, including:

- Infra-Structure Health and Safety Association ("IHSA").
- Association of Electrical Utility Safety Professionals ("AEUSP"). .
- Canadian Society of Safety Engineers ("CSSE").
- Occupational Hygiene Association of Ontario ("OHAO").

- Board of Canadian Registered Safety Professionals ("BCRSP").
- National Safety Council.
- American Industrial Hygiene Association.

In addition, as an active member of the Canadian Electricity Association ("CEA") Toronto Hydro exchanges safety information with other utilities and collaborates with its peers on public safety initiatives. For example, in 2013, Toronto Hydro assisted with the production of a public safety video directed at promotion awareness among construction contractors to about the hazards of electricity on construction sites, how to avoid electrical contact, and what to do if contact is made.

As illustrated below, from 2008 to 2013, Toronto Hydro achieved significant and sustained improvement relating to occupational safety, including:

- 56% decrease in total recordable injury frequency (TRIF) (Figure 2);
- 89% decrease in lost time injury severity (LTIS) (Figure 3);
- 83% decrease in lost time injury frequency (LTIF) (Figure 4); and
- 79% decrease in restricted work days (Figure 5).

Figure 2: Total Recordable Injury Frequency

Figure 3: Lost Time Injury Severity

Figure 4: Lost Time Injury Frequency

Figure 3: Restricted Work Days

The above-noted performance improvements are a testament to the effectiveness of the Toronto Hydro's EHSMS and related policies, programs and procedures. Due to its outstanding safety performance records in 2011, the utility was recognized by the IHSA in August 2013 for having worked 3.5 million consecutive hours without a lost time injury. In addition, in 2013 Toronto Hydro was not issued a single order for non-compliance from the Ministry of Labour or Ministry of the Environment despite numerous inspections, and there were no unplanned work refusals. The utility achieved these performance improvements while keeping the segment cost increases from the 2011 historical to 2015 test year at budgets to about 8%.

3.4. Sustainable Development

Toronto Hydro also uses the ISO 26000 standard to promote sustainable development and to integrate social responsibility into the utility's core values, processes and operations. The diagram below (Figure 6) illustrates these key principles and core subjects of the ISO 26000 standard:



Figure 4: ISO 26000 Key Principles and Core Subjects

A Sustainability Committee, made up of the executive team and staff from the HR & Safety program, was formed in 2013 to govern and oversee sustainable development at Toronto Hydro. This committee establishes goals, objectives and targets, and approves programs relating to sustainable development.

In 2014, Toronto Hydro's first analysis of its alignment with ISO 26000, which was reviewed and verified by an independent third party auditor, revealed only four gaps out of approximately 250 requirements. Actions plans have been established to close the identified gaps.

3.5. Environmental Stewardship

The DSC (s. 4.6.5) requires distributors to have an environmental stewardship policy that applies to all of the distributor's operations. Toronto Hydro complies with this obligation through its Environmental Policy, which applies to all Toronto Hydro employees and contractors who perform work on behalf of Toronto Hydro. The objective of this policy is to help ensure that the utility conducts its business in a manner that minimizes the impacts on the environment and embodies the principles of continual improvement.

The following are Toronto Hydro's core environmental principles:

1) Comply With Legal Requirements: At a minimum, comply with applicable environmental legislation and other environmental commitments.
2) Continual Improvement: Continually improve environmental performance through the establishment of and review objectives, targets and programs.
3) Employee Engagement: Engage and educate employees on the requirements of this policy and the environmental management system, and provide required training.

4) Community Engagement: Work constructively on environmental issues and with open dialogue with stakeholders including suppliers, customers, regulators, industry and the public.
5) Prevention of Pollution: Implement policies, programs, procedures or other actions for the prevention of pollution that may result from Toronto Hydro's activities.
6) Consider The Environment In Business Processes: Integrate environmental considerations into our business processes.

EHS delivers a number of environmental protection and compliance programs, such as:

- management of non–hazardous and hazardous wastes, and of Polychlorinated Bi-Phenyls ("PCBs") and PCB-containing equipment;
- environmental spill response and clean-up, investigation and reporting;
- delivery of prescribed environmental training (e.g., Transportation of Dangerous Goods Act, 1992[9] and the associated regulations);
- maintenance of air permits for equipment that discharges contaminants into the atmosphere;
- completion of annual reporting to federal, provincial, and municipal agencies; and
- hazardous waste streams registrations with the Ministry of the Environment.

The segment also responds to public concerns about the environmental effects of Toronto Hydro's activities (e.g., electromagnetic fields ("EMF"), presence of PCB's, contaminated soil).

[9] S.C. 1992, c. 34. ["TDG Act"]

4. WORKER'S COMPENSATION

The EHS segment processes and monitors occupational health and injury claims on behalf of Toronto Hydro, and works with injured employees to ensure their recovery through appropriate treatment and to encourage their participation in the workplace through meaningful work within their prescribed restrictions until they can safely return to their pre-injury role. Diligence in executing this function helps the utility manage risk in excess of $2 million (difference between the maximum rebate and the maximum surcharge under the NEER program).

The NEER program is a mandatory program administered by the WSIB, which tracks and projects costs for WSIB claims. Each year, the WSIB establishes an expected annual cost based on industry claim history and the size of organization, and compares the employers' performance against this expected cost (calculated as the performance index).

NEER costs are a combination of actual accident costs and compensation paid plus a future reserve for the claim. This value is adjusted every four quarters over a four-year period. The performance index is a ratio of actual NEER costs divided by expected costs. The smaller the value of the performance index, the better the performance of the utility. If WSIB actual costs are below the expected cost, the employer receives a rebate of the difference between the actual and expected costs. On the other hand, if the WSIB actual costs exceed the expected cost, the employer must pay a surcharge up to three times the expected cost.

Through diligent case management of WSIB claims and effective accident prevention programs, Toronto Hydro's actual NEER costs have decreased by 84% from 2008 to 2013 (see Figure 7, below) and the WSIB performance index improved by 81% over the same timeframe (see Figure 8, below).

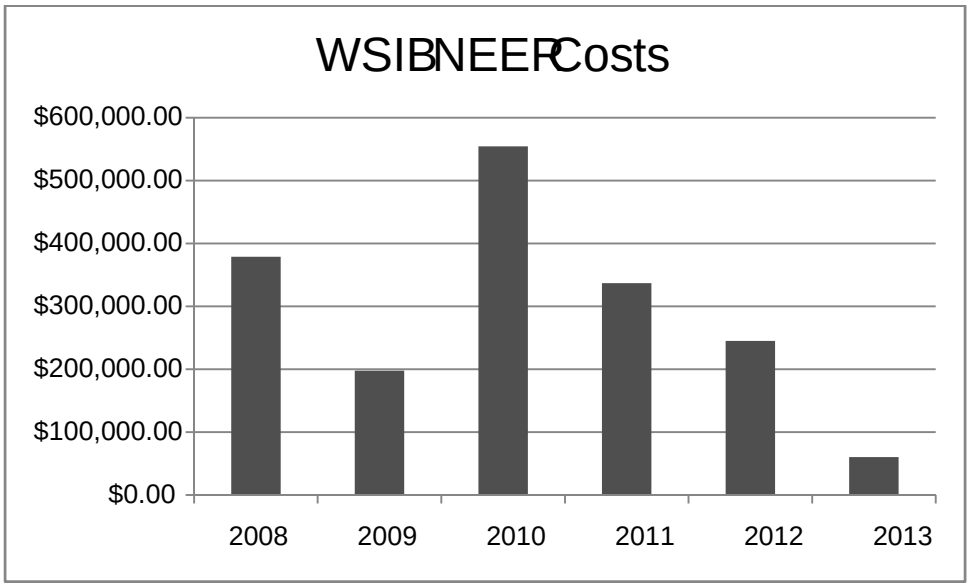


Figure 5: WSIB NEER Costs

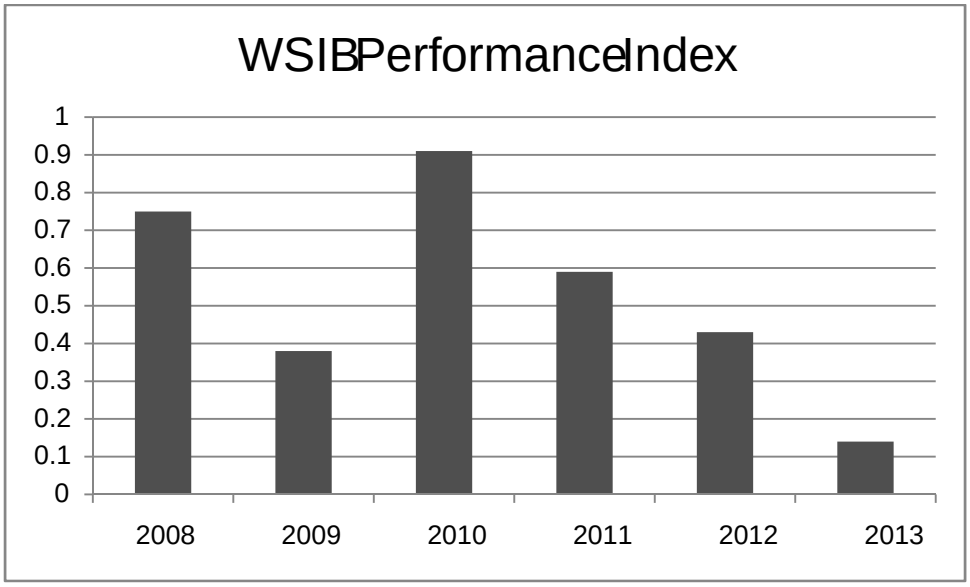


Figure 6: WSIB Performance Index

4.1. Internal and External Reporting

Toronto Hydro regularly reports on EHS performance for both internal and external purposes. Internally, the EHS team issues reports weekly, monthly, quarterly, and annually to management summarizing EHS activities and events and to the Joint Health and Safety Committees (as prescribed by OHSA).

External reporting includes mandatory reports and notifications to the City of Toronto[10], the Ministry of Labour under sections 51, 52 and 53 of OHSA, the Ontario Workplace Safety and Insurance Board under the Workplace Safety and Insurance Act, 1997[11], the Ministry of the Environment under Ontario Regulation 341 of the Environmental Protection Act[12] and Environment Canada under the Canadian Environmental Protection Act, 1999[13]

4.2. Segment Costs

Table 2 provides the Historical (2011-2013), Bridge (2014) and Test Year (2015) costs associated with the EHS segment.

Table 2: EHS Segment Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Environment Health & Safety	$2.3	$2.2	$2.4	$2.7	$2.8

4.3. 2011 – 2012

The cost of this segment decreased by $0.1 million from 2011 to 2012 through: (1) rebalancing the core of the workforce through downsizing and a voluntary exits

[10] City of Toronto, by-law No. 457-2000, Sewers Bylaw (6 July 2000).
[11] S.O. 1997, C. 16. Sched. A. ["Workplace Safety and Insurance Act"]
[12] R.S.O. 1990, C. E.19. ["Environmental Protection Act"]
[13] S.C. 1999, c. 33. ["Canadian Environmental Protection Act"]

program; and (2) organizational and job design in 2012 to adapt to changing circumstances.

4.4. 2012 – 2013

EHS segment costs increased by $0.2 million from 2012 to 2013 as additional resources were required to support the safe execution of the utility's capital work program.

4.5. 2013 - 2014

EHS segment costs increased by $0.3 million from 2013 to 2014 as additional resources were required to support the safe execution of the utility's capital work program.

4.6. Test Year Costs

The proposed 2015 Test Year costs associated with the delivery of the functions and responsibilities of the EHS segment is approximately $2.8 million, which represents an increase of $0.5 million from the utility's last rebasing year (2011), $0.4 million from the most recent historical actual year (2013), and $0.1 million from the bridge year (2014). The primary driver of these projected variances is the cost associated with the additional resources that Toronto Hydro requires to support the safe and responsible execution of the utility's work plans over the 2015-2019 rate period (refer to the Distribution System Plan filed at Exhibit 2B).

If the utility does not receive the funding it requires to execute this segment as described, Toronto Hydro's employees could be exposed to unacceptable levels of risk, including injuries and illness due to occupational health and safety hazards, and risks related to legislative and regulatory non-compliance, such as fines and penalties, and stop work orders. When inadequate resources are applied to accident prevention and environmental protection, occupational injury and illness rates can increase, as can the risk and severity of environmental contamination. Associated costs rise as the level of risk increases, and such costs can exceed the cost of preventative activities. The utility could also experience a

decline in its safety performance record, which could result in an increase in WSIB premium rates, a reduction of its overall levels of productivity and an adverse effect on its ability to achieve key operating objectives.

5. HUMAN RESOURE SERVICES AND EMPLOYEE RELATIONS SEGMENT

This segment is responsible for effective management of all employee relations, including the interpretation and administration of the collective agreement provisions, organization design, non-occupational employee claims and case management, design and administration of the compensation and benefits program, as well as facilitation and oversight of human resource technology systems and solutions. The segment maintains and enforces human resources policies and legislative requirements and provides corporate-wide human resource support in the execution of business deliverables. The following discussion addresses the key operational dimensions of the HR Services and Employee Relations segment, namely:

- Case Management;
- Employee Relations;
- Policies;
- Technology Systems and Reporting; and
- Compensation and Benefits.

5.1. Case Management

Case management focuses on the prevention, monitoring, mitigation, and resolution of specific issues relating to attendance, health, short and long-term disability, and employee compliance with corporate practices and collective agreement provisions. This function is delivered through the comprehensive case management program outlined below, which

enables Toronto Hydro to promptly identify cases, provide support and resources, and monitor situations appropriately to minimize work disruptions.

Toronto Hydro's exceptional corporate attendance record demonstrates the effectiveness of the case management function. From 2008 to 2013, the corporate attendance number improved by 45%, from 9.48 days in 2008 to 5.23 days in 2013. In addition, the utility achieved and sustained a 79% reduction in restricted work days, from 2008 to 2013. Effective health case management also resulted in a Long-Term Disability ("LTD") refund of $847,661 in 2013.

Through the comprehensive case management process, Toronto Hydro can identify cases promptly, provide resources, and monitor appropriately to minimize work disruption. The diagram below outlines Toronto Hydro's four step case management process.

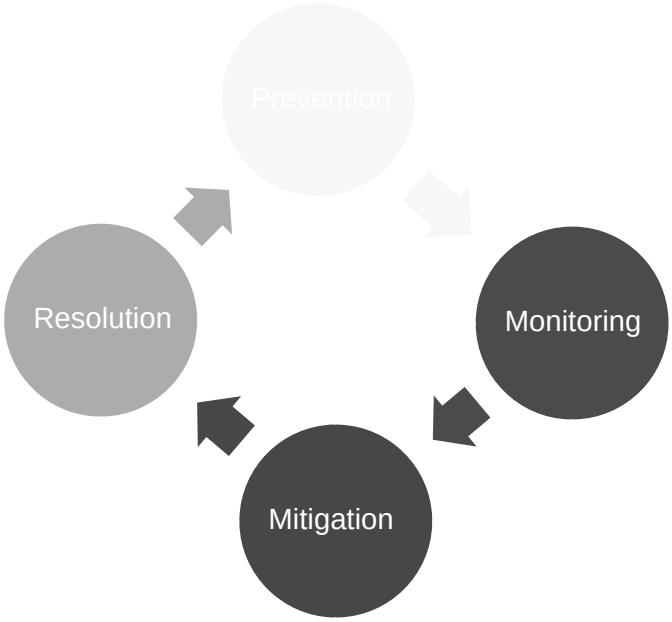


Figure 7: Case Management Process

5.1.1. Prevention

Prevention consists of biological monitoring,[14] health case management, health prevention programs, and compliance education. In 2013, Toronto Hydro expanded the safety culture to include a focus for health prevention. The key focus in 2013 was mental health awareness. Toronto Hydro fosters a preventative health culture through the offering of a wellness topic as part of monthly safety meetings. Compliance education occurs through employee engagement functions to ensure awareness of, and compliance with, corporate policies and legislative requirements. For example, all Toronto Hydro employees have been educated on the Accessibility for Ontarians with Disabilities Act, 2005,[15] requirements.

5.1.2. Monitoring And Mitigation

The Employee Relations and Human Resources Services team monitors employment related trends and issues, develops mitigation strategies to address workplace problems and proactively manages cases with business leaders in support of desired outcomes, such as training, returning to work, health management, performance management, or collective agreement adherence.

Toronto Hydro relies on a variety of tools and resources to support employees and achieve the appropriate result in the particular circumstances of each case. These tools and resources may include training, coaching for leaders, ergonomic assessments, health assessments, or counseling.

An example of this work is the case of an employee whose primary responsibility was computer work, who was diagnosed with Carpal Tunnel Syndrome and Elbow Tendinitis.

[14] Biological monitoring is legislatively required under the OHSA as an early detection resource for Toronto Hydro employees exposed to designated substances and specific environmental conditions.
[15] S.O. 2005, C. 11. ["AODA"]

The Health Services team conducted an ergonomic assessment of the employee's workstation as well as an assessment of the individual's duties. Following this assessment, the team determined that the employee's computer monitor had to be adjusted and that a computer mouse with less movement was required. In addition, a computer-based stretching tool was loaded to ensure the employee took the required stretch break and did not overuse their arms/wrists. Within two weeks the employee felt better and by four weeks the individual was performing their full duties. The ergonomic modifications and the rotation of work duties facilitated the individual's complete recovery and ability to return to their responsibilities.

5.1.3. Resolution

The Case Management cycle is complete with the resolution of the specific claim. This can occur through the health recovery, reintegration, or development of a new process/procedure to improve or resolve the claim. For example, in a situation with an occupational or non-occupational illness or injury that results in a reintegration into the workplace, Toronto Hydro utilizes the Early & Safe Return to Work ("ESRW") process. The goal of the ESRW program is to return workers to their regular duties in a safe and timely manner to the extent possible given the worker's restrictions. Where return to pre-injury position is not possible, permanent accommodation is pursued. In 2013 and 2014, 74 employees returned to positions at Toronto Hydro through the ESRW process.

5.2. Employee Relations

Toronto Hydro has a complex and diverse workforce of approximately 1,537 employees in variety of roles and functions including trades and skilled trades, and designated and technical professionals. Toronto Hydro also operates within a dynamic labour environment, as approximately 67% of its employees belong to a union. Unionized employees are organized into three bargaining units (inside workers, outside workers, and

professional engineers) and are represented by sophisticated and established labour unions, Canadian Union of Public Employees, Local 1 ("CUPE") and the Society of Professional Engineers (the "Society").

The Employee Relations function supports the operation of all of Toronto Hydro's unionized and non-unionized work groups by ensuring workplace issues are investigated and addressed promptly and appropriately. The Employee Relations team also helps ensure that the utility follows all applicable labour and employment related legislation, policies, and collective agreement requirements, and drafts and reviews policies and related documentation.

This work requires a team of sophisticated labour relations and legal professionals who can provide proactive advice on how to address these challenges, and where necessary, assist in preparing for litigation. Litigation preparation includes grievance arbitration, civil employment claims, labour board matters, and human rights claims. The Employee Relations stream also provides legal advice and assistance in regards to privacy matters and freedom of information requests that pertain to employees of the organization.

The Employee Relations team plays a primary role in planning for and engaging in collective bargaining. Since 2011, the team has negotiated two four-year agreements with its bargaining units, providing stability for the organization over the next four years with an average increase of 1.75% for CUPE and 1.8% for Society. These agreements also allow the utility to have a more flexible and productive workforce, improve customer service delivery and reduce costs through operational efficiencies.

5.3. Policies

Toronto Hydro develops, maintains and reviews a number of employment related policies. These policies, which are summarized in Table 2 below, enable the utility to

satisfy key legislative obligations, manage its workforce in accordance with best practices, or avoid employment-related risks.

Table 3: Toronto Hydro Employment-Related Policies

Policy	Source
Toronto Hydro's Violence Prevention in the Workplace Policy	Legislative Compliance with *Occupational Health and Safety Act*
Occupational Health & Safety Policy	Legislative Compliance with *Occupational Health and Safety Act*
Toronto Hydro's Workplace Harassment Policy	Legislative Compliance with *Occupational Health and Safety Act*
Toronto Hydro Code of Business Conduct	Best Practices
Accessibility Standards for Customer Service Policy	Legislative Compliance with *Accessibility for Ontarians with Disabilities Act* (AODA)
Employee Privacy Policy	Legislative Compliance with *Municipal Freedom of Information and Protection of Privacy Act*[16] (MFIPPA)
Recruitment and Selection Policy	Best Practices
Credentials Verification Policy	Best Practices
Fraud and Theft Policy	Best Practices
Toronto Hydro's Social Media and Digital Communications Guidelines	Best Practices
Cyber Security Policy and Technology Use Guidelines	Best Practices

5.4. Technology Systems and Reporting

This segment oversees a number of human resource technology systems and processes to support mangers and leaders in the execution of their workforce management duties. This allows for fact-based decision-making in the program areas of performance and

[16] R.S.O. 1990, C. M.56. ["MFIPPA"]

attendance, health and safety, training and development, and workforce planning. Oversight includes maintaining data integrity for employee and safety data, work flow, reporting, security, and technical processing. As an example of supporting data integrity, timely orientation and exit protocol of employees ensures accurate data is available for corporate financial reporting.

Data from the employee and safety systems directly feeds into other management systems which are critical to the utility's operational activities, such as financial and engineering systems. This segment provides foundational design support and oversight to the critical corporate systems that employee and safety interfaces with. As an example, current enhancements to the time and attendance system ensure availability of appropriate capital and operational expense representation, critical to reporting on the progress of the operational plan.

A number of these systems and processes, such as the Attendance Management System, Resource Requisition, and Organization Change tool, have been automated to streamline business processes and enable these functions to be executed more efficiently. For example, the Organization Change tool which was released in 2013 resulted in timely hierarchy information being interfaced to key systems that rely upon hierarchy information to manage the business operations, such as allowing for accurate safety incident reporting.

In a similar manner, the performance management system was recently consolidated and automated to provide increased functionality, data integrity, and reporting capabilities. Additional systems have also been developed to support employee communication and claims management. Toronto Hydro enhanced the safety inspection process in 2011 with the implementation of the EHS management software which allows supervisors to enter

inspection findings on their wireless laptops while in the field and automates reporting, reducing administrative time.

6. COMPENSATION AND BENEFITS

This stream of the Human Resource Services and Employee Relations segment oversees and administers Toronto Hydro's workforce compensation strategy and practices.[17] The services provided through this function are critical to utility's ability to secure and maintain a workforce that is skilled, adaptable, committed and performance-driven. Toronto Hydro strives to achieve these key outcomes in a financially responsible manner by providing wages and benefits that are competitive in the markets where Toronto Hydro competes for talent, and by recognizing employee contributions in achieving individual, divisional, and corporate performance goals.

This function is responsible for the benchmarking and annual review activities that enable Toronto Hydro to strike an appropriate balance between controlling costs and providing market-competitive compensation. It is also responsible for administering the performance review program as it relates to compensation. This program is vital to operational success because it drives desired behaviours and performance results with respect to key areas of the utility's strategy,[18] such as customer service, operational efficiency and safety.

The Compensation and Benefits function also monitors and evaluates the employee benefit program to ensure the program provides value for money, and that benefit carriers comply with the benefit agreements and service level expectations. The team's efforts in this respect enabled Toronto Hydro to save over $2 million in 2012 and $1.1 million in 2013 in benefit costs by successfully negotiating lower rate increases with benefit providers.

[17] Exhibit 4A, Tab 4, Schedule 5.
[18] Exhibit 1C, Tab 1, Schedule 1.

In addition, the team implemented a number of cost-curtailing initiatives with respect to Toronto Hydro's benefit program, which have resulted in lower costs for the utility and greater flexibility and awareness by plan members regarding their benefits plan.[19]

6.1. Segment costs

Table 4 provides the Historical (2011-2013), Bridge (2014) and Test Year (2015) costs associated with the Human Resource Services and Employee Relations segment.

Table 4: Human Resources Services & Employee Relations Segment Costs
($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Human Resource Services and Employee Relations	$4.7	$5.2	$6.2	$5.7	$5.8

6.2. 2011 – 2012

From 2011 to 2012, costs increased by $0.5 million due to: 1) additional resources required to assist with the case management process, particularly attendance management, and to review and improve the benefit management process by implementing best practices, adopting cost containment measures and negotiating better rates with benefit providers; and 2) an increase in legal fees associated grievance arbitrations and labour board matters.

6.3. 2012 – 2013

From 2012 to 2013, costs increased by $1 million due to: 1) an increase in legal fees associated with grievance arbitrations and other matters; and 2) additional resources required to support employee labour relations matters, and case management. The additional resources were necessary to manage an increase in Freedom of Information

[19] Exhibit 4A, Tab 4, Schedule 5.

("FOI") requests, and to deliver additional human resource services to support the safe and efficient execution of the utility's capital work program.

6.4. 2013 – 2014

From 2013 to 2014 the budget is expected to decrease by approximately $0.5 million, as a result of reductions relating to professional fees.

6.5. Test Year Costs

The 2015 Test Year costs associated with the delivery of the functions and responsibilities of the Human Resources Services and Employee Relations are approximately $5.8 million, which represents a $1.1 million increase from the last rebasing year (2011), a $0.4 million decrease over the most recent actual year (2013), and a $0.1 million increase from Bridge Year forecast (2014).

Historically, the cost of delivering this segment has fluctuated to some extent due to legal expenses associated with grievance actions and other employment related legal matters, all of which are beyond management's control and ability to forecast. Toronto Hydro's legal expenses for employment related matters are expected to continue to fluctuate over the 2015-2019 rate period.

Although Toronto Hydro's overall staffing levels have decreased since its last rebasing application in 2011, the utility requires additional resources to manage the complexities associated with its aging workforce,[20] and to support the safe and efficient execution of the utility's capital program.[21] Toronto Hydro also needs the requested level of funding to sustain the initiatives and programs that the utility has put in place over the current rate period to foster greater productivity, enable the achievement of performance goals, and curtail workforce-related costs.

[20] Exhibit 4A, Tab 4, Schedule 3.
[21] Exhibit 2B.

If Toronto Hydro does not receive the requested level of funding to carry out the functions and responsibilities that comprise this segment, the utility may be exposed to a number of risks. These risks could include legislative or regulatory non-compliance as a result of having insufficient resources to monitor, advise on, and enforce compliance with the utility's statutory and regulatory obligations; lower levels of productivity across the organization due to the inability to investigate and remedy employment issues such as attendance management; and other miscellaneous risks such as the inability to defend itself against employment related claims, or to pursue further efficiencies and cost-saving opportunities.

7. TALENT MANAGEMENT AND ORGANIZATIONAL DEVELOPMENT SEGMENT

The Talent Management and Organizational Development segment is responsible for the development and execution of the workforce staffing plan, succession, and employee development strategies and programs. The primary objective of this segment is to attract and maintain a skilled, productive and adaptable workforce that Toronto Hydro requires to execute its programs and deliver safe and reliable electricity service to its customer.

Functions that enable Toronto Hydro to achieve these outcomes include: workforce staffing; short-term and long-term succession planning; job and organizational design; attraction, recruitment and selection of new employees; employee orientation, engagement and communication; performance and change management systems; training and development; and employee retention.

Toronto Hydro's operational realities and workforce challenges (i.e., dense urban landscape, complex underground system, congestion due to growth and construction in

the City of Toronto, and aging workforce) have important implications for the Talent Management and Organizational Development segment. For example, the Talent Management team must establish and implement multiple attraction and recruitment strategies in order to satisfy the utility's diverse workforce requirements. These strategies include promoting from within, hiring from the external market, and building partnership with colleges and universities to hire new graduates.[22]

Likewise, the Organizational Development team must establish and implement a wide variety of training, development and change management initiatives in order to ensure that Toronto Hydro's employees have the skills, resources and tools they require to execute the utility's plans safely, effectively and efficiently.

7.1. Talent Management

The Talent Management function plans and executes the utility's short- and long-term staffing strategy[23] with regard to a number of factors including: the resources that the utility needs to execute its capital plans and operational programs, the availability of talent within the utility and in external market, and the actual and projected turnover rates. This segment is also responsible for establishing and administering industry specific collaborations with colleges and universities, attraction strategies, and the recruitment and selection processes.

Talent Management guides and executes both the internal and external selection process, ensuring that it is fair, barrier free, and that competition is not biased. Toronto Hydro relies on a number of strategies to attract highly skilled and diverse candidates from the external market. To be more specific, the utility,

- maintains a presence on professional social networking websites and uses these websites to promote and protect its employment brand;

[22] Exhibit 4A, Tab 4, Schedule 3.
[23] Exhibit 4A, Tab 4, Schedule 3.

- participates in job fairs at universities, colleges and professional associations; and
- leverages collaborations with educational institutions, such a Ryerson University and Georgian College, local City colleges and community organizations such as The Learning Partnership, Micro Skills and the Toronto Regional Immigrant Employment Council.

Collaborations with educational institutions are particularly important because they allow Toronto Hydro to spread awareness about its human resource requirements, build recruitment relationships with future graduates, and influence and shape the programs and curriculum offered to students with the utility's strategic goals and long-term needs. Through these partnerships, Toronto Hydro hired approximately 18 full time employees into the certified and skilled trades and graduated and technical professional positions between 2011 and 2013.

Toronto Hydro uses a competency-based selection process to fulfill vacancies, whereby candidates are evaluated on both behavioural corporate competencies and technical job specific requirements. Examples of behavioral competencies include the ability to demonstrate a commitment to EHS and tasks associated with championing change, productivity and innovation. Manual and physical dexterity are examples of technical job specific requirements for the Certified Powerline Person position. These skills would be demonstrated by the completion of cabling, installation and taping tasks while working in a "stooped" position.

The balance between behavioural and technical competencies ensures that highly qualified candidates are identified and considered by the organization. Through this comprehensive selection process, Toronto Hydro has been able to maintain a low turnover rate over the 2011 to 2013 period.

A number of process improvement initiatives have been undertaken by the Talent Management team to secure market competitive costs for various talent management services. These initiatives included the execution of request for proposals ("RFPs") to establish preferred vendor relationships, the benefits of which are efficiencies relating to pre-negotiated terms and condition of service and discounted service rates with temporary staffing agencies, leadership and technical search firms, and background screening providers. These services are also valuable because they allow internal resources to focus on more strategic activities such as job design, attraction strategies, and competency evaluations.

7.2. Organization Design

Organization design assesses the functionality of Toronto Hydro's business departments and operational divisions by reviewing each business units' functional responsibilities and associated processes for meeting these responsibilities. Organization design staff also work with the business units to plan for long-term goals and objectives, consider succession opportunities, and devise the appropriate short-term and long-term workforce requirements for meeting those goals and objectives. In addition, staff work with other teams to review the organizational structure and identify strategies to enhance existing processes, achieve operational efficiencies and cost savings, and improve overall organization performance. This review also allows Toronto Hydro to be confident that job roles are clearly defined, that performance is adequately measured and that employees are compensated based on the appropriate job evaluation.

7.3. Change Management

The Organizational Development team collaborates with other business units to design and administer change management functions, the objective of which is to implement specific programs and initiatives to align the workforce with the utility's goals and objectives.

As an example, in 2013, Toronto Hydro relied on its internal change management expertise to develop a program about working in energized chambers. A pilot project is currently in place to train 30 employees, and the utility expects that the program will be fully rolled out to in 2015. The objective of this initiative is to develop and implement a procedure for safely working in live cable chambers, in order to overcome a number of operational disadvantages associated with de-energizing cables. More specifically, when cables are de-energized, all affected feeders are placed in an abnormal state, meaning that nearby feeders have to carry the additional load, which puts additional strain on highly loaded equipment and increases the risk of wide spread outages. This practice also reduces the life span of cables and the availability of system redundancy which is critical to reliability. In addition, it increases the complexities of job planning, as well as the number of planned outages that Toronto Hydro has to undertake to perform work on the system.

The change management team supports the staffing and training strategies associated with this initiative, and plays an instrumental role in encouraging worker participation by demonstrating that this work can be done safely

7.4. Training and Development

In order to develop and sustain a qualified and competent workforce, Toronto Hydro's Organizational Development team administers an array of training and development programs, including the new employee orientation, apprenticeship and leadership programs. In 2013, the Organizational Development team organized and successfully delivered 103 training programs, as summarized in the chart below (Table 5).

Table 5: Training Programs

Area	2011 Courses	2012 Courses	2013 Courses
Compliance (e.g., Environmental and Safety legislative training, EUSA and ESA Rules, Confined Space, Work Protection Code, Network Switching)	10	20	42
Legislative (e.g., WHMIS, Defensive Driving, Forklift Training)	5	17	20
Apprentice (e.g., Distribution Systems Technologist, Power Systems Controllers, Certified Power Cable Persons, Certified Power Line Persons, Meter Mechanics)	10	16	19
Leadership (e.g., Safety Leadership, Performance Management, Management Control & Reporting System , Project Management, Policy Administration)	9	7	6
Technical & Customer Service Training (e.g., Engineering Technicians, Electrical Awareness, Project Execution , Customer Education Training)	14	14	16
Total	**48**	**74**	**103**
Total Cost	**$1.23M**	**$1.18M**	**$1.47M**

Successful integration of new employees depends upon the timely delivery of specific training programs and initiatives to ensure that employees are competent and capable of safely and effectively performing all components of their job. Training programs at

Toronto Hydro include courses with respect to the utility's operating standards and procedures, as well as a host of legislative and compliance requirements, such as those outlined in sections 25 and 26 of the Occupational Health and Safety Act.

Effective leadership and succession planning are essential to the utility's success and provide value to Toronto Hydro's customers by driving productivity and efficiency, and protecting the continuity of the utility's operations. Training and development facilitates these objectives, in conjunction with the performance management program which allows employees to identify career development goals, specific interests and any skill or knowledge gaps that they would like to fill. This information is critical to recognizing and developing potential leaders and successors from within the utility, and to delivering Toronto Hydro's staffing strategy.[24]

The development process unfolds over the employment lifecycle through various training programs and initiatives. For example, the leadership program provides training with respect to effective conflict resolution, improving productivity, developing regulatory acumen, and providing exceptional customer service. Employees who participated in this program have reported a significant improvement in their supervisory skills and management capabilities. Without these initiatives, Toronto Hydro's present and future ability to meet customers' needs and satisfy operational requirements could be negatively affected as the utility may not have the available internal talent to satisfy leadership requirements.

To track and administer its training programs more efficiently, the Organizational Development team developed a comprehensive matrix that identifies the specific training requirements applicable to each position and role within the utility. The matrix is used to develop training plans for newly-hired, transferred, or promoted employees, as well as for

[24] Exhibit 4A, Tab 4, Schedule 3.

tracking and identifying the need to retrain existing employees. The matrix is periodically reviewed and updated as requirements change and evolve.

Comprehensive training is not only a legislative requirement under the Occupational Health Safety Act and other key statutes and codes that govern Toronto Hydro, but it also contributes to higher employee productivity, efficiency and safer operations. For example, the graph below (Figure 10) illustrates the correlation between Toronto Hydro's safety results as a measure by the Total Recordable Injury Frequency ("TRIF") metric, and the number of training days per year. This graph shows that TRIF figures have decreased signficantly since Toronto Hydro implemented its comprehensive training program in 2006.

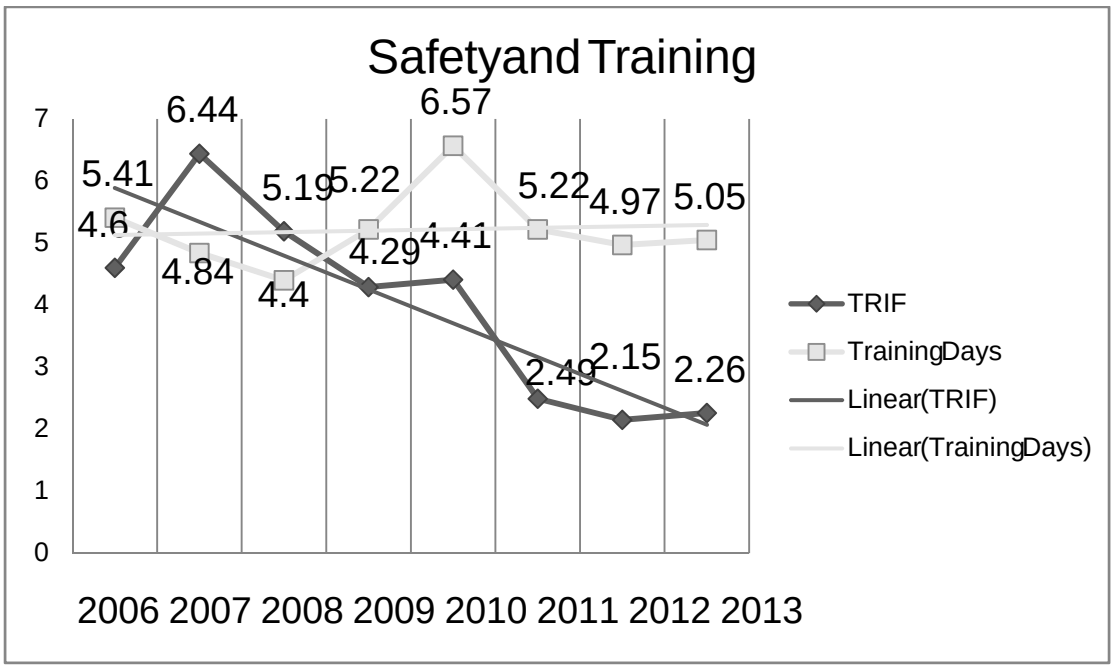


Figure 8: Safety Results vs. Training Days

Toronto Hydro's technical training and development programs are an essential resource for meeting all legislative, compliance and utility specific training requirements. These

programs are tailored and customized to address the specific needs and challenges of Toronto Hydro's distirbution system, and to equip the utiltiy's workforce with key safety practices and operational procedures.

In addition, the technical training and development programs play a key role in facilitaiting the development and transfer of core knowledge about the complexities of Toronto Hydro's distribution system and in maintaining the specialized work skills which are critical at Toronto Hydro (e.g., network switching, work on box construction, and lead cable splicing in the underground system), to allow retiring older workers an opportunity to share the complexities of the utility's assets with new workers.

Complexities related to box construction include equipment age, accessibility and safety constraints. Complexities related to oil-Insulated Lead Cable ("PILC") include exposure to hazardous materials and when unconditioning, there is a potential for an arc flash fire.

Through the technical training an development programs, Toronto Hydro administers five certified apprenticeship training programs:

- certified power line persons ("CPLP"),
- certified power cable persons ("CPCP"),
- distribution system technologists (DST),
- power system controllers ("PSC"), and
- certified meter mechanics ("CMM").

Toronto Hydro also admnisters two technical training programs: engineering technologist and engineers.

The table below (Table 6) illustrates Toronto Hydro's historical and forecast apprenticeship hiring.

Table 6: Training Programs

Apprentice Group	2011	2012	2013	2014	2015	2016	2017	2018	2019
CPCP	13	0	0	9	18	18	18	18	27
CPLP	12	0	0	0	24	12	12	12	12
DST	12	0	9	9	16	8	0	0	8
PSC	8	4	0	4	6	4	2	2	2
CMM	0	0	0	0	5	0	4	5	4
Engineering Technologist	17	6	2	15	6	6	8	2	12
Engineer	16	2	6	2	2	2	2	1	1
Total	**78**	**12**	**17**	**39**	**77**	**50**	**46**	**40**	**66**

The utility's CPLP program is recognized and accredited by the Ministry for Training, Colleges and Universities ("MTCU"). The other four apprenticeship programs are designed with the objective of developing and maintaining the specialized skills and knowledge that certified and skilled tradesmen and designated and technical professionals require to work on Toronto Hydro's distribution plant safely and effieciently.

The MCTU considers Toronto Hydro a Training Delivery Agent ("TDA"), which means that Toronto Hydro's apprenticeship programs must satisfy certain educational standards and criteria, as outlined in the MTCU's TDA Approval Process Guidelines. These requriements apply to the CPLP program, and these standards are consistently applied to all other programs. Pursuant to these criteria and standards, Toronto Hydro must:

- support increased apprenticship registrations, participations and completions;
- improve the apprenticeship delivery system in at least one of the key cornerstones as determined by MTCU;

- indicate labour market demand for the specific program requested and provide proof of local industry support for delivery at the requesting institution;
- demonstrate that it has and will make available for the course all curriculum standards and equipment necessary to deliver ministry-approved curriculum meeting all learning outcomes;
- outline the criteria it will use to select course instructors including, where appropriate, language and cultural sensitive skills;
- demonstrate the availability of academic assistance programs and accomodiations for persons with disabilities or special needs;
- allow Ministry staff or a third party the required acces to evaluate curriculum delivery, including access to the premises, their staff and apprentices; and
- Comply with all applicable legislation including the Ontario College of Trades and Apprenticeship Act, 2009[25] ("OCTAA"), the OHSA, and any other laws and regulations that may apply.

7.5. Performance Management

Toronto Hydro drives and incentivizes its employees to demonstrate specific behaviours and achieve desired results through the annual performance management program. Performance management is the process of jointly establishing performance expectations, monitoring and evaluating performance throughout the year, providing regular coaching, and assessing and recognizing employee achievements. This function ensures that employees know what is expected of them and that they understand how their roles support the strategic direction and core objectives of the utility.[26] In addition to mobilizing Toronto Hydro's workforce to achieve the core objectives outlined in the corporate strategy, the annual performance management cycle facilitates career development and contributes to employee engagement and enrichment.

[25] S.O. 2009, C. 22. ("OCTAA")
[26] Exhibit 1C, Tab 3, Schedule 1.

7.6. Employee Engagement and Communication

The Organizational Development stream oversees employee engagement and communications at Toronto Hydro. This is achieved through the new employee orientation program, employee communications and employee events such as organizational updates and community involvement. Research indicates that companies who rank in the top quartile with respect to employee engagement have a higher rate of productivity and experience a decrease in turnover and in safety incidents relative to companies that rank in the bottom quartile.[27]

In 2012, a comprehensive employee engagement program was established to support and engage employees during a time of ambiguity and change. This program encourages leaders to be accountable and visible to employees, to ensure that employees understand the messages and direction of the organization, and to address employee concerns.

7.7. Segment costs

Table 7 provides the Historical (2011-2013), Bridge (2014) and Test Year (2015) costs associated with the Talent Management and Organizational Development segment.

Table 7: Talent Management and Organizational Development Segment Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Talent Management and Organization Development	$6.7	$5.9	$6.6	$6.9	$7.5

7.8. 2011 – 2012

From 2011 to 2012, segment costs decreased by $0.8 million. This was achieved by: (1) rebalancing the core of the workforce through downsizing and a voluntary exits

[27] James K. Harter et al, Q12® Meta-Analysis, (Lincoln: The Gallup Organization, 2014).

program; and (2) organizational and job design in 2012 to adapt to changing circumstances. Recruitment and selection were also declined beginning in 2012. All of these factors led to restructuring of the team responsible for delivering this segment and a corresponding decline in associated labour costs.

7.9. 2012 – 2013

From 2012 to 2013, segment costs increased by $0.7 million to support recruitment activities, training and development programs, and change management initiatives. The increases were required to enable the safe, and efficient execution of the utility's capital work program.

7.10. 2013 – 2014

From 2013 to 2014, segment costs are expected to increase by $0.3 million to account for compensation and inflationary increases, and to support expanded functions relating to recruitment and employee communication.

7.11. 2015 Test Year Costs

The 2015 test year costs associated with the delivery of the functions and responsibilities of the Talent Management and Organizational Development segment are approximately $7.5 million. This represents an $0.8 million increase from the last rebasing year (2011), a $0.9 million increase from the most recent historical year (2013), and a $0.6 million increase from the bridge year forecast (2014).

The primary driver of this variance is the need to support expanded recruitment, training and development activities associated with ramping-up the apprenticeship hiring plan, which is a critical aspect of the utility's workforce staffing strategy.[28] Toronto Hydro must ramp-up the apprenticeship hiring program in order to: 1) facilitate prudent

[28] Exhibit 4A, Tab 4, Schedule 3.

succession planning; 2) prepare itself for the wave of retirements that it expects to encounter in the next five to ten years; and, most importantly, 3) ensure that the utility has the internal resources it requires to execute its work plans safely and efficiently over the rate period and thereafter.

If Toronto Hydro does not receive the requested level of funding to perform the functions and satisfy the responsibilities identified in this segment, the utility could be exposed to a number of risks. These risks most notably include a reduced ability to successfully recruit and develop the skilled and specialized resources that Toronto Hydro requires in the next five years, and to comply with the legislative training requirements that the utility is subject to under statutes such as the OHSA. If these risks materialize during the 2015 to 2019 rate period, Toronto Hydro's exceptional safety performance record may decline, and the utility may face financial consequences such as increased WSIB premium rates and/or fines and penalties associated with non-compliance.

FINANCE PROGRAM

1. SUMMARY

Table 1: Finance Program Costs ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Finance	16.1	14.7	15.7	17.0	17.9

Toronto Hydro's Finance program oversees all functions related to ensuring the utility's financial viability, sustainability, fulfillment of its financial obligations and maintenance of compliance requirements imposed by the relevant regulatory bodies. The Finance program supports every aspect of Toronto Hydro's operations through business planning activities, payroll services, accounts payable, internal audit and other issue area-specific functions.

2. PROGRAM DESCRIPTION

The Finance program provides support to segments and programs at Toronto Hydro. It enables Toronto Hydro to satisfy its statutory and regulatory financial reporting obligations. Statutory financial reporting requirements primarily relate to the preparation and issuance of quarterly and audited annual financial statements, including the Management Discussion & Analysis ("MD&A") and Annual Information Form ("AIF") as specified by the Ontario Securities Commission ("OSC") and the Canada Revenue Agency ("CRA"). Regulatory financial reporting required by the Ontario Energy Board ("OEB") includes quarterly and annual reporting under the OEB's Electricity Reporting and Record Keeping Requirements (the "RRR") and compliance with the OEB's Accounting Procedures Handbook ("APH").

The Finance program also delivers traditional finance functions such as Payroll services, Accounts Payable, Treasury and Internal Audit that allow Toronto Hydro to meet its regular and long-term financial and other obligations to its employees, external suppliers and service providers, Toronto Hydro's debt holders, government agencies and the external auditors. In addition, this program oversees a number of operational processes (i.e., capital services, financial planning and budgeting, financial reporting and analysis, and regulatory and revenue management) that monitor the utility's financial performance and support management's ability to make informed, strategic decisions.

The Finance function is the backbone of the utility's operational effectiveness and financial sustainability. Absent the requested level of funding to execute the Finance Program as described, Toronto Hydro could be exposed to a number of risks, including

- reporting errors and material misstatements in financial reporting purposes;
- reduced oversight and management controls that can impact operational decisions and compromise the achievement of strategic objectives;
- inability to satisfy financial obligations to third party suppliers, employees and the government;
- a compromised ability to secure funding to finance the capital programs and/or risk of violation of the covenants contained in the existing debt issuances.

The Finance program at Toronto Hydro utilizes a centralized business model where all the resources are part of one group. Such resources are at times allocated to various business units to provide on-going support for the day-to-day operations. This program is comprised of three segments:

1) Controllership which leverages knowledge of operational processes and internal controls to verify the accuracy, completeness and relevance of financial information, and facilitates corporate and operational planning by providing appropriate financial business support and senior management.

2) Financial Services which encompasses essential functions that allow Toronto Hydro to meet its regular and long-term financial obligations to its employees, external suppliers and service providers, debt holders and other stakeholders; and
3) External Reporting which oversees the preparation of external financial reporting materials, such publically filed annual and interim financial statements and disclosures, in accordance with applicable accounting standards and Securities legislation

Table 2 provides the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for each of the program's segments.

Table 2: Finance Program Costs by Segment ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Controllership	5.3	5.4	6.4	6.7	7.3
External Reporting	2.9	2.6	2.6	3.1	3.2
Financial Services	7.9	6.7	6.7	7.2	7.4
Total	**16.1**	**14.7**	**15.7**	**17.0**	**17.9**

The remainder of this schedule provides further details as to the scope, nature and value propositions of the functions and activities in each of the three segments comprising the Finance program.

3. CONTROLLERSHIP SEGMENT

The Controllership segment provides timely and accurate financial information and financial support to Toronto Hydro's senior management and operational business units,

and allows the utility's financial reports to meet both statutory and regulatory financial reporting requirements. The Controllership segment leverages knowledge of operational processes to produce accurate and relevant financial information, and to provide appropriate financial context for decision making by the operational business units and senior management. This function is crucial in enabling management to make informed decisions and for monitoring and analyzing the utility's financial performance against short-term goals, long term plans and regulatory filings. The activities comprising this segment encompass the following functions: financial planning and budgeting, financial reporting and analysis, financial processes and internal controls, regulatory and revenue reporting, and capital services.

3.1. Financial Planning and Budgeting

The financial planning and budgeting function oversees the development of the utility's annual budget and long-term financial projections. The team leverages the analysis provided through the Financial Reporting and Analysis function described below to identify issues that may impact Toronto Hydro's ability to achieve its financial objectives. Financial planning and budgeting is a key function to any successful organization as it allows management to effectively make decisions that enable the achievement of the company's strategic goals and performance objectives. Without this function, Toronto Hydro's business planning and budgeting processes would be de-centralized, which would likely introduce a variety of risks to the utility.

3.2. Financial Reporting and Analysis

The financial reporting function oversees internal management reporting and supports the external reporting segment of the Finance program discussed in more detailed below. Responsibilities of this function include: managing financial systems and processes to effectively deliver timely reports and outputs; reviewing, consolidating and preparing analyses for management reports to enable timely decision making, external reporting

and disclosure; and reviewing and consolidating monthly financial outlooks. Without this function, management would not have access to reliable financial information to make effectives decisions related to operation expenditures and capital investment. This could expose the utility to a number of material financial risks.

External financial reporting supports the preparation and issuance of quarterly and annual financial statements, including the Management Discussion & Analysis ("MD&A") and other financial reports required by Ontario Securities Commission ("OSC"), and the Canada Revenue Agency ("CRA"). The function also supports Toronto Hydro's auditors in relation to quarterly reviews and annual audits. The specific duties of the external financial reporting team include: collecting and reviewing account reconciliations for financial consolidation and OSC reporting purpose; researching accounting standards and preparing documentation to comply with these standards; addressing requests from external auditors and the external reporting team; preparing account reconciliations and analyses to support external disclosures; and preparing and providing feedback on note disclosures. The team reviews all financial information to minimize the risk of material errors, to confirm that the information complies with reporting requirements and accounting standards, and to enable management to attest to the accuracy and completeness of publically filed financial information.

3.3. Financial Processes and Internal Controls

Toronto Hydro must comply with numerous external requirements, including the OSC's financial disclosure rules, the OEB's filing requirements and accounting procedures for regulated utilities, accounting and reporting standards under United States Generally Accepted Accounting Principles ("USGAAP") and International Financial Reporting Standards ("IFRS"). In addition, Toronto Hydro adheres to an array of internal controls and processes imposed by way of corporate governance or as a matter of best practice. This function of the Controllership segment allows the utility to comply with the various

external and internal requirements and processes that govern Toronto Hydro's financial operations. In addition, the financial processes and internal controls function supports the identification, assessment, management, and mitigation of organizational risks relating to Toronto Hydro's financial operations.

The financial processes and internal control function enable a more efficient external auditing process, improve operational effectiveness, reduce the potential for reporting errors, and review and improve the design and operation of existing controls to achieve more efficient practices. These outcomes are achieved through the ongoing use and administration of the internal control over financial reporting ("ICFR") process, a financial governance framework of checks and balances, based on best practices, monitored by management and the Board of Directors, and reviewed by external auditors. ICFR facilitates the integrity of financial information for financial reporting purposes. For example, as part of the ICFR, controls have been implemented that require review and sign off, attesting to the accuracy and completeness of financial information, by appropriate finance representatives. ICFR facilitates the preparation of Toronto Hydro's Financial Statements.

3.4. Regulatory and Revenue Management

The Regulatory and Revenue Management function oversees financial activities associated with OEB and is responsible for accounting in relation to Toronto Hydro's transactions with the IESO and other suppliers for cost of power expenses and other related regulatory settlements. Other responsibilities include budgeting, forecasting, financial analysis and reporting under the OEB's Electricity Reporting and Record Keeping Requirements (the "RRR") and for the purpose of rate applications. This function also supports OEB audits, enables compliance with the OEB financial and regulatory accounting procedures outlined in the Accounting Procedures Handbook ("APH") and supports the External Reporting, Financial Reporting and Analysis and

Financial Planning and Budgeting functions in relation to Regulatory Assets and Liabilities.

3.5. Capital Services

The Capital Services function records capital projects in the fixed asset register, and maintains tangible, intangible and regulatory assets financial data under both USGAAP and IFRS. The team provides monthly, quarterly and yearly fixed assets, capital expenditure ("Capex"), depreciation expense, construction work in process ("CWIP") and in-service additions ("ISA") continuities, reconciliations, reports and analysis to ensure compliance with OSC and OEB requirements. By providing regular reports and analysis of the capital work plan, this function enables Toronto Hydro to track and monitor its performance relating to execution of the plan. In addition, the team collaborates with operation groups to develop, implement and optimize internal controls and processes to maintain the integrity of financial data and improve efficiency. These services are essential to Toronto Hydro's ability to comply with regulatory standards, to produce accurate financial statements, and to successfully deliver the utility's capital work plans.

3.6. Segment Costs

Table 3 provides the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Controllership segment.

Table 3: Controllership Segment Expenses ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Controllership	5.3	5.4	6.4	6.7	7.3

3.7. 2011 – 2012

Segment costs increased from 2011 to 2012 by $0.1 million due to normal inflationary pressures.

3.8. 2012 – 2013

Costs increased by $1 million from 2012 to 2013, due to the addition of new resources to support the increased reporting requirements and reporting complexity related to Financial Planning and Budgeting, Regulatory Reporting and Capital Services as described below in Test Year Costs section

3.9. 2013 – 2014

Costs are forecasted to rise by $0.3 million due to inflation and the addition of resources to support increased reporting requirements and reporting complexity related to Financial Planning and Budgeting, Regulatory Reporting and Capital Services as described below in Test Year Costs section

3.10. Test Year Costs

The 2015 proposed test year costs associated with the delivery of the functions and responsibilities of the Controllership segment are projected to be $7.3 million, which represents an increase of $2.0 million from the utility's last rebasing year (2011), $0.9 million from the most recent historical actual year (2013), and $0.6 million from the bridge year (2014). These variances are attributable to the following facotrs:

3.11. Implementation of IFRS/MIFRS:

- In 2011, a revised capitalization process involving the componentization of assets was completed following the initial conversion to IFRS. Due to this change, fixed assets are created and tracked at a more granular level of detail.

- In 2013, the Capital Services function completed the conversion to IFRS and MFIRS (with an adoption date of January 1, 2014 for regulatory reporting purposes). The Capital Services team now manages multiple ledgers, each of which has their own reporting requirements.
- Under IFRS, the utility is required to administer de-recognition process to facilitate the removal of assets from the fixed asset sub-ledger that are no longer in use. To maintain the process, a monthly review of the operational data is conducted by the Capital Services team to review and validate asset removals.
- Additional internal controls have been implemented to comply with financial audit and regulatory reporting requirements under IFRS/MIFRS.

3.12. Increased size and complexity of capital program:

- The capital program is expected to grow from approximately $445 million in 2011, to a forecasted $524 million in 2015.
- The number of capital projects processed by the Capital Services team increased from 1,943 in 2011 to 2,621 in 2013.
- Regulatory requirements regarding the accounting treatment of capital projects (i.e., ICM) have increased the complexity of the financial planning, control and reporting functions of this segment.
- Increased external audit scrutiny resulting in increased volumes of sample selections. The number of audit samples selected for testing grew from 182 in 2011 to 301 in 2013.
- Additional resources are required to support the increase in the volume and complexity of the work associated with Toronto Hydro's capital program.

3.13. Other Drivers

The implementation of smart meters has increased the quality of metering data available for analysis, allowing for increased focus on Revenue and Cost of Power accounting.

This work includes implementing new controls for ensuring integrity and accuracy of all the related components and more predictive data to support financial data.

If Toronto Hydro does not receive the funding it requires to perform the functions captured within this segment, the utility could be exposed to a number of risks, including: reporting errors and material misstatements for financial reporting purposes; a reduced ability to process financial data for internal and external reporting purposes; reduced quality of financial planning, oversight and management functions which could have detrimental consequences to operational effectiveness and the utility's ability to deliver its plans.

4. FINANCIAL SERVICES SEGMENT

The Financial Services segment encompasses essential functions that allow Toronto Hydro to meet its regular and long-term financial obligations to its employees, external suppliers and service providers, Toronto Hydro's debt holders and the government. It also allows the utility to plan for, secure and provide timely payments for market-competitive debt instruments that it needs to finance its growing capital work program.

The Financial Services segment provides Toronto Hydro with a means to objectively evaluate the accuracy, consistency and efficiency of its core functions and processes to ensure compliance to internal and external policies and facilitate transparency in all corporate activities. The scope of activities comprising this segment is typical for organizations of Toronto Hydro's size, mandate and legal status, and includes the following functions:

- Accounts Payable;
- Payroll Administration;
- Corporate Tax;

- Treasury; and
- Internal Audit.

4.1. Accounts Payable

The Accounts Payable function facilitates timely and accurate payment of all valid invoices to Toronto Hydro from its suppliers and service providers. It also processes payments for eligible customer refunds initiated by the customer service program. In performing these functions Accounts Payable utilizes financial software applications to validate and/or correct the amounts and timing of supplier invoices, review the payment files generated by the other applications and approve the resulting bank transfer files or cheque runs. Where the invoice validation procedures uncover errors or other inconsistencies, Accounts Payable works with suppliers and internal business units to confirm the scope, timing and nature of corrective entries and ensure proper completion of all transactions.

4.2. Payroll Administration

The Payroll function ensures that Toronto Hydro employees are paid for their services in a timely and accurate manner, consistent with relevant time-keeping or other human resources applications and records. The function also ensures that all relevant legislative requirements and statutory deductions are properly applied to each employee's payments, including the maintenance of accurate pension records for all eligible employees.

4.3. Corporate Tax

The Corporate Tax function is responsible for processing corporate income taxes, harmonized sales tax, debt retirement charge, non-resident withholding tax, and payroll taxes. This group also executes Toronto Hydro's tax-related financial planning activities, performs tax-related monitoring and reporting work, and supports compliance audit activities as required by applicable legislation and internal policies. Corporate Tax also

plays a role in business planning and regulatory compliance. For example, the group prepares Payment in Lieu of Taxes ("PILs") calculations for the purposes of rate filings.[1]

4.4. Treasury and Insurance

The Treasury and Insurance function oversees Toronto Hydro's cash management activities, debt management and investor relations services, and corporate insurance requirements. Cash management activities include: daily investing and borrowing work which provides the utility with adequate funds to meet its financial obligations; risk control and independent verification of borrowing activities; and daily reporting and reconciliation of Toronto Hydro's cash position and general ledger and sub-ledger accounts.

Toronto Hydro has issued both long term and short term debt instruments to fund its capital program, and this function manages Toronto Hydro's relationship with bond investors, independent financial and credit analysts and credit rating agencies. The activities performed by this group of finance professionals help facilitate a reliable debt market from which Toronto Hydro may access funds to carry out its operations and fund its long term capital program.

The Financial Services function also oversees the utility's comprehensive insurance requirements, the purpose of which are to ensure that Toronto Hydro has adequate protection for asset exposure, corporate liability and other activities which may expose the utility to financial loss. Current insurance policies administered by this group provide coverage for a variety of losses and expenses, including comprehensive general liability, all risk property and boiler and machinery insurance, liabilities of directors and officers, automobile liability, professional liability and crime insurance. Without these protections, the utility could face significant financial losses. Toronto Hydro's

[1] Exhibit 4B, Tab 2.

comprehensive insurance program provides value for customers by protecting the utility against a variety of financial risks associated with its operations.

4.5. Internal Audit

Internal Audit provides independent and objective reports to the utility's Audit Committee[2] and management through operational, compliance and performance audits. Internal Audit focuses on assessing the adequacy and effectiveness of the utility's risk management, governance and system of internal controls, and provides consultation and advisory services on the design, implementation and maintenance of internal controls and reporting systems, governance activities, fraud detection procedures and other matters requested by senior management. Internal Audit also provides an opinion on the utility's compliance with Bill 198/CSA Instrument 52-109 (securities regulation related to disclosure and internal controls). Compliance with Bill 198/CSA Instrument 52-109 is a financial reporting requirement of the OSC.

4.6. Segment Costs

Table 4 provides the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Financial Services segment.

Table 4: Historical, Bridge and Test year Costs ($ Millions)

Segment	2011	2012	2013	2014	2015
Financial Services	7.9	6.7	6.7	7.2	7.4

4.7. 2011 – 2012

Segment costs declined by $1.2 million from 2011 to 2012 due to savings in payroll costs related to a reduction of staff as part of the utility's reorganization efforts. In particular, the Accounts Payable department decreased as the transaction-heavy elements of the

[2] A copy of the Audit Committee Charter is filed at Exhibit 1C, Tab 2, Schedule 1, Appendix E.

work performed by this segment have been outsourced to an external service provider. The remaining staff reductions occurred across each of the other functions within the Financial Services segment.

4.8. 2012 – 2013

From 2012 to 2013, the utility sustained increased property insurance costs of $0.4 million. The increases were offset by a further reduction of payroll costs relating to staff reorganization in the Internal Audit Department.

4.9. 2013 – 2014

Costs are forecast to increase by $0.5 million from 2013 to 2014 due to: insurance cost increases of $0.2 million, and costs of living and inflationary increases.

4.10. Test Year Segment Costs

The 2015 test year costs associated with the delivery of the functions and responsibilities of the Financial Service segment are projected to be $7.4 million, which represents a decrease of $0.5 million from the utility's last rebasing year (2011), an increase of $0.7 million from the most recent historical actual year (2013), and a $0.2 million increase from the bridge year (2014).

As a result of the utility's reorganization efforts over the 2011 to 2013 period, the forecast cost of delivering the Financial Services segment in the 2015 test year is notably lower than in 2011. The payroll savings gained through the reorganization were partially offset by increased property insurance premiums in 2013 due to external drivers in the commercial property insurance market.

The functions performed by the Financial Services segment are all necessary to effectively facilitate daily operations and long-term financial sustainability of a large and

complex corporation like Toronto Hydro. This segment enables Toronto Hydro to achieve the following: 1) satisfy its financial obligations vis-a-vis third parties, employees and the government; 2) secure necessary funding for operational and capital programs; and 3) manage corporate financial risk exposure.

5. EXTERNAL REPORTING SEGMENT

The External Reporting segment oversees the preparation and compilation of external financial reporting materials such as those required by the OSC. Among other things, this function requires preparation of publically filed annual and interim financial statements and disclosures. In addition to preparing and publishing the external reporting documentation, the segment is responsible for reviewing, documenting and communicating all changes in accounting standards to relevant stakeholders.

To minimize the risk of material errors and to allow compliance with the applicable accounting standards and other requirements, Toronto Hydro follows a strict process for the preparation of publicly filed financial documents. The specific activities and internal controls underlying these processes are subject to regular reviews by independent internal and external auditors. Toronto Hydro is required to maintain the necessary documentation that underlies its financial statements and disclosures to facilitate effective audits and support management's attestation to the accuracy of publicly filed information.

To enable timely and accurate execution of its core functions, the segment undertakes two sets of primary activities. First, the segment performs central accounting functions such as consolidation entries, intercompany settlements and eliminations, accounting for post-employment benefits, and other account reconciliation and management activities. Second, it uses information in the company's accounting systems to prepare all required financial filings. These include the audited annual financial statements and notes

(consolidated and for each legal entity separately), the Management Discussion and Analysis, the Annual Information Form ("AIF") and other reporting requirements from time to time. With the exception of the AIF, the above documents are filed quarterly.

5.1. Segment Costs

Table 5 provides the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the External Reporting segment.

Table 5: Historical, Bridge and Test Year Costs ($ Millions)

Segment	2011	2012	2013	2014	2015
External Reporting	2.9	2.6	2.6	3.1	3.2

5.2. 2011 – 2012

Cost decreased by $0.3 million from 2011 to 2012, due to the reduction of staff upon winding down of the initial IFRS conversion project. This reduction was offset by cost increases due to cost of living increases for existing staff and inflationary impacts on non-payroll costs.

5.3. 2012 – 2013

There was no change from 2012 to 2013. Cost of living increases for existing staff and inflationary impacts on non-payroll costs were offset by savings in non-payroll costs.

5.4. 2013 – 2014

Toronto Hydro forecasts the cost to increase by $0.5 million from 2013 to 2014 due the transition from USGAAP to IFRS, and inflation. These costs relate to the incremental, ongoing reporting requirements under IFRS that the utility is required to incorporate into all its OSC corporate financial reports including, financial statements, the MD&A and the AIF.

5.5. Test Year Segment Costs

The 2015 Test Year costs associated with the delivery of the functions and responsibilities of the External Reporting segment are projected to be $3.2 million, which represents a decrease of $0.3 million from the utility's last rebasing year (2011), an increase of $0.5 million from the most recent historical actual year (2013), and a $0.1 million increase from the Bridge Year (2014). The Bridge and Test Year costs represent the incremental work required under IFRS to produce the corporate financial statements, the notes to the financial statements, the MD&A and AIF.

The functions and activities comprising this segment are non-discretionary for a public issuer like Toronto Hydro. Internal accounting and verification is required in order to prepare accurate external filings and reports. If Toronto Hydro does not receive the funding to execute this segment as described, it may not be able to satisfy it financial reporting obligations as required by the OSC. In turn, this could inhibit Toronto Hydro's ability to borrow funds to finance its capital programs, and could trigger a violation of the covenants contained in its existing debt issuances.

INFORMATION TECHNOLOGY

Table 1: Information Technology (IT) Program Expenditures ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Information Technology	30.3	28.5	31.0	33.4	34.9

1. SUMMARY

The Information Technology ("IT") Program manages operational and information technologies and services that support every aspect of Toronto Hydro's business. IT infrastructure and applications (collectively referred to as "systems") allow Toronto Hydro to provide a safe, secure and reliable supply of electricity to its customers and facilitate efficient business operation of the utility.

Toronto Hydro's IT Program deploys, supports and operates all information systems and associated components including hardware, software, network, telephony, communications and information security. The types of technology managed by the program include a mixture of computer resources, communications and storage infrastructure, user-facing applications and decision support software. Toronto Hydro performs this work under clearly defined architectural standards and governance frameworks.

2. PROGRAM DESCRIPTION

The IT Program delivers operational asset management, support and other services to Toronto Hydro's internal clients and external electricity customers. The utility carries

out its IT work in a secure, timely and cost-effective manner by adhering to key objectives, which include:

- working closely with utility business units to identify and prioritize products and services required to attain clearly defined objectives;
- providing timely technical maintenance and support to maximize the reliability and operability of key business applications and underlying IT infrastructure;
- managing IT asset investments and IT Asset Lifecycle (asset definition, renewal or replacement, operation and maintenance, disposal) according to industry technical standards and risk management practices; and
- delivering effective and user-friendly IT products that keep pace with Toronto Hydro's evolving operational requirements, customer preferences and support continuous improvement across the utility.

In accordance with the above objectives, Toronto Hydro's IT Program consists of four discrete segments, each of which fills a unique role within the program. The four IT Program segments are:

- Security & Enterprise Architecture: Defines and implements utility-wide IT strategy, develops and oversees the adherence to corporate IT policies and standards, and manages enterprise IT risks including cyber security. As set out in Figure 1 (below), this segment provides the following outputs:
  - IT Policies and Standards (for all segments);
  - IT Goals (for all segments);
  - Program and Project Business Cases (for the Project Execution and Governance segments);
  - Cyber Security and Asset Management Frameworks (for the IT Operations segment);
  - Architectural resources (for the Project Execution segment).

- IT Operations: Supports the day-to-day operation of Toronto Hydro's IT assets, including core back-end infrastructure and customer-facing applications. As set out in Figure 1 (below), this segment provides the following outputs:
  - Provide operations resources (for the Project Execution segment)
  - Manage and maintain all IT Assets and Services

- IT Project Execution: Facilitates the development and manages the implementation of new IT solutions (projects, programs and applications) requested by internal clients or otherwise required to achieve Toronto Hydro's strategic objectives. As set out in Figure 1 (below), this segment provides the following outputs:
  - Project Status reports (for the Governance segment)
  - Completed, operations ready solutions (for the IT Operations segment)

- IT Governance: Provides program governance, budget control, contract and vendor management, records management, quality assurance and audit services. As set out in Figure 1, this segment provides the following outputs:
  - Prioritized program/project list (for the Project Execution segment)
  - Governance and services (for the Project Execution and IT Operations segments)
  - Track and report on Divisional Budget, Project Status and associated metrics for the IT senior leadership team.

Figure 1 provides a graphical representation of the IT program segments and their interaction, including brief summaries of key activities comprising each segment.

Figure 1: IT Program Segments and their Interaction

The Historical (2011-2013), Bridge Year (2014), and Test Year (2015) costs of Toronto Hydro's IT Program and each of the segments that comprise this program are shown in Table 2 below.

Table 2: IT Program Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Security & Enterprise Architecture	2.0	2.0	1.4	1.4	1.4
IT Operations	25.6	24.5	28.0	29.7	30.9
Project Execution	1.3	0.9	0.5	0.8	1.1
IT Governance	1.3	1.2	1.1	1.5	1.5
TOTAL	**30.3**	**28.5**	**31.0**	**33.4**	**34.9**

3. SECURITY & ENTERPRISE ARCHITECTURE SEGMENT

The Security & Enterprise Architecture segment manages and oversees Toronto Hydro's corporate Information Technology portfolio, implements utility-wide IT architecture practices, and identifies and manages key enterprise IT risks, such as cyber security.

The segment performs several key functions, including:

- produces corporate IT standards, policies and enterprise architecture principles;
- manages compliance to the above policies and architecture principles;
- manages the enterprise information security posture and risk profile;
- drives operational cost efficiencies and business process streamlining; and
- develops the IT portfolio of programs and projects.

Due to the breadth of services comprising the Security & Enterprise Architecture mandate, the segment operations are subdivided into two functional streams:

- The Enterprise Architecture Stream performs research on new technologies, develops and oversees the implementation of technology standards and associated governance frameworks, infrastructure architecture, physical and logical security architecture, data and reporting architecture and application architecture principles.

- The Strategic Solutions Stream develops and implements the IT program strategy, defines and manages program- and segment-level performance expectations, and facilitates the development of business plans for new technological solutions.

Security and Enterprise Architecture outputs guide and integrate the elements of Toronto Hydro's IT infrastructure operations strategy, application support strategy and project delivery strategy to enable compliance with technical standards, corporate policies and practices. Some examples of the initiatives developed by the segment include server consolidation and virtualization, perimeter security optimization and internal directory services consolidation. These initiatives are further described in the IT Operations Segment, where the strategies developed within the Security & Enterprise segment are applied to the utility's operational activities to drive process consistency and operational efficiencies.

The segment's scope of work also includes evaluation of major projects that include an IT component. This analysis allows Toronto Hydro to evaluate the merits of IT-driven initiatives on a consistent basis before committing to their implementation.

3.1. Segment Costs

Table 3 summarizes Historical (2011-2013), Bridge Year (2014), and Test Year (2015) costs expenditures for the IT Security & Enterprise Architecture segment, and shows that costs have and continue to remain below the 2011 levels.

Table 3: IT Security & Enterprise Architecture Segment Expenditures ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Security & Enterprise Architecture	2.0	2.0	1.4	1.4	1.4

A reduction of costs relative to 2011 was driven by organizational restructuring and realignment within the IT program throughout the historical period. The impact of the organizational restructuring and realignment within the IT Division upon completion yielded a total actual cost reduction of $0.6 million in 2014 when compared to 2011 levels, despite inflationary pressures.

Since 2011, Toronto Hydro's Security & Enterprise Architecture segment developed conceptual frameworks for, and implemented, a number of new information technology standards and other governance structures. These standards incorporate industry best practices within Toronto Hydro's business conditions to deliver procedural and technological benchmarks that position the utility to achieve operational efficiencies across the IT operations functions.

Among the key accomplishments is the development of Server and Storage Infrastructure Standards, Integration & Middleware Standards, Naming and Access Control Standards and many others. These standards and operating procedures homogenize and streamline existing operational processes, resulting in enhanced operational service levels by:

- reducing the need for technology/application-specific knowledge;

- mitigating the risk of vendor technology obsolescence;
- driving efficiencies in emerging program/project architectural designs;
- mitigating costs through standardized hardware and software procurements; and,
- simplifying the information technology environment, thereby creating faster and more efficient planning processes.

Standardizing system requirements and operational processes simplifies program and segment execution and audits, as fewer "unique" and non-standard factors require consideration. This allows Toronto Hydro to more easily drive program-wide continuous improvement through consistent performance measurement and evaluation processes.

3.2. Test Year Segment Costs

The forecasted 2015 Test Year expenditures for the IT Security and Enterprise Architecture segment of $1.4 million are in line with the 2014 Bridge and 2013 Historical Year costs and remain below the 2011 actuals. Toronto Hydro was able to keep the segment expenditures flat despite normal inflationary increases through the efficiencies described above.

The Security & Enterprise Architecture segment is the main driving force behind all Information Technology projects, programs and initiatives that create operational efficiencies and enhance business value while maintaining and improving systems reliability and availability. The segment defines Toronto Hydro's IT landscape in light of current business requirements, future state forecasts and IT industry trends and opportunities. The portfolio of Technical Standards, Policies and Strategy documents developed as a part of the segment ensures predictable budgeting, cost containment, forward planning and implementation of IT assets, projects and processes.

Moreover, due to rapid changes and advancements in the IT sector, the Security & Enterprise Architecture segment performs research of vendor and associated technology offerings in order to mitigate any technology obsolescence risks. The segment embarks on Proof of Concept assessments, keeping pace with the broader IT sector, to determine emerging opportunities and associated benefits offered by new technologies. These Proof-of-Concept assessments also help promote compatibility between disparate, but hierarchically interdependent technology layers. The resulting architecture enhancements and IT standard updates establish predictable service level baselines in terms of performance, availability, scalability and lifecycle of the entire IT landscape at Toronto Hydro.

Reducing the footprint or scope of the Security & Enterprise Architecture segment would likely place pressure on infrastructure reliability levels, create challenges to fulfilling business requirements, increase the risk of service outages due to a lack of IT architecture and governance, and could ultimately result in customer impacts such as web services issues or billing system complications.

4. OPERATIONS SEGMENT

The Operations segment is responsible for the day to day operation, deployment, maintenance and support of all IT systems at Toronto Hydro. This includes maintaining the integrity, availability and security of all corporate data, ensuring adequate computer resources to support real time data processing of applications and databases, proactive capacity and performance planning, routine systems maintenance and continuous monitoring of all critical business systems.

Toronto Hydro's business processes rely on core back end IT hardware assets, technology and end user software to remain reliable, available and secure. To facilitate

continued operation of these and other systems, the segment includes a 24/7 monitoring and response structure to ensure timely resolution of incidents and problems to prevent or quickly address major system outages.

Operations deploys, operates, maintains and supports all aspects of Toronto Hydro's IT systems. This includes vendor payments for maintenance contracts, which provide technology "bug" and performance fixes (i.e., patches), new features and functionality, and critical cyber vulnerability fixes. The IT operations segment also administers patches to the utility's technology assets on an ongoing basis as they are released by vendors, thereby mitigating cyber and system performance risks.

The Operations segment consists of two streams: 1) Hardware & Security and 2) Software & Service Management.

The Hardware & Security stream is responsible for the deployment and management of the following asset components and services:

- data and voice networks, fibre optic and radio infrastructure, telephony and communication infrastructure;
- Advanced Metering Infrastructure and control management networks (e.g. SCADA - Supervisory Control And Data Acquisition);
- servers and operating system infrastructure;
- data storage and backup environments;
- IT security technologies such as firewalls, proxies, intrusion and data loss prevention systems; and
- physical data centre infrastructure, (power, HVAC, fire suppression, floor plans, cabling and racking).

The Software & Service Management team is responsible for introduction and continuous operation of the following asset components and services:

- client-facing software assets;
- database and middleware software assets such as Oracle, Microsoft SQL and Middleware such as WebSphere;
- end user devices, including desktops, laptops, phones and printer asset deployment as well as services such as the upcoming deployment of Microsoft Office software applications;
- end user application development and reporting software assets and services; and
- Service request management, incident management facilitation, and change management services based on industry best practices.

4.1. Segment Costs

Table 4 summarizes Historical (2011-2013), Bridge (2014) and Test Year (2014) expenditures for the IT Operations Segment

Table 4: IT Operations Segment Expenditures[1] ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Software & Service Management	12.9	13.2	14.9	16.4	17.2
Hardware & Security	12.7	11.7	13.1	13.3	13.8
IT Operations Total	**25.6**	**24.5**	**28.0**	**29.7**	**30.9**

[1] Toronto Hydro has broken down the segment expenditures into Hardware and Software for ease of reference with the IT capital program expenditures captured in the Distribution System Plan (Exhibit 2B, E8.4 and E8.5).

4.2. 2011-2012

The segment costs decreased by $1.1 million in 2012 relative to the 2011 levels, mainly due to the conclusion of contract negotiations for Smart Meter Communication services. The negotiations resulted in a credit from the provider in the amount of $1.2 million applied in 2012.

4.3. 2012-2013

The 2013 costs increased by $3.5 million mainly due to a combination of the following factors:

- Communications expenditures returned to normal levels following the above-noted credit.
- Commencement of an annual information security assessment to mitigate cyber-security risk exposure in the amount of $0.3 million to align with industry best practices.
- Maintenance contract costs increased by $1.5 million due to the support budget required for new and critical systems implemented from 2011 through 2013, including Customer Care & Billing ("CC&B"), Mobile System Response Report ("SRR"), Enterprise Service Bus ("ESB"), GPS system, Human Resources safety tracking systems. This increase was partially offset by the savings in cases where new technology replaced the incumbent technology that performed the same or similar functions in the past (e.g., the legacy Customer Information System that was replaced with CC&B).
- Inflation and costs driven by customer growth accounted for the remainder of variance.

4.4. 2013-2014

The 2014 forecasted increase of $1.7 million relative to 2013 is attributable to the following drivers:

- Modest increases due to growing storage requirements due to the Smart Meter and other operational data volume increases.
- Maintenance contract cost increases in the amount of $1.5 million to support a series of newly implemented critical systems: Warehouse Management System ("WMS"), Employee Time Tracking, Customer Self Service Portal ("CSS"), and the Advanced Mmetering Infrastructure (AMI) Suite Metering system.
- Cost inflation and customer growth amount to the remainder of variance.

When the incremental requirements driven by business needs or changes outside of IT are removed, as identified above, the IT Operations segment budget remained relatively flat over the period, despite inflationary and organic growth pressures.

Since 2011, Toronto Hydro achieved a number of operational efficiencies through standardization of the network architecture and implementation of new design and equipment specifications. The utility improved its network, voice and associated communication infrastructure services through introduction of fully redundant network topologies and diverse cabling paths to eliminate single points of failure in the critical communication networks, mitigating potential risks to the system.

Toronto Hydro achieved further operating efficiency gains by leveraging new server, storage and backup architecture standards developed by the Security & Enterprise Architecture segment. These standards helped Toronto Hydro minimize costly "technology sprawl" (i.e., system growth using non-standard technologies) that is often the result of data, service and resource demand growth. Moreover, migration from tape backup libraries to a storage array-based disk duplication system eliminated obsolete and expensive hardware, reduced archive storage costs and increased the capacity and integrity of backup data environments.

The utility also carried out a large-scale server virtualization project, achieving 95% consolidation of physical servers in order to improve the density and use of available computer resources and reduce software licensing costs. Further operational efficiencies were attained by decoupling server systems from underlying hardware resources, resulting in improved service flexibility and increased system uptime. This enabled the implementation of database and middleware standards that minimized the volume and costs of database and middleware assets.

Finally, Toronto Hydro introduced new technology to reduce the risk of cyber-attacks that are not normally preventable through conventional means such as firewalls and intrusion prevention systems. Among these improvements was the implementation of a critical threat prevention application, which uses sophisticated "sandboxing" methods to stop "zero day" attacks.

4.5. Test Year Costs

The $1.2 million increase over the 2014 forecast expenditures is the result of a combination of several factors:

- Migrating the SCADA Communication Fibre-Optic plant and SONET communication equipment to IT Operations from the Engineering & Construction Division increased operating costs by $0.6 million. This includes asset maintenance and support staff costs.
- The mandatory maintenance and software subscriptions of the new Voice Portal technology required to expand the capacity of the Call Centre environment to provide adequate customer service during large outage events results in another $0.3 million of annual operation cost increases.
- Enrolment in the province's Microsoft Enterprise volume licensing agreement resulted in a $0.5 million budget increase. This increase offsets $3.0 million of

capital funding that would have otherwise been required for the same licence volumes if purchased individually.

It should be noted that the primary driver for the increases in segment expenditures were the incremental business requirements, originating primarily outside of the IT program's mandate. When normalized for these incremental expenditures, the IT Operations segment costs have remained generally flat despite inflationary and organic growth pressures.

The IT Operations segment enables Toronto Hydro to keep up with growing customer, data and service request volumes. The proposed expenditures are necessary to continue to ensure proper maintenance of Toronto Hydro's information technology environment and to allow Toronto Hydro to retain appropriate skill sets and knowledge to meet the needs of the organization and its customers. Reductions to this budget would likely put at risk the utility's ability to adequately maintain and support critical systems, processes and functions such as physical security, SCADA, metering, and business and customer applications services.

4.6. Project Execution Segment

The IT Project Execution segment is responsible for the execution of Toronto Hydro's IT programs that leverage the utility's existing IT assets and often require amendments to, or implementation of, new applications procured externally or developed internally. This is particularly true for efficiency and productivity-enhancing initiatives. Timely and professional project management services will allow Toronto Hydro to efficiently delivery the utility's IT work program.

Services provided by the Project Execution segment include:

- project needs identification reflecting consensus from all parties involved;

- identifying and analyzing gaps, risks and opportunities in project management and execution;
- defining and communicating process improvement mechanics targeted by project sponsors;
- developing project execution strategy options and comparison analyses;
- classifying and quantifying project execution metrics, including tracking and reporting;
- managing Vendors and System Integrators;
- overseeing project change management and scope parameter adherence; and
- managing and monitoring project resources.

Toronto Hydro's IT Project Execution practices are consistent with industry standards of project management frameworks, such as the Project Management Body of Knowledge ("PMBOK") and include developing and delivering project status reporting, project related change documentation and other project artifacts. The staff who perform this work have extensive experience and professional designations in project management and other related fields. Since 2011, the Project Management segment has managed anywhere from 10-20 complex projects per year, amounting to approximately $12-$15 million in annual capital expenditures.

4.7. Segment Costs

Table 5 summarizes Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the IT Project Execution segment.

Table 5: IT Project-Execution Segment Expenditures ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
IT Project Execution	1.3	0.9	0.5	0.8	1.1

The reduction of costs since 2011 is attributable to organizational restructuring and realignment of functional responsibilities within the IT program. Since 2011, the IT Project Execution segment introduced and implemented a uniform IT project management framework across the utility, consolidated and re-existing project management plans into a single planning document. Toronto Hydro also streamlined the project gating process, which allowed the utility to significantly expedite project approvals and reduce the complexity of a number of existing programs and processes.

In addition, Toronto Hydro consolidated, eliminated or streamlined other project management governance documents. The utility developed several key project management artefacts and associated guidelines to support transparency across the utility and identify future improvement opportunities.

4.8. Test Year Segment Costs

The proposed 2015 Test Year costs for the IT Project Management segment are $1.1 million, which represents a $0.3 million increase from the 2014 Bridge Year forecasts, but a net $0.2 million reduction from the 2011 actual costs.

Project Execution provides centralized IT project management oversight aligned to the functional divisions within the organization. These expenditures allow Toronto Hydro to retain business knowledge and deploy appropriate resources to fulfil new requirements of IT Projects and Programs that are commonly driven by regulatory, legislative and other requirements.

Reduction of the proposed budget would likely have a tangible impact on Toronto Hydro's ability to identify and execute IT projects to support the utility's operations. IT Project Execution is essential to support new projects and program development, and to facilitate customer-facing products such as the Toronto Hydro customer internet portal.

Reductions to the program could place at risk the successful execution of ongoing and planned IT capital programs[2], including initiatives related to safety, regulatory compliance or customer service.

5. IT GOVERNANCE SEGMENT

The Governance segment provides oversight, budget control, contract and vendor management, records management, quality assurance, and compliance and audit services for Toronto Hydro's IT projects and services. The segment also facilitates implementation of the IT capital portfolio. This entails activities such as compliance review, project review and prioritization, project status monitoring/reporting and benefit attainment monitoring/reporting. It Governance also houses all project and portfolio documentation as the official enterprise custodian. By continuously monitoring the IT portfolio through the above mentioned tools and processes, the Governance segment facilitates timely, cost effective and otherwise successful delivery of IT projects.

The Governance segment is further divided into four parallel streams as follows:

- The Project Governance stream performs the necessary oversight, tracking and reporting associated with the IT-based portfolio of programs and projects. The scope of this stream's work also includes project reviews, status and change control reviews, project prioritization and benefit attainment monitoring.
- The Contract Management stream oversees the administration of external IT vendors, internal work order setup and purchase requisitions. This entails monitoring contract expiry dates and vendor negotiations, service level analysis and vendor consolidation work to drive savings.
- The Records Management stream supports the enterprise-wide tracking and reporting requirements needed to comply with Toronto Hydro's Records

[2] Exhibit 2B, E8.4 and E8.5.

Management Policy. The stream enables Toronto Hydro to meet its regulatory and legal obligations for the retention and destruction of records, and to educate staff on the utility's Records Retention Schedule, policy, and program guidelines.

- The Budget Control and Oversight stream tracks and reports on IT program expenditures and their alignment with the overall budget. This enables Toronto Hydro to book IT expenditures to the correct expense accounts, and to post transactions in accordance with reporting requirements.

5.1. Segment Costs

Table 6 summarizes Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the IT Governance Segment.

Table 6: IT Governance Segment Costs ($ Millions)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
IT Governance	1.3	1.2	1.1	1.5	1.5

The segment expenditures decreased during the historical period, due to program-wide efficiencies previously described.

The $0.4 million increase projected in the Bridge Year is primarily attributed to the inclusion of new responsibilities and services to the Governance segment, which is part of the utility's Records Retention Policy release and implementation. The increase is also inclusive of inflationary pressures.

Since 2011, the IT Governance segment achieved a number of savings and efficiencies by consolidating vendor contracts and streamlining service provider arrangements. These activities include identifying opportunities to consolidate contractual arrangements for

the delivery of IT services, which allows Toronto Hydro to access volume rebates and minimize administrative mark-ups with IT contract staffing agencies.

The Records Management stream successfully reduced off-site physical records and associated storage costs since the program's inception in the fall 2012 by identifying and managing the destruction of volume of paper records that were outside of the policy-defined retention schedule.

The work of the Budget Control and Oversight stream ensured that the division is operating and reporting in a manner that supports Toronto Hydro's strategic direction.

5.2. Test Year Segment Costs

The proposed 2015 expenditures are projected to be $1.5 million, consistent with the Bridge year forecast, despite normal inflationary pressures, which are offset through internal efficiencies.

The IT Governance segment helps ensure the delivery of quality solutions to the business units. The absence of a proper governance framework could expose Toronto Hydro to increased financial risk, manifesting itself in project overruns, contract inflation or late penalties. Reduction or elimination of segment funding could also hinder Toronto Hydro's ability to meet its regulatory and legal obligations for the retention and destruction of records.

RATES AND REGULATORY AFFAIRS

1. SUMMARY

Table 1: Rates & Regulatory Program Expenses ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test[1]	
Rates and Regulatory Affairs Total	7.2	7.8	8.4	9.9	10.1	/C
Rates and Regulatory Affairs - 2015 Revenue Requirement					8.4	/C

Rates and Regulatory Affairs program provides Toronto Hydro with services related to the regulatory environment within which the utility operates. This includes regulatory oversight of the utility's operations and interaction with the Ontario Energy Board ("OEB"), Provincial Ministries, the Independent Electricity System Operator ("IESO") and the Ontario Power Authority ("OPA"). The main services provided include the development and execution of rate filings and other applications before the OEB, regulatory research and policy development, regulatory compliance monitoring, load forecasting, rate design, and liaising with the provincial government.

2. PROGRAM DESCRIPTION

Operating within a regulated industry requires specialized skills and knowledge. The program's current staffing complement includes individuals with education, professional designations and experience in areas as such as law, public policy, engineering and economics. The program's staffing levels facilitate a steady workload year-round, given a variety of one-time and reoccurring projects and processes that require the direction, input or oversight of the Regulatory and Rates program. When additional resources are required (such as development of major rate filings), Toronto Hydro fills incremental

[1]The 2015 forecast spending amount depicted in Table Row ! 1 reflects Toronto Hydro's full anticipated OM&A expenditures for the year prior to the application of the amortization methodology as proposed by the utility. The amount captured in Row 2 ($8.4 million) reflects the proposed 2015 revenue requirement contribution, based on the proposed amortization methodology. For further cost breakdown and derivation of the amount proposed for inclusion in Toronto Hydro's 2015 revenue requirement, refer to Table 2. /C

needs with short-term contract resources and third-party service providers to effectively manage workloads and costs.

Since regulatory policy developments in the province of Ontario affect all utilities, the Regulatory Affairs program maintains coordination with other utilities and industry groups to participate in consultations and other collaborative processes. In recent years, Toronto Hydro has often voiced its position on the emerging regulatory and ratemaking matters through the joint submissions of the Coalition of Large Distributors ("CLD").

The program is also the primary point of contact between Toronto Hydro and the provincial government ministries and agencies, most notably the Ministry of Energy. Maintaining a close relationship with the provincial government ensures that Toronto Hydro's planned or ongoing activities are informed by the latest government policy developments that may directly or indirectly affect Toronto Hydro and its customers.

The program is comprised of the Regulatory Affairs and Rates functional areas, as explained in more detailed below. These two functions are highly integrated in the oversight and fulfillment of Toronto Hydro's regulatory obligations.

2.1. Regulatory Affairs

The Regulatory Affairs function is Toronto Hydro's contact and liaison with the OEB, the IESO, the Ontario Power Authority ("OPA"), government ministries, and other electricity sector agencies on all regulatory matters. In consultation with internal and external stakeholders, the Regulatory Affairs function develops Toronto Hydro's positions on emerging sector issues, prepares regulatory filings and rate applications, and makes submissions in industry consultations coordinated by the OEB or the Ministry of Energy.

Development of Toronto Hydro's rate filings and other OEB applications is a major responsibility of the Regulatory Affairs function. Distribution rate applications involve extensive co-ordination and development of evidence across the entire utility. In special cases, such as with the current application, complex regulatory filings require extensive research, strategy formulation and regulatory risk analysis, all of which are performed by the Regulatory Affairs function with input from external advisors and legal counsel as necessary.

Regulatory Affairs works closely with other areas of the utility to ensure that the information provided in rate filings is complete, correct, and satisfies regulatory filing requirements, as well as other OEB and government policy objectives. On an ongoing basis, the function provides education to all business areas on the regulatory aspects of their respective activities to increase the general awareness and specific regulatory acumen across the utility. This work allows Toronto Hydro to better integrate utility operations with the applicable regulatory regimes, thus facilitating compliance on all matters and minimizing the likelihood of potential regulatory risks. It also ensures that regulatory information provided to Toronto Hydro's customers (generally through intervenor representatives in rate applications) is clear, well-organized and informative so as to enable the participation of interested parties in Toronto Hydro's rate applications.

In addition to rate applications and other regular OEB proceedings, the Regulatory Affairs function facilitates the communication of Toronto Hydro's position on emerging regulatory matters through OEB policy-making consultations such as the Renewed Regulatory Framework for Electricity[2] proceedings (EB-2010-0377/78/79) and other proceedings that are material to the utility, its customers, and to the industry in general. Being the largest municipally-owned distributor in Ontario, the policy decisions affecting

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[2] Ontario Energy Board, *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (Toronto: Ontario Energy Board, 2012), online: Ontario Energy Board < http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf>. ["*RRFE*"]

/C

Toronto Hydro have a direct bearing on 15% of Ontario's electricity customers. The staff members' experience and knowledge of the industry and regulatory environment is a significant and important input to these exercises. As noted previously, the Regulatory Affairs function works closely with other utilities and industry associations in order to provide input in an informed, efficient and coordinated manner.

Regulatory Affairs also facilitates Toronto Hydro's link with provincial government ministries and agencies that oversee Toronto Hydro's regulated activities. Acting as a single point of contact with Toronto Hydro's industry experts, the Regulatory Affairs function supports all types of requests and collaborative efforts between the utility, provincial policymakers and entities under their oversight. Most commonly, Toronto Hydro works with the Ministry of Energy on matters involving securing and interpreting confidential data on customer consumption patterns, or reviewing the utility's plans with respect to testing or deploying Smart Grid technologies. Toronto Hydro also provides the government with constructive inputs on contemplated policy directions when the opportunities to provide such feedback present themselves. For example, staff coordinated the preparation of Toronto Hydro's submission for the Ontario Distribution Sector Review Panel.

Beyond the Ministry of Energy, Regulatory Affairs staff facilitate an ongoing dialogue between the utility and other government stakeholders affected by the utility's activities, such as the Ministry of Transportation ("MOT"), the Ministry of Municipal Affairs and Housing ("MMAH"), GO Transit, Metrolinx and others.

Toronto Hydro takes compliance with regulatory requirements very seriously. The Regulatory Affairs function oversees the gathering and reporting of information to the OEB through quarterly and annual Reporting and Record Keeping Requirements (the "RRR") filings, and assists the utility's business units in interpreting and responding to

any new requirements. Continually evolving regulatory requirements (e.g., Ontario Clean Energy Benefit, Class A global adjustment, updated OEB codes, Distributor Scorecard, etc.) require a significant effort in co-ordinating with affected areas of the utility and the OEB. The group also guides the utility's processes to promote compliance with the Affiliate Relationships Code ensuring confidentiality of customer information, as well as assisting business units in interpreting and complying with other applicable requirements.

2.2. Rates

The Rates function oversees distribution rate development and implementation, wholesale monitoring and settlement activities, and develops annual forecasts of the utility's load and number of customers. Beyond undertaking regular functions driven by OEB rate decisions and wholesale market activities, the Rates function staff participate in OEB policy consultations such as the Review of Cost Allocation Policy for Unmetered Loads (EB-2012-0383) and the Development of Standby Rates Policy for Load Displacement Generation (EB-2013-0004).

Rate case filings are the utility's source of funding for regulated activities. Rates staff support regulatory filings through the development of the revenue requirement, cost allocation, and rate design exhibits as well as potential approaches to rate mitigation. They also provide analytical support and other services in the clearance of regulated asset deferral and variance accounts as required in the course of Toronto Hydro regulatory proceedings. The group's knowledge of cost allocation and rate design help ensure that the revenue requirements are allocated and collected from the correct customer classes, minimizing any inter-class cross subsidization.

Implementation of rate decisions, semi-annual commodity rate changes and other regulated rate updates (e.g., RRRP, WMSC, RPP, CDM, TSRs) usually require configuration,

updating, and testing in Toronto Hydro's billing system to ensure that Toronto Hydro charges applies the right rates to the appropriate customer classes and otherwise properly implements OEB decisions. This function also responsible for the configuration and maintenance of the rates component of the utility's Customer Care and Billing ("CC&B") system, and for advising Customer Care programs[3] on a range of issues requiring specialized knowledge of rate-making principles and specific analytical skills, such as providing explanations for bill components and rate riders for customers. Changes to provincial legislation and OEB policy (such as the introduction of the Global Adjustment Class A category) require significant effort in the area of rates configuration and testing in the billing system. The Rates function assists other Toronto Hydro programs in completing the tasks that ensue from such decisions.

Another major area of activity for the Rates staff is forecasting. Staff utilize their skills and experience in economics, econometrics and other related fields to develop the forecasts of Toronto Hydro's load and number of customers. Performing this work requires regular communication with other Toronto Hydro programs, such as Conservation and Demand Management and Customer Connections. Beyond the customer and load forecasts that support the utility's rate applications, this function also facilitates the analysis of incoming customer and load data to refine future financial and asset management planning activities, and assess the impact of a variety of conservation programs offered by the utility.

The Rates function enables Toronto Hydro's participation in the IESO Wholesale Market settlement activities by providing daily reconciliation of IESO meter data with internal meter readings to ensure that any discrepancies which impact electricity commodity costs are handled according to IESO Market Rules. The group is also responsible for the monthly settlement of the IESO invoice, and providing the necessary data to the IESO fo /C

[3] Exhibit 4A, Tab 2, Schedule 13.

generation, global adjustment, and RPP amounts. As a Market Participant, Toronto Hydro has numerous obligations under the Market Rules that it must perform in a timely and accurate fashion. The Rates function ensures that Toronto Hydro complies with these obligations.

Staff supporting the Rates segment is highly knowledgeable and experienced in the areas of cost allocation, rate design, and forecasting. When required, consulting resources are acquired (such as for the Suite Metering issue as part of EB-2010-0142) to supplement internal resources and provide additional specialized expertise.

3. PROGRAM COSTS

The Historical (2011-2013), Bridge (2014) and Test Year (2015) program costs are summarized in Table 2. These costs include labour and operating expenses associated with the activities described above. Since Toronto Hydro's last rebasing in 2011, Rates and Regulatory Affairs program costs have increased in total by approximately $ 2.9M, or just over 4% annually. The main drivers of this increase are costs of preparing rate applications, namely the 2012-14 Incremental Capital Module ("ICM") application (EB-2012-0064), the wireless attachment fee appeal application (EB-2013-0234) and the current 2015 Custom Incentive Rate-Setting ("CIR" or "Custom IR") application, the proposed treatment of which is discussed below.

Table 2: Rates & Regulatory Program Expenses ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Total Rates and Regulatory Affairs	7.2	7.8	8.4	9.9	10.1

/C

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Total CIR + Wireless costs		0.1	1.2	3.3	3.2
Rates and Regulatory Affairs excluding CIR + Wireless costs	7.2	7.7	7.1	6.5	6.9
CIR + Wireless costs amortized over 2015-19 period					1.6 (= 7.8 / 5)
Rates and Regulatory Affairs budget included in 2015 OM&A					8.4

/C

3.1. 2011 – 2012

From 2011 to 2012, costs increased by $0.6 million largely due to the preparation and filing of Toronto Hydro's 2012-2014 ICM application (EB-2012-0064). This included the need for the production of expert reports and supporting materials, in addition to continued efforts by internal staff.

3.2. 2012 – 2013

The $0.6 million increase from 2012 to 2013 is solely a result of the continuation of the 2012-2014 ICM proceeding, as well as additional costs required as a result of the filing of Toronto Hydro's wireless attachment forbearance application (EB-2013-0234).

3.3. 2013-2014

The 2014 forecast of $9.9 million includes an estimate of $2.7 million in incremental costs associated with legal and consulting costs for the current 2015 CIR application and

/C

approximately $0.7 million in costs related to the wireless forebearance application. For the purposes of setting rates for 2015-19, these incremental costs are proposed to be amortized over the 2015-19 period.

3.4. Test Year Program Costs

The 2015 Test Year program costs are forecast to be $10.1 million, reflecting continued legal, consulting, and intervenor costs for the CIR filing of approximately $3.2 million.

Toronto Hydro's current rate filing will set rates for the following five years. In addition to the regular responsibilities of the group, this period will include implementation, monitoring, and potential reporting on aspects of the current Custom Incentive Rate-setting application, the preparation and filing of a clearance application relating to Toronto Hydro's ICM Deferral Accounts, development of the utility's 2020 rebasing application, as well as several expected major policy consultations. The program will also continue to provide ongoing regulatory consulting and services to the rest of the utility.

For the purposes of determining the Rates and Regulatory Affairs operating budget to be included in 2015 Revenue Requirement, Toronto Hydro proposes to amortize the costs incurred over the 2013-2015 period associated with the CIR application costs over the 2015-2019 rate period, as well as the costs associated with the Wireless Forbearance (Wireless) application. None of these costs were included in setting rates in the last 2011 cost of service application, which formed the basis for distribution rates over the 2011-14 period. For regulatory accounting purposes, these costs will be recorded in Account 1525 Miscellaneous Deferred Debits, and drawn down over the 2015-19 period. /C

The legal, consulting and intervenor costs associated with the 2015 CIR application are driven primarily due to the work involved in preparing a comprehensive five year

application, being one of the first to be heard under the new rate-setting framework, meets and surpasses the OEB's requirements. Toronto Hydro expects the hearing of this case to involve a significant amount of OEB Staff and intervenor involvement, and has budgeted accordingly.

Appendix 2-M provides the breakdown of the actual and anticipated CIR and Wireless application costs as required by s. 7.2.5 of the OEB Filing Requirements (July 17, 2013). /C

OEB Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2011 Board Approved)	Most Current Actuals Year 2013	2014 Bridge Year	Annual % Change	2015 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 3,177,253	$ 3,217,753	$ 3,216,000	r0.05%	$ 3,270,672	1.70%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ 56,296	$ 76,667	$ 63,337	r17.39%	$ 79,734	25.89%
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 138,025	$ 116,273	$ 119,976	3.19%	$ 120,924	0.79%
4	Expert Witness costs for regulatory matters	5655		One-Time	note5	note5	note5		note5	
5	Legal costs for regulatory matters	5655		One-Time	$ 299,600	$ 1,027,651	$ 1,491,893	45.18%	$ 1,926,047	29.10%
6	Consultants' costs for regulatory matters	5655		One-Time	$ 797,837	$ 811,288	$ 1,709,814	110.75%	$ 967,319	r43.43%
7	Operating expenses associated with staff resources allocated to regulatory matters			On-Going	note6	$ 1,733,069	$ 4,828,578		note6	
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments	5655		On-Going	$ 800	$ 800	$ 800	0.00%	$ 800	0.00%
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs	5655		One-Time	$ 322,817	$ 563,916	$ 322,360	r42.84%	$ 650,000	101.64%
12	Sub-total - Ongoing Costs [3]		$ r		$ 3,372,374	$ 5,144,562	$ 8,228,692	59.95%	$ 3,472,130	r57.80%
13	Sub-total - One-time Costs [4]		$ r		$ 1,420,254	$ 2,402,855	$ 3,524,067	46.66%	$ 3,543,366	0.55%
14	Total		$ r		$ 4,792,628	$ 7,547,417	$ 11,752,758	55.72%	$ 7,015,495	r40.31%

Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period

		Historical Year(s)	2014 Bridge Year	2015 Test Year
4	Expert Witness costs	note 5	note 5	note 5
5	Legal costs - CIR			
5	Legal costs - Wireless			
6	Consulting costs - CIR			
6	Consulting costs - Wireless			
7	Incremental operating expenses associated with staff resources allocated to this application.			
8	Incremental operating expenses associated with other resources allocated to this application. [1]			
11	Intervenor costs - CIR			
11	Intervenor costs - Wireless			

/C

1 Please identify the resources involved.
2 Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing cost
3 Sum of all ongoing costs identified in rows 1 to 11 inclusive
4 Sum of all one-time costs identified in rows 1 to 11 inclusive.
5 Expert Witness and Consulting costs aggregated
6 For 2013 and 2014, this is an estimate of all Toronto Hydro staff involved in rate filing. Estimates for 2011 and 2015 not availabl

LEGAL SERVICES PROGRAM

1. SUMMARY

Table 1: Legal Services Program ($Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Legal Services	5.5	4.3	4.5	5.3	5.5

The Legal Services program provides legal advice and guidance, strategic direction and project leadership in respect of a wide variety of legal issues that arise within the course of the utility's business. It is focused on providing its business unit clients with timely, accessible, specific and accurate advice and support. The Legal Services program ultimately helps the utility operate in an efficient and legally compliant manner, and develop corporate strategy with an understanding of the organization's legal requirements.

The Legal Services program also includes dispute resolution services, which both defends the utility from legal threats and claims from external parties, and supports Toronto Hydro's efforts to redress damages suffered by the utility. The program also enables the utility to carry out commercial and real property transactions with necessary legal protections and due diligence, and ensures that corporate practices and organizational structure meet legal standards. To fulfill these obligations, the Legal Services program employs and engages a combination of internal professional and administrative staff and external legal experts, with an appropriate balance to provide optimal service levels.

2. PROGRAM DESCRIPTION

The Legal Services program is comprised of the following segments:

1) Corporate, Commercial and Real Property; and
2) Litigation and Claims.

Table 2 showcases the Historical (2011-2013), Bridge (2014) and Test Year (2015) costs for the Legal Services program by segment.

Table 2: Legal Services Program Expenses ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Corporate, Commercial and Real Property	3.2	2.5	2.1	2.9	3.1
Litigation and Claims	2.3	1.8	2.4	2.4	2.5
Total	**5.5**	**4.3**	**4.5**	**5.3**	**5.5**

By integrating their practice with the operations of the utility's business units, the Legal Services program is able to proactively provide timely and context-specific legal service. Legal staff engage with their internal clients and colleagues to support legal compliance in operational matters and provide risk analysis and mitigation in transactional and dispute situations. In this way, the Legal Services program works to limit the operational and financial risk to the utility and related costs that could potentially be passed along to Toronto Hydro's customers.

Key issues covered by legal review in typical operational and transactional matters include interpretation of rights and obligations of the parties, liabilities, confidentiality, events of default, remedies and termination. The Legal Services program provides value to Toronto Hydro by facilitating the correct structuring of transactions and operations to prevent legal disputes and compliance issues from arising in the first place.

The department utilizes a mixed legal services model, which combines a dedicated team of internal legal counsel with specialist resources provided by external legal firms. This

model provides significant value in comparison to alternative approaches, by developing and making available internal legal service providers with company and industry-specific knowledge and experience, and augmenting those assets with specific technical expertise and market experience of highly skilled external practitioners.

The majority of expenditures made by the Legal Services department relate to costs for legal advice, including both internal legal professional staff and external legal firms and consultants. Therefore, to provide optimal value to the organization, the Legal Services program must find the appropriate balance between the utilization of internal and external resources. Beginning in 2012 and continuing into 2014, the Legal Services department that delivers the program underwent a phased re-organization to establish the appropriate balance between internal and external resources and maximize value for expenditures. The re-organization resulted in lawyers both leaving and joining the department and a reduction in non-professional administrative staff.

The market of available lawyers with knowledge of the electricity distribution industry is limited and expensive. Accordingly, the re-organization focused on procuring less costly junior lawyers with strong general skills that could be further developed and specialized in the utility's business. The development of new legal staff requires exposure to the various operational areas of the utility, with senior counsel more focused on key practice areas, such as information technology and finance. The program has expended significant development time on its new staff to enable better client service.

As a result of the reorganization completed between 2012 and 2014, the Legal Services program is now comprised of a slightly younger, but more diverse group of lawyers as compared to the staffing complement in 2011. The new staffing structure is better positioned to provide more efficient customer service to a broader set of business activities.

Under the reorganized Legal Services department, external resources are only employed to deal with unique or complex situations which require specialized practice knowledge and experience which internal lawyers are unable to provide at that time. This covers insurable litigation files, highly specialized practice issues (e.g., construction law, securities law and intellectual property), significant matters consuming a number of legal resources or times of extraordinary demand on an internal legal staff. By staffing challenging files with a combination of external counsel and more junior internal counsel, Toronto Hydro's legal staff members are able to develop their skills and knowledge in such specialized practices.

In 2013, Legal Services undertook a review of the department's use of external law firms, resulting in a request for proposals ("RFP") process by which interest from law firms was solicited for the provision of services in corporate/commercial, litigation and real estate. The RFP process was responded to with proposals from 13 firms. After careful consideration, Legal Services selected three firms and entered into agreements with two firms (one of the selected firms ceased operations in early 2014). The arrangements have resulted in reduced rates for external services (in the range of 5 to 25% depending on practice area) and the attainment of various additional benefits (e.g., access to law libraries, training and professional development sessions and practice management services) at no additional cost. The arrangements are expected to continue to drive value as the firms vie for work and Legal Services directs more of the externally resourced work to the firm that demonstrates the best value for money.

Despite increasing demands, as discussed above, the Legal Services program provides timely responses and improved customer service at lower overall costs. Beginning in 2013, the program commenced the measurement of the initial response times to requests from client programs. The performance standard was set at a rate of 90% of requests

responded to within 48 hours. In 2013, professional staff members were able to achieve a response rate of 100% against that standard.

3. CORPORATE, COMMERCIAL AND REAL PROPERTY SEGMENT

This segment of the Legal Services program covers day to day legal advice to operational clients, the review, negotiation and drafting of commercial agreements and completion of corporate, financial and commercial transactions for all of the organization's business units. It also includes the corporate secretarial function of the utility, and all corporate reorganization and governance matters. In addition, this segment includes a real property function which provides legal advice with respect to real estate matters including reviewing, negotiating and drafting legal documents relating to real property such as offers to connect, supply agreements and easements as well as real property dispositions and acquisitions and leasing arrangements. The legal staff supporting the real property function work closely with the construction, asset management, fleet and facilities operational units in their activities to help ensure that existing legal requirements of the utility and its counterparties related to property access, maintenance and repair, are complied with and, where necessary, new rights are obtained. This allows such projects to move forward efficiently and avoid penalties or damages relating to non-compliance with existing legislative restrictions or contractual obligations.

In 2013, approximately 67 percent of the expenses of the Corporate, Commercial and Real Property segment were attributed to services provided by internal counsel, compared with less than 63 percent in 2011. This demonstrates Toronto Hydro's effort to bring more legal work inside the department at a lower hourly cost and to develop internal expertise. Legal staff are also working with other business units across the utility and various outside agencies regarding the creation of standard work coordination arrangements. Such arrangements are expected to simplify large the plant relocation

work projects requested by external agencies[1], drive greater process efficiency in the completion of such projects, and reduce the risks associated with this work to the utility.

3.1. Segment Costs

Table 3 presents the Historical (2011-2013), Bridge (2014) and Test Year (2015) costs of delivering the Corporate, Commercial and Real Property segment of the Legal Services program.

Table 2: Corporate, Commercial and Real Property Segment Expenses ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Corporate, Commercial & Real Property	3.2	2.5	2.1	2.9	3.1

3.2. 2011 – 2012

From 2011 to 2012, the cost of delivering this segment decreased by $0.7 million due a reduction in staff as part of the departmental re-organization initiative.

3.3. 2012 – 2013

From 2012 to 2013, segment costs further decreased of $0.4 million due to: 1) ongoing reorganization efforts and unfilled vacancies during recruitment of new staff; and 2) a reduction in the costs associated with external legal services for various reasons, including the completion of the RFP process. This reduction, along with that incurred from 2011 to 2012, was not sustainable due to the significant increase in demand on existing staff and the organizational objective to build a more robust legal practice based on customer service excellence and responsiveness.

[1] The project are outside the control of Toronto Hydro, as discussed in Exhibit 2B, E5.3.

3.4. 2013 – 2014

From 2013 to 2014, Toronto Hydro forecasts the segment costs to return to historical (2011) levels, but reflecting the operational efficiencies and productivity savings gained from the reorganization and the RFP for legal services. Overall, this represents a $0.7M increase from the 2013 costs due to various factors including: 1) additional internal and external resources required to address increased demands on existing staff, particularly relating to capital projects and key initiatives (e.g., Anti-Spam); and 2) the transfer of the procurement document management function from the Supply Chain Services program.

3.5. Test Year Segment Costs

The 2015 Test Year costs associated with the delivery of the functions and responsibilities of the Corporate and Commercial segment are projected to be $3.1 million, which represents an increase of $0.2 million from the forecasted Bridge Year costs and a $0.1 million reduction from the last rebasing year (2011). The primary driver of these variances is the costs associated with additional resources required to support the execution of the utility's capital program, particularly additional legal support related to material and equipment procurement, project advice and construction services. Although the utility's proposed capital program over the 2015-2019 rate period is approximately 18 percent larger than the program in 2011, Toronto Hydro plans to operate the supporting legal functions captured within this segment within the historical expenditure levels. Efficiencies driven by the reorganization, the development of previous junior-level professional hires, maintenance of a steady state staffing levels, and the use of external firms from the RFP process are anticipated to help address the workload pressures associated with the capital work program and other key initatives.

4. LITIGATION AND CLAIMS SEGMENT

The Litigation and Claims segment manages the investigation of incidents and supervises external adjusters in the review of damage claims. It is part of the segment's function to manage and settle matters prior to proceeding to formal litigation.

Legal professional staff in the Litigation and Claims segment also lead the preparation and filing of statements of claim, statements of defence and related documentation, and undertake, or work with external counsel in respect of, the defence and prosecution of personal injury and property damage matters and commercial disputes as they proceed to formal litigation.

The segment's legal practitioners also oversee class action matters should they arise. For matters which may be covered by the organization's insurance policies, Toronto Hydro retains external counsel approved by its insurers. In addition, Litigation and Claims advises on privacy compliance, customer issues and many other business unit and external requests. Finally, Litigation and Claims supports the company's business units when issues are raised that have the potential to become legal disputes. In 2013, the Litigation and Claims segment handled over 1,100 new general liability claims matters and in excess of 120 files under actual litigation.

As part of the Legal Services department reorganization, the claims function, which handles processing and determinations with respect to claims prior to the formal commencement of litigation, was combined with the litigation function. The segments were placed under a single legal manager to provide strategic oversight for dealing with claims made by or against the utility from beginning to end. Combining the litigation and claims functions under one segment allows for significant process improvements.

In addition to resolving claims brought against the utility, the Litigation and Claims segment also support Toronto Hydro's efforts to obtain compensation when the organization has been harmed, such as when the utility's plant is damaged through third-party actions. By pursuing demands and legal actions, Litigation and Claims is able to make recoveries in respect of damages suffered by Toronto Hydro which otherwise would be unrecovered losses.

The chief risk in anticipating and budgeting for legal costs arising from Litigation and Claims is the inherently reactive nature of the area. Typically, claims arise from unanticipated matters, which the utility attempts to resolve through its claims settlement process, including the use of collections agents, prior to engaging in more costly and protracted legal procedures. Should that process not reach a conclusion that Toronto Hydro or the opposing parties are willing to accept, the matter may advance to litigation. The formal litigation process is considerably more expensive than using the internal claims function, due to costs for external legal counsel's time and efforts and court-related fees and costs, and may not lead to a successful result depending on many factors. If a party is unsuccessful in litigation, it may be required to pay for a portion of the other side's legal fees.

4.1. Segment Costs

Table 3 presents the Historical (2011-2013), Bridge (2014) and Test Year (2015) costs of delivering the Litigation and Claim segment of the Legal Services program.

Table 3: Litigation and Claims segment Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Litigation & Claims	2.3	1.8	2.4	2.4	2.5

4.2. 2011 – 2012

From 2011 to 2012, segment costs decreased by $0.5 million due a reduction in staff as part of the department's reorganization initiative, and a reduction in payments made in respect of claims.

4.3. 2012 – 2013

From 2012 to 2013, segment costs increased by $0.6 million due to a significant increase in the value of claims made and settled against the utility. These results were much more closely in line with historical trends than those experienced in 2012.

4.4. 2013 – 2014

From 2013 to 2014, Toronto Hydro forecasts the segment costs to remain steady, despite increases in claims, privacy information requests and litigation activity. This is achieved through leveraging the efficiencies gained through organizational and the improved value from external counsel as result of the legal RFP process.

4.5. 2015 Test Year Segment Costs

The 2015 Test Year costs associated with the delivery of the functions and responsibilities of the Litigation and Claims segment is forecasted to be $2.5 million, which represents an increase of $0.2 million from the utility's last rebasing year (2011), and a $0.1 million increase from the forecasted Bridge Year (2014) costs. Efficiencies driven by the completion of the reorganization, synergies between litigation and claims and the transfer of external workload to firms chosen under the RFP process are anticipated to balance increased litigation arising as a result of more construction-intensive capital work and aging infrastructure.

Although the Legal Services department has been able to accomplish significant productivity gains to provide better value to its clients and Toronto Hydro without

increasing the costs of the segment, there is a risk of markedly increased litigation and claims costs that could arise when major extended damage events takes place. As a result of the changes required by insurers, commencing in 2013 Toronto Hydro became responsible for a deductible of $250,000 per matter, as opposed to the previous cost of $100,000. This increase in deductible consequently results in an increased liability to the utility for legal and other costs in insurable matters.

Maintaining this level of expenditure in the Litigation and Claims segment is vital to Toronto Hydro, since a reduction in budget could limit the utility's ability to support and defend the utility effectively against external claims or make claims for damages where it has been harmed. Equally important, a reduction in Legal Services' budget could also diminish the ability of the utility to properly anticipate and consider legal issues in its operations, so that potential damages are mitigated.

The proposed amount of expenditures for this segment is based on the utility's historical experience with respect to litigation and claims. However, since it is anticipated that the litigation and claims caseload will likely continue to increase due to the growth in size and complexity of the capital program, increasing legislative compliance requirements, and because of the largely unpredictable nature of damage occurrences, the Legal Services program expects to at least maintain its historical budgetary levels.

CHARITABLE DONATIONS AND LOW-INCOME ENERGY ASSISTANCE PROGRAM ("LEAP")

1. SUMMARY

Toronto Hydro's total historic and forecast charitable contributions are summarized in Table 1 below.

Table 1: Charitable Contributions Summary ($000s)

Category	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Rate Recoverable	720	660	660	660	850
Non-Rate Recoverable	83	50	54	50	250
Total	**803**	**710**	**714**	**710**	**1,100**

Toronto Hydro's non-rate recoverable charitable contributions are comprised of multiple minor donations to a number of registered charities and charitable causes within the Toronto area, in addition to a $200,000 donation to George Brown College in 2015. Toronto Hydro's sole rate recoverable charitable contributions for the 2015-2019 period are its payments towards the Low-Income Energy Assistance Program ("LEAP")[1].

In accordance with the Ontario Energy Board's ("OEB") directives concerning LEAP funding, Toronto Hydro has allocated 0.12 percent of its total (service) distribution revenue requirement towards LEAP. This amounts to approximately $850,000 disbursed annually over the 2015-2019 period.

[1] Toronto Hydro ceased its participation in the legacy Winter Warmth program upon the adoption of LEAP in 2011.

In addition to the normal LEAP funding, Toronto Hydro is also proposing to disburse a one-time donation of $16,682 for 2015, composed of outstanding over-collected late payment charges on currently inactive accounts. Toronto Hydro originally presented these credits to the OEB for consideration in its Reconciliation Report as part of an OEB Decision (see below) authorizing certain temporary exemptions from select customer care provisions within the Distribution System Code ("DSC") and the Retail Settlement Code ("RSC").

At present, Toronto Hydro continues to rely on the Neighbourhood Information Post ("NIP") as its designated LEAP agency. NIP has been responsible for operating Toronto Hydro's LEAP program since 2011, and was the United Way's designated agency for the Toronto area for the preceding Winter Warmth program. The extended working relationship with NIP has allowed Toronto Hydro to establish operational efficiencies in qualifying low income customers, processing approved grants, and resolving any potential operational issues.

2. PROGRAM DESCRIPTION

2.1. Expenditure Summary

The table below shows Toronto Hydro's annual LEAP contributions and grant amounts:

Table 2: Toronto Hydro LEAP Program Disbursement Summary ($000s)

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Annual Contribution[1]	720	660	660	660	850
Carryover from prior years	62	325	464	95	0
One-Time Contribution[2]	0	0	0	0	17
Total Available	782	985	1124	755	867
Total Dispersed (including admin fees)[3]	457	521	1029	755	N/A
Total Unused	325	464	95	0	N/A

1. In 2011 Toronto Hydro disbursed a slightly higher amount than required by the OEB LEAP directive.
2. Consists of over-collected late payment charges outstanding to currently inactive customer accounts (see below for details)
3. Calculations exclude grants using Garland Settlement funds administered by the United Way (see below for details)

Prior to the OEB's LEAP program coming into effect in 2011, Toronto Hydro had participated in the preceding Winter Warmth program. As the Winter Warmth program was only available during winter months and accordingly required lower funding levels, Toronto Hydro and NIP faced initial challenges to transition from a seasonal to an annual cycle and to increase its volume of processed grants up to the new levels required by LEAP.

In early 2011, only two-thirds of the annual allotment was distributed to customers in need of financial assistance. In response, Toronto Hydro worked with NIP to increase promotion and communication of the program in 2012, which resulted in a corresponding

increase in both the amount of funds distributed and the number of LEAP applicants approved.

By 2013, continued efforts to improve outreach and communications, as well as efforts to augment the existing LEAP program using Garland Settlement Funds (see below), resulted in a significant increase in LEAP assistance to customers, using up the entire annual allotment and a majority of carryover funding accumulated over 2011 and 2012. Toronto Hydro expects that its new annual contribution level, in combination with available Settlement Funds, will be sufficient to meet the demand of its low income customers over the 2015-2019 period.

2.2. Settlement Funds

Toronto Hydro was subject to the Garland Settlement, through which $4.4 million was entrusted to the United Way in 2012 for the purposes of energy assistance to Toronto customers. As of the end of 2013, approximately $3.5 million of the original fund amount remains undisbursed, and the United Way continues to collaborate with Toronto Hydro on the most efficient way to make use of this funding.

In 2012 and 2013, when Toronto Hydro's annual funding was sufficient to cover LEAP grants, the Settlement Funds were used to augment the OEB's existing LEAP program with two specific measures:

1) Customers who did not qualify using the LEAP income criteria (gross income < LICO+15%) could be provided with a grant using Settlement Funds by qualifying under slightly less restrictive criteria (gross income<LICO +25%).
2) Customers who were in arrears in excess of $500 (the LEAP individual grant maximum), could be granted the net amount in excess of $500 (i.e., up to an additional $500, to a maximum of $1,000) from the Settlement Funds.

In 2014, Toronto Hydro expects that its annual OEB-directed LEAP funds will be insufficient to cover demand throughout the entire year, given an increased rate of distribution of LEAP grants in Toronto Hydro's service territory. As a result, the United Way discontinued the above measures and the remaining Settlement Funds have been reserved to cover any shortfall in funding once Toronto Hydro's annual LEAP fund allocation is expended. The magnitude of the remaining Settlement Funds, in combination with existing utility contribution levels ($850,000 per year over the next five years) are expected to allow Toronto Hydro to fully meet LEAP demand through to the end of 2019.

2.3. Late Payment Charge Credits To Inactive Customers

On July 18, 2011, Toronto Hydro filed an application seeking temporary exemptions from certain portions of the DSC and RSC (EB-2011-0269). By decision dated February 22, 2012, the OEB granted the relief sought by Toronto Hydro in its application.[2] As part of that decision, the OEB ordered Toronto Hydro to provide a Reconciliation Report to the OEB, outlining the measures Toronto Hydro had taken to become compliant with the relevant sections of the DSC and RSC and to confirm that any affected customers had been properly reimbursed all owed amounts.

Toronto Hydro filed its Reconciliation Report on December 3, 2012 (attached as Appendix A to this schedule), and while it had managed to become compliant in all aspects for which exemptions were granted, it identified a sum of $36,241.35 of over-collected late payment charges that remained outstanding to customers who no longer had active accounts with Toronto Hydro.

Given that most of these refunds were of immaterially small amounts, Toronto Hydro sought the OEB's guidance on how best to treat this balance. By Toronto Hydro's

[2] EB-2011-0269, Decision and Order, (February 22, 2012).

estimation, the cost of actively issuing cheques to these inactive customers would greatly exceed the value of the credits themselves. In addition, it is very likely that despite the effort and cost required, Toronto Hydro would not be successful in returning a majority of these funds to the rightful customers, nor that all customers would particularly want to receive cheques for such diminutive amounts.

As a result, as part of this application, Toronto Hydro proposes to donate the outstanding balance of these credits to its LEAP contribution for 2015. Toronto Hydro notes that of the original amount of $36,241, only $16,682 is currently outstanding, the difference having been already returned over the preceding years to any customers who had contacted Toronto Hydro inquiring about the outstanding credit on their account, in addition to any relatively larger credits for which Toronto Hydro actively attempted to locate the rightful recipient. An updated summary of the outstanding credits is provided below:

Table 3: Outstanding Late Payment Charge Credits for Inactive Accounts

Amount of Credit	Number of Affected Accounts	Total Credit (LPC Over-collection + Accumulated Interest)
<$1	10,844	($4,360.17)
$1 to $2	2,713	($3,803.21)
>$2	1,739	($8,518.95)
Total	**15,296**	**($16,682.33)**

Amanda Klein
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December 3, 2012

via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("THESL")
OEB File No. EB-2011-0269
THESL's Temporary Exemption from Certain Sections of the Distribution System Code ("DSC") and the Retail Settlement Code ("RSC")

THESL writes in respect of the above-noted matter.

Pursuant to the Board's February 22, 2012 decision, please find attached THESL's Reconciliation Report outlining the measures THESL had taken to become compliant with the relevant sections of the DSC and RSC.

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

Amanda Klein
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:AK/jl

EB-2011-0269

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application pursuant to section 74 of the Ontario Energy Board Act, 1998 by Toronto Hydro-Electric System Limited for temporary exemption from certain provisions of the Distribution System Code and the Retail Settlement Code.

Reconciliation Report

Background

On July 18, 2011, Toronto Hydro-Electric System Limited ("THESL") filed an application seeking temporary exemptions from certain portions of the Distribution System Code ("DSC") and Retail Settlement Code ("RSC") (the "Exemption Application"). By decision dated February 22, 2012, the Ontario Energy Board (the "OEB") granted the relief sought by THESL in its Exemption Application – such temporary exemptions lasting until December 17, 2012.

As part of that decision, the OEB ordered THESL to provide a Reconciliation Report to the OEB by December 3, 2012, outlining the measures THESL had taken to become compliant with the relevant sections of the DSC and RSC and to confirm that any affected customers had been properly reimbursed all owed amounts (the "Order").

Status of THESL's Compliance

Pursuant to the Order, THESL advises the OEB that as of November 30, 2012, THESL is fully compliant with the sections of code previously subject to the exemption. Furthermore, with the exception of the Inactive Accounts (as defined and discussed in detail below), THESL has taken

all necessary steps to reimburse all customers that may have been affected by THESL's temporary non-compliance with specific code measures.

Section 2.4.26A of the DSC – Application of Security Deposits prior to issuance of Disconnection Notices

THESL is now fully compliant with the requirements of section 2.4.26A of the DSC.

In its reply submissions dated November 28, 2011, THESL indicated that it was operating at approximately 100% compliance with this section as a result of manual workarounds, but would implement an automated solution in 2012 to ensure that manual workarounds would not be necessary.

However, after an extensive analysis of its security deposit system, and the existing regulatory framework governing their ongoing collection and return, THESL determined that from a business perspective, it would no longer be effective nor prudent to continue to collect security deposits from its residential customers. Consequently, in the third quarter of 2012 THESL ceased collecting new security deposits from residential customers, and began systematically refunding all existing deposits.

As of November 30, 2012, all residential security deposits have been refunded. THESL continues to maintain full compliance with section 2.4.26A of the DSC, as it no longer makes use of residential security deposits.

Section 7.7.1 of the RSC – Option of Refunds for Over Billing Corrections

THESL is now fully compliant with the requirements of section 7.7.1 of the RSC.

At the time of its exemption application, THESL was operating at approximately 90% compliance with section 7.7.1 of the RSC through the use of manual workarounds. While most

customers were notified of the option of a refund of large credit balances as a result of overbilling adjustments, the system functionality resulted in a few situations where manual cancellation of bills and automatic recalculations could occur without a notification being sent to the customer. For these few customers who were inadvertently omitted but requested refunds on their own initiative, THESL provided them with a cheque refund.

As of November 30, 2012, THESL completed the implementation of a solution that identifies accounts that have been overbilled by an amount greater than or equal to a customer's average monthly bill, and letters are issued to customers outlining the options prescribed in section 7.7.1 of the RSC. This new solution computes the average monthly bill, compares this to the credit balance on the account due to a billing adjustment to determine if it is above the threshold and outputs the required parameters required to issue the customer a letter.

Section 4.2.2.4 of the DSC – Attempting to Contact Customers 48-hours Prior to a Scheduled Disconnection

THESL is now fully compliant with the requirements of section 4.2.2.4 of the DSC.

At the time of its exemption application, THESL had been operating at approximately 100% compliance with section 4.2.2.4 of the DSC as a result of manual workarounds. On February 3, 2012, THESL implemented a solution by which it identifies all accounts that should receive a 48-hour call prior to disconnection, and relays this account list to its third party auto-dialer contractor to make the required outbound calls. This solution has eliminated the manual intervention involved in reviewing planned field activities to determine which customers should receive the standard 48-hour call, and manually preparing and dispatching this list to the third-party vendor. The new solution references disconnection event date parameters and dollar thresholds of the automated severance process to identify the accounts that should be extracted and transmitted.

Section 2.6.5 of the DSC – Late Payment Charges

Compliance

On February 21, 2012, THESL implemented code in its new CIS that brought it into compliance with Section 2.6.5 of DSC. All late payment charges as of this date have been and continue to be correctly calculated.

Reimbursement

Customers that were overbilled late payment charges during the affected period from July 6, 2011 to February 21, 2012, were reimbursed on November 24, 2012 through a credit to their account for the amount of the overbilling plus appropriate interest, calculated in accordance with Section 7.7.9 of the RSC. The late payment charge and interest credit applied to active accounts has been used to off-set any outstanding balances or will be applied against charges on future bills. Where a substantial credit balance exists, customers also have the option of requesting a refund cheque as per section 7.7.9 of the RSC. As detailed in Table 1 below, the average dollar amount reimbursed per active customer account is $2.48 (inclusive of interest).

Table 1 – Reimbursement of Late Payment Amounts - Summary

	Active	Inactive	Total
Number of Accounts Affected	176,209.00	20,325.00	196,534.00
Late Payment Charge Credited	($422,751.85)	($35,108.35)	($457,860.20)
Interest Credited	($13,560.44)	($1,133.00)	($14,693.44)
Total Credit Applied	($436,312.29)	($36,241.35)	($472,553.64)
Average Credit per Account	($2.48)	($1.78)	($2.40)

Inactive Accounts:

Of the total number of accounts affected, 20,325 are no longer active and as such, THESL no longer has a confirmed address for the former customers associated with those accounts. THESL has issued and sent bills, notifying these credits, to the last address on record. Nevertheless, THESL is uncertain whether any substantial portion of these bills will reach the right customers (i.e. those customers who are entitled to the credits). More importantly, and as

detailed in Table 2 below, of the 20,325 inactive accounts, 17,339 involve refunds of $2.00 or less (and a majority of these are for particularly small amounts of as little as $0.10). The aggregate credit total for these inactive accounts is $36,241.35, inclusive of interest.

By THESL's estimation, the cost of actively issuing all cheques to inactive customers would exceed the value of the credits themselves. In addition, it is very likely that despite the effort and cost required, THESL would not be successful in returning a majority of these funds to the rightful customers, nor that all customers would particularly want to receive cheques for such diminutive amounts.

Table 2 – Summary of Inactive Accounts

Amount of Credit	Number of Accounts	LPC Charge	Interest Credited	Total Credit
<$1.00	13,722.00	($5,658.98)	($180.23)	($5,839.21)
$1.00 to <$2.00	3,617.00	($5,068.84)	($162.89)	($5,231.73)
$2.00 and >	2,986.00	($24,380.53)	($789.88)	($25,170.41)
Total	20,325.00	($35,108.35)	($1,133.00)	($36,241.35)

In seeking the relief sought by THESL in its Exemption Application, THESL committed to reimburse any funds owed to its customers resulting from its non-compliance during the affected period. However, given the above-noted difficulties and inefficiencies involved in refunding such small amounts to inactive accounts, THESL feels it is prudent to explore alternative solutions.

THESL seeks the OEB's guidance as to how to proceed with the amounts currently due to customers of inactive accounts, and would be pleased to work with the OEB to find a pragmatic solution in this regard. Given the circumstances, one approach would be for THESL to publish a notice, requesting that any customer who has received a bill for these credits be given a time-limited option to request a cheque from THESL for their credit, after which THESL would make a contribution corresponding to any outstanding unclaimed amount (of the total of $36,241.35) to a charitable organization, or to its LEAP agency partner. THESL respectfully seeks the OEB's guidance concerning this issue, and is eager to work with the OEB to develop an appropriate course of action.

COMMON COSTS AND ADJUSTMENTS

1. SUMMARY

Table 1: Common Costs and Adjustments ($Millions)

Cost/Adjustment Type	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test	
Ongoing or Recurring	2.5	4.3	0.5	2.3	1.0	/C
One-time	3.2	-10.3	0.0	0.0	0.0	
Total	5.7	-6.0	0.6	2.3	1.0	/C

This schedule describes Toronto Hydro's costs that are not attributable to a specific program or would be administratively difficult or immaterial to allocate. The total expenditures associated with this segment are made up of two types of entries: ongoing or recurring items and one-time events.

2. ONGOING OR RECURRING COSTS AND ADJUSTMENTS

2.1. Difference in Forecast and Actual Employee Benefits Costs

Toronto Hydro provides current employees with benefits that include medical, dental and life insurance benefits for current employees and includes a provision for employee future benefits. Benefit costs are allocated through the payroll process using budgeted rates. The actual costs for benefits are based on consumption. The difference between the budgeted cost of benefits and the actual benefit costs incurred by the company remains in this segment.

2.2. Future Employee Benefits Provision

Toronto Hydro also provides benefits to employees upon their retirement, including medical, dental and life insurance benefits. The accrued benefit obligation and net

periodic benefit cost are calculated by independent actuaries using the projected unit credit method and based on assumptions that reflect management's best estimate.[1] Differences in the Budgeted employee future benefits cost and the final valuation are accounted for here.

2.3. Financing Costs

Financing costs are made up of standby fees and the amortization of the upfront and arrangement fees for Toronto Hydro's revolving credit facility and letters of credit fees. This cost also includes interest paid on customer deposits.

2.4. Governance

This category includes the costs that the company incurs for the development, implementation and monitoring of corporate-wide strategic planning, which includes enterprise risk management initiatives and disaster preparedness frameworks.

2.5 Investment Tax Credits

For the 2011 to 2014 Bridge period this segment contains refundable Investment Tax Credits ("ITC") that are received each year. Non-refundable ITCs are charged to PILS. The 2015 Test year reflects both refundable and non-refundable ITCs in compliance with International Financial Reporting Standards ("IFRS").

/C

3. ONE-TIME COSTS AND ADJUSTMENTS

3.1. Christian Helm Class Action

On April 30, 2012, a settlement reached by the parties of the Christian Helm Class Action was approved by Order of the Ontario Superior Court of Justice. Pursuant to the terms of the Order, Toronto Hydro was required to pay the amount of $5.8 million plus costs in settlement of all claims, substantially all of which had been paid as at December 31, 2012. Toronto Hydro previously accrued a liability in 2010 to cover the expected settlement. This amount proved to be in excess Toronto Hydro's actual liability and so the corresponding net one-time reduction in operating expenses is accounted for here.

[1] See Exhibit 4A, Tab 4, Schedules 5 and 7 for more information.

3.2. Refund of Payments in Lieu of Additional Municipal and School Taxes

On August 31, 2011 Ontario Regulation 423/11 was issued by the Ontario Ministry of Finance that corrected a technical error of its assessment of Toronto Hydro's payments in lieu of additional municipal and school taxes under Section 92 of the Electricity Act, 1998.[2] The new regulation corrected the inaccurate information the Ministry had collected to calculate those amounts retroactively to 1999. In May 2012, the Ministry of Finance completed its reassessment, resulting in a one-time refund to Toronto Hydro.

3.3. Special Purpose Charge

This amount represents a one-time Special Purpose Charge collected on behalf of the Ministry of Energy and Infrastructure in 2011 for energy conservation and renewal programs. An offsetting amount is charged to Revenue Offsets.[3]

[2] S.O. 1998, C. 15, Sched. A ["Electricity Act"]
[3] Please see Exhibit 3, Tab 2, Schedule 1 for details.

ALLOCATIONS AND RECOVERIES

1. SUMMARY

This schedule discusses the adjustments to Toronto Hydro's total Operations, Maintenance and Administration ("OM&A") costs to reflect the recovery of certain expenditures such as Warehousing, IT, Facilities Fleet and Equipment from the internal user departments through other OM&A and/or capital programs and Shared Services.

2. DESCRIPTION

Table 1 provides a breakdown of the Historical (2011-2013), Bridge (2014) and Test Year (2015) Allocations and Recoveries adjustments to Toronto Hydro's OM&A expenditures. The manner of allocating each individual component is discussed in more detail below.

Table 1: Allocation and Recoveries Adjustments to OM&A ($ Millions)

Allocations & Recoveries	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test	
On-cost Recovery	(9.3)	(7.8)	(10.7)	(11.0)	(10.7)	
Fleet Recovery	(10.8)	(10.7)	(10.3)	(12.4)	(13.2)	
IT and Occupancy Charges	(0.6)	(0.5)	(0.5)	(0.6)	(0.5)	
Shared Services	1.2	1.6	1.0	4.1	4.2	
Other Allocated Costs	(0.4)	(0.0)	7.1	-	-	/C
Allocations & Recoveries Total	**(19.9)**	**(17.4)**	**(13.3)**	**(19.9)**	**(20.2)**	/C

3. ON-COST RECOVERY

On-cost recovery is a material handling surcharge applied to all inventory issuances from warehouse to both capital and operating projects.[1] As a result, if the items issued from the warehouse are associated with capital projects, the on-cost charge is capitalized, whereas if the items issued are associated with operating projects, the on-cost charge is expensed in the period in which it is incurred.

The costs included in the on-cost recovery are mainly comprised of:

- Compensation costs;
- Directly attributable support costs; and
- Warehouse overhead.

4. FLEET RECOVERY

The allocation of fleet costs to other programs is done to optimize the number of vehicles and to allocate the vehicles to either maintenance or capital projects. The allocation is based on the number and type of vehicles. In the case of maintenance projects, the allocation provides for a transfer of operating costs from the Fleet and Equipment program to other programs using the service. In the case of capital projects, the allocation provides for a transfer of operating costs to capital investments. The allocation to capital is based on the nature of the work performed and follows Toronto Hydro's labour costing methodology.

The costs included in the fleet allocation are mainly comprised of:

- Fleet compensation costs;
- Parts and material;
- Vehicle insurance, licensing and registration; and
- Fleet overhead.

[1] Exhibit 4A, Tab 2, Schedule 12.

Fleet and Equipment Services program also allocates costs related to large tools and laboratory services using the same methodology. Costs allocated to unregulated affiliates include a component for depreciation and return on assets.

Fleet and Equipment Services program[2] employs a vehicle "lease-rate" cost recovery model, whereby vehicle expenses are recovered using a monthly user charge at the vehicle class level (e.g., "Compact Car", "Passenger Minivan up to 2500 kilograms"). The lease-rate is calculated on an annual basis to ensure that operating cost changes at the vehicle class level are accurately reflected in user lease rates as of the following year.

5. IT AND OCCUPANCY CHARGES

The allocation of IT costs to business units is done to optimize the use of technology assets. The allocation is based on IT support to the end users, including directly attributable labour and support costs. The allocation provides for a transfer of operating costs in the IT program[3] to other client units.

The costs included in the IT allocation are comprised mainly of:

- Compensation costs; and
- Directly attributable support costs.

The allocation of Occupancy/Facilities costs to business units is done to optimize the use of space within Toronto Hydro's facilities. The allocation is based on square-footage and type of space. The allocation provides for a transfer of operating costs from the Facilities program[4] to the business units.

[2] Exhibit 4A, Tab 2, Schedule 10.
[3] Exhibit 4A, Tab 2, Schedule 16.
[4] Exhibit 4A, Tab 2, Schedule 11.

The costs included in the Occupancy/Facilities allocation mainly consist of:

- Compensation costs;
- Property leases;
- Maintenance costs;
- Facilities overhead;
- Utilities costs; and
- Property taxes.

6. SHARED SERVICES[5]

Shared services recoveries have historically been reported in OM&A; however in accordance with section 2.6.3 and 2.7.3.2 OEB's Filing Requirement (July 17, 2013), the 2014 Bridge and 2015 Test Year shared services recoveries are reported as revenue offsets.[6]. The $3.1 million increase in 2014 Bridge, compared to 2013 is due to this change in reporting.

7. OTHER ALLOCATED COSTS

Other allocated costs represent costs which are not specifically attributed to an OM&A program. The costs of $7.1 million shown in 2013 actuals represent the recognition of operating expenses due to the disposition of the 2008-2010 smart meter deferral account balances.

/C

[5] Refer to Exhibit 4A, Tab 5 for more information about Toronto Hydro's shared services.
[6] Refer to Exhibit 3, Tab 2, Schedule 1for more information about Toronto Hydro's revenue offsets.

PURCHASE OF NON-AFFILIATE SERVICES

The objective of Toronto Hydro's Procurement Policy (the "Policy")[1] is to help ensure that the services, equipment and materials procured by Toronto Hydro represent the best value for its customers while also satisfying the operational needs of the utility. The Policy helps Toronto Hydro achieve three of the performance outcomes set out by the Ontario Energy Board ("OEB") in the Renewed Regulatory Framework for Electricity Distributors.

- Customer Focus: the efficient procurement of services, equipment and materials at favourable total cost of ownership helps Toronto Hydro deliver overall value for its rate payers.
- Operational Effectiveness: the use of a robust and competitive procurement system helps to ensure that effective purchases are made, minimizing costs and enhancing productivity.
- Policy Responsiveness: the use of a fair vendor selection process helps ensure that selected vendors meet or exceed quality, safety, regulatory, and environmental requirements.
- Financial Performance: over time, use of the Policy generates data that allows Toronto Hydro to minimize both operational and capital costs, contributing to the utility's financial performance.

Except as described below, procurements with a contract value exceeding $25,000 are sourced in compliance with Toronto Hydro's Procedure for Competitive Bids (Appendix A). Limited and specific exceptions are set out in the Exceptions to General Procurement Rules (Appendix B). The Procedure for Competitive Bids (Appendix C) outlines the general competitive bid process and sets out rules with respect to communications, negotiations, bid reviews and conflicts of interest. This formalized competitive bidding

[1] Filed as Exhibit 4A, Tab 3, Schedule 2.

process helps to ensure that the procurement process remains transparent, efficient and consistent.

While recognizing that there are justified exceptions, Toronto Hydro's objective is to maximize the use and success of the competitive bid process. Procurement staff work with various Toronto Hydro departments to enable earlier recognition of business needs. In addition, efforts have been made to collaborate with Toronto Hydro's legal department to improve the clarity and accessibility of procurement documents whilst reducing the average competitive bid process timeline, from initiation to the execution of contracts and/or issuance of purchase orders (additional info concerning Toronto Hydro's Supply Chain program is provided at Exhibit 4A, Tab 2, Schedule 12).

Once a procurement is finalized, either through a competitive process or a documented exception, applicable terms and conditions are set out in a negotiated contract and/or a purchase order with a vendor.

When Toronto Hydro contemplates a civil or electrical construction project, potential contractors are pre-qualified in accordance with Toronto Hydro's Construction Contractor Pre-Qualification Application. A contractor's pre-qualification signifies that the contractor has met the minimum requirements established by Toronto Hydro for the purposes of a project. The factors used for evaluating contractors at this stage include, but are not limited to, technical skill and competence, experience, financial viability, health and safety record, reputation, workload, and any previous relationship with Toronto Hydro. Contractor pre-qualification does not guarantee that a contractor will be invited to bid on projects; rather, it simply establishes a baseline reassuring Toronto Hydro that the respondents selected for particular projects are sufficiently qualified.

Toronto Hydro's levels of signing authority are provided in Appendix D.

In accordance with s. 2.7.3.3 of the OEB's Filing Requirements (July 17, 2013), the tables below identify non-affiliate services that were procured without a competitive process in 2011, 2012 and 2013 that meet or exceed Toronto Hydro's materiality threshold. Toronto Hydro confirms that all non-affiliate services in the 2011, 2012 and 2012 historical year were procured in compliance with the utility's Policy.

Table 1: 2011 Non-Affiliate Purchased Products or Services over $1 Million Procured without a Competitive Process

Vendor Name	Product and Service	Method of Selection	Justification
Oracle Canada ULC	Staff augmentation and change request for the implementation of the Oracle Utilities Customer Care and Billing System.	Sole source	Extension of support agreement with incumbent pending technical availability of the new Customer Care and Billing System.
Elster	Purchase of the Elster Transformer Smart Meter that was required to complete pilot installations.	Sole source	To help ensure compatibility with existing technologies.
Nedco	Nedco acts as the program manager for the Direct Install Lighting & Water Heating Initiative, to bridge gap between master agreement sign-off & development of new request for proposal. CDM initiative.	Sole source	Extension of existing contract pending issuance and award of RFP.
BOMA	Channel partner for the Equipment Replacement Incentive initiative.	Sole source	Vendor selected due to expertise delivering OPA/CDM programs in

Vendor Name	Product and Service	Method of Selection	Justification
	CDM initiative.		2007-2010.
Borden Ladner Gervais	Provide professional legal consulting services.	Sole source	Continuation of existing counsel.
The Herjavec Group	Managed Security Services for Security Info & Event management, Data Loss Prevention and Monitoring services for Intrusion Protection Services, Firewall and Governance Risk & Compliance.	Sole source	Awarded work based on success evidenced by other Toronto-based companies and excellent history with Toronto Hydro.
Bell Canada	Master Communications Agreement renewal.	Sole source	Leveraging City of Toronto rates for City affiliates to avoid risks associated with migrating to a new provider.

Table 2: 2012 Non-Affiliate Purchased Products or Services over $1 Million Procured without a Competitive Process

Vendor Name	Product and Service	Method of Selection	Justification
Various Providers	OPA directed incentive payments for retrofit projects. CDM initiative.	Sole source	OPA directed payments.
Rogers Communication	Continuation of a contract awarded for airtime and data services for cellular pagers, blackberries, mobile devices, smart meters and substations in addition to	Sole source	Terms continued from previous agreement. Negotiated material annual discount with provider as opposed to going out to market.

Vendor Name	Product and Service	Method of Selection	Justification
	cable and video services.		
Hydro One	Provide Agincourt TS Bypass Capacity.	Sole source	The nature of the assets requires Toronto Hydro to use Hydro One for this work.
Optima Communications	Call centre/clerical services.	Sole source	The work subsequently went out for RFP in November 2012. Prior to that point, time constraints prevented Toronto Hydro from undertaking a competitive bidding process.
Vmware	Software licenses and maintenance for Vmware virtualization software products.	Sole source	Updated licenses are only provided by the original supplier of the application.
Olameter Inc.	Meter reading services.	Sole source	To cover spend between expiry of existing agreement and final award of RFP.
Emeter Corporation	Five years of licensing and support for Energy IP software and two years of support for register reads on the bill (RROB) solution.	Sole source	Emeter is the only provider capable of providing this service. As well, this vendor is required for compatibility reasons.
IBM Canada	Augmentation of existing contract with IBM for helpdesk services.	Sole source	Expansion of existing services in contract.
Oracle Canada ULC	Consolidation of multiple software license renewals for existing applications.	Sole source	Updated licenses are only provided by the original supplier of the application.

Vendor Name	Product and Service	Method of Selection	Justification
Hydro One	Replacement of wholesale revenue metering to comply with Independent Electricity System Operator (IESO) requirements.	Sole source	The nature of the assets requires Toronto Hydro to use Hydro One for this work.
Bell Canada	Voice and data services for all rims meters, smart meters, analog and digital circuits, pagers, mega links and related support services	Sole source	Leveraging City of Toronto agreed-rates for city affiliates to avoid risks associated with migrating to a new provider.
Carte	Supply pad mount transformers.	Sole source	To cover spend for the time between the expiry of existing agreement and final award of RFP to new provider.
Hydro One	Temporary bypass at Agincourt station.	Sole source	The nature of the assets requires Toronto Hydro to use Hydro One for this work.
IBM	Cover the cost for IBM support services under the Gold Card Agreement option.	Sole source	These services are proprietary.

Table 3: 2013 Non-Affiliate Purchased Products or Services over $1 Million Procured without a Competitive Process

Vendor Name	Product and Service	Method of Selection	Justification
DDP Technologies	Inspection services for Pad Tx, Sub Tx, network vaults	Sole source	The need to commence the program on an urgent basis

Vendor Name	Product and Service	Method of Selection	Justification
	and building vaults along with "Find it - Fix it" repairs for each program.		prevented the use of a competitive bid process. Informal quotes were obtained from five suppliers and the program was granted to the lowest, qualified provider.
Carillion Construction Inc.	Carillion originally awarded work on Copeland Station via RFP. The increase in contract value associated with the change in scope.	Sole source	To cover increase of scope identified after award of RFP.
Panasonic Canada	Three years supply of Panasonic tough books and tough pads consistent with existing technology used by field staff	Sole source	Negotiations with Panasonic coupled with market benchmarking indicated it was cheaper to deal direct with manufacturer instead of issuing RFP to resellers.
QX Technical Services	Locates agreement extension to align with other Locate Consortium members.	Sole source	To cover spend for the time between the expiry of existing agreement to new RFP in June 2014.
Tyco Integrated Security	Station close circuit TV cameras (CCTV) and locking hardware upgrade.	Sole source	Purchase from current security provider to ensure compatibility with existing systems.
Metsco Energy Solutions	Additional spend incremental to awarded dollars for Engineering Services on RFP 12P-046.	Sole source	Increase of spend versus original estimates.

POLICY

PROCUREMENT	**Policy Owner:** **Executive Vice President, Grid Operations (THESL)**
	Policy Approver: **Policy Administration Steering Committee**
	Version Approval Date: **V3.1 2013-12-09**
	Last Reviewed by PASC: **2013-12-09**
The most recent version of this policy can be obtained from the Toronto Hydro intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/DistributionGridManagementPolicies.aspx	
The distribution of this policy is not restricted.	

This policy was approved by the Policy Administration Steering Committee on:

2013-12-09

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1 DOCUMENT REVIEW & REVISION HISTORY

This policy is reviewed annually.

Version Number	Date of Review	Reviewed By	Brief Description of Change
V1.0	2007-07-01	PASC	V1.0 approved by PASC.
V2.0	2009-10-23	PASC	V2.0 Approved outside of regular scheduled PASC meeting
V3.0	2013-04-25	PASC	V3.0 approved by PASC members
V.3.1	2013-12-09	PASC	V.3.1 approved by PASC

2 DISTRIBUTION HISTORY

Version Number	Date of Issue	Recipients
V1.0	2007-07-01	Toronto Hydro @ Home Employee Extranet
V2.0	2009-10-26	Toronto Hydro @ Home Employee Extranet
V3.0	2013-05-10	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/
V.3.1	2013-12-09	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/

3 POLICY OVERVIEW

This policy outlines the process that is to be followed for the procurement of any good or service by or on behalf of Toronto Hydro Corporate Entities. The goals of this policy are to ensure Toronto Hydro business objectives are achieved and to facilitate compliance with applicable internal standards and requirements as well as regulatory, statutory and other legal requirements.

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4 DEFINITIONS AND ABBREVIATIONS

TERM or ACRONYM	DESCRIPTION
Affiliate	Toronto Hydro-Electric System Limited, and any other affiliate of Toronto Hydro Corporation from time to time.
Authorization Level Document	The most recent version of the Authorization Level Document setting out expenditure levels for authorized persons.
Board	The Board of Directors of Toronto Hydro Corporation or of any Affiliate as may be applicable.
Business Unit	The Toronto Hydro Corporation or Affiliate department requesting a Procurement.
CEO	President and Chief Executive Officer of Toronto Hydro Corporation.
CIO	Chief Information Officer of THESL.
Contract Value	The total amount of expenditures required under any Procurement, which shall be determined by calculating ■ The total amount of all possible expenditure over the term of the contract, o Including all years of a multi-year term and all years of all possible contract renewals, o Including the potential maximum of all conditional, contingent or variable payments, ■ Excluding all applicable taxes. Procurements shall not be artificially divided so as to constitute a Contract Value below applicable threshold values
Manager	The Director, Senior Manager or Manager of any Business Unit with responsibility for an approved budget for the Procurement in question.
President	President of THESL.
Procurement	A purchase, agreement to purchase, licence, lease or rental of any good or service, including an agreement to purchase construction services. Includes any extension or renewal of any procurement or construction contract made prior to the date of this Procurement Policy.
Operation Support Services Department	THESL's Operation Support Services Department.
Manager of Operation Support Services	The Manager or Director responsible for the operation of the Operation Support Services Department.
Procurement Policy	This Procurement Policy together with all forms and procedures referenced herein.
Signing Policies	The most recent versions of the signing policies of Toronto Hydro Corporation and its Affiliates, as approved by the Policy Administration Steering Committee.

TERM or ACRONYM	DESCRIPTION
THESL	Toronto Hydro-Electric System Limited.
Toronto Hydro	Toronto Hydro Corporation and all of its Affiliates

5 SCOPE

This policy applies to all Procurements made by Toronto Hydro except as otherwise authorized in writing by the Board, the President or the CEO.

6 OBJECTIVES

6.1 The Procurement Policy is intended to assist in achieving Toronto Hydro business objectives such as:

- Ensuring efficient Procurements at most favourable acquisition cost
- Promoting the use of competition in selecting suppliers and contractors.
- Providing for the fair and equitable treatment of all suppliers and contractors.
- Providing safeguards for maintaining a procurement system of quality and integrity.
- (QVXULQJ VXSSOLHUV PHHW RU H[FHHGquality, safety and environmental requirements
- Ensuring that all Procurements are made in compliance with all regulatory requirements and applicable laws.

7 GENERAL PROCUREMENT RULES APPLICABLE TO ALL BUSINESS UNITS

Unless otherwise authorized in writing by the Board, the President or the CEO:

7.1 All Procurements shall be administered by the Operation Support Services–Department and authorized by the Manager of Operation Support Services or his/her authorized delegate.

7.2 Other than the exceptions in *Appendix A - Exceptions to General Procurement Rules*, all Procurements with a Contract Value exceeding $25,000, shall be sourced via the *Procedure for Competitive Bids*.

7.3 All approved Procurements (regardless of value or whether they were approved via a competitive bid process) shall be processed and documented in accordance with the *Procedure to Document Approved Procurements*.

7.4 All Procurements of information technology related goods or services (including computer equipment, software or related services) must be made in accordance with the most recent version of 7 R U R Q W R *Systems and Client Support Services ±CSS660- Hardware and Software Purchasing Procedure* and any such Procurement with a Contract Value greater than $25,000 must also be approved by the CIO in writing **.**

7.5 The initial term for any Contract shall not exceed five (5) years, and any renewal term(s) shall not exceed a total of five (5) years.

7.6 The Manager of Operation Support Services may at any time request that a particular Procurement be made through the *Procedure for Competitive Bids*.

8 OWNERSHIP, APPROVAL AND RESPONSIBILITIES

Policy Owner

8.1 This policy is owned by the Executive Vice President, Grid Operations (THESL).

8.2 The Executive Vice President, Grid Operations is responsible for*:*

- Ensuring that this policy is comprehensive, clear and current.
- Ensuring that this policy is implemented and communicated to the departments and staff that are impacted.
- Ensuring ongoing compliance with this policy.
- Reviewing this policy annually.

Policy Approver

8.3 This policy is approved by the Policy Administration Steering Committee.

8.4 The Policy Administration Steering Committee is responsible for:

- Considering the impact of the proposed policy to the identified risk.
- Reviewing and approving any proposed amendments or extensions to this policy.
- Reviewing and approving this policy annually.

Designated Responsible Person (DRP)

8.5 This policy is managed by the Manager of Operation Support Services.

8.6 The Manager of Operation Support Services is responsible for:

- Immediately communicating any exceptions or violations of this policy to the Executive Vice President, Grid Operations.
- Reviewing this policy annually and communicating any proposed amendments to the Executive Vice President, Grid Operations.
- Conducting quarterly reviews to ensure compliance with this Policy.

Staff

8.7 All Toronto Hydro employees, officers and directors are required to comply with this policy.

9 POLICY COMMUNICATION

TYPE OF COMMUNICATION	COMMUNICATION TRIGGER	PARTY RESPONSIBLE FOR POLICY COMMUNICATION	AUDIENCE	ACKNOWLEDGEMENT?
E-mail	Policy Revision	Manager of Operation Support Services	All Business Unit employees involved in any Procurement	No
Presentation	Policy Revision	Manager of Operation Support Services	All Business Unit employees involved in any Procurement	Attendance Sheet and Quiz

10 POLICY COMPLIANCE AND VIOLATIONS

10.1 Any employee who fails to comply with this policy is subject to disciplinary action up to and including dismissal.

10.2 Failure to comply with this policy will pose significant financial, operational, legal and regulatory risks to Toronto Hydro.

11 RELATED LAWS, REGULATIONS AND DOCUMENTATION

11.1 This Procurement Policy shall be read and applied in conjunction with the Signing Policies, the Authorization Level Document, as well as the following procedures and forms:

- *Procedure for Competitive Bids*
- *Competitive Procurement Request Form*
- *Competitive Bid Evaluation Report/Recommendation*
- *Sole Source Justification Report*
- *Extending Existing Contract Justification Report*
- *Procedure to Document Approved Procurements*
- *Non-Discretionary Providers List*
- *Construction Contractor Pre-Qualification Application*
- *Systems and Client Support Services ± CSS660 - Hardware and Software Purchasing Procedure*

- *Signing Policies*
- *Authorization Level Document*

PROCUREMENT POLICY
APPENDIX ±EXCEPTIONS TO GENERAL PROCUREMENT RULES

Exception 1 ±Petty Cash or Procurement Credit Card Purchases	This policy does not apply to Procurements that are processed via Toronto Hydro Corporation's Petty Cash or Corporate Card (Procard) procedures or policies, as implemented or amended from time to time.
Exception 2 ± Purchases Below $25,000	Procurements with a Contract Value below $25,000 need not be sourced via the competitive procedures described in Rules 7.2 or 7.3 of the Procurement Policy. Instead, a Manager may, in his/her discretion, approve Procurements not exceeding $25,000 in Contract Value in writing without receiving any competitive bids The Business Unit shall retain all documentation substantiating the Procurement, approval and the award for annual review by Operation Support Services, or Toronto Hydro Corporation ¶V , Q W H U Q Department, or otherwise as necessary. Such documentation should be retained for no less than six \ H D U V L Q F R Q M X Q F W L R Q Document Retention Policy. Procurements shall not be artificially divided so as to constitute a Contract Value below $25,000.
Exception 3 ±Contract Value Adjustments	1.1 Procurements which represent an amendment to the original Contract Value of an active, unexpired Contract need not be sourced via the competitive procedures described in Sections 7.2 or 7.3 of the Procurement Policy, nor need to meet the procedure for Sole Source procurements so long as the incremental increase in cost is less than or equal to 10% of the Contract Value, or $250,000 whichever is less. Instead, the responsible Manager, Director or Vice President, depending on required approval level, may approve such Procurements. 1.2 The Business Unit shall retain all documentation substantiating the change to the Contract Value for review by Operation Support 6 H U Y L F H V 7 R U R Q W R + \ G U R ¶V / H J D O ' L necessary. Such documentation should be retained for no less than seven years in conj X Q F W L R Q Z L W K 7 R U R Q W Retention Policy. 1.3 Procurements shall not be artificially divided so as to constitute an adjustment below 10% or $250,000 whichever is less. 1.4 In the event of multiple adjustments, the cumulative value of the adjustments shall apply.
Exception 4 ±Sole Source Procurements	The following procedure shall be followed when a Business Unit wishes to purchase any goods and/or services (including construction contracts) from a sole source vendor without going through the competitive procedures described in Rules 7.2 or 7.3 of the Procurement Policy: (i) In order to obtain approval for a sole source purchase, the Business Unit must complete, sign, and submit a *Sole Source Justification Report* to the Operation Support Services Department. The *Sole Source Justification Report* will require appropriate signing authority in accordance with the Authorization Level Document. (ii) Upon receiving a completed *Sole Source Justification Report*, the Operation Support Services Department will conduct a due diligent review of the sole source purchase request to confirm that: (a) only one vendor is uniquely capable of providing the goods and/or services

	required and no other vendor can provide such goods and/or services; (b) an unforeseeable situation of urgency or emergency exists and the goods and/or services or construction cannot be obtained by means of a competitive process as required by the Procurement Policy: or (c) the Contract Value of an active, unexpired Contract for a good and/or service increases by greater than 10% or $250,000, whichever is less, versus its original approved value. The review will also determine if the sole source purchase is in the best interests of Toronto Hydro, and include a review of the proposed contract's specifications, scope, definition, commercial terms, liabilities, and insurance requirements. (iii) If approved, the Sole Source Procurement shall be processed by the Operation Support Services Department in accordance with the *Procedure to Document Approved Procurements*.
Exception 5 ± Procurements From Non-Discretionary Providers	Procurements from specified government entities, utilities, and organizations providing certain corporate industry or professional memberships need not be sourced via the competitive procedures described in Rules 7.2 or 7.3 of the Procurement Policy, nor meet the procedure for Sole Source procurements. Instead, an authorized person under the Authorization Level Document may approve such Procurements, regardless of Contract Value, without receiving any competitive bids or submitting a Request For Sole Source Procurement so long as the vendor appears on the *Non-Discretionary Providers List.* *The Non-Discretionary Providers List* shall be updated on an annual basis. Any proposed amendments to such list shall be reviewed by the Vice President, Distribution Grid Management, and subject to the approval of the Policy Administration Steering Committee.
Exception 6 - Extension of Existing Contracts	When a Business Unit wishes to exercise its contractual right to extend an existing Procurement as set out in an existing contract : (i) In order to obtain approval to extend an existing contract, the Business Unit must complete, sign and submit an *Extending Existing Contract Justification Report* to the Operation Support Services Department. The *Extending Existing Contract Justification Report* will require approval by an authorized person in accordance with the Authorization Level Document. (ii) Upon receiving a completed *Extending Existing Contract Justification Report*, the Operation Support Services Department in consultation with 7RURQWR +\GUR¶V will conduct a due diligent review of the extension request to determine if the current contract permits such an extension and whether such extension is in the best interests of Toronto +\GUR LQFOXGLQJ D UHYLHZ RI WKH SUR scope, commercial terms, liabilities, and insurance requirements. (iii) If approved by the Operation Support Services Department, the Extension to the Existing Contract shall be processed by the Operation Support Services Department in accordance with the *Procedure to Document Approved Procurements*.

PROCEDURE FOR COMPETITIVE BIDS

1. Application: This Procedure for Competitive Bids shall apply whenever the Procurement Policy, the President or CEO, the Board, or the Manager of Operation Support Services requires that a purchase of goods and/or services be made via a competitive process.

2. Procurement Request Form: In order to begin the competitive process, the Business Unit must complete, sign, and submit a Competitive Procurement Request Form to the Operation Support Services Department. The Competitive Procurement Request Form shall be signed by a Manager.

3. Contract Administration Form: Upon receiving a duly completed and authorized Competitive Procurement Request Form, the Operation Support Services Department will open a new file to administer the competitive process

4. Solicitation Document: The Operation Support Services Department in consultation with Toronto Hydro's Legal Division will then conduct a due diligent review of the Procurement request to determine which of the following standard-form solicitation documents are appropriate for the Procurement in question:

   (a) a Request for Proposals shall be utilized whenever the Business Unit knows what goods and/or services it requires, but is seeking proposals from respondents regarding the method, ability and price of the Procurement;

   (b) a Request for Quotations shall be utilized whenever the Business Unit knows what goods and/or services it requires, and how such goods and/or services should be provided (e.g. specifications, terms of contract) and is seeking bids from respondents in order to determine the best available price for such goods and/or services;

   (c) an Invitation to Tender and Construction Contract shall be utilized whenever the Business Unit seeks bids for any construction project; or

   (d) such other form of solicitation document as approved by the Manager of Operation Support Services and/or Toronto Hydro's Legal Division.

Once the proper form of solicitation document has been determined, the Operation Support Services Department will assist the Business Unit in completing the solicitation document and determine the list of prospective suppliers or contractors. All solicitation documents shall be reviewed and approved by Toronto Hydro's Legal Division, prior to being sent to prospective respondents.

5. Construction Contractor Pre-Qualification: Invitations to Tender for construction projects shall only be granted to contractors having met THESL's Construction Contractor Pre-Qualification requirements.

6. Evaluation Criteria: The Operation Support Services Department, working in conjunction with the Business Unit shall develop a written set of evaluation criteria and marking scheme prior to sending out the solicitation document to prospective respondents/bidders. This evaluation criteria and marking scheme shall be applied to all proposals/bids equally, and without revision.

7. Communications: The Operation Support Services Department shall be responsible to issue and administer all competitive processes. No Business Unit representative nor any other representative of Toronto Hydro shall communicate with any of the prospective respondents regarding the competitive process without having a representative of the Operation Support Services Department present.

8. Amendments or Supplements to Solicitation Document: Any amendments or supplements to the solicitation document shall be made prior to the deadline for the submission of proposals/bids, and shall be issued in writing by the Operation Support Services Department to all prospective respondents.

9. Receipt of Bids: The Operation Support Services Department shall receive and keep an original copy of all proposals/bids received. All proposals/bids shall be time-stamped but not opened upon receipt, and shall be stored in a secure place until opening.

10. Modifications or Withdrawals to Proposals/Bids before Submission Deadline: Respondents shall be permitted to modify or withdraw their proposals/bids at any time prior to the submission deadline, in accordance with the instructions found in the solicitation document. After the submission deadline, all decisions to allow for the correction or withdrawal of proposals/bids shall be authorized in writing by the Manager of Operation Support Services.

11. Opening: The Operation Support Services Department shall arrange for the opening and recording of proposals/bids, including the completion of an Opening Bids Summary Page to determine which proposals/bids are compliant with the requirements as stated in the solicitation document. At least one (1) representative of the Operation Support Services

Department and at least one (1) representative from the Business Unit shall be present and witness the opening of proposals/bids and shall sign the Opening Bids Summary Page. All parties present shall also sign each proposal/bids price summary sheet.

12. Proposal/Bid Review by Business Unit. The Business Unit along with Operation Support Services will then perform a full evaluation of the proposals/bids and complete the Competitive Bid Evaluation/Recommendation Report, including award recommendation. The Competitive Bid Evaluation/Recommendation Report shall be signed by authorized representatives of the Business Unit, in accordance with the Signing Policies. The Business Unit shall then return its completed and signed Competitive Bid Evaluation/Recommendation Report to the Operation Support Services Department, for approval and signature. The Operation Support Services Department shall forward a completed and signed copy of the Competitive Bid Evaluation/ Recommendation Report to Toronto Hydro's Legal Division for processing in accordance with the Procedure to Document Approved Documents.

13. Negotiations. Negotiations may only be conducted in accordance with the instructions and specifications as specified in the solicitation document. The communication of such negotiations shall be made either solely by or together with the Operation Support Services Department. No respondent shall be provided information about any other respondent's bid/proposal, and no respondent shall be assisted in bringing its bid/proposal up to the level of any other bid/proposal. Respondents shall not be directed to reduce their proposed prices to a specific amount in order to be considered for award. A common deadline shall be established for receipt of bid/proposal revisions based on negotiations.

14. Cancellation of Competitive Process. A competitive process may be cancelled and all proposals/bids that have already been received may be rejected by the Business Unit and the Operation Support Services Department if:

    (a) the Business Unit no longer requires the Procurement in question;

    (b) the Business Unit can no longer reasonably expect to fund the Procurement or construction project;

    (c) necessary amendments to the solicitation would be at such magnitude that a new solicitation would be desirable;

    (d) prices exceed available funds and it would not be appropriate to adjust quantities to come within available funds;

(e) there is reason to believe that proposals/bids may not have been independently arrived at in open competition, may have been collusive, or may have been submitted in bad faith;

(f) for any other good cause of a similar nature that is in the best interest and sole discretion of Toronto Hydro.

The reasons for cancellation shall be documented in the Operation Support Services Department and a written notice of cancellation (without reasons) shall be sent by the Operation Support Services Department to all recipients of the solicitation document.

15. Award: The Operation Support Services Department shall approve the Business Unit's award recommendation if such award to be made to a compliant respondent/bidder who, in the Business Unit and Operation Support Services Department's evaluation, offers the greatest overall value to Toronto Hydro, taking into account price, technical, and other factors as specified in the solicitation. If only one compliant proposal/bid is received, an award shall not be made unless a cost analysis verifies the reasonableness of the price. All awards shall be made to responsible contractors, i.e., those who have the technical and financial competence to perform and who have a satisfactory record of integrity, compliance with applicable laws, record of past performance, and financial and technical resources. All parties having submitted a proposal/bid in response to a competitive process shall be advised, in writing, of whether their proposal/bid has been selected or not.

16. Award Protests: If an actual or prospective supplier or contractor protests the solicitation or the award of a contract, such protest shall be requested to be submitted in writing to the Manager of Operation Support Services, who may, in his or her discretion, suspend the Procurement pending resolution of the protest, if warranted by the facts presented. The Operation Support Services Department shall advise Toronto Hydro's Legal Division and Toronto Hydro's Internal Audit Department of any such award protest.

17. Conflicts of Interest: No employee or contractor of Toronto Hydro shall participate directly or indirectly in the selection, or in the award or administration of any contract if a conflict of interest, real, perceived, or apparent, would be involved. Such conflict of interest will be deemed to arise where financial or other interest in the supplier or contractor is held by the employee or contractor involved in making the awards, by his or her partner or other relatives, or by an organization under the control (as defined by relevant corporate legislation) of the employee or contractor in question. Without limiting the generality of the foregoing, employees and contractors shall not solicit or accept opportunities, favors, or anything of monetary value from any respondent's suppliers, contractors, or parties to subcontracts, and shall not use any of the bidder/respondent proposals for actual or anticipated personal gain.

18. Documenting Award. Once a successful supplier or contractor has been selected, the Operation Support Services Department, with the assistance of the Business Unit and Toronto Hydro's Legal Division, shall proceed to document the purchase in accordance with the Procedure to Document Approved Procurements.

19. Previous Procedures. This Procedure and all forms mentioned herein shall be deemed to replace and supersede any and all other competitive bid procedures or forms and, unless otherwise authorized by the Board, no other procurement method or forms shall be utilized to administer a competitive process.

20. Defined Terms. Any capitalized terms used but not defined herein shall have the meaning as defined in the Procurement Policy.

AUTHORIZATION LEVEL

10-Mar-14

APPROVAL LEVEL	PURCHASE REQUISITION AND MANUAL INVOICE APPROVAL LIMITS
THC (District 5)	
Board of Directors and Approved Officer(s)	Unlimited
President & CEO	$30,000,000
Chief Financial Officer	Unlimited to Canada Revenue Agency (ie. tax payments)
Chief Financial Officer	$3,000,000 (all other payments)
THESL/THESU (District 1/District 8)	
Board of Directors and Approved Officer(s)	Unlimited
President & CEO (THC)	$30,000,000
Chief Financial Officer (THC)	Unlimited to IESO (ie. energy costs)
Chief Financial Officer (THC)	Unlimited to Canada Revenue Agency (ie. tax payments)
Chief Financial Officer (THC)	$3,000,000 (all other payments)
Executive Vice President/Vice President	$1,000,000
Controller	$1,000,000
Director/Manager	$150,000
Supervisor	$2,000
THESI - Generation (District 2)	
Board of Directors and Approved Officer(s)	Unlimited
President & CEO (THC)	$30,000,000
Chief Financial Officer (THC)	Unlimited to Canada Revenue Agency (ie. tax payments)
Chief Financial Officer (THC)	$3,000,000 (all other payments)
Executive Vice President/Vice President	$1,000,000
Director/Manager	$25,000
Supervisor	$2,000
THESI - Street Lighting (District 2)	
Board of Directors and Approved Officer(s)	Unlimited
President & CEO	$30,000,000
Chief Financial Officer (THC)	Unlimited to Canada Revenue Agency (ie. tax payments)
Chief Financial Officer (THC)	$3,000,000 (all other payments)
Executive Vice President/Vice President	$1,000,000
Director/Manager	$25,000
Supervisor	$2,000

EXECUTIVE SUMMARY

The evidence filed in Exhibit 4A, Tab 4, Schedule 1 presents and discusses Toronto Hydro's workforce staffing plans and challenges (Schedules 3 and 4), and compensation strategies and costs (Schedule 5 and 6).

Toronto Hydro submits that the plans, strategies and costs set out in this evidence are aligned with, and necessary to, fulfill the following key objectives:

- execute planned programs in a safe and cost effective manner;
- provide customer value by maintaining and improving reliability of service without compromising safety, and by satisfying external obligations and legal requirement in a timely and cost effective manner;
- mitigate the risks associated with the projected retirement of approximately 50% of Toronto Hydro's workforce over the next decade by investing in training and development programs which facilitate knowledge transfer and allow new hires to acquire the specialized skills required to work on the utility's plant safely and effectively;
- attract, develop and retain a highly skilled, responsive and adaptable workforce within a results-driven framework that is aligned with the utility's objectives;
- constrain compensation costs by maintaining relatively stable staffing levels and market competitive wage increases; and
- continue to prudently manage the workforce complement and costs over the course of the rate period (2015-2019).

1. EMPLOYEE COST BREAKDOWN (OEB APPENDIX 2-K)

A copy of OEB Appendix 2-K, which summarizes Toronto Hydro's historical and forecast staffing levels and compensation costs, is filed at Exhibit 4A, Tab 4, Schedule 2. This table shows the following:

- the number of full-time equivalent employees ("FTEs")[1] is expected to continue to decrease from approximately 1,820 in 2011 to 1,564 in 2015; and
- total compensation costs[2] are expected to continue to decrease from approximately $234.6 million in 2011, to $225.3 million in 2015.

2. STAFFING PLAN AND CHALLENGES

Toronto Hydro relies on a highly skilled and dedicated workforce to provide safe and reliable electricity service to its customers. The 2013 ice storm highlighted the dedication and commitment of the utility's employees, who put serving customers ahead of their own needs. Toronto Hydro's crews worked around the clock throughout the holiday season to restore electricity service, communicate with customers about the restoration efforts, and ensure public safety. Despite extreme conditions, not a single Toronto Hydro employee suffered a serious injury or fatality. This remarkable outcome is attributable to the skills and training of the workforce.

Toronto Hydro employees also play an essential role in the execution of planned work programs that are necessary to maintain the distribution system's integrity, mitigate unacceptable risks in the areas of reliability and safety, and operate the system responsibly. As detailed in the Distribution System Plan ("DSP") filed at Exhibit 2B, over the course the next five years, the utility plans continue to executing the largest capital investment program in its history, renewing critical parts of its aging

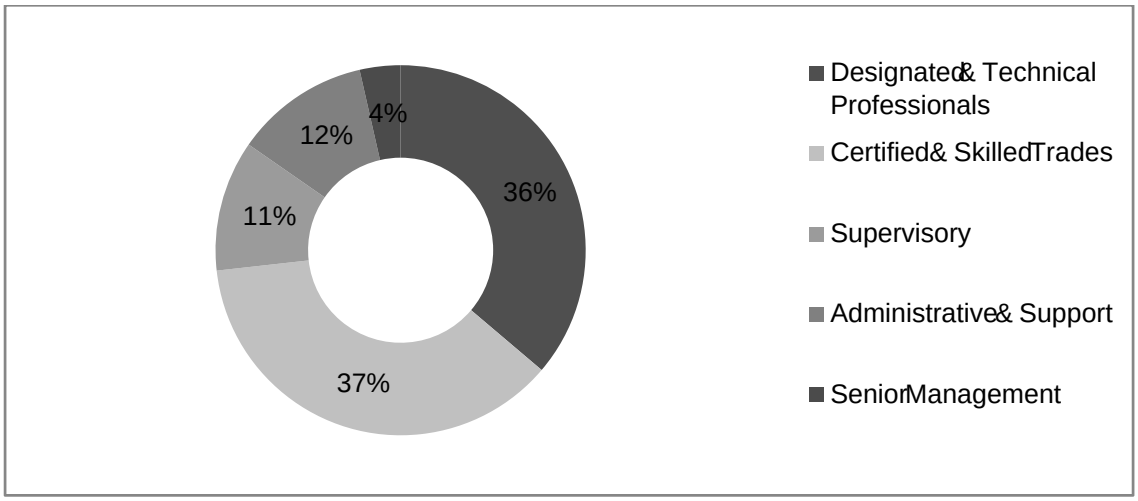
[1] The definition of a full-time equivalent (FTE) employee is aligned with the Board's Filing Guide for Electricity Distributors' Reporting and Record Keeping Requirements (the "Guide") dated April 3, 2012.
[2] Total compensation costs include: salary, wages, overtime, incentive pay, and benefits.

infrastructure and to meet the growing needs of the City of Toronto. To succeed in these endeavours the utility must maintain a workforce that is dependable, adaptable, highly skilled and knowledgeable.

2.1. Workforce Segmentation

In 2013, Toronto Hydro employed approximately 1,527 FTEs. As illustrated in Figure 1 below, Toronto Hydro's workforce can be broken down into the following segments:

Figure 1: Toronto Hydro's Workforce Segments



- Certified and skilled trades are critical for executing the capital and maintenance programs. Without funding to maintain the core staffing levels, Toronto Hydro will not be able to execute its work plan and its ability to respond to customer needs may be compromised.
- Designated & Technical Professionals include engineering technologists, engineers and corporate professionals. These employees are required to ensure Toronto Hydro is compliant with legislative standards and best practices. They are essential to designing and planning a safe, secure and reliable grid.

- Supervisors who are trained and developed internally to oversee the safe and efficient design and execution of the work plan. They perform inspections, audits, investigations, training, role-modeling, performance management and case management, and are instrumental to the safe and cost efficient delivery of service and operations.
- Administrative and Support staff perform important functions that enable operations, customer care and the corporate functions to operate with enhanced efficiency.
- Senior Management (including the executive team) provide the strategic leadership and guidance required to effectively operate the utility. They have extensive accountabilities and provide oversight to multiple subject portfolios, enhancing organizational productivity.

2.2. Aging Workforce Challenge and Mitigation Strategy

Toronto Hydro expects that approximately 25% of its workforce (approximately 400 FTEs) will retire between 2014 and 2019. Of this number, approximately half are from the key segments (certified and skilled trades, designated and technical professionals, and supervisory positions), which are critical to maintaining and operating the distribution system in a safe and efficient manner. Refer to the Conference Board of Canada Report (Schedule 3) for a discussion of the range of market challenges facing Toronto Hydro, including levels of retirement that are higher than the utility sector overall.

To constrain compensation costs over the period, Toronto Hydro plans to continue to replace retiring employees on a "just-in-time" basis; however, this is not ideal because it does not address the knowledge gap that will be created between the retirements and the time it takes to train new certified and skilled trades (four to six years), and develop new supervisors (one to two years).

Toronto Hydro also proposes to utilize an integrated, multi-faceted staffing model to fulfill its human resource requirements over the plan period, which consistent of the following approaches:

1. Hire new graduates and train them in a staged manner – Toronto Hydro plans to admit 320 individuals to its in-house apprentice program over the 2014 to 2019 period. This program provides cost-effective training that enables crews to learn the specialized skills which are required to work safely and efficiently on Toronto Hydro's distribution plant.

2. Promote from within – Between 2011 and 2013 approximately 150 vacancies were filled internally. This is cost effective approach as it builds on existing knowledge, talent and skills, and rewards high performance. The utility plans to continue to develop its existing workforce to fill positions as they become available.

3. Hire skilled labour from the external market – This approach is utilized when there is a lack of qualified internal candidates. However, for a number of reasons, it is not a viable option to fill positions for certified and skilled trades. External hires in these categories typically require an additional year of on-the-job training before they can safely work on Toronto Hydro's plant. In addition, the external labour market for certified and skilled trades is also constrained by aging workforce challenges.

4. Rely on third party service providers – This option provides Toronto Hydro flexibility to cost-effectively resource peak demands, while maintaining a stable complement of employees.

3. COMPENSATION COSTS AND STRATEGIES

Toronto Hydro expects to reduce compensation costs from $234.6 million in its last re-basing year (2011) to $225.3 million in the 2015 test year. In preparing this forecast, Toronto Hydro considered inflation rates contained in its collective agreements, relevant labour market-data and other factors such as the increasing size and complexity of the work-plan over the next five years.

3.1. Compensation Strategy

Toronto Hydro's strategy is to provide wages and benefits that are competitive in the markets where Toronto Hydro competes for talent. Refer to Compensation and Benefits Benchmarking Report prepared by Towers Watson (Schedule 6), which found that Toronto Hydro's compensation levels are generally aligned with the market.

Toronto Hydro's strategy also includes offering a compensation program that aligns the behaviour and performance of the workforce with the core objectives and goals of the utility. The compensation strategy is an important tool for communicating performance expectations, fostering productivity and rewarding employees for their contributions.

Between 2015 and 2019, Toronto Hydro intends to continue to rely on these principles to manage human resource requirements and costs appropriately and responsibly. The utility must do so with regard to the dynamic labour relations environment that it operates within, and the workforce challenges that it must contend with over the next five years.

3.2. Non-Bargaining Unit Employees

Less than one-third of Toronto Hydro's employees are not members of a bargaining unit. These employees receive a total cash compensation package comprised of base salary and variable performance pay. Salary grade levels are set to correspond to a salary range. Salaries are set and adjusted with regard to external market benchmarking.

3.3. Bargaining Unit Employees

Approximately two-thirds of Toronto Hydro's employees are represented by the following bargaining units with collective agreements in-place:

- CUPE collective agreement effective February 13, 2014 to January 31, 2018.
- The Society collective agreement effective April 12, 2012 to December 31, 2015.

3.4. Benefits and Pensions

Full-time employees are entitled to medical and dental benefits, short and long-term disability income protection, life insurance, accidental death and dismemberment, and leaves of absence (maternity, adoption and parental leaves). Employees are also eligible to participate in the OMERS pension plan and receive post-retirement benefits. The cost of employee benefits is expected to decrease from $57.47 million in 2011 to $55.87 million in 2015.

OEB Appendix 2-K
EMPLOYEE COSTS /COMPENSATION TABLE

	2011 Actuals	2012 Actuals	2013 Actuals	2014 BRIDGE	2015 TEST
Number of Employees (FTEs including Part-Time)[1]					
Management(including executive)	61.8	53.0	55.2	55	55
NonrManagement(union and non runion)	1,675.2	1,547.8	1,472.2	1,482	1,509
Total	1,737.0	1,600.8	1,527.4	1,537	1,564
Total Salary and Wages (including ovetime and incentive pay)					
Management(including executive)	$ 11,503,925	$ 10,484,857	$ 10,916,952	11,357,809	11,676,362
NonrManagement(union and non runion)	$ 165,601,764	$ 149,723,035	$ 147,970,550	152,531,929	157,754,790
Total	$ 177,105,689	$ 160,207,891	$ 158,887,502	$ 163,889,738	$ 169,431,152
Total Benefits (Current + Accrued)					
Management(including executive)	$ 3,700,705	$ 3,207,397	$ 3,497,371	3,622,390	3,586,525
NonrManagement(union and non runion)	$ 53,771,361	$ 52,158,435	$ 54,433,118	53,051,955	52,279,791
Total	$ 57,472,066	$ 55,365,832	$ 57,930,489	$ 56,674,344	$ 55,866,316
Total Compensation (Salary, Wages, & Benefits)					
Management(including executive)	$ 15,204,630	$ 13,692,253	$ 14,414,323	$ 14,980,199	$ 15,262,887
NonrManagement(union and non runion)	$ 219,373,125	$ 201,881,469	$ 202,403,668	$ 205,583,884	$ 210,034,581
Total	$ 234,577,755	$ 215,573,723	$ 216,817,992	$ 220,564,082	$ 225,297,468

WORKFORCE STAFFING PLAN AND STRATEGY

This schedule describes Toronto Hydro's workforce segments, and provides an overview of the utility's past, present and expected staffing levels, further to the data outlined in the OEB Appendix 2-K – Employee Cost, filed at Exhibit 4A, Tab 4, Schedule 2.

The schedule also describes Toronto Hydro's aging workforce challenge and discusses the staffing and development strategy that the utility has adopted to respond to this challenge over the 2015 to 2019 rate period. The evidence is presented as follows:

1) Introduction
2) Toronto Hydro's Workforce Segments
3) Staffing Levels: Past, Present and Future
4) Aging Workforce Challenge
5) Staffing and Development Strategy

1. INTRODUCTION

To facilitate the safe and efficient execution of Toronto Hydro's planned capital and operational programs, while meeting customer expectations and external obligations, Toronto Hydro needs to maintain a highly skilled workforce with a focus on certified and skilled trades, designated and technical professionals workforce, and leadership. The graph below (Figure 1) illustrates the relationship between Toronto Hydro's staffing levels and the utility's historical and proposed capital expenditures from 2007 to 2019. At a high-level, this graph demonstrates the progress that Toronto Hydro has made toward finding efficiencies in executing its work programs.

While Toronto Hydro is committed to continuous improvement and operational efficiency, the reality is that it must, at the very least, maintain current staffing levels in

order to secure the specific knowledge and talent that the utility requires to meet operational requirements going forward. The utility must also balance this need against the wave of projected retirements over the next five to ten years, and the varying training durations required for new entrants to the workforce to become fully competent.

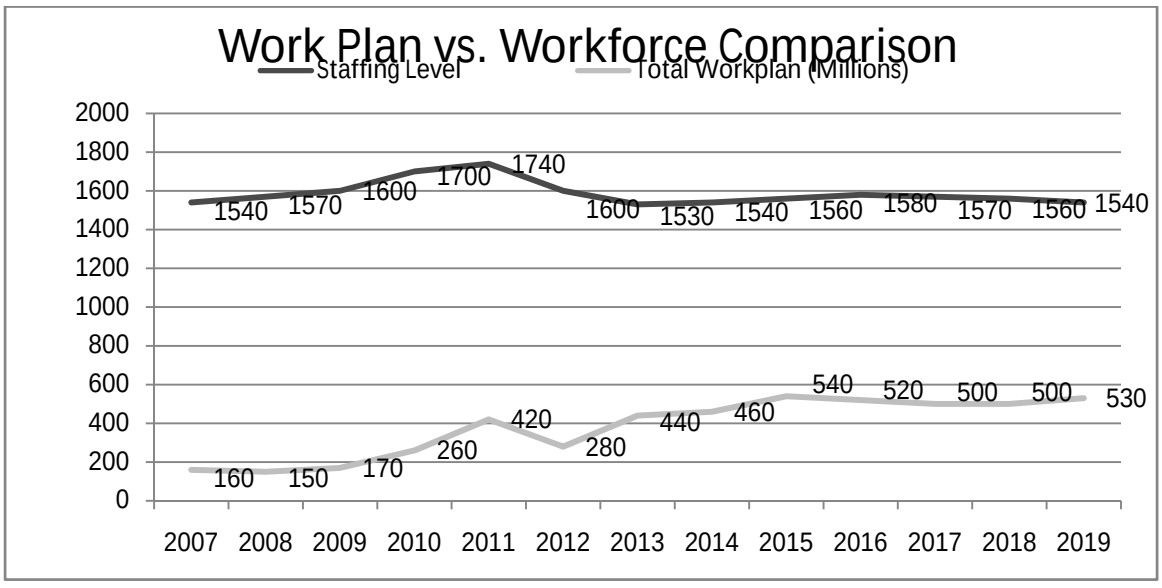


Figure 1: Capital Expenditures vs. Staffing Levels (2007 – 2019)

To deliver its capital programs, Toronto Hydro relies on a number of key Certified and Skilled Trades and Designated and Technical Professional positions, such as Certified Power Cable Person ("CPCP"), Certified Power Line Person ("CPLP"), Distribution System Technologist ("DST"), Certified Meter Mechanic/Tester, Power System Controller ("PSC"), Engineering Technologist ("ETL"), and Engineers. The utility forecasts a large number of retirements in these positions over the next five to ten years, and must continue to invest in training and development in order to facilitate the transfer of critical knowledge and key skills that employees in these positions require to safely and efficiently plan and execute the utility's work programs.

Detailed descriptions of Toronto Hydro's workforce segments are set out in section 2 of this schedule. The summary below provides an overview of the roles and responsibilities of the key Designated & Technical Professionals and Certified & Skilled Trades.

- Engineer – Participates in short and long range strategic planning on technical matters; prepares engineering reports and studies; performs analysis and evaluations; provides timely technical support/consultation, project management and testing; develops proposals and plans; prepares and/or reviews methods, procedures (process re-engineering) and designs. Engineers are accountable, and legally responsible, for personal drawings, calculations, documents and the work of others for which the Engineer has signed.
- Engineering Technologist (ETL) – Supports the formulation of electric system plans and co-ordinates system operation services with the control centre. Develops distribution plans by developing load forecasts; prepares conceptual and detail designs and cost estimates for projects related to system expansion, rehabilitation and maintenance of the electrical and civil infrastructure. Conducts studies, prepares reports, makes recommendations relating to station and system distribution load forecasts, engineering studies, technical standards, utility materials, tools and construction practices. Prepares, reviews and maintains project schedules.
- Power System Controller (PSC) – Operates the electrical distribution system to provide safe, reliable and cost-effective delivery of electrical power on a 24-hour basis. In performing this function, Power System Controllers monitor system conditions, develop, direct and dispatch system switching, work protection and trouble response for planned and emergency events.
- Certified Meter Mechanic/Tester – Installs, removes, repairs, inspects, conducts tests and calibrates all types of meters and metering equipment and troubleshoots to determine faults in meters, metering equipment and test boards.

Assists in high voltage testing, repairing street lights and fault rate relays. Investigates and reports on system anomalies.

- Distribution System Technologist (DST) – Operates, installs, commissions, constructs, repairs, maintains, and decommissions all types of substation equipment, protective relay and control systems, station metering, distribution automation equipment, and SCADA systems, including completion of all associated work orders, specifications, engineering drawings, reports, and work procedures.
- Certified Power Line Person (CPLP) – Responsible for the construction and maintenance of the overhead and underground distribution systems, and all voltages, in a safe and efficient manner. Constructs, maintains, operates, and troubleshoots the overhead and underground distribution plant, including emergency repairs and switching operations. Performs line clearing duties as required.
- Certified Power Cable Person (CPCP) – Responsible for maintaining, operating and troubleshooting the underground distribution systems for all voltages. Installs, removes, constructs, alters, operates, inspects and maintains equipment associated with the underground distribution system, including transformers, switchgear, protectors, primary switches, cables and related equipment located in cable chambers, transformer vaults, etc. containing energized circuits.

2. TORONTO HYDRO'S WORKFORCE SEGMENTS

Toronto Hydro employs a workforce of skilled employees who serve customers, allow the utility to satisfy its legal and regulatory obligations, safely maintain and operate the distribution system and execute the utility's plans. As explained in more detail below, the major segments of the workforce include certified and skilled trades, designated and

technical professionals, supervisory staff, administrative and support staff, and senior management.

2.1. Certified and Skilled Trades

Approximately 37 percent of Toronto Hydro's workforce is comprised of recognized certified and skilled trades. These positions (two of which are illustrated below in Figure 2) are critical for executing the primary activities and programs that enable the utility to construct and maintain the distribution system, to deliver safe and reliable power to its customers and to respond to trouble calls and emergency situations.

CPCP Underground Plant

CPLP Overhead Plant

Figure 2: CPCP and CPLP Employees at Work

The table below provides some of examples of the capital and operational work programs executed by certified and skilled trades. For more information about these programs, please refer to the Distribution System Plan ("DSP") filed at Exhibit 2B, and the Maintenance Programs filed at Exhibit 4A, Tab 2.

Table 1: Examples of Work Programs Executed by Certified and Skilled Trades

Capital Program (Exhibit 2B)	**Type of Resources Required**
Feeder Automation (E7.3)	CPLP and DST
Stations Switchgear Replacement (E6.13)	DST
Station Power Transformer Renewal (E6.14)	CPCP and DST
Underground Circuit Renewal (E6.1)	CPCP and CPLP
Box Construction Conversion (E6.7)	CPCP, CPLP and DST
Overhead Circuit Renewal (E6.4)	CPLP
Circuit Breaker Renewal (E6.15)	DST
Reactive Capital (E6.20)	CPCP, CPLP and DST
Maintenance Programs (Exhibit 4A, Tab 2)	**Type of Resources Required**
Station Inspections and Auxiliary Equipment Maintenance (Schedule 1)	DST
Switchgear Maintenance (Schedule 1)	DST
Station Equipment Maintenance (Schedule 1)	DST
Network Protector Maintenance (Schedule 1)	CPCP
Overhead Switch Maintenance (Schedule 1)	CPCP
Corrective Maintenance (Schedule 2)	CPCP, CPLP and DST
Emergency Maintenance (Schedule 3)	CPCP, CPLP and DST

Over the next five years, Toronto Hydro plans to continue making significant investments in the distribution system, undertaking the largest capital and maintenance work program in the utility's history in order to maintain reliable electricity service for its customers, renew aging infrastructure, and sustain the pace of growth within the City of Toronto. To do so safely and responsibly, the utility relies on having a stable complement of certified and skilled trades.

If Toronto Hydro does not receive the funding it requires to maintain a core staffing level, its ability to execute the work plan, and respond to customer needs may be compromised. Customer impacts may include increased frequency and duration of power outages as a result of insufficient resources to respond to trouble calls or to renew aging infrastructure.

2.2. Designated and Technical Professionals

Approximately 36 percent of Toronto Hydro's workforce is employed in designated and technical professional positions which include engineering technologists, engineers and corporate professionals. This segment of the workforce is responsible for planning, designing and executing the programs that enable the utility to construct and maintain the distribution system, and deliver safe and reliable power to its customers.

Technical positions complete studies, calculations and reports, plan, design, co-ordinate, and support infrastructure projects and maintenance programs. Additionally, the corporate professionals in this group enable the utility to satisfy a variety of external obligations and internal responsibilities in the area of Finance (Exhibit 4A, Tab 2, Schedule 15), Information Technology (Exhibit 4A, Tab 2, Schedule 16), Legal and Regulatory Services (Exhibit 4A, Tab 2, Schedule 18 and 17, respectively), and Human Resources and Environment, Health and Safety (Exhibit 4A, Tab 2, Schedule 14). For more detailed information about the activities that these employees perform, please refer to Toronto Hydro's capital investment plan filed at Exhibit 2B, Section E, and the operational programs filed at Exhibit 4A, Tab 2.

Without appropriate staffing levels of these designated and technical professionals, Toronto Hydro may not have the necessary resources to maintain legislative compliance and to adhere to standards and best practices, to design and plan for a safe, secure, and reliable grid.

2.3. Supervisory

Approximately 11 percent of Toronto Hydro's workforce supervises the design and execution of the work plan. This segment is primarily trained, developed and promoted from within the organization, leveraging the wealth of specific internal knowledge developed within the utility. The responsibilities associated with these positions include

inspections, audits, investigations, training, role modeling, performance management, and case management.

The supervisory segment is critical to the delivery of the work program and instrumental in ensuring that employees work in a safe and productive manner. Toronto Hydro attributes its positive developments in safety and attendance records to the work performed by employees in these positions. The utility's achievements in this respect are set out in the HR & Safety Program (Exhibit 4A, Tab 2, Schedule 14), and include:

- recognition by the Infrastructure Health and Safety Association in August 2013 for having worked 3.5 million consecutive hours without a lost time injury;
- a decrease of 56 % in the Total Recordable Injury Frequency (TRIF) between 2008 and 2013; and
- a reduction of 26 % in the average absenteeism rates from 2011 to 2013.

Relative to its accountabilities, this segment represents a small-but-critical portion of the Toronto Hydro's workforce. Without an appropriate complement of supervisory positions, Toronto Hydro may experience a reduction in productivity, and its exceptional safety record may be compromised.

2.4. Administrative and Support

Approximately 12 percent of Toronto Hydro's workforce provides support to Operations, Customer Care and corporate functions in the delivery of the work plan. Administrative and support employees also play an important role in enabling the utility to satisfy a variety of external obligations and internal responsibilities, such as scheduling and timekeeping, invoicing, project coordination, tracking and reporting, and research. Without appropriate staffing levels in these positions, Toronto Hydro may experience a reduction in productivity as a result of more highly skilled resources having to perform this type of work.

2.5. Senior Management

Senior management employees, including the executive team, represent approximately four percent of the utility's workforce. These individuals provide the leadership and strategic guidance that a utility of Toronto Hydro's size and complexity requires in order to perform effectively and responsibly in a complex regulatory business environment. Their accountabilities are extensive, with many senior management positions providing oversight to multiple subject portfolios.

3. WORKFORCE COMPLEMENT: PAST, PRESENT AND FUTURE

In 1998, after Toronto Hydro was formed through the amalgamation of six former utilities, the utility's workforce was comprised of approximately 2,400 employees. Over a period of four years (i.e., 1998-2001), the workforce was reduced to approximately 1,550 employees. This reduction in headcount was achieved as a result of voluntary retirement program and a voluntary separation program in 2001 that resulted in the loss of critical positions for the utility (such as those in the certified and skilled trades).

Over time, Toronto Hydro has been working towards staffing up its workforce in these critical positions in preparation for the wave of retirements expected over the next five to ten years, to support capital infrastructure renewal, and to allow for the lead-time required to safely train new workforce entrants.

From 2011 to 2013, Toronto Hydro experienced another notable reduction in the size of its workforce, from approximately 1,737 full time equivalent ("FTE") employees in 2011 to 1,527 FTEs in 2013. The workforce reduction that Toronto Hydro sustained between 2011 and 2013 was a result of: (1) rebalancing of the critical workforce (such as certified and skilled trades and designated and technical professional) through a voluntary exit

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program[1] and workforce downsizing; and (2) organizational and job design, following the Ontario Energy Board's ("OEB") decision in EB-2011-0144.[2]

In April 2013, the OEB substantially approved the investments proposed in Toronto Hydro's Incremental Capital Module ("ICM") application.[3] The capital work in that application represented a continuation of the elevated level of capital spending (and specifically system renewal spending) that the utility has been engaged in for several years. While it represented a significant management challenge, Toronto Hydro was able to safely execute the ICM plan using the funding available to it in that period. The utility accomplished this through various means, including the efficient planning and hiring decisions, as well as the prudent use of external resources.

In the 2015-2019 rate period, Toronto Hydro plans to execute the largest capital work program in utility's history (refer to the DSP in Exhibit 2B), using approximately the same number of internal resources as did in the 2012-2013 period. One of the greatest risks to the safe and responsible execution of this work program is the increasing wave of retirements projected in the next five to ten years.

As discussed in more detail in the Aging Workforce Challenge section below, Toronto Hydro expects a large wave of retirements in the next five to ten years and must invest in developing and maintaining a dependable, trainable and highly-skilled workforce. To prudently manage costs during the upcoming rate period, Toronto Hydro proposes a conservative staffing plan, despite challenges it faces over the next five years (i.e., 25 percent of the workforce is expect to retire in the next five years, and the size of capital program is expected to increase by approximately 22 percent, relative to 2013).

[1] The program targeted administrative and clerical positions, and focused on the reduction of non-certified trades jobs in areas where automation increased and outsourcing opportunities at a lower operating cost presented itself.
[2] EB-2011-0144, Decision with Reasons (January 5, 2012).
[3] EB-2012-0064, Partial Decision and Order (April 2, 2013).

To limit the rate increases for the upcoming rate period, Toronto Hydro proposes to continue to replace employees as they retire on a "just in time" basis. This is not the optimal approach to workforce renewal, given the time that is required to safely and effectively train new workforce entrants to work on Toronto Hydro's distribution system. It was adopted, however, to constrain costs over the 2015 to 2019 period. As a long-term strategy, this approach is not preferred because it may compromise Toronto Hydro's ability to satisfy its commitments.

Toronto Hydro has implemented a multi-faceted staffing strategy to maintain quality service and value to rate payers, and to plan for upcoming retirements. Toronto Hydro's Workforce Renewal Strategy is discussed in more detail in section 4 below.

4. AGING WORKFORCE CHALLENGE

The Canadian utility industry faces a major workforce renewal challenge over the next decade, as the wave of baby-boomer[4] retirements intensifies (refer to the Conference Board of Canada Report on Labour Market and Human Resource Trends for the Canadian Utility Sector, which is filed at Exhibit 4A, Tab 4, Schedule 4).

To illustrate the effect of this challenge on Toronto Hydro's workforce, the chart below (Table 2) compares, by age group, the Canadian population to Toronto Hydro's workforce. The average age at Toronto Hydro currently is 46.

[4] The term "baby boomers" refers to those individuals that were born between 1947 and 1965.

Table 2: Population by Age Group (Canada and Toronto Hydro)

Demographic Cohorts	Statistics Canada % of Workforce	Toronto Hydro % of Workforce
Age		
Age <25	14.87%	1.75%
Age 25-34	21.60%	22.17%
Age 35-44	21.24%	14.41%
Age 45-54	23.47%	42.21%
Age 55-64	15.35%	18.03%
Age >65	3.48%	1.42%

The 45 to 54 age group, which include the youngest baby boomers, is the focus of the aging workforce challenge, as these employees represent approximately 42 percent of Toronto Hydro's workforce. More specifically, the challenge is that the 35 to 44 age-group that immediately follows the youngest boomers, is relatively small (14.41%) in comparison to the percentage of the workforce that is over 45. The immediate consequence of this challenge is that as young boomers step in to fill the roles of senior boomers who, by 2015, will be in their mid to late 60s, the employees in the 35 to 44 age group will be called on to fill their positions. To ensure the workforce is prepared to safely and effectively perform these senior roles, the workers in the 35 to 44 age group must undergo the required training and development before they are called on to fill more senior positions.

To manage the challenge of the large wave of retirements that are expected to place in the next five to ten years, Toronto Hydro requires funding to invest in hiring new entrants and facilitating apprenticeships, co-op programs and in-house training. Toronto Hydro must pursue these investments now to account for the time it takes to train new employees and to transfer corporate and technical knowledge to them from senior employees.

The potential consequences to delays in hiring and lack of funding to administer training programs include not having adequate numbers of resources to maintain and operate the systems or relying on an inexperienced and inadequately trained workforce to perform highly complex, safety-sensitive tasks. If these consequences materialize, they could have significant effects on all critical aspects of the utility's business: customer experience, reliability, safety, and financial performance.

As highlighted in the chart above (Table 2), the aging workforce challenge is particularly acute for Toronto Hydro. Approximately 42 percent of the utility's workforce is situated in the 45 to 54 age group, and 18 percent of employees in the 55-64 age group. This means that over the next decade (i.e., by 2025), more than 50 percent of Toronto Hydro's workforce is expected to be eligible for retirement.

In the wake of a retirement, the organization must deal with not only a loss of knowledge and experience, but also a need to train and develop the individuals that have been promoted or newly hired to fill critical positions. As the chart below illustrates (Figure 3), the aging workforce challenge is even greater for those segments of the workforce which are instrumental to executing the utility's capital programs, maintaining existing infrastructure and sustaining safe and reliable operations into the future.

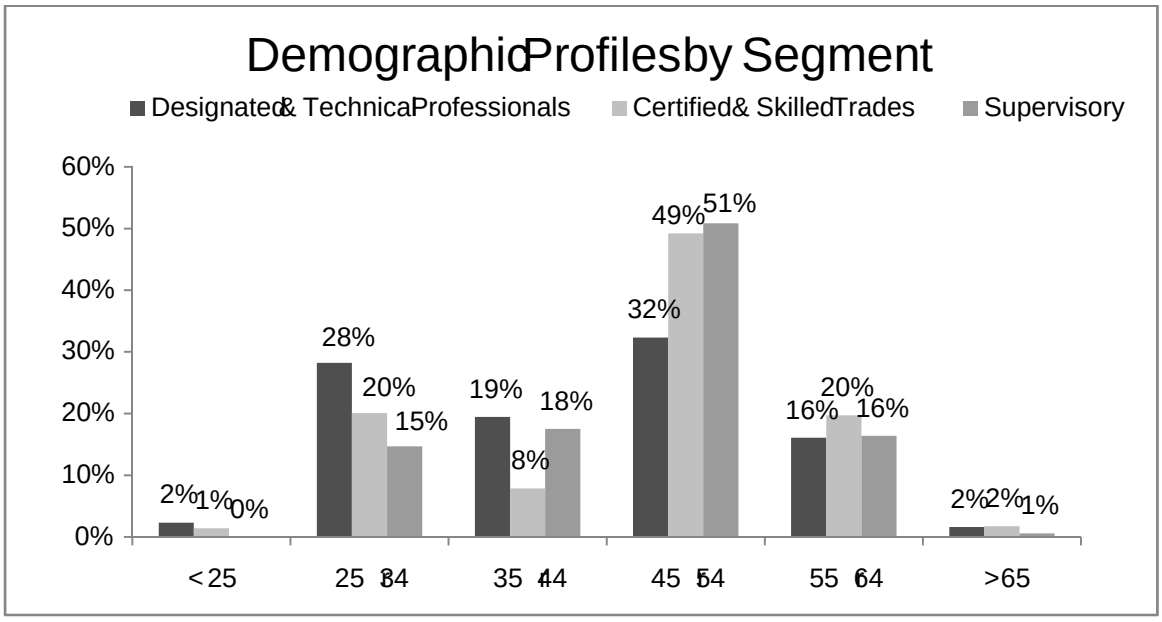


Figure 3: Toronto Hydro Workforce Demographic Profiles by Segment

Because Toronto Hydro employees below age 45 represent approximately 38 percent of the utility's workforce, relative to the 62 percent of employees over age 45, the utility could face a significant labour shortage in the next ten years if it does not continue investing in workforce renewal. Given the physical nature of certain positions, particularly in the certified and skilled trades segment, and the participation of employees in a defined benefits pension plan, retaining employees beyond their eligible retirement date is a challenge.

The staffing plan endeavours to maintain an appropriate complement of employees to respond safely and effectively to the needs of customers and to maintain and renewal Toronto Hydro's distribution system.

Toronto Hydro's second largest demographic profile is the 25 to 34 age group. Employees in this bracket are those that have been hired in recent years and that typically

require significant training and development over the course of the next five years to fulfil the roles and positions of retiring employees.

On average, it takes approximately four to six years to train a new certified and skilled trades hire, and one to two years to develop a new supervisor. The development period for Certified and Skilled Trades positions considers legislative training requirements, Toronto Hydro compliance training based on operational requirements and best practices, and apprenticeship training (technical training and testing) requirements. The table below (Table 3) provides an example of training requirements for a CPCP Apprentice.

Table 3: CPCP Apprentice Training Requirements

Course Type	Legislative	TH Compliance	Apprentice	Total Courses
Year 1	8	10	16	34
Year 2	N/A	3	18	21
Year 3	N/A	2	22	24
Year 4	5	7	9	21
Total Courses	13	22	65	100

In 2010, Toronto Hydro adopted more stringent education requirements for certain apprenticeship positions. At a minimum, the utility now requires new hires to have a university or college diploma in an electrical background. As a result of this change, Toronto Hydro apprentices' in-class training-time has decreased by 13 percent allowing employees to work on Toronto Hydro's distribution system four weeks sooner. Toronto Hydro attributes this improvement to a variety of qualities that are associated with higher education; namely, enhanced problem-solving skills, increased learning abilities, communication and comprehension aptitude, and heightened initiative and resourcefulness.

4.1. Retirements

In the 2014 to 2019 period, approximately 25 percent of Toronto Hydro's current workforce (i.e., 400 employees) will be eligible for retirement (please refer to Table 4 below). Of the 400 projected retirements, approximately half are expected to be from the Certified and Skilled trades, Designated and Technical Professionals, and Supervisory positions, which are critical to maintaining and operating the distribution system. As of April 30, 2014, 55 employees have actually retired, and nine additional employees have notified the utility of their intention to retire, or have initiated retirement planning. The table below (Table 4) summarizes Toronto Hydro's retirement projections up to the end of the upcoming rate period.

Table 4: Toronto Hydro Retirement Projections (2014-2019)

YEAR	2014	2015	2016	2017	2018	2019
ANNUAL	80[5]	36	47	59	72	106
CUMULATIVE	80	116	163	222	294	400

Toronto Hydro uses the following criteria to project retirements: OMERS normal retirement age (65 years old), Toronto Hydro's average retirement age based on historical trends (59 years old), combined with eligibility for an unreduced pension under OMERS.[6] Using these criteria, Toronto Hydro has been able to forecast the expected number of retirements in the past with reasonable accuracy. Based on the retirement projections that Toronto Hydro has provided in its three most recent cost of service applications before the OEB, Toronto Hydro's accuracy rate for forecasting retirements exceeds 90%.

[5] 2014 projection includes individuals who were eligible to retire in 2013 but have not yet retired.
[6] OMERS pension eligibility criteria for an unreduced pension stipulate that a member must be:
- a minimum of 55 years of age with 30 years of OMERS service,
- a minimum of 55 years of age, with total years of service and the age of retirement totaling 90, or
- OMERS Normal Retirement Age 65.

Table 5: Toronto Hydro Forecast of Retirements

Rate Application	EB-2009-0139	EB-2010-0142	EB-2011-0114
Accuracy Rate %	98%	96%	90%

The decision to retire is a highly personal life choice that is influenced by a number of factors (e.g., economic conditions, health, physical nature of role, family finances), which are beyond the utility's control and visibility. Being mindful of these complexities, Toronto Hydro submits that its retirement forecasting practices are reasonable and appropriate, as evidenced by the utility's rate of accuracy at its most recent applications.

5. STAFFING AND DEVELOPMENT STRATEGY

Workforce planning is a continuous process aimed at ensuring that the organization has sufficient talent to meet its human resource needs. The process is forward-looking and considers various sources of talent including permanent employment, contracting, and partnerships. The appropriate mixture of talent is determined by examining various factors including changing business requirements, actual resource availabilities and utilization, projected and actual loss of knowledge (e.g., retirements, attrition), and the results of recruitment, training, development, and other (e.g., job harmonization) initiatives. Prudent workforce planning enables the utility to have a cost-effective and sustainable workforce, and facilitates continuous improvements over time. For example, through responsible workforce planning Toronto Hydro has been able to consolidate 41 job classifications into 10, since 2007.

The overarching principles of Toronto Hydro's staffing strategy are to:

1) provide flexibility in the allocation of resources (internal resources and external contractors) to complete the approved work program;

2) align future professional and trades and technical hiring with the capital and maintenance program volumes; and
3) continually review requirements to drive decision-making for effective resource cost management.

As discussed in the Aging Workforce Challenges section above, Toronto Hydro must find a solution to bridge the gap between the utility's current staffing levels, projected retirements and the resources it requires to deliver its programs and satisfy its obligations over the next five years. Failing to do so could expose the utility to a multitude of operational and financial risks, such as not having the resources required to provide safe and reliable electricity service to its customers, and not being able to fulfill legal and regulatory requirements (as set out in the OM&A programs, at Exhibit 4A, Tab 2).

Toronto Hydro utilizes a number of solutions to address this problem. These include: 1) promoting from within the utility, 2) hiring skilled labour from the external market, 3) acquiring and training new graduates, or 4) use third-party service providers. As explained in more detail below, each of these alternatives has its relative advantages and disadvantages, but none of these solutions are independently sufficient to address Toronto Hydro's human resource requirements. Toronto Hydro decided that the most prudent solution is an approach that allows the utility to leverage the relative strengths of each of these options as appropriate in the circumstances.

Toronto Hydro has adopted a multi-faceted staffing strategy because it provides the utility the flexibility to staff up or down as required to effectively plan and manage its staffing needs over the next five years and likely beyond. Given the breadth and complexity of the utility's operations, and the rate at which the City of Toronto is growing and expanding, flexibility is particularly important for Toronto Hydro. Toronto Hydro also considers a multi-faceted approach to be a more effective and cost-efficient

solution to addresses the aging workforce challenge that the utility faces in the next five to ten years, than implementing a single or double-pronged strategy.

5.1. Hire from Within

Hiring from within allows Toronto Hydro to recognize and advance those employees that have demonstrated exceptional skills, knowledge and leadership qualities. These individuals are critical to training the new generation of employees and overseeing the key functions of the utility. Toronto Hydro relies on this strategy to fulfill supervisory positions, and for senior certified and skilled trades' positions and designated and technical professionals. Despite the obvious advantages of hiring from within, Toronto Hydro cannot rely on this strategy for entry level positions, and cannot rely on this option alone to fulfill retirement vacancies because the utility does not have a sufficient pool of employees. Between 2011 and 2013, approximately 150 vacancies were filled internally.

5.2. Hire from the External Market

This option entails going to market to hire the skilled and experienced resources that the utility requires over the next five years. To the extent that the external market has an available pool of qualified candidates, this option allows the utility to meet its human resource needs. However, because of the complexity of its distribution plant and dynamic operating conditions, it is challenging for Toronto Hydro to hire skilled labour without investing in training and development. For example, an experienced CPLP from the external market would require one year of additional on-the-job training to become fully-competent to work on Toronto Hydro's plant. Due to the lack of qualified candidates in the job market, hiring skilled labour is not an optimal strategy in and of itself, especially for Certified and Skilled Trades positions.

5.3. Hire New Graduates

The third option is to hire new graduates and rely on the utility's training and apprenticeship programs to teach these employees the specialized skills and knowledge that they require to safely work on the distribution system. This has proven to be a reliable source for skilled entry level positions; however, while this option allows Toronto Hydro to develop and maintain a dependable workforce that is capable of servicing the operational needs well into the future, it is not desirable for the utility to rely on this option alone, as the utility is limited by the ability to safely absorb and integrate apprentices.

Toronto Hydro seeks opportunities to collaborate with colleges and universities like Ryerson University and Georgian College to offer academic programs that are aligned to entry level qualifications for Certified and Skilled Trades and Designated and Technical professionals. Collaborations like these are valuable because they allow Toronto Hydro to:

- influence and shape the programs and curriculum offered to students with the utility's strategic goals and long-term needs,
- spread awareness about the utility's human resource requirements, and
- build recruitment relationships with future graduates.

Toronto Hydro's partnership with Georgian College has yielded 17 recruits since the inception of the partnership in 2011 (12 Certified and Skilled Trades and five Designated and Technical professionals). As Toronto Hydro ramps up its recruitment program to fill retirement- related vacancies, Toronto Hydro expects that it will continue to leverage it alliances with universities and colleges to recruit new graduates.

5.4. Use Third Party Service Providers:

Outsourcing Toronto Hydro's workforce requirements to third-party service providers is another option employed by the utility. In many cases, third-party service-providers enable the utility to cost-effectively resource peak demands, maintain flexibility in operations, and gain access to specialized expertise. However, it would not be feasible for the utility to outsource all of its workforce needs, as third party service providers are also constrained by demographic challenges and must invest in replenishing their workforces. Further, it would not be prudent for Toronto Hydro to rely solely on third-party service providers because the utility requires a stable complement of employees to satisfy its on-going legislative and regulatory requirements and customer obligations.

5.5. Development Strategy

Toronto Hydro's workforce development strategy focuses on in-house training to cultivate skilled apprentices, technical staff, and leaders. Due to the complexity of its system, the aging workforce challenges that it faces over the next five to ten years, and the utility's need for sustained capital investment to renew its infrastructure, Toronto Hydro must resource these positions from within. To do so, the utility relies on having a robust talent pool for entry-level certified skilled trades and designated and technical professional positions, and requires funding to accelerate its training and development programs. In the long-term, this strategy helps to ensure that Toronto Hydro has the resources it requires to perform core activities and satisfy key obligations.

As summarized in the chart below (Table 6), from 2011 to 2013, Toronto Hydro administered more than 200 training and development programs at a total cost of approximately $1.5 million per year. While many of these programs were targeted at developing the specialized skill sets required to work on Toronto Hydro's distribution system, the utility also leveraged its training facilities to deliver a variety of legislative

and compliance programs. For more information about the value of these initiatives, refer to the Human Resources and Safety Program at Exhibit 4A, Tab 2, Schedule 14.

Table 6: Training and Development Programs (2011 – 2013)

Area	2011 Courses	2012 Courses	2013 Courses
Compliance (e.g., Environmental and Safety legislative training, EUSA and ESA Rules, Confined Space, Work Protection Code, Network Switching)	10	20	42
Legislative (e.g., WHMIS, Defensive Driving, Forklift Training)	5	17	20
Apprentice (e.g., Distribution Systems Technologist, Power Systems Controllers, Certified Power Cable Persons, Certified Power Line Persons, Meter Mechanics)	10	16	19
Leadership (e.g., Safety Leadership, Performance Management, Management Control & Reporting System, Project Management, Policy Administration)	9	7	6
Technical & Customer Service Training (e.g., Engineering Technicians, Electrical Awareness, Project Execution, Customer Education Training)	14	14	16
Total	**48**	**74**	**103**
Total Cost	**$1.23M**	**$1.18M**	**$1.47M**

The apprenticeship program is a key aspect of the Toronto Hydro's workforce development strategy because it enables the utility to train and develop employees with

the specialized skills including Certified Power Cable Persons, who work on the underground system (see Figure 4 below), and Distribution Station Technologists, who operate and maintain equipment in the stations.

Figure 4: Underground cable chamber in Toronto Hydro's system.

Toronto Hydro initiated the apprenticeship program in 2003, when the utility realized the basic training that crews acquired externally was insufficient to enable them to work safely and efficiently in Toronto Hydro's system. For example, Figure 4 shows a complex underground cable chamber that is common in Toronto Hydro's distribution system.

Between 2003 and 2013, Toronto Hydro added over 200 apprentices to the program and retained approximately 88 percent of these individuals as full-time employees. The table below (Table 7) summarizes the number of certified and skilled trades that the

utility developed through its apprenticeship program, and retained as full-time employees, as of the end of the second quarter in 2014.

Table 7: Apprenticeship Program Summary (as of Q2 2014)

	CPLP	DST	Meter Mechanic	PSC	CPCP	ETL	Engineer	Total
Apprentices	106	24	7	25	54	86	54	356
# Retained	87	24	7	20	51	78	44	311
% Retained	82.1	100.0	100.0	80.0	94.4	90.7	81.5	87.4%

To prepare itself for the large wave of retirements that it expects to encounter over the next five to ten years, Toronto Hydro expects to admit approximately 320 individuals to the apprenticeship program during the 2014-2019 timeframe. Toronto Hydro plans to hire apprentices in a staged approach as outlined in table below (Table 8), to facilitate workforce renewal in a safe and effective way, while ensuring knowledge transfer and maintaining productivity.

The staged approach allows for new entrants to be safely absorbed and integrated into Toronto Hydro's system with the appropriate training, supervision and mentoring on Toronto Hydro practices, procedures, and standards. It also allows for supervision and mentoring practices to be undertaken without jeopardizing the utility's objectives or its ability to safely and effectively deliver its capital and maintenance work programs.

Table 8: Apprenticeship Hiring Plan (2014 – 2019)

Apprentice Group	2014	2015	2016	2017	2018	2019	TOTAL
CPCP	9	18	18	18	18	27	108
CPLP	0	24	12	12	12	12	72
DST	9	16	8	0	0	8	41
PSC	4	6	4	2	2	2	20
Certified Meter Mechanic	0	5	0	4	5	4	18

Apprentice Group	2014	2015	2016	2017	2018	2019	TOTAL
Engineering Technologist	15	6	6	8	2	12	**49**
Engineer	2	2	2	2	1	1	**10**
Total	**39**	**77**	**50**	**46**	**40**	**66**	**318**

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Labour Market and Human Resources Trends
CanadianUtility Sector

July24, 2014

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Executive Summary

Toronto Hydro faces a number of complex and interwoven sector-wide economic and demographic trends that are expected to exert significant pressure on its workforce management approach and human resources strategies over the next five to ten years. X ^] š µ š] v } v } (v [• u } • š À] labour markets t fueled by the Pan Am Games, housing growth, investments in transportation and power-related infrastructure, and surrounded by a half dozen or more direct sector specific competitors t Ontario Power Generation, Hydro One, Bruce Power and multiple municipally owned utilities Toronto Hydro is facing high levels of retirement at the same time as many other competitor organizations face the same challenges as well as a shrinking high skilled labour pool.

t Z] o š Z } v (Œ v } Œ } (v [• Œ • Œ Z u } v • š Œ š • Z] P Z o À o broad Canadian labour market, the forecasted retirement rate for the Canadian utility sector as a whole is much greater, and as detailed in our report, Toronto Hydro [levels of retirement are higher than the sector overall.

Category	Retirement Rate over the next Five Years (2014-2018)*
All	4.2%
Utilities	16.3%
Toronto Hydro	19.1%

Source: The Conference Board of Cana
Toronto Hydro data provided by Toronto Hydro

*For comparative purposes, this table looks at the years 2014 through to 2018 inclusive. For more detailed information on the period of 2014 to 2019, please see Table 12.

Not only does the sector face higher than average levels of retirements, but the nature of the Toronto Hydro workforce demands significant lead time for training and development in order to achieve optimal levels of both high skill capability and productivity. Given the time needed to train a number of the skilled technical and trades roles in the unique operations of Toronto Hydro (four to six years), Toronto Hydro must increasingly shift to a recruitment model that is more proactive in anticipating upcoming recruitment profiles and preparing well in advance.

In addition, as the labour market data attests, the available talent pool is shrinking, and as such, Toronto Hydro must focus on a more multi pronged model for staffing in the future, which further incorporates other models of partnership such as contracting or outsourcing. Staffing strategies for the future must consider new models as well as new sources for talent. For Toronto Hydro, like all employers, the shift in staffing strategies will demand shifts in a wide range of other related human resources (HR) programs to ensure engagement of an increasingly diverse population is achieved and translates into high levels of safety and productivity.

While levels of retirement, other exits and the challenge of recruitment point to the demand for more complex staffing strategies, Toronto Hydro is also faced with the operational and service transformation challenge of infrastructural renewal. Given the natural ebbs and flows in renewal and construction, Toronto Hydro will also have to design a workforce model that is inherently flexible to respond to changes in workforce needs volume, skill and competences. In order to plan and manage the Á } Œ l (} Œ U d } Œ human resource [leadership will be required to make investments

technology, training and development to lead the complex workforce analytics required to support this effort.

Toronto Hydro, in designing future-oriented and responsive human resources practices, must also be cognizant of two additional and linked HR considerations: the collective bargaining environment, and cost implications and trade-offs. Toronto Hydro operates in a highly unionized environment, with a demonstrated ability of labour to secure the support of its membership for a strike mandate, which brings additional pressure and complexity to its labour relations climate. While we are of the view that the short-term economic environment will moderate the demands made by unions, as the labour market begins to tighten over the next decade, unions may find themselves with greater leverage which will translate into cost pressures for employers. Moreover, as noted in the report, retiree benefit costs are significant, and with the retirement profile for Toronto Hydro rising, Toronto Hydro will likely need to address related and increasing cost pressures and demands.

The human resources trends, profiles and challenges facing Toronto Hydro are real business issues that if not optimally addressed and mitigated, will represent material risks to its ability to fulfill its mandate and service commitments to its customers and stakeholders. Moreover, the Conference Board of [illegible] report, Shedding Light on the Economic Impact of Investing in Electricity Infrastructure: Economic Performance and Trends detailed how integral the supply of electricity is to a modern economy, to driving competitive advantage, to overall economic activity, and to broader employment realized through capital investment. The report concluded that over a 20 year period (2011-2030), investments in the sector will result in an annual contribution to real gross domestic product of almost $11 billion and approximately 156,000 jobs per annum. In turn, this increased economic activity will lift household income as well as return significant value to government.

With Boards of Directors and Chief Executive Officers increasingly focused on human resources issues, the priority of the talent agenda within organizations is at the forefront. This not only signals the centrality of the talent agenda for business, but will put greater and greater demands on Human Resources leaders for innovative and effective strategies. With the attention of the CEO office squarely focused on HR issues, the people dimension of business will continue to be a key driver and differentiation of organizational performance. At the same time that Human Resources issues are rising to the top of Canadian CEOs agenda, so too are Canadian Boards of Directors prioritizing talent issues as [illegible] 2013 Edition, April, 2014).

1. Introduction

Section Highlights
x The broad Canadian energy sector will face increased competition internally and with other related sectors, such as construction, for skilled technical workers at a time when the labour pool is shrinking. x The pressure on recruitment will demand a broadening of approach and strategy as well as increased innovation across all human resources practices in order to attract and retain talent. o New models of staffing including full time employment, outsourcing/contracting, and contingent supply sources o New sources of talent x With the sector itself undergoing significant transformation through infrastructure renewal as well as the introduction of new technologies, the nature of the workforce will continue to evolve. x While uneven across the country, there are signs of economic recovery that will put new pressures on the Canadian labour market. With high levels of construction and infrastructure renewal in Toronto, the prospects for a strengthening economy are encouraging.

1.1 Report Overview

The Conference Board of Canada was retained to provide independent research on current labour market and human resources trends for the utility and related sectors in connection with Toronto Hydro [• Œ P µ o š } Œ Ç • µ u] • •] } v v Œ š ‰ ‰ o] š] } v X

Over the last number of years, the Conference Board of Canada has undertaken a number of studies to identify trends and implications related to the changing demographic profile of the Canadian labour market with a focus on supply and demand as well as related human resources practices. Our work includes each of national, provincial as well as select metro perspectives across a number of key areas including:

- Demographics / Supply and Demand
- Talent Acquisition / Recruitment
- Leadership
- Development and Learning
- Compensation and Benefits
- Collective Bargaining

This report largely focuses on trends and data relevant to the Canadian utilities sector. However, recognizing that Toronto Hydro is located in one of the most competitive labour markets in Canada competes for talent beyond technical operations in areas such as strategy, finance, information technology, human resources, etc., the report also provides data related to the Ontario/Toronto market

place. In addition, given the highly technical nature of the work undertaken by Toronto Hydro and competitive labour markets for skilled and knowledge workers across the broader construction and energy sectors, a national and broader sectoral view has also been provided.

The report is structured into the following key sections:

- Introductory Strategic Context
- Perspective on Labour Market and Human Resources Trends
- Conclusions and Implications

The report also includes tables with key statistical trends.

1.2 Information and Data Sources

In preparing this submission, the Conference Board of Canada not only relied on existing Conference Board of Canada proprietary data and research, but also undertook a literature search to identify other key, relevant information for contextual purposes. Of note is the most recent report of Electricity Sector Council, Power in Motion: Labour Market Information (LMI) Study Full Report 2012 Update. This report builds on two earlier studies: 2004 titled Keeping the Future Bright (Canadian Electricity Association), and 2008 titled Powering up the Future (Electricity Sector Council).

1.3 Sector Context and Trends

The 2012 report update Power in Motion provides a number of key statistics, trends and considerations that are relevant for Toronto Hydro and its workforce planning and strategies:

- For the period 2011 to 2016, the combined energy and renewable energy sector will recruit over 45,000 new employees representing a two-fold increase from the previous five year period, and equal to 40 per cent of the current workforce.

- These 45,000 employees will be comprised of a mixture of workforce segments from across the sector and include both technical and more traditional management and administrative roles. (Source: Statistics Canada). Among the electrical occupations, more than fifty per cent of the employment resides in four occupations, which are key to Toronto Hydro:

  - Electrical and Electronic Engineering Technicians and Technologists
  - Electrical Power Line and Cable Workers
  - Power System Electricians
  - Power System and Power Station Operators

- The new workforce profile will pose major challenges for employers including a need to replace skilled, experienced workers at a time when the sector is increasing in complexity due to changing technology and infrastructure needs.

- Industry churn will continue with up to 30 per cent of the required human resources moving between existing sectors, specific employers, leaving a major gap to be filled from other sources. In this regard, it should be noted that development and recruitment of sector-specific talent is a critical workforce challenge.

- Recruitment practices will have to broaden to include sources of talent that are under-represented across the sector.

- The electricity sector will face increasing competition from other sectors (oil and gas, construction) particularly for new recruits.

- Retirement rates and transition must be managed to ensure effective knowledge transfer.

- The challenge of filling technically skilled jobs will be matched by the need for supervisory and management roles.

- While outsourcing and contingent workforces provide options for talent acquisition, the outsourcers and suppliers] v š Z • š } Œ (u v Ç } (š Z • u Z o o v P • • v utility sector organizations, both public and private.

- The magnitude of the workforce transformation is so large that any one organization cannot solve the challenges faced by the electricity sector and will require each of employers, government, unions and the education/training sectors to participate in solutions.

It is also important to recognize that the changing demands for human resources within the electricity sector are both driven by and compounded by fundamental changes to the sector itself; the challenge is not simply one of high levels of workforce exits due to retirement, although that is perhaps the most significant issue. Large municipal and provincial energy organizations that historically have not had to compete with new market entrants and/or intensifying competition from other sectors, now face increased competition for a limited talent pool as demographics shift. Deregulation and restructuring combined with changes to technology and high levels of investment in infrastructure are having profound impacts on human resources practices within the electricity sector, ranging from recruitment and training through to leadership development and succession management.

d Z } v (Œ v } Œ } (v [Shedding Light on the Economic Impact of Investing in Electricity Infrastructure: Economic Performance and Trends detailed how integral the supply of electricity is to a modern economy, to driving competitive advantage, to overall economic activity and to broader employment realized through capital investment. The report concluded that over a 20 year period (2011 to 2030), investments in the sector will result in an annual contribution to real gross domestic product of almost $11 billion and approximately 156,000 jobs per annum. In turn, this increased economic activity will lift household income as well as return significant value to government.

Shedding Light on the Economic Impact of Investing in Electricity Infrastructure: Economic Performance and Trends further notes that the labour requirements to accommodate the investment in electricity infrastructure will exert pressure on an already tight labour market. For example, employment in electric power engineering construction is expected to increase by 49,000 jobs per year over the period 2011 to 2030. Given the front-loaded nature of investment, the pressure on the labour market from 2011 to 2016 will be even greater where 78,000+ jobs will be created in electric power engineering. The increase in employment will, of course, result in a decline in unemployment rates.

1.4 Economic Context

This section of the report provides an overview of the relevant economic and labour market trends impacting Toronto Hydro, at each of the national, provincial and sector levels.

Canada

Given that Toronto Hydro operates to some extent within the context of the broader Canadian labour market, it is important to understand key related trends across the country. Economic growth is uneven in Canada, with some provincial and regional economies [western Canada] experiencing more robust economic growth than others. At the same time, v [• } v } u Ç Á] o o v ( ] š (Œ } u o } Á Œ dollar and improving US economy overall but growth will be modest at 2.3 per cent in 2014.

The labour market is expected to benefit from stronger economic activity, with job growth forecast to average 1.6 per cent per year between 2014 and 2015, up from 1.3 per cent in 2013. Unemployment will realize further reduction from 7.1 per cent (2013) to a forecast of 5.7 per cent (2018). However, rates will vary significantly across the country t lower in the western Canadian economy than in Toronto or Ontario (Toronto 8.2 per cent; Ontario 7.5 per cent; Saskatchewan 4.0 per cent; Alberta 4.6 per cent). Given the competitive national labour market, there is strong domestic migration to Alberta from elsewhere in Canada.

Ontario

d Z } v (Œ v re }] Œ Ho [v • Canada Performs research reveals that Ontario remains a relatively healthy economy. However, Ontario remains in a long-term transition that started more than a decade ago. This has implications (} Œ K v š Œ] } [• } v } u] o] u š U v] v } u ‰ Œ ,] • } v Á] š Z and puts pressure on labour migration patterns and compensation as a shrinking talent pool becomes more competitively targeted:

- Income per capita t Ontario score • ^ _] v š Z } v (Œ v } Œ } (v [• , } Á Performs analysis, comparable to Canada. Ontario ranks (Œ Z] v o Œ š ~ ^ = _ • } v š Z income per capita metric.
- On the metric of labour productivity growth U K v š Œ] } • } Œ • ^ _ e P Œ U P] v] v Canada as a whole.
- Gross Domestic Product t K v š Œ] } [• P Œ (} Œ ' W P Œ } Á š Z Z • • š] o Ç • o] % decades an µ Œ Œ v š o Ç • } Œ • ^ _ P Œ

K v š Œ] } [• } u • š] } v } u Ç] • ‹ µ] l o Ç o } •] v P • š u U µ š U • š Œ l } v P Œ Æ š help support growth this year and next. Real GDP growth will pick up a little this year compared to 2013, increasing 1.8 per cent as the recovery south of the border solidifies. But growth will be restrained by weak investment and consumption in Ontario. Next year, the economy will see healthier growth of 2.7 ‰ Œ v š • Æ ‰ } Œ š • • š Œ K v š Œ] } A [s • summarized in } Table } below] š • • o µ u ‰ X

- The Ontario-specific price index will continue to move upward.
- On-going upward pressure on wages/salaries.
- Limited growth in the available workforce and the unemployment rate will continue to fall.

Table1: KeyEmployment-RelatedEconomic Indicators, Ontario

	2013 (actual)	2014 (forecast)	2015 (forecast)	2016 (forecast)	2017 (forecast)	2018 (forecast)
Consumer Price Index (2002=1.0)	1.2	1.3	1.3	1.3	1.3	1.4
Wages & Salary Per Employee (Thousands)	46.5	47.4	48.7	50.0	51.4	52.9
Population Of Labour& } Œ P ~ Z	11,204	11,340	11,478	11,619	11,765	11,915
> } µ Œ & } Œ ~ Z ì ì ì •	7,440	7,480	7,569	7,650	7,729	7,818
u ‰ o } Ç u v š ~ Z ì ì ì •	6,879	6,935	7,057	7,155	7,264	7,365
Unemployment Rate	7.5	7.3	6.8	6.5	6.0	5.8
Source: The Conference Board of Cana						

Employment has grown at a faster rate than the size of the labour force since the recession; this] ((Œ v Z • o o } Á š Z µ v u ‰ o } Ç u v š Œ š š } o] v X d Z ‰ Œ } ‰ } Œ 15-24 that is employed (known as š Z ^ u ‰ o } Ç u v š Œ š }] v] Œ [• Œ] v Á •] v î ì ì ô X D v Á Z] o U š Z u ‰ o } Ç u v š Œ š climb unabated, sitting two percentage points higher now than in 2008.

Toronto

d Z } v (Œ v } Œ [• Œ Economic Insights into 13 Canadian Metropolitan Economies, ‰ Œ } À] • v } À Œ À] Á } (d } Œ } v š] [• Ontario, Toronto is expected to experience somereal growth in the coming years. As highlighted in Table 2, in future years, Toronto is expected to match or outperform a number of Canadian cities.

Table 2: RealGDP Growth for Select Canadian Cities

City	2013 (actual) (per cent)	2014 (forecast) (per cent)	2015-2018 (forecast) (per cent)
Calgary	3.7	3.4	3.1
Regina	5.1	3.3	2.3
Edmonton	5.1	3.1	3.0
Saskatoon	6.7	2.9	2.4
Halifax	2.2	2.7	2.6
Vancouver	2.5	2.7	3.2
Toronto	1.8	2.7	3.0
Hamilton	0.4	2.1	2.2
Montreal	1.7	2.1	2.2
Quebec City	1.2	1.9	2.0
Winnipeg	1.1	1.8	2.6
Victoria	0.2	1.4	2.2
Ottawa-Gatineau	0.1	0.9	2.2
Source: The Conference Board of Cana			

This level of growth is reflected in higher employment and a falling unemployment level.

Table 3 Key Employment Related Economic Indicators for Toronto

Economic indicators	2013 (actual)	2014 (forecast)	2015 (forecast)	2016 (forecast)	2017 (forecast)	2018 (forecast)
Total employment (000s)	3,120	3,186	3,264	3,334	3,405	3,477
Percentage change	3.8	2.1	2.4	2.2	2.1	2.1
Unemployment rate (per cent)	8.2	7.8	7.2	6.9	6.5	6.3

Source: Statistics Canada

In the midst of the ongoing construction activity and infrastructure renewal in Toronto, the demand for semi-skilled and skilled labour will build. With forecasted growth of 2.1 per cent in 2014, total employment is expected to increase by just over two per cent per year through to 2017. At the same time, the unemployment rate is expected to fall from 8.2 per cent in 2013 to 6.5 per cent in 2017.

2.0 Perspectives on Labour Market and Human Resources Trends - Implications for Toronto Hydro-Electric System Limited

Section Highlights
x Human resource challenges, particularly those related to the aging workforce and the ne for effective recruitment and retention strategy are now clearly on the agenda of Canadia K v } Œ } ( ] Œ š } Œ [• s new see workforce management as one of their top strategic priorities. x The Canadian electricity sector faces a higher than average age profile compared to the broader Canadian labour market. Toronto Hydro has projected retirements of almost 5 times the overall Canadian labour market. In select instances, such as Certified and Skille Trades, the retirement rate exceeds 7 times the overall Canadian labour market. Over the next ten years, Toronto Hydro will see a retirement rate of approximately 50%. x The magnitude of Œ š] Œ demographics that sectors operate in tandem to create solution and that individual organizations such as Toronto Hydro develop a range of approaches to workforce management. A more proactive and longer term strategy is require to ensu a trained and productive workforce for the future. Human resources challenges and implications include: x The need for a related knowledge transfer strategy between generations of workers. x Cost implications related to pension and post-retirement benefits. x The need to recruit many workers that are seasoned and experienced as new graduates will not be adequate to meet the technical demands. x Sophisticated workforce analytics. x Strong value proposition (work-life balance, compensation/benefits, culture [employee engagement and leadership strength] and presence in a wide ran of traditional and new media x Development of relationships with universities, colleges and other organizations that are talent pipelines x Effective alumni networks x Effective succession management processes built on best-in-class performance management processes for talent development and high-potential identification. x Investments in learning and development x Upward pressure on total compensation including base salary and benefit x v [• ‰ µ o] • š } Œ Á] š Z] š • À Œ Ç Z] P Z Œ š } (µ v] } v on employers.

2.1 Introduction

As discussed in the preceding section, the Canadian utilities sector, including Toronto Hydro, faces two key, related challenges:

- The sector is expanding to meet growing demand, adapting to meet new technological advancements, and making a major investment to deal with aging infrastructure, all of which demand significant investments in financial, material and human resources.

- The sector is beginning to experience unprecedented levels of retirement and a shrinking talent pool to draw from, and a talent pool which is under increased competitive pressures from other, related sectors such as construction, oil and gas.

This section of the report provides both a qualitative and qualitative perspective on key labour market and human resources challenges for the sector broadly and the specific implications for Toronto Hydro. The section is structured around the following key issues:

- > Œ • Z] ‰ [•. W Œ] } Œ] š] •
- Demographics of Supply and Demand
- Talent Acquisition / Recruitment
- Leadership
- Development and Learning
- Compensation and Benefits
- Retention and Turnover
- Collective Bargaining

This section of the report builds on the work of the Conference Board of Canada and most specifically the 2014 Human Resources Trends and Metrics: HR Measurement Benchmarking, Edition, to provide an overview of both the broader Canadian labour market as well as the utility sector. Undertaken during 2012/2013, Human Resources Trends and Metrics: HR Measurement Benchmarking, Third Edition provides data for 169 Canadian organizations with the following characteristics:

- Forty-seven per cent of organizations were based in Ontario.
- Over one-third of participant organizations were public sector organizations.
- Fifty-five per cent of organizations included a unionized workforce.
- Almost one-quarter of the organizations were of similar size to Toronto, while almost one-half of the total participants were equal to or larger based on their number of employees.
- Five per cent of organizations represent v [• h š] sector (11 organizations), while an additional five per cent represent organizations in those sectors that compete for talent with Toronto Hydro – oil, gas, and construction.

While detailed information and insights are provided throughout this section of our report, the overall conclusion of the Human Resource Trends and Metrics report is relevant to organizations in the utility sector broadly and Toronto Hydro specifically and states

Building leadership capacity and attracting and retaining talent with critical skills will be top priorities for employers as a sputtering economy gains a more solid footing in 2014. Even in a moderate growth scenario, labour markets will tighten beyond 2015 as retirements accelerate and the number of new employees joining the workforce declines. A slow growth environment has provided employers with breathing room to evolve talent management practices rather than simply reacting to the demands of rapid growth. Nevertheless, the combination of demographic shifts and global competitive pressures, as well as concerns about cost, lagging productivity, and the need to innovate, suggests that there are significant risks to optimal business performance. Without effective organizational responses, these pressures will constrain } Œ P v] Ì š] } - term productive capacity.

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While CEOs remain focused on traditional business issues such as productivity and risk, the agenda has shifted to the people dimension of the business, regardless of sector. The issues of attracting and retaining talent have never been as central to the CEO agenda as is the case now. This is expected to continue over the next decade. The convergence of high levels of retirements with shrinking labour supply, have moved the conversation to the top of the leadership agenda both in Canada and around the world given the risk to operations that current and future HR challenges present.

The Conferen } Œ [• v v µ o Œ Ç • EO Œ Challenge 2014 asked Chief Executive Officers around the world to identify their top anticipated business challenges for the coming year and to provide their preferred strategies to meet these challenges. The global survey has been conducted by the Conference Board Inc. since 1999. Globally, a total of 1,020 chief executive officers were surveyed in the regions of Asia, including India (479), China (139), India (55), the United States (233), Latin America (114), Europe (105), Canada (74), and Rest of World (15).

d Z] • Ç Œ [• ( ] v] v P • that Canadian CEOs are focusing their efforts and resources where they have more control and influence to operational excellence and, of particular note, human capital (see Table 4). While the economy continues in a slow growth mode within Canada and abroad, the competitive differentiators will be internal practices and programs to enhance efficiency, alignment and increased emphasis on performance and accountability. While Ç ast Œ [• Œ • µ o š •] v] š v u % on engaging and developing employees, it appears that in 2014 CEOs will be more focused on the "top" of the organization working to improve alignment, performance and accountability of senior management, improving leadership development and succession planning programs and the effectiveness of their senior management teams.

Table4: Top 10 Challenges of Greatest Concern to CEOs in Canada

Challenge	Canada	United States	Global
Operational excellence	1	3	T3
HumanCapital	2	2	1
Customer relationships	3	1	2
Innovation	4	4	T3
Corporate brand and reputation	T5	T5	5
Government regulation	T5	T5	7
Sustainability	7	8	8
Global political / economic risk	8	7	6
Global / international expansion	T9	9	9
Trust in business	T9	10	10

T=denotesa tie

Source: The Conference Board of Cana

Canadian and US CEOs are strongly aligned in the identification of their top challenges: operational excellence, human capital, customer relationships and innovation. Interestingly, this alignment carried across most of the world underlining the global nature of many business challenges, most importantly Human Capital. In fact, Human Capital rated as either 1 or 2 for each of Europe, Latin America, Asia, China and India.

Chief Executive Officers were also asked to comment on strategies to respond to the top five challenges that Operational Excellence, Human Capital, Customer Relationships, Innovation, Corporate Brand and Government Regulation. In their responses, not only does the Human Capital vertical focus on people issues such as performance, succession, employee engagement, but so too do many of the other verticals. For example, CEOs note that Operational Excellence is achieved through employee engagement, performance and organizational flexibility while Customer Relationships are about the personal relationships, and Innovation is dependent of building innovation into employee skills sets.

CEOs were also asked about the more immediate, tactical issues that are keeping CEOs up at night. Once again, for Canadian CEOs, many of their issues are the people-related issues such as labour relations and leadership. Canadian CEOs also pointed to volatility in the energy markets as a significant business concern. As this report highlights at different points, the centrality of the broad energy sector, including electricity/utilities, cannot be underestimated. The sector itself is a lynchpin for other sectors of the Canadian economy.

With Chief Executive Officers increasingly focused on human resources issues, the priority of the talent agenda within organizations is increasingly at the forefront. This not only signals the centrality of the talent agenda for business, but will put greater and greater demands on Human Resources leaders for innovative and effective strategies. With the attention of the CEO office squarely focused on HR issues, the people dimension of business will continue to be a key driver and differentiation of organizational performance.

At the same time that Human Resources issues are rising to the top of the Canadian CEO agenda, so too are Canadian Boards of Directors prioritizing talent issues as a governance priority and a key

competitive, strategic differentiator (Source: } v (Œ v } Œ } (v v] v [•] Œ š } Œ • [Compensation Practices, 20th Edition, April, 2014).

2.3 Human Capital Challenges and Human Resources Issues

Increasingly, the CEO agenda and the human resources agenda are aligned and focused on the people dimension of business success. Participants (HR leaders) from the Conference Board of Canada's third edition of HR Measurement and Benchmarking identified their top human capital challenges in both the short term (one year horizon) and for the longer term (three-to-five year horizon). While the timeline is not significantly different, by extending the timeline by just a couple of years, employers identify the aging workforce more often than any other issue (over 40 per cent of all organizations list this as their most significant challenge / v š Z v Œ Œ š Œ). Employers, including those in the utility sector, are concerned about the ability to attract and retain the talent needed. As will be discussed later in this section, the challenge of the demographic shift (increased retirements and a smaller incoming labour pool) is driving the issue of recruitment and retention to the top of the HR agenda.

While all Canadian organizations from across sectors are concerned about leadership capacity and challenges in attracting and retaining employees, it is of note that over the longer term, organizations representing the utility sector highlight the challenge of capacity to respond to change. With changing demands and expectations related to infrastructure renewal, cost pressures, customer expectations, heightened requirements for environmentally sound practices, the utilities sector, much like the oil and gas sector, faces unprecedented change beyond workforce capacity.

Table 5: Top 3 Human Capital Issues in the Canadian Labour Market

Short Term Human Capital Challenges		Long Term Human Capital Challenges	
All organizations	Utility sector	All organizations	Utility sector
Leadership capacity	Leadership capacity	Aging workforce	Aging workforce
Attracting and recruiting	Retaining employees	Leadership capacity	Leadership capacity
Employee engagement	Attracting and retaining	Attracting and retaining	Capacity to respond to change
Source: The Conference Board of Cana			

Given the top Human Capital challenges facing the broader Canadian labour market, it is not surprising that the top three Human Resources priorities for both the broader labour market and the utilities sector focus on solutions to building and managing organizational capacity at all levels (leadership development and succession planning, managing retirement exits (knowledge transfer) and learning and development.

Table 6: Top 3 Human Resource Priorities in Canadian Labour Market

Short Term Human Resource Priorities		Long Term Human Resource Priorities	
All organizations	Utility sector	All organizations	Utility sector
Management/ leadership development	Management/ leadership development	Strategic workforce planning	Succession management
Strategic workforce planning	Employee retention	Succession management	Management/ leadership development
Performance management	Learning and development	Management/ leadership development	Managing retirement exits

Source: The Conference Board of Cana

Each of these challenges – workforce planning, succession management, leadership development and retiree management – demand sophisticated technological tools that provide the foundation for effective workforce analytics as well as highly skilled Human Resources professionals to design and deliver programs and strategies.

2.4 Demographics, Retirements and other Exits

Over the last 10 to 15 years, much has been made about the shift in the Canadian labour market as baby boomers begin to retire. This shift to an aging workforce is also true for organizations in the electricity sector, and, in fact, more pronounced. The following tables from Statistics Canada provide a profile of the aging workforce for the Canadian Labour Force.

Table 7: Age Distribution of Labour Force in Canada / All Industries (2013)

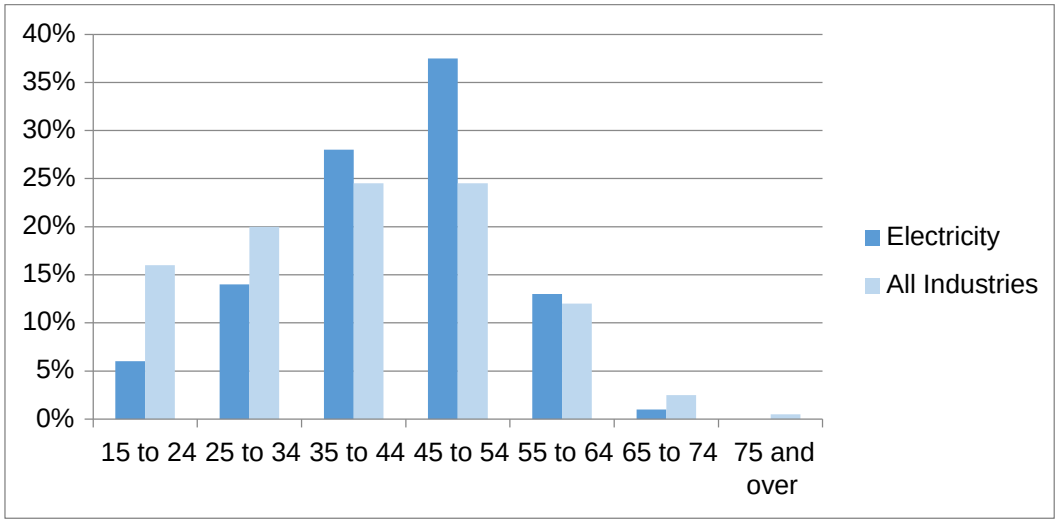
Age	Actual Labour Force (All Industries)	Percentage of Labour Force (All Industries)
15-24	2,837,900	14.87%
25-34	4,120,400	21.60%
35-44	4,051,600	21.24%
45-54	4,478,500	23.47%
55-64	2,927,800	15.35%
65+	663,200	3.48%
Total	19,079,400	100%

Source: Statistics Canad

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per cent and 56 per cent respectively for workers aged 45-54, and a much larger proportion over the age of 45 for Utility Managers, 77 per cent, and for Supervisors, 74 per cent (See Table 8).

Chart 1: Electricity Industry in Canada – Age Distribution of the Workforce (Per Cent)



Source: Statistics Canada, 2006 Census

Table 8 Age Distribution, Electricity Sector Occupations

Category	Per cent of Sample By Age							
	n	<25	25-34	35-44	45-54	55-64	>65	Total
Engineering Managers	43	0	4	22	49	24	1	143
Utilities Managers	38	0	4	19	58	19	0	138
Construction Managers	27	0	4	18	48	29	1	127
Supervisors of Electricians and Electrical Power Line Workers	50	1	7	19	56	17	1	151
Electrical and Electronic Engineers	37	4	29	24	27	14	1	136
Electrical and Electronics Engineering Technicians and Technologists	36	4	22	22	38	13	1	136
Electrical Power Line and Cable Workers	50	9	29	22	28	12	1	151
Power System Operators	29	7	23	20	37	13	0	129
Power Station Operators	20	4	23	26	36	12	0	121
All Other Trades	29	4	16	18	43	19	1	130
Total ESC	359	33	161	210	420	172	7	1362
Percentage of Total Sample	26.4	2.4	11.8	15.4	30.8	12.6	0.5	100

Source: Electricity Sector Council (Power in Motion)

The implications of an aging workforce are many, but most notably when looking at workforce retirement profiles. Table 9 below provides a profile of projected retirements for each of the broad Canadian labour market, the Utility sector overall as well as Toronto Hydro in particular. As is clear

from the data, Toronto Hydro faces a major challenge in the level of retirements it faces. This challenge is compounded by the fact that there are unique roles within Toronto Hydro, and the sector broadly, that demand significant levels of training in order to achieve full levels of productivity. Replacement must be planned and managed well in advance of actual retirements.

Table 9: Retirement Profile (as per cent of workforce)

Category	Retirement Rate over the next Five Years (2014-2018)
All	4.2%
Utilities	16.3%
Toronto Hydro	19.1%

Source: The Conference Board of Canada, Toronto Hydro data provided by Toronto Hydro

*For comparative purposes, this table looks at the years 2014 through to 2018 inclusive. For more detailed information on the period of 2014 to 2019, please see Table 12.

The Power in Motion study also highlights the relatively younger age of retirement for the electricity sector relative to the broader Canadian labour market at 58 years of age versus 61 years of age. In addition, the report also points to a number of specific occupations where the rate of retirement is projected to escalate over the period 2011 to 2016.

Table 10: Retirement Projections, Electricity Sector Occupations

Category	n	Per cent of Workforce Retiring in 2011	Per cent of Workforce Retiring in 2016
Engineering Managers	20	4.9	8.3
Utility Managers	27	6.3	10.6
Construction Managers	18	7.3	12.9
Supervisors of Electricians / Electrical Power Line Workers	28	7.0	19.8
Electrical and Electronic Engineers	20	2.7	5.8
Electrical Engineering Technicians and Technologists	23	3.4	10.0
Electrical Power Line and Cable Workers	33	1.7	4.5
Power System Operators	24	6.4	25.4
Power Station Operators	14	3.2	7.0
All Other Trades	18	5.7	18.8

Source: Electricity Sector Council (Power in Motion)

The following table provides a profile of the past and current workforce profile for Toronto Hydro (at year end), demonstrating a flat or downward trend in overall workforce size:

Table 11: Toronto Hydro Workforce Profile

Category	2011	2012	2013
Designated & Technical Professionals	591	528	559
Certified and Skilled Trades	712	624	573
Supervisory	190	153	177
Administrative and Support	234	183	183
Senior management	62	56	55
Total	1,789	1,544	1,547
Source: Toronto Hydro			

Looking forward to 2019, Toronto Hydro will experience significant actual numbers of retirees representing a high percentage of its overall workforce. Similar to the profile found in Power in Motion, the rate varies by occupational category.

Table 12: Toronto Hydro Retirement Projections

Category	2014		2015		2016		2017		2018		2019	
	n	%	n	%	n	%	n	%	n	%	n	%
Designated & Technical Professionals	23	4.1	16	2.9	13	2.3	23	4.1	21	3.8	34	6.1
Certified and Skilled Trades	41	7.2	23	4.0	15	2.6	21	3.7	22	3.8	41	7.2
Supervisory	11	6.2	2	1.1	7	4.0	5	2.8	6	3.4	15	8.5
Administrative and Support	4	2.2	9	4.9	6	3.3	8	4.4	13	7.1	9	4.9
Senior Management	1	1.8	1	1.8	1	1.8	0	0	3	5.5	1	1.8
Annual Total	80	5.2	51	3.3	42	2.7	57	3.7	65	4.2	100	6.5
Cumulative Total	80	5.2	131	8.5	173	11.2	230	14.9	295	19.1	395	25.5
Source: Toronto Hydro												

Note: Percentages are calculated using 2013 workforce headcount as a base

Projections for a ten year period are even more pronounced, using the 2013 workforce profile as the baseline, almost 50 per cent of the total workforce will retire. For many of the roles found within the Certified and Skilled Trades, there is a long period of training, development and apprenticeship which will demand an approach that cannot be just-in-time, and may also have to consider alternative models such as contracted and contingent workforce sources. As highlighted in the introduction and supported by the industry-wide retirement patterns, no single organization within the sector will be able to solve the challenges related to high levels of retirement and lower levels of new entrants. Sector-wide strategies and increasing levels of partnership and outsourcing will be needed. This will become increasingly important as the retirement projections over the next decade are realized. With a loss equal to 50 per cent of staff in key categories (Certified and Skilled Trades / Supervisory) the need for alternative models of workforce deployment will be required. This will be compounded by the challenge of "ebbs and flows" in the requirement for highly skilled technical and trade roles for the renewal and building of infrastructure.

Table 13: Toronto Hydro Ten Year Retirement Projection

Category	10 Year Retirement Projection	10 Year Total as % of 2013 Workforce
Designated & Technical Professionals	217	38.8%
Certified and Skilled Trades	298	52.0%
Supervisory	88	49.7%
Administrative and Support	90	49.2%
Senior management	19	34.5%
Total	712	46.0%

Source: Toronto Hydro

While the retirement profile is concerning, and requires concerted and immediate effort to plan and manage the change, Toronto Hydro can also expect to lose additional staff through typical processes where employees depart on both a voluntary and involuntary basis. Using 2013 as an illustrative example, in addition to 54 retirements, there are an additional 44 departures from the organization. (See Table 14).

Table 14: Toronto Hydro Total Exits in 2013

Category	2012 Staff*	Retirement 2013	Other Exits 2013	Total Exits 2013
Designated & Technical Professionals	528	10	23	33
Certified and Skilled Trades	624	29	9	38
Supervisory	153	12	4	16
Administrative and Support	183	1	6	7
Senior management	56	2	2	4
Total	1,544	54	44	98

Source: Toronto Hydro

*Note: 2012 headcount was used to calculate exits

It is important to note that by comparison with other organizations in its sector as well as the broader Canadian labour market, Toronto Hydro appears to be doing an excellent job of managing retention and therefore other exits, both voluntary and involuntary; related rates as a per cent of workforce are significantly lower than any of the comparators provided in Table 15.

Table 15: Voluntary and Involuntary Turnover

Category	Voluntary (%)	Involuntary (%)
Overall	7.3	3.7
Utilities	5.0	1.7
Public sector	8.1	4.2
Private sector	5.1	2.3
Toronto Hydro	1.4	0.9

Source: The Conference Board of Canada, Toronto Hydro data provided by Toronto Hydro

Conclusions and Implications

As discussed in the Electricity Sector Council Report, *Power in Motion*, there will be a need for a significant intake of employees to meet the wave of retirement and to fill the need created by system expansion and renewal. Similar to the sector broadly, Toronto Hydro estimates a cumulative retirement in its trades, technical and supervisory workforce segments in excess of 50 percent over the next decade. Any organization, but particularly those with highly educated and trained technical specialist roles must view this as a major business challenge requiring significant planning and investment. As discussed in the overview of the economic context, while past years of slow growth have provided employers some breathing room to respond to this challenge, the expectation of increased economic performance in the near term will put significant pressure of employers to respond.

The aging workforce has a number of key human resources implications for Toronto Hydro including:

- Increased competition for talent and corresponding pressures on talent acquisition (from sourcing through to on-boarding)
- Management of retirement rates and types, and the need for a related knowledge transfer strategy between generations of workers
- Cost implications related to pension and post-retirement benefits
- Potential for gaps in technical, supervisory, management and leadership positions, and the corresponding impact on productivity and innovation
- Skill and knowledge replacement

Given the combined levels of growth and retirement occurring within the utility sector and Toronto Hydro particularly, there are unique demands for talent acquisition. Not only will there be a need for a strategy that leverages a wide range of approaches such as use of contractors, partnerships and full time staffing, but given the nature of the work and the need for significant training to achieve levels of full productivity, advanced planning and retention will be critical. It will likely not be adequate for Toronto Hydro to undertake a short-term planning cycle for replacement, but there will be a need to be more proactive, while also recognizing the need to manage costs (balancing immediate staffing needs with longer term training to productivity cycles). It will be important to find the balance between the value of building long-term workforce development and deployment and incurring short-term costs in order to do so. Below we discuss the challenges related to talent acquisition.

2.5 Talent Acquisition and Recruitment

Within the Canadian utility sector, the current and future wave of retirement is the critical workforce issue. Given the demand for well-educated and highly trained professionals across all facets of operations (technical, management and leadership), strategies for talent acquisition must be best-in-class. As highlighted in Tables 7 and 8, the attraction and retention of talent are reported as being among the most significant issues facing organizations in the utility sector.

As reported in š Z } v (Œ v } Œ H } R (Measurement Benchmarking report, while the vast majority of all Canadian organizations report real challenges in recruitment of quality candidates, the µ š] o] š Ç • š } Œ Œ ‰ } Œ š • š À v Z] P Z Œ o À o • (} Œ [1] With ( ] v • ^ Z } š

[1] Critical skills are skills needed to perform key tasks identified as essential to an organization. Hot skills are skills that are in short supply and high demand in the labour market.

declines in both labour market participation and unemployment levels, skills shortages will intensify and the already challenging market for recruitment will continue become increasingly challenging.

Table 16: Challenges in Recruiting Quality Candidates by Industry and Skill Type
(Per cent of organizations reporting yes)

Select Industries	Hot Skills	Critical Skills	Management/ Executive Talent	All Categories
All industries	72	80	22	12
Utilities	100	90	10	0
Natural Resources (including oil and gas)	92	82	3	0
Manufacturing and construction	92	100	33	9
Finance, insurance and real estate	77	83	28	26

Source: The Conference Board of Canada

Interestingly, while leadership capacity remains a challenge for all organizations, the ability to recruit quality leadership and management candidates remains relatively low as a challenge relative to either hot or critical skill jobs. Challenges related to the leadership category was reported by less than one quarter of all respondent organizations, and only 10 per cent of those organizations representing the µ š] o] š Ç • š } Œ X • } v š Z } v (Œ v } Œ } (v [•] š µ] v o rise over the period 2005 to 2008 and 2008 to 2013. It is clear that while the challenge of recruiting top talent has been long standing, it is heating up in recent years, particularly as the Canadian economy continues to improve.

At the same time that Toronto Hydro is preparing for and managing significant waves of retirement, the organization is also focused on hiring, particularly roles that are critical skills/hot jobs in a highly competitive labour market. Over the past three years, Toronto Hydro has hired over 470 staff. The vast majority are new hires and are from two occupational categories designated and technical professionals and certified and skilled trades.

Table 17: Total Toronto Hydro Hires

Category	2011		2012		2013		Total		Composite Total
	External	Internal	External	Internal	External	Internal	External	Internal	
Designated & Technical W Œ } ([•	111	37	21	5	55	18	187	60	247
Certified and Skilled Trades	41	43	0	0	6	8	47	51	98
Supervisory	19	17	1	2	17	7	37	26	63
Administrative & Support	25	0	5	0	8	2	38	2	40
Senior Management	5	2	2	8	2	4	9	14	23
Total	201	99	29	15	88	39	318	153	471
Total by Year	300		44		127		471		
% of Total by Year	67%	33%	66%	34%	69%	31%	68%	33%	

Source: Toronto Hydro

Of the total Toronto Hydro hires in the three-year period above in Table 17, an overall average of 68 per cent were recruited from the external market, with the remaining one-third of the workforce was replaced internally from promotion and development. The profile varies significantly within select occupational categories having higher/lower levels of entrants from the external market, with variation over time.

Table 18: Occupational Category Hires from External Market
(Percent of total hire pool per occupational group)

Category	2011	2012	2013	Total
Designated and technical professionals	75.0	80.8	75.3	75.7
Certified & Skilled Trades	48.8	NA	42.9	48.0
Supervisory	52.8	33.3	70.8	58.7
Administrative and Support	100	100	80.0	95.0
Senior Management	71.4	20.0	33.3	39.1

Source: Toronto Hydro

The above profile reflects broader market practices of vacancies that are filled from within an organization and the balance from the external market. T Z } v (Œ v H R Œ measurement Benchmarking survey reported that 42.5 per cent of vacancies are filled from within. When looking specifically at the Trades category, Toronto Hydro has an average of 52 per cent of vacancies that are filled from within the organization, as compared to 41.9 per cent š Z } v (Œ v } Œ [• • µ Œ À Ç Table 19).

Table 19: Vacancies Filled from Within

Category	Mean	Median
Overall	42.5	39.3
Senior executives	29.1	0
Executives	46.0	45.0
Management	51.9	53.0
Professional – technical	37.5	36.5
Professional – non technical	36.6	25.0
Technical and skilled trades	41.9	44.0
Clerical and support	46.4	50.0
Source: The Conference Board of Cana		

It is important to highlight that while Toronto Hydro will recruit a number of employees with limited work experience, albeit with higher than average levels of education, like most Canadian organizations, there is a high need for experienced employees. Given that Toronto Hydro will be competing directly with both sector-specific organizations as well as organizations that have similar workforce demands (i.e. oil and gas, construction) there is an expectation that not only will there be challenges to find the talent, but that the shortage and competitive market will also drive premium compensation and benefits levels as well as place increased pressure on organizations for programs that effectively retain employees.

Conclusions and Implications

Canadian organizations see talent acquisition and management as critical workforce issues. As such, talent acquisition has shifted from being [illegible] and takes a long term perspective to ensure robust talent pipelines are in place to meet needs.

In addition to a more strategic approach, all organizations have expanded recruitment strategies. As discussed in the Power in Motion Study, the electricity sector will need to work collaboratively to develop a ready talent pool (education and training) and to look beyond what has been its traditional talent pool. Strategies, policy and programs to engage with the diversifying workforce will be essential. Not only must employers develop programs for more diversified populations, but they must also develop the necessary human resources and cultural infrastructure to ensure ease and success in orientation and retention.

Given the combination of higher levels of retirement in the utilities sector and the challenge of hiring experienced employees, organizations like Toronto Hydro will require a forward looking, aggressive recruitment strategy characterized and underpinned by:

- Sophisticated workforce analytics.
- Strong value proposition (work-life balance, compensation/benefits, culture [employee engagement and leadership strength] and presence in a wide range of traditional and new media.
- Relationships with universities, colleges and other organizations that are talent pipelines.

- Effective alumni networks.
- Effective succession management processes built on-the-job performance management processes for talent development and high potential identification.

2.6 Leadership, Development and Learning

Whether data are Œ Á v (Œ } u š Z } v (Œ v 2014 HRMA Measurement Benchmarking, CEO Challenge 2014 any number of reports by reputable research and consulting practices, leadership continues to grow as a priority human resources issue. While retirement is a major contributor to the challenge, perhaps more so, is the changing nature of leadership and the changing expectations and demands of those that are led. All organizations must make greater and greater levels of investment in o Œ • Z] ‰ À o } ‰ u v š U š o o o À o • X / š] • µ v] š š U v } µ µ P š Z š (} } Œ v š o Œ µ (• } š µ be focused on front line managers and supervisors, at the same time that the future leadership pipeline at all levels is being groomed.

d Z } v (Œ v } Œ Learning and Development Outlook Strong Learning Organizations, Strong Leadership 12th Edition, 2014) highlighted the following:

- Over half (55 per cent) of all Canadian organizations indicate that learning is a top priority.
- From the period 2010 to 2013, Canadian organizations increased their spending per employee from $688 to $705.
- In the utilities sector, spending was above average at $1,080 per employee.
- Employees across Canada received, on average, 28.3 hours of training.
- Organizations are increasingly building internal capacity for delivery of learning with a corresponding drop in the reliance on external vendors.
- There is greater reliance and use of informal learning options such as social networking, online peer information sharing.

Establishing a strong learning culture is critical for organizations to ensure they remain competitive in the face of challenging and dynamic economic and labour market trends. As reported in our 2014 Learning and Development Outlook, the International Institute for Management Development ranked Canada 28th out of 59 countries in terms of the importance placed on workforce training. Prior to 2000, Canada was consistently in the top 20 and stood at 19th in 2012. Whether in professional or highly specialized technical areas, not only must organizations do more to simply ensure an available workforce, but Canadian organizations must do more to ensure an innovative and productive workforce. Moreover, as employee engagement surveys consistently demonstrate, access to learning and development are a major lever for improved engagement and retention.

Table 20: Direct Learning and Development Expenditure, 2012/13

	n	Per employee investment in training (mean)	n	Annual hours of training, per employee (mean)
Overall	115	$705	58	28.3
Utilities	3	$1,080	3	25.1
Public sector	54	$628	25	23.9
Private sector	61	$773	33	31.6
Toronto Hydro		$963		35.5

Source: The Conference Board of Cana
Toronto Hydrodata provided byToronto Hydro

Conclusions and Implications

Toronto Hydro[•] v À • š u v š] v š Z Œ } (o Œ v] v P v À o } ‰ o u v š Á] o o v
Hydrowill have to continue to have a best-class school for training specialized skill sets[as has been the case for a number of years]While the programs have been operational for a number of years, there will be a need to continue to refresh the curriculumas technologies and infrastructure continue to evolve.

Beyond the continuous efforts to develop specialized skill sets, Toronto Hydrowill also need to focus on sustainingbest-in-class organizational performanceand retaining top talent. In order to do so, Toronto Hydrowill have to make investments in learningand developmentacross the organizationfor professional, supervisory, management andleadership development. As highlighted in the Conference } Œ } (v Learning and Development Outlook, organizations across Canada are repatriating learning and development fromexternal providers/contractors to buildin-house capacity.

2.7 Compensation and Benefits

Generally speaking, tight labour markets and skill shortages drive compensation levels upwards over time, and there is perhaps no better evidence in this regard than Alber š [• o } µ Œ profile Ed š ive to the rest of CanadaDrawing from the data presented in the } v (Œ v } Œ } (v [• Compensation Planning Outlook 2014report, it is clear that those provincial labour markets in Canada that are having the greatest attraction success are those having to offer premium compensation differentialsas measured by actual annual compensation adjustments:

Table 21: Annual Compensation Increases in 2013 by Province

Province	Percentage Increase
Atlantic	2.9
Quebec	2.7
Ontario	2.3
Manitoba	3.2
Saskatchewan	3.9
Alberta	3.8
British Columbia	2.6
Source: The Conference Board of Cana	

When a sector perspective is used, the premium variation is even more pronounced:

Table 22: Annual Compensation Increases in 2013 by Selected Industries

Industry	Percentage Increase
Oil and gas	4.8
Construction	3.9
Natural Resources	3.3
Government	2.9
Utilities	2.9
Finance	2.7
Source: The Conference Board of Cana	

We are of the view that as the Toronto Hydro labour market continues to tighten as a result of retirement and labour shortages, there will likely be upward pressure on compensation.

In addition, post-retirement costs can be significant, and based on the data from the 2014 Human Resource Trends and Metrics: HR Measurement Benchmarking, Third Edition, post-retirement benefits are significantly higher for utility sector organizations. For all participant organizations, 1.23 per cent of annual payroll is required, while for utilities sector the mean is 2.03 per cent of payroll. As Toronto Hydro continues to see increasingly levels of retirement, there will likely be incremental financial resources required.

Conclusions and Implications

Toronto Hydro is facing increased costs in compensation and benefits through the dual pressures of an increasingly competitive labour market as well as increasing levels of retirees. While a wide range of HR programs (strong learning and development, effective leadership, work/life, etc.) can be used in part to offset compensation and benefit costs, the reality is that each program has a range of both hard and soft costs to development, lost productivity t š Z š]u ‰ š v }ŒP v]Ì š]}v[• }šš}u o]v X

2.8 Collective Bargaining

I v š Z } v (Œ v } Œ E] • Challenges to • Œ Z • š µ Ç U K • Á Œ • l } µ š ^ Z } issues t the more immediate, tactical issues that are keeping CEOs up at night. Labour relations was identified as the number one issue by Canadian CEOs in 2014.

Unions are operating in a new reality as a result of lingering impacts of the recession and the related fiscal landscape for government, globalization, deregulation, and a shifting political landscape. While union density has been in relative decline in the private sector, it remains high in the public sector and in the energy and utilities sector. Given the current economic outlook, it is increasingly difficult to manage expectations ahead of collective bargaining and for both management and labour to reach mutually agreeable settlements. It is] u ‰ } Œ š v š š } v } š U Z } Á À Œ U š Z š Á Z] o v [• µ v] } declined from a í õ ô ì [• ‰ l } (ï ð ‰ Œ v š š } ï í ‰ s Œ increasingly dominated by ‰ Œ v š] high levels of public sector unionization. In fact, almost 85 per cent of all public sector employees are covered by a union contract.

The Conference Board is of the view that this challenging environment for labour will become increasingly so, making the bargaining process more and more difficult. Research from the Conference Board of Canada provides some evidence that wages, benefits and pensions will be a focus in bargaining as will issues of productivity and competitiveness (Back to Basics for the Labour Movement). However, given the challenging labour market, the overall economic environment, and the willingness of governments to intervene to end strikes and lockouts, it is expected that there will be limited labour disruption in the near future.

Conclusions and Implications

Toronto Hydro operates in a highly unionized environment, with a demonstrated ability of labour to secure the support of its membership for a strike mandate, which brings additional pressure and complexity to its labour relations climate. While we are of the view that the short-term economic environment will moderate the demands made by unions, as the labour market begins to tighten over the next decade, unions may find themselves with greater leverage which will translate into cost pressures for employers.

Sources Consulted

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COMPENSATION STRATEGY & WORKFORCE GOVERNANCE

This schedule includes evidence regarding Toronto Hydro's compensation strategy and workforce governance practices. Further to the information outlined in the OEB Appendix 2-K Employee Cost (Exhibit 4A, Tab 3, Schedule 2), this schedule provides an overview of Toronto Hydro's compensation costs and practices, and pension and benefit programs and costs. The evidence is organized as follows:

1) Compensation Costs Overview;
2) Compensation Strategy and Workforce Governance;
3) Compensation Practices for Non-Union Employees;
4) Compensation Practices for Bargaining Unit Employees; and
5) Benefits and Pensions.

1. COMPENSATION COSTS OVERVIEW

Table 1 below summarizes Toronto Hydro's total compensation costs, which include base salary wages, overtime and incentive payments, and actual and accrued benefits.

Table 1: Salary and Wages including Overtime and Incentive Pay ($ Millions)

Year	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test Year
Management (including executive)	15.2	13.7	14.4	15.0	15.3
Non-Management (union and non-union)	219.4	202.0	202.4	205.6	210
Total	234.6	215.7	216.8	220.6	225.3

*Rounding errors may exist

Since 2011, Toronto Hydro has made notable improvements relating to its compensation costs, and the utility plans to sustain these efficiencies over the 2015 to 2019 period by

managing its compensation expenses in a manner that is financially responsible and cost-constrained manner. Toronto Hydro's plan to control compensation costs between 2015 and 2019 presents a considerable challenge for the utility, both on its own and in the context of the utility's plans over that period. During the same timeframe, Toronto Hydro is proposing to execute the largest capital program (Exhibit 2B) in the utility's history, as well as prepare itself for the large of wave of retirements that it expects to encounter in the next five to ten years. For more information about the utility's aging workforce challenge, please refer to the evidence at Exhibit 4A, Tab 4, Schedule 3.

The total compensation costs for management positions decreased 8.9 percent from 2011 to 2012 as a result of the corporate downsizing and restructuring that occurred in 2012 (Exhibit 4A, Tab 4, Schedule 3). Management costs increased 4.1 percent from 2012 to 2013 due to hiring and internal promotions related to expanded portfolios and to meet increased statutory and regulatory reporting requirements. As an example, refer to the Finance program filed at Exhibit 4A, Tab 2, Schedule 15. Toronto Hydro forecasts that management costs will remain relatively static in 2014 and 2015.

Compensation costs for non-management positions declined 10.6 percent from 2011 to 2013 as a result of the corporate downsizing and restructuring that occurred in 2012 (Exhibit 4A, Tab 4, Schedule 3). Toronto Hydro's non-management compensation costs are forecast to increase by 9.6 percent from 2013 to 2015, due to the addition of new staff, cost of living increases with respect to salary and wages, and succession planning to address upcoming retirements.

In preparing its 2014 and 2015 forecasts, Toronto Hydro considered the inflation rates set out in its collective agreements, as well as relevant labour market data. Other factors, such as the increasing size and complexity of the utility's work plan over the next five years, were also taken into consideration.

2. COMPENSATION STRATEGY AND WORKFORCE GOVERNACE

Toronto Hydro's workforce is the means by which the utility provides service and value to its customers, carries out its business objectives, and complies with its obligations. The utility strives to secure and maintain a workforce that is skilled, adaptable, committed and performance-driven. To achieve these key outcomes in a financially responsible manner, Toronto Hydro's strategy is to provide wages and benefits that are competitive in the markets where Toronto Hydro competes for talent. Toronto Hydro's strategy also includes offering a compensation program that aligns the behaviour and performance of the workforce with the core objectives and goals of the utility. The utility's compensation program is therefore an important tool for communicating performance expectations, fostering productivity and rewarding employees for their contributions.

2.1. Market-Competitive

Toronto Hydro's compensation strategy aims to strike a balance between controlling costs and providing market-competitive compensation. Providing value to customers means spending prudently, while maintaining the ability to attract, motivate, and retain employees who have the skills that are critical to the utility's success and who are capable of exceptional performance.

Maintaining a market-competitive compensation program is essential to the utility's ability to complete its proposed workload, achieve its performance objectives and otherwise meet its obligations. In addition to the fact that the uniqueness and complexity of Toronto Hydro's distribution plant makes it challenging to hire skilled labour, the utility competes with industries and organizations like Ontario Power Generation and Hydro One, which also currently have a high demand for many of the same certified and skilled trades, designated and technical professional, supervisory, and leadership positions.

Over the 2015 to 2019 period, Toronto Hydro expects to encounter additional constraints on the eligible talent pool and its retention capabilities as a result of a number of factors, including: the aging Canadian population, a declining unemployment rate in the Ontario, and economic growth and ongoing construction activity in the City of Toronto. For more information about these factors, refer to the Conference Board of Canada Report on Labour market and Human Resources Trends for the Canadian Utility Sector (Exhibit 4A, Tab 4, Schedule 4).

The utility periodically reviews the external competitiveness of its compensation programs, to help ensure that the level, and mix of compensation offered by Toronto Hydro is competitive with those provided for comparable jobs in the markets where the utility competes for talent. For example, in December 2013, Toronto Hydro engaged an independent human resources consulting firm, Towers Watson, to undertake a detailed compensation and benefits benchmarking study. The results of the study indicate that the utility is generally aligned with the market in which it competes, in relation to both compensation (base salary and performance pay) and benefits (Exhibit 4A, Tab 4, Schedule 6).

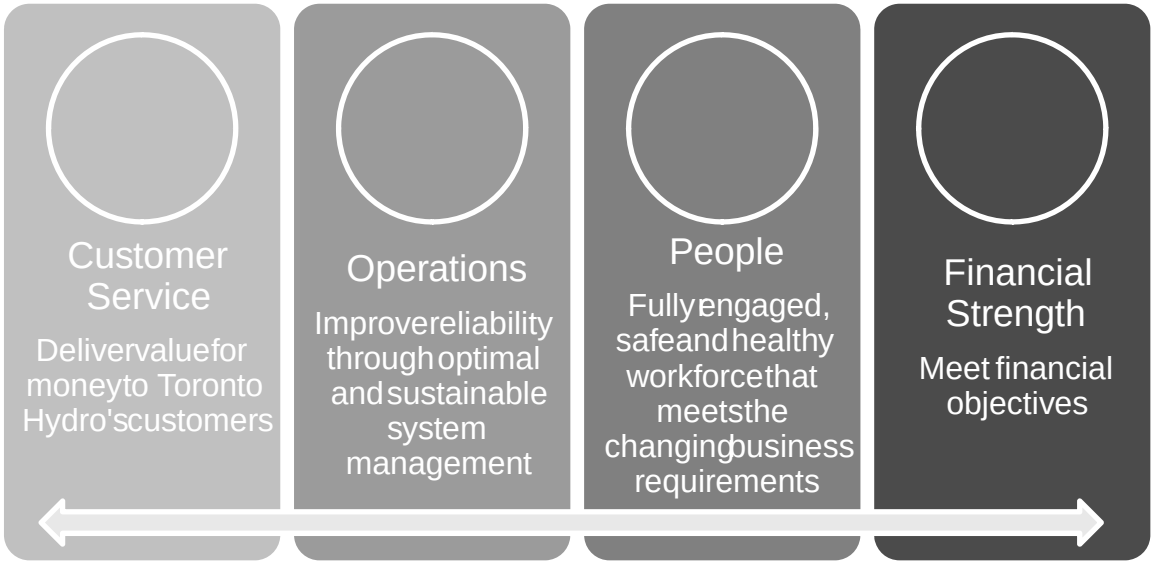
Toronto Hydro reviews the market-competitiveness of its compensation packages for non-union employees as part of its annual business planning and budgeting process. This review begins with participating in total compensation salary surveys offered through independent consulting firms, such as Mercer and Towers Watson, which specialize in the compilation of aggregate compensation data. Following receipt of the compiled external compensation survey data, Toronto Hydro compares the available compensation data (i.e., base salary, target performance pay, and target total cash compensation) against aggregate information from companies of similar size, industry, and/or geographic location.

Toronto Hydro uses benchmarking results to review and adjust the job rates to align salary ranges with the competitive market. The final salary budget requires the approval of the Board of Directors. The findings of the benchmarking exercise and the corporate budget are the key considerations for any recommendation to the Board of Directors regarding merit adjustments for the coming year.

2.2. Performance-Based Compensation

Toronto Hydro's compensation strategy is to align the capabilities and competencies of its workforce with the core objectives and goals of the utility, which are embodied in the four pillars outlined below (Figure 1). The utility's philosophy is to reward employees who demonstrate a particular set of competencies – such as commitment to safety and a customer service focus – that allow the utility to achieve its goals and objectives more efficiently and effectively. In 2013, this philosophy enabled the utility to achieve 3.5 million consecutive hours without lost time injury.

Toronto Hydro developed a set of corporate competencies to manage its workforce in an integrated fashion, and to encourage employees to demonstrate certain behaviours and achieve defined performance expectations. The diagram below (Figure 1) illustrates Toronto Hydro's corporate pillars and the chart that follows (Table 2) lists the competencies and descriptors that the utility relies upon to attain these core objectives.



1 Figure 1: Toronto Hydro's Corporate Pillars (Exhibit 1C, Tab 3, Schedule 1)

2 Table 2: Toronto Hydro's Workforce Competencies and Descriptors

Workforce Competencies	Workforce Descriptors
Drives Results & Accountability	› Set high standards x Holds self and others accountable x Stays focused on priorities
Demonstrates Customer-Focus	› Decisions and actions consider impact on customer
Builds Strong Relationships	› Collaboration x Communication x Networking x Strategic Influence x Trust/Integrity/Respect
Develops Culture & People	› Empowers staff x Focus on people development x Has coaching conversations x Attracts talent and retains employees
Champions Change, Productivity & Innovation	› Continuous improvement x Forward-thinking x Flexibility x Adaptability
Demonstrates Commitment to Environment, Health & Safety	› Does not sacrifice safety to achieve results x Proactive about social responsibility, environment, health and safety

Toronto Hydro's corporate competencies guide all areas of human resource management:

- Recruitment and Selection – Toronto Hydro utilizes the corporate competencies in developing the recruitment process for a particular position and takes the competencies into consideration as part of the selection criteria.
- Training and Development – The corporate competencies underpin the utility's training initiatives. As an example, if Toronto Hydro determines through the performance management process that an individual or team lacks in the customer focus competencies, a training needs assessment would be performed, and based on the results, an appropriate customer awareness training program would be implemented to assist in closing this gap.
- Performance Management and Compensation – The corporate competencies are integrated with Toronto Hydro's compensation practices. For non-union employees, this occurs through the assessment of performance ratings, which evaluate employees' performance in relation to the corporate competencies. The performance rating is one of the components that determine the base salary increase. For unionized employees, Toronto Hydro uses performance assessments to determine base increases for employees with a solid performance rating that are not at the top of the defined salary range.
- Succession Planning and Promotion – Decisions on succession planning and promotion focus on developing employees who consistently meet the corporate competencies, as indicated by their annual performance ratings.

3. COMPENSATION PRACTICES FOR NON-UNION EMPLOYEES

Toronto Hydro provides non-unionized employees with a total cash compensation package comprised of two elements: base salary and variable performance pay. Base salary compensates an employee for completion of their responsibilities, accountabilities and technical skills, while variable performance pay rewards employees for their

contribution to the achievement of business goals and objectives tied to the utility's pillars in combination with the successful demonstrated corporate competencies.

Each non-union position at Toronto Hydro has a salary grade level with a corresponding salary range. To maintain alignment with the competitive market, the utility adjusts salary ranges based on annual market reviews.

Non-union employees receive a portion of their annual compensation through the variable performance pay program. This program is an incentive performance-based compensation tool designed to retain, motivate and reward employees for reaching performance objectives, which are established at the beginning of each calendar year. Each employee's variable performance pay is based on a weighting of performance objectives, which are measured by Key Performance Indicators, and by individual goals set out in the employee's annual performance contract.

4. COMPENSATION PRACTICES: BARGAINING UNIT EMPLOYEES

Approximately two-thirds of Toronto Hydro's employees are represented by collective bargaining units: CUPE Local No. 1 ("CUPE") and the Society of Professional Engineers ("the Society"). Toronto Hydro's compensation costs with respect to these employees are negotiated through the period collective bargaining processes. The utility is obliged to bargain in good faith with the unions, pursuant to section 17 of the Ontario Labour Relations Act, 1995[3] and has a contractual and statutory obligation[4] to honour the terms of its collective bargaining agreements.

Toronto Hydro's bargaining interests are focused on changes that improve the organization's ability to safely execute capital and operational programs in an efficient

[3] S.O. 1995, C. 1, Sched. A,, at section 17 ["Ontario Labour Relations Act"]
[4] Ontario Labour Relations Act, at section 56.

and cost effective manner while preserving management's rights to manage and direct the workforce. For example, the most recent round of bargaining that the utility engaged in with CUPE resulted in a variety of changes aimed at improving efficiency and productivity and reducing costs in both the short and long term, including agreeing to a modest 1.75% average wage increase over four years and significant cost containment with respect to post-retirement benefits.

Toronto Hydro bargains with the focus of achieving the best outcomes with its customers in mind. For example, in the most recent round of bargaining with CUPE, Toronto Hydro introduced provisions that allow for work to be performed outside of the traditional scheduled hours of work. This change improves Toronto Hydro's ability to serve its customers, to respond to troubles more efficiently, and to accommodate the realities of operating in large and dynamic urban environment.

The utility continually reviews external compensation data to understand the compensation landscape both at the time of negotiation, as well as in the years preceding and following bargaining. In doing so, the utility monitors bargaining trends and reviews past settlements. In preparation for the most recent round bargaining with CUPE, the utility also undertook a compensation study by an independent third party, Towers Watson. To review the results of this study, refer to report filed at Exhibit 4A, Tab 4, Schedule 6.

4.1. CUPE Collective Agreement

The current collective agreement with CUPE was signed on February 13, 2014 and is valid until January 31, 2018. The table below (Table 3) summarizes the year over year percentage increases in base salary under the previous and current collective agreement.

Table 3: CUPE Base Salary Increases (2011 – 2017)

2011	2012	2013	2014*	2015	2016	2017
3.0%	3.0%	3.0%	1.5%	1.75%	1.75%	2.0%

*New collective agreement effective February 1, 2014 until January 31, 2018.

In negotiating the modest wage rate increases illustrated above, Toronto Hydro considered: 1) the OEB's 4th Generation IRM inflation parameters,[5] which were released in November 2013; and 2) the Towers Watson compensation benchmarking study (Exhibit 4A, Tab 4, Schedule 6), which found that CUPE positions were somewhat ahead of the market. Based on these key considerations, Toronto Hydro's bargaining position was that the year over year increases had to stay relatively close to inflation in order to maintain alignment with the competitive market.

4.2. Society Collective Agreement

The current Collective Agreement with the Society was ratified on April 12, 2012 and is valid until December 31, 2015. The table below (Table 4) summarizes the year over year base salary percentage increases for Society employees.

Table 4: Society Base Salary Increases (2011-2015)

2011	2012	2013	2014	2015
2.75%	1.5%	1.75%	2.0%	2.0%

Toronto Hydro's objectives during the 2012 negotiations with the Society – all of which were achieved, were to:

(1) obtain stability through a long term agreement,

(2) control current and future costs through modest wage rate increases, and

(3) resist any changes that would limit or restrict management's right to manage and direct the workforce.

[5] EB-2010-0379 Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (Issued November 21, 2013 and corrected on December 4, 2013).

(4) to clarify the process that applied to employees progressing along wage scales in the Collective Agreement.

All of these objectives were achieved during the 2012 negotiations.

For the purpose of these negotiations, Toronto Hydro considered comparable market data, which was collected through a review of external surveys and external compensation data. Toronto Hydro compared base salary and variable performance pay against information from companies within the utility sector (such as Hydro One). As a result of these analyses, Toronto Hydro's compensation position was that year-over-year increases had to stay relatively close to inflation in order to maintain alignment with the market.

Employees who are part of the Society are also eligible for variable performance pay based on their achievement of the deliverables outlined in their annual performance contract, as well as the achievement of the utility's performance objectives.

5. BENEFITS AND PENSIONS

Toronto Hydro's employee benefit programs provide coverage for full-time employees in the following areas:

- Medical, including vision care, prescription drugs, and paramedical services;
- Dental, including major dental and orthodontic services;
- Short term and long term disability income protection;
- Life Insurance and accidental death and dismemberment (AD&D) insurance;
- Leaves of absence, including maternity, adoption and parental leaves; and
- Refundable expenses, such as the fitness reimbursement program.

The historical and forecasted cost of providing the above noted employee benefit programs are summarized in the table below (Table 5).

Table 5: Employee Benefit Costs (2011-2015) ($ Millions)

	2011	2012	2013	2014	2015
Employee Benefit Total Cost	57.47	55.37	57.93	56.67	55.87

Toronto Hydro periodically reviews the trends and costs associated with its benefit programs to help ensure that the utility receives value for its money, and that it is aligned with the markets within which it competes for talent.

In 2013, Toronto Hydro retained the firm Towers Watson to conduct a review of its compensation and benefits programs, (Exhibit 4A, Tab 4, Schedule 6). This study found that the value of the Toronto Hydro employer-paid benefits is just below the median observed for the peer group, primarily driven by the high employee pension contributions in comparison to plans offered by other organizations in the peer group. With consideration to the employee contributions, Toronto Hydro benefits are just above the market median due to the higher than typical employee pension contributions.

Since 2011, Toronto Hydro has implemented a number of cost-curtailing changes to its employee benefit programs. For example, the utility bundled paramedical treatment allotment and included reasonable and customary rates for certain services such as dental service using the general practitioners' fee guides. These initiatives have resulted in lower costs for the utility and greater flexibility and awareness by plan members regarding their benefits plan.

As a long-term cost mitigation strategy, Toronto Hydro implemented a comprehensive health prevention program in 2012. Key initiatives of this program include physical

activity, eating well, stress management, mental health, and smoking cessation. Toronto Hydro hopes that this program will reduce future benefit costs relating to prescription drugs, and disability costs, and to improve employee absenteeism, productivity, engagement, and retention.

In addition to benefits, Toronto Hydro also provides a pension for fulltime employees through its membership in the Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer defined benefit pension plan. Under this plan, both participating employers and their employees are required (by virtue of their membership in the plan) to make contributions to the plan. The required contribution rates are based on the employee's earnings, and are periodically reviewed by the OMERS Sponsors Corporation in light of the assets and obligations of the plan.

The most recent annual valuation of the OMERS Pension plan and additional considerations reviewed by the OMERS Sponsors Corporation resulted in no change to the contribution rates for 2014. The table below (Table 6) summarizes Toronto Hydro's historical and forecasted contributions to the plan over the 2011 to 2015 period, as well as the employer and employee contribution rates required by OMERS.

Table 6: OMERS Contribution Rates (2011 – 2015)

	2011	2012	2013	2014	2015
Employer Rate	7.4% to YMPE 10.7% over YMPE	8.3% to YMPE 12.8% over YMPE	9% to YMPE 14.6% over YMPE	9% to YMPE 14.6% over YMPE	9% to YMPE 14.6% over YMPE
Employee Rate	7.4% to YMPE 10.7% over YMPE	8.3% to YMPE 12.8% over YMPE	9% to YMPE 14.6% over YMPE	9% to YMPE 14.6% over YMPE	9% to YMPE 14.6% over YMPE

Employees and employers in the OMERS pension plan contribute less to the pension plan on earnings received up to the annual Yearly Maximum Pensionable Earnings

("YMPE"), and a higher amount on earnings above the YMPE. The YMPE is the Canadian Pension Plan ("CPP") earnings limit: contributions to the CPP are made on earnings up to this limit. The OMERS Plan contribution rate is lower up to the YMPE because OMERS is designed to work together with CPP to provide combined pension benefits.

The table below (Table 7) summarizes Toronto Hydro's historical (2011 – 2013) and forecasted (2014 – 2015) pension costs, including capitalized and expensed amounts each year.

Table 7: Pension Costs (2011 – 2015) ($ millions)

	2011	2012	2013	2014	2015
Pension Premiums	13.56	16.13	17.85	17.02	17.45
Less: Amount Capitalized	5.49	5.79	6.81	8.82	10.14
Amount Expensed in Each Year	8.07	10.34	11.04	8.20	7.32

In addition to pension benefits, employees also earn an entitlement to certain post-retirement benefits, including health, dental and life insurance. These future benefit expenses are based on the most recent actuarial valuation by Tower Watson, which was performed in January 2012 (refer to Exhibit 4A, Tab 4, Schedule 7), and are recognized on an accrual basis in the period during which employees render their services. As a long-term cost-containment measure, effective February 1, 2014, new hires to the organization have been limited to post-retirement health and dental benefits until age 65, provided they satisfy the ten years of service eligibility criterion.

The table below (Table 8) presents Toronto Hydro's historical (2011 – 2013) and forecasted (2014 – 2015) post-retirement benefits costs, including capitalized and expensed amounts.

Table 8: Post-Retirement Benefit Costs (2011-2014) ($ Millions)

	2011	2012	2013	2014	2015
Post-Benefit Costs	16.67	20.35	17.35	16.33	16.46
Capitalized Amounts	6.76	7.31	6.62	6.47	6.52
Expensed Amounts	9.94	13.05	10.72	9.86	9.94

Toronto Hydro Electric Systems Limited

Toronto Hydro Compensation and Benefits Review

Completed: January 2014

TOWERS WATSON

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INTRODUCTION AND EXECUTIVE SUMMARY

Towers Watson was retained by Torys on behalf of its client Toronto Hydro to complete a review of market competitive compensation and benefits levels in January 2014.

Methodology

The review, findings and observations focused on compensation and benefits separately. Towers Watson encourages Toronto Hydro to consider compensation and benefits in aggregate when reviewing overall position to market for a given level or role.

The compensation review covered analysis of annualized base pay, target short-term incentive levels, and total target cash (base pay plus target short-term incentive) at Toronto Hydro and in the external market (see peer group notes below).

)ROORZLQJ 7RZHUV :DWVRQ¶V DGYLFH DQG EHQFKPDUN UHVXOWV at Toronto Hydro were identified to support the compensation analysis. Balanced selection criteria were applied to ensure functional or level based bias did not disproportionately skew the analyses. BHQFKPDUN UROHV FRYHUHG RI 7RURQWR Hydro with the range (50% to 75%) typically suggested for this type of analysis).

The benefits review covered aggregate analysis of both employer paid value and total (employer plus employee paid) value for all core benefits, including pension, savings, disability, health (active and retiree), dental (active and retiree), life insurance (active and retiree), vacation and holidays.

Peer group selection

2Q 7RZHUV :DWVRQ¶V UHFRPPHQGDWLRQ DQG WR HQVXUH UHOHYDQW FRPSHQVDWLRQ DQDO\VLV WKH ³H[WHUQDO PDUNHW´ was defined as the following peer groups identified:

- $ QDPHG FRPSDUDWRU JURXS RI FRPSDQLHV IURP 7RZHUV :DWVRQ Survey to cover as many roles as possible (but focusing mostly on industry-specific jobs),
- $ QDPHG FRPSDUDWRU JURXS RI FRPSDQLHV IURP 7RZHUV :DWVRQ Energy Industry Survey to cover as many roles as possible (focusing mostly on the utilities industry),
- $ EURDGHU ³ZKROH VDPSOH´ SHHU JURXS FRYHULQJ DOO SDUWLFL Compensation Survey,
- A named comparator group of GTA companies from 7RZHU :DWVRQ¶V *HQHUD Survey that meet headcount and revenue / budget scope criteria for non-industry-specific jobs, and
- $ EURDGHU ³ZKROH VDPSOH´ SHHU JURXS FRYHULQJ DOO SDUWLFL Survey as a supplementary reference point.

Benchmark jobs were matched to equivalent survey jobs and levels in the aforementioned Towers Watson and Hay Group compensation surveys to support the analysis. Survey matching was validated by Towers Watson and Hay Group consultants.

A single named peer group was identified to support the benefits analysis. Comparator organizations were selected on the basis of industry (vertically integrated electricity organizations and electricity and gas organizations ±Canada-wide) and geography (energy companies operating solely in Ontario). 2QFH HVWDEOLVKHG 7RZHUV :DWVRQ¶V SURSULHWDU\ EHQHILWV YDO SURYLGH D FRQVLVWHQW YDOXDWLRQ RI WKH 7RURQWR +\GUR¶V EHQ group organizations.

Details for each peer group are presented in the Appendix to this report.

Observations and findings

Compensation and benefits at Toronto Hydro are closely aligned to mid-market (median) rates across all peer groups.

Compensation

In most instances, and against all comparator groups, Toronto Hydro pay sits within what we would consider a market competitive range of +/-15% of the relevant mid-market data. Competitive positioning does not vary significantly between base pay and total target cash, with target short-term incentive award levels closely aligned to mid-market rates.

Benefits

The value of employer paid benefits is just below the median observed for the peer group. Including, employee contributions, Toronto Hydro sits just above the market median. This position is due to higher than typical employee pension contributions.

REPORT DETAIL

Introduction

Towers Watson was retained by Torys on behalf of its client Toronto Hydro to undertake an analysis of external market compensation and benefits levels.

Following consultation with Towers Watson on the most robust approach to market comparison, Toronto Hydro selected the following areas to include in the scope of the review:

Compensation:

- Annualized base pay
- Target short-term incentive
- Total target cash ((annualized) base pay plus target short-term incentive award)

Please note that our analysis excludes long-term incentive eligibility and award levels which do not constitute S D U W R I 7 R U R Q W R + \ G U R ¶ V U H Z D U G S D F N D J H

Benefits:
Benefits data and information is presented at an aggregate and summary benefit level for all core benefits irrespective of level. The benefits review looks at market competitiveness through two lenses:

- Employer paid value of all core benefits ±total value less employee contributions
- Total value of all core benefits ±the combined value of employer and employee paid contributions

The balance of this report details the review methodology followed in arriving at our findings and observations, including peer group considerations and any assumptions made through the course of the analysis. Findings and observations are outlined at a summary level from page 11 with further detail in the Appendix.

Methodology

Summary

Jobs across all grades were benchmarked against equivalent roles within organizations from one or PRUH RI 7RURQWR +\GUR¶V (see below). Data was drawn from the following Towers Watson surveys:

- The Towers Watson 2013 Energy Compensation Survey[1]
- The Towers Watson 2013 General Industry Middle Management, Professional and Support Compensation Survey
- The Towers Watson 2013 Benefit Data Source ±Canada (BDS Canada)

Additionally ZH UHYLHZHG GDWD IURP +D\ *URXS¶V 2013 Industry Compensation Survey to ensure that Ontario based utilities organizations that are not represented in Towers Watson compensation surveys were reflected in our findings and observations. Towers Watson and Hay Group data was supplemented with collective agreement data for national utilities organizations collected and provided by Toronto Hydro (see Appendix 4).

Compensation benchmarking and analysis

7RZHUV :DWVRQ¶V Performance Benchmarking Methodology assesses jobs on two bases. First, we assess job content as outlined in Toronto Hydro job descriptions to establish appropriate matches to compensation survey jobs. Second, we evaluate the level of each job, drawing on our knowledge and understanding of both internal (Toronto Hydro) relativities and external comparability.

To support the benchmarking process, Toronto Hydro provided Towers Watson with current job GHVFULSWLRQV IRU HDFK ³LQ VFRSH´ UROH ZLWK VXJJHVWHG FRPSHQ used to support the business as usual annual compensation review. Survey job and level matches for each in-scope role were independently reviewed and validated by Towers Watson.

3OHDVH QRWH WKDW 7RZHUV :DWVRQ GLG QRW YDOLGDWH 7RURQWR Energy Industry Compensation Survey. However, based on discussion with Toronto Hydro it is our view that matching was completed accurately and we understand that all matches and data have been confirmed by Hay Group Compensation Consultants.

Aggregate results of our analysis of market competitive pay are presented from page 8. Aggregate data is presented for mid-market (median) statistics only. Data is presented in tabular form to show 7RURQWR +\GUR¶V PDUNHW SRVLWLRQLQJ DJDLQVW WKH PDUNHW DV D ratios). VRQ UDWLR¶V FRPS

Compa-ratios, expressed as a percentage, illustrate the extent of divergence between our mid-market assessment of market competitive pay and current levels of pay within Toronto Hydro. A positive compa-ratio of more than 0% shows that pay at Toronto Hydro is above the market median. A negative compa-ratio of less than 0% suggests that pay at Toronto Hydro is behind the mid-market rates.

[1] *Note: 2013 Energy Survey data has been supplemented with 2012 data for direct comparator organizations that were participants in 2012 but have since opted out.*

For this analysis, compa-ratios for multiple incumbent positions are based on median incumbent pay.

Our analysis summarized market competitiveness for the following compensation elements:

- Annualized base pay
- Target short-term incentive
- Total target cash ((annualized) base pay plus target short-term incentive award)

When interpreting the findings of the review, it is important to note that our analysis of market competitive pay is based on the data available to us. The findings presented in this report do not constitute a recommendation of pay for any particular individual. In our experience, pay levels of up to 15% either side of the mid-market data FDQ EH FRQVLGHUHG WR EH ³PDUNHW FRPSHWLWLYH´ FRXUVH GHSHQGHQW RQ D QXPEHU RI IDFWRUV LQFOXGLQJ DQ LQGLYLGXDO¶V performance. We would normally expect companies to apply judgement in reaching individual pay decisions.

Benefits benchmarking and analysis

Benefits benchmarking was completed through 7RZHUV :DWVRQ¶V SURSULHWDU\ EHQHILWV YDOXDWLRQ (BENVAL®) which provides a consisten W YDOXDWLRQ RI W Kenefits compared to those UR¶V offered by other peer group organizations on a named basis. ³& RUHµ benefits covered in our review include pension, savings, disability, health (active and retiree), dental (active and retiree), life insurance (active and retiree), vacation and holidays.

BENVAL® analysis shows the competitiveness of the value of existing benefits programs by plan and LQ DJJUHJDWH 7KH PHWKRGRORJ\ KDV EHHQ WHVWHG DQG UHILQHG DSSOHV´ FRPSDULVRQ

The tool is underpinned by a controlled environment in which differences in the reported value of each UHJDUGOHVV RI Plan's are exclusively a function of differences in plan provisions. Each UHJDUGOHVV RI¶V EHQHILWV FRVWV DUH DIIHFWHG E\ SURJUDP GHVLJ captured in this analysis such as funding decisions, plan experience and demographics.

To develop reported values, benefits are initially analyzed in terms of when they become payable:

- **Benefits payable in the future:** defined benefit pension plans (all ancillary benefits included) and post-retirement, health care and dental care benefits ±are valued, in terms of anticipated SURVSHFWLYH EHQHILW SD\PHQWV EHLQJ DOORFDWHG RYHU WKH (Projected Unit Credit with services prorate method).
- **Benefits potentially payable in the current year:** defined contribution pension plans, savings plans, pre-retirement death, health care and dental care benefits, disability benefits and vacations and holidays ±are valued based on the probabilities of the various events occurring within the year, multiplied by the value of the benefit (Term Cost Method).

The employer-provided value of benefits is determined by deducting employee contributions from the total value of benefits provided. Each plan is valued under the same actuarial valuation method using a common set of actuarial assumptions and consistent employee population assumptions.

Peer group considerations

To support the selection of relevant and appropriate peer groups for the analysis, Towers Watson recommended that Toronto Hydro consider:

- Organizations with a similar ³industry´ orientation, including those within and outside of the province and other prominent organizations that face regulatory and public scrutiny
- Organizations that are similar to Toronto Hydro in terms of scope (size/complexity, etc.). This criterion is more important than others, although the specific elements which vary widely in interpretation from organization to organization.
- Organizations that Toronto Hydro is most likely to lose individuals to and hire individuals from ±this varies from job to job
- Organizations that key stakeholders (internally and externally) viewed as relevant (most likely to focus on utilities and public sector/crown corporate comparison)

On the advice of Towers Watson, six peer groups (five to support the compensation analysis and one to support the benefits analysis; detailed in Appendix 1) were established, including:

- Compensation
  - A named peer comparator group of companies from Towers Watson¶s Energy Compensation Survey to cover as many roles as possible (but focusing mostly on industry-specific jobs)
  - A named comparator group of companies from Hay Group¶s Energy Compensation Survey to cover as many roles as possible that were not reported in the Towers Watson surveys. This survey focused mainly on utilities industry
  - A broader ³whole sample´ peer group covering all participants from Towers Watson¶s Energy Compensation Survey
  - A named comparator group of GTA companies from Towers Watson¶s General Industry Survey that meet headcount and revenue/budget scope criteria for non-industry-specific jobs
  - A broader ³whole sample´ peer group covering all participants from Towers Watson¶s General Industry Survey as a supplementary reference point. This was reviewed only in instances where there was no named peer group or ³whole sample´ data available
- Benefits
  - A named comparator group of companies from Towers Watson¶s Energy Survey Database to provide benefits data for roles at all levels in the organization

Toronto Hydro together with Towers Watson carefully considered the relevance of each peer group for each role. Peer group relevance consideration included, for example, the requirement for industry specific experience and expertise, and the prevalent market for talent (focussing on organizations that Toronto Hydro tends to lose people to and hire people from).

Assumptions and inputs

All incumbent pay data was provided to Towers Watson by Toronto Hydro and was accurate as at November 30th, 2013.

In-VFRSH MREV ZHUH VHOHFWHG E\ 7RURQWR +\GUR IROORZLQJ 7RZHU reasonable representation of employees across all functions and levels in the organization. To support the matching validation process, Toronto Hydro shared job descriptions for all 65 in-scope jobs with Towers Watson. We relied on these job descriptions to obtain an understanding of the in-scope jobs and believe them to be up-to-date and accurate.

Target short-term incentive award levels were used rather than actual incentives paid to smooth out year-to-year differences in variable payments that are often subject to individual, team and company performance.

Hay Group compensation survey data has been provided to Towers Watson by Toronto Hydro and is accurate as at May 1st, 2013.

Compensation review findings

The tables below illustrate 7RURQWR +\GUR¶V SRVLWLRQ WR PDUNHWin DW DQ DJJU the organization. Data presented reflects mid-market (median) values.

Incumbent data has been aggregated to illustrate median for:

- Annualized base pay:
  - For hourly rate employees, annualized base pay is calculated taking hourly rate x 2080 hours
  - For weekly rate employees, annualized base pay is calculated taking weekly rate x 52 weeks
- Target short-term incentive (STI target %, expressed as a percentage of base pay), and
- Total target cash compensation (TTC ((annualized) base pay plus target short-term incentive)).

Competitive data for each compensation element are reported when median statistics are provided for positions with at least four participant matches. Average statistics are provided for positions with at least three participant matches.

As described in the methodology section of the report, compa-ratio analysis is presented for each of 7RURQWR +\GUR¶V FXUUHQW JUDGHV $OO UROHV IDOO Within D ERYH RU highlighted in red to highlight what Towers Watson considers to be a material variance from the market.

Aggregate Market Results by Grade: Grades Y3 to V3

				Towers Watson: 2013 Compensation Data (000s)											Hay Group: 2013 Compensation Data (000s)		
Toronto Hydro Compensation Data by Grade				Energy ±Named Peer Group			Energy ±Whole sample			General Industry ± Named Peer Group			General Industry ± Whole Sample			Utilities Peer Group		
Grade	Base Pay	Target STI	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC
Y3	$152.5	25%	$190.6	$166	24%	$192	$145	21%	$175	$166	24%	$182	$113	15%	$130	$130	---	$147
				-8%	---	*-1%*	*6%*	---	*9%*	*-8%*	---	*5%*	*35%*	---	*47%*	*17%*	---	*30%*
Y2	$128.2	15%	$147.4	---	---	---	$132	20%	$161	$133	16%	$150	$105	13%	$119	$121	---	$135
				---	---	---	*-3%*	---	*-8%*	*-4%*	---	*-2%*	*22%*	---	*24%*	*6%*	---	*10%*
X1	$136.0	12%	$152.3	---	---	---	$129	18%	$153	$142	16%	$163	$129	18%	$148	$118	---	$130
				---	---	---	*5%*	---	*0%*	*-4%*	---	*-7%*	*5%*	---	*3%*	*15%*	---	*17%*
W4	$108.1	10%	$118.9	---	---	---	$107	11%	$120	$104	14%	$117	$140	20%	$158	$108	---	$119
				---	---	---	*1%*	---	*-1%*	*4%*	---	*2%*	*-23%*	---	*-24%*	*0%*	---	*0%*
W3	$104.3	10%	$114.7	---	---	---	$106	13%	$123	$107	13%	$118	$121	18%	$137	$95	---	$100
				---	---	---	*-2%*	---	*-6%*	*-3%*	---	*-3%*	*-13%*	---	*-16%*	*10%*	---	*15%*
W2	$98.3	8%	$106.2	---	---	---	$71	10%	$75	$84	10%	$90	$85	12%	$94	$91	---	$94
				---	---	---	*38%*	---	*42%*	*17%*	---	*18%*	*16%*	---	*13%*	*8%*	---	*13%*
V4	$109.2	8%	$118.0	---	---	---	$103	10%	$113	---	---	---	$80	12%	$90	$100	---	$108
				---	---	---	*6%*	---	*4%*	---	---	---	*37%*	---	*31%*	*9%*	---	*9%*
V3	$100.0	8%	$108.0	$99	---	$109	$88	10%	$96	$94	10%	$100	$72	10%	$76	$85	---	$89
				1%	---	*-1%*	*14%*	---	*12%*	*6%*	---	*9%*	*39%*	---	*42%*	*18%*	---	*22%*

Aggregate Market Results by Grade: Grades V2 to CUPE

Toronto Hydro Compensation Data by Grade				Towers Watson: 2013 Compensation Data (000s)												Hay Group: 2013 Compensation Data (000s)		
				Energy ±Named Peer Group			Energy ±Whole sample			General Industry ± Named Peer Group			General Industry ± Whole Sample			Utilities Peer Group		
Grade	Base Pay	Target STI	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC
V2	$85.2	8%	$92.1	$96	---	$105	$84	10%	$94	$81	10%	$88	$63	9%	$68	$84	---	$88
				-11%	---	*-12%*	*2%*	---	*-2%*	*6%*	---	*5%*	*35%*	---	*36%*	*1%*	---	*5%*
V1	$85.7	8%	$92.6	---	---	---	---	---	---	---	---	---	$61	8%	$66	$75	---	$76
				---	---	---	---	---	---	---	---	---	*41%*	---	*40%*	*15%*	---	*21%*
U3	$64.8	6%	$68.7	$81	10%	$89	$74	10%	$80	$73	10%	$79	$60	10%	$63	$73	---	$72
				-20%	---	*-23%*	*-12%*	---	*-14%*	*-11%*	---	*-13%*	*8%*	---	*9%*	*-11%*	---	*-4%*
U2	$64.6	6%	$68.4	---	---	---	$64	8%	$69	$65	8%	$69	$53	7%	$55	$73	---	$72
				---	---	---	*1%*	---	*-1%*	*-1%*	---	*-1%*	*22%*	---	*24%*	*-11%*	---	*-4%*
U1	$64.7	6%	$68.6	---	---	---	$62	0%	$64	$66	8%	$73	$58	8%	$61	$69	---	$71
				---	---	---	*4%*	---	*7%*	*-2%*	---	*-6%*	*13%*	---	*13%*	*-7%*	---	*-3%*
T2	$58.7	6%	$62.2	---	---	---	---	---	---	---	---	---	$45	6%	$48	$64	---	$65
				---	---	---	---	---	---	---	---	---	*30%*	---	*30%*	*-8%*	---	*-4%*
T1	$48.3	6%	$51.2	---	---	---	$48	6%	$50	$50	7%	$53	$40	7%	$41	$66	---	$66
				---	---	---	*2%*	---	*3%*	*-3%*	---	*-3%*	*22%*	---	*25%*	*-27%*	---	*-23%*
SOCIETY	$101.4	8%	$109.5	$94	10%	$95	$94	12%	$111	$90	10%	$95	$79	10%	$84	$91	---	$94
				8%	---	*15%*	*8%*	---	*-1%*	*13%*	---	*15%*	*28%*	---	*30%*	*12%*	---	*16%*
CUPE	$86.3	0%	$86.3	$95	---	$94	$73	6%	$76	$56	4%	$59	$54	7%	$57	---	---	---
				-9%	---	*-8%*	*18%*	---	*14%*	*54%*	---	*47%*	*61%*	---	*53%*	---	---	---

Observations

With the exception of a minority of grades (see below for more detail), Toronto Hydro pay is closely aligned to mid-market rates across all peer groups. Following the peer group selection criteria, it is 7RZHUV :DWVRQ¶V YLHZ WKDW WKH HQHUJ\ SHHU JURXSV 7RZHUV :DV general industry peer group were of most relevance since they represent the companies that Toronto Hydro is most likely to recruit individuals from and lose employees to. For this reason, we advise that the whole sample general industry peer group is only reviewed in instances where there is very limited or no peer group data.

Target total cash (TTC)

Data was very limited for Tow HUV :DWVRQ¶V QDPHG FRPSDQ\ HQHUJ\ SHHU JURXS was available, Toronto Hydro TTC levels were broadly aligned to market. The one exception is grade ³8 ´ ZKLFK DW DQ DJJUHJDWH OHYHO ZDV EHKLQG PDUNHW E\

Toronto Hydro TTC levels were HTXDOO\ ZHOO DOLJQHG WR 7RZHUV :DWVRQ¶V ZKF JURXS :LWK WKH H[FHSWLRQ RI JUDGH ³: ´ ZKLFK ZDV DKHDG RI W positioned within the market competitive range of +/-15% of mid-market rates. Although at face value ³: ´ SD\ OHYHOV DSSHDU DQRPDORXV ZKHQ FRPSDUHG WR WKH RWKHU JUDGHV WKLV is a result of comparisons with data from the WKDW bargaining unit.

$JDLQVW 7RZHUV :DWVRQ¶V QDPHG JHQHUDO LQGXVWU\ SHHU JURXS
Toronto Hydro g U D G H V ³: DQG ³& 8 3(ZHUH Wthe market, sitting 18% and 47% ahead
of the market respectively.

$V QRWHG DERYH GDWD IRU 7RZHUV :DWVRQ¶V ZKROH VDPSOH JHQH
relevant given the wide variance in organizational size and geographic dispersion and should be
considered supplementary in instances where named peer group data is not available. Against this
SHHU JURXS 7RURQWR +\GUR 77& OHYHOV ZHUH KLJK ZLWK RQO\ JU
within the market competitive range of +/-15% of the market median.

Against the Hay Group data, we observed that the majority of grades are positioned within the
FRPSHWLWLYH PDUNHW UDQJH ZLWK JUDGHV IDOOLQJ DERYH PDUNH
JUDGH ³7 ´ EHLQJ WKH Hqv the Market by 23%.OOLQJ EHO

Base pay

1RWZLWKVWDQGLQJ GDWD OLPLWDWLRQV IRU 7RZHUV :DWVRQ¶V QDP
+\GUR EDVH SD\ OHYHOV ZHUH EURDGO\ DOLJQHG ZLWK WKH PDUNHW
which, on an aggregate level, was behind the market by 20%.

7RURQWR +\GUR EDVH SD\ OHYHOV ZHUH ZHOO DOLJQHG WR 7RZHUV
JURXS :LWK WKH H[FHSWLRQ RI JUDGHV ³ and ³ which were 38% and 18% ahead of the market,
all grades are positioned within the market competitive range of +/- 15% of mid-market rates.

$JDLQVW 7RZHUV :DWVRQ¶V QDPHG JHQHUDO LQGXVWU\ SHHU JURXS
³: ´ DQG ³&83(´ ZHUH WKH RXWOLHUV LQ WKLV LQVWDQFH VLWWLQJ

Against 7RZHUV :DWVRQ¶V ZKROH VDPSOH JHQHUDO LQGXVWU\ SHHU JU
were high with only 4 JUDGHV ³: ´ ´ 8 ´ DQG ´ sitting within the market competitive range of
+/- 15% of the market median.

Toronto Hydro base pay levels were well aligned to the Hay Group data with only 2 grades falling
DERYH PDUNHW ³< ´ DQG ³9 ´ DQG RQH JUDGH ³7 ´ IDOOLQJ EHORZ

Benefits review findings and observations

Detailed graphs that illustrate Toronto +\GUR¶V SRVLWLRQLQJ UHODWLYH WR WKH PDUNHW ZLWK UHVSHFW WR WRWDO SURYLGHG YDOXH DQG WRWDO EHQHILWV RIIHULQJ DV D ZKROH LQ DGGLWLRQ WR WKH core benefits programs described earlier in this report.

Toronto Hydro offers a generous pension plan in comparison to the named peer group. However, employee contributions were high in comparison to plans offered by other organizations in the peer group. Most active group benefit plans were close to the market median, except the dental plan that is more generous than that offered by comparator organizations. Two areas where the Toronto Hydro plan ranked particularly favourably include the uncapped maximum for basic and major services, and the competitive orthodontic coverage.

Toronto Hydro provided a slightly less generous paid time-off schedule than the peer group at median.

The graphs in Appendix 3 indicate that the employer-SDLG YDOXH RI 7RURQWR +\GUR¶V EHQ aggregate was equivalent to 31.8% of base pay compared to a market median at 34.7%. This suggests that Toronto Hydro program was behind market by approximately 2.9%. This was off-set by employee contributions which ±as illustrated in Appendix 3 ±contribute significantly to the competitiveness of the overall benefits offering.

Please note that benefit plan values are expressed as a percentage of base pay and represent the average value, per employee, for the valuation year. Plan valuations are based on the provisions that applied to newly hired salary employees only. Legacy benefits that are no longer available to new hires were not considered.

Appendix 1: Peer Group Details

Named energy peer group

Organizations within the Towers Watson 2013 Energy Compensation Survey were selected based on the following criteria:

- Electricity or gas organizations
- Vertically integrated electricity company
- Energy company operating solely in Ontario
- The OPA and IESO

%HORZ LV 7RURQWR +\GUR¶V QDPHG SHHU JURXS IURP 7RZHUV :DWVR Survey:

ATCO Electric	Ontario Power Generation
AlttaLink	Saskpower
British Columbia Hydro and Power Authority	Spectra Energy Transmission
Bruce Power	TransCanada
City of Medicine Had (Hydro Division)	Independent Electricity System Operator
Enbridge Inc.	New Brunswick Power Corporation
Enmax Corporation	Newfoundland & Labrador Hydro Electric Corporation
EPCOR Utilities	Nova Scotia Power
Fortis Alberta	Ontario Power Authority
Hydro-Quebec	

Where we observed insufficient data availability from the above peer group, a whole sample energy survey peer group was used (see below).

Whole sample energy peer group

Agrium	Columbia Power	Ontario Power Generation
Alberta Energy Regulator	ConocoPhillips	Pembina Pipeline Corporation
Alliance Pipeline Ltd.	Devon Canada Corporation	Penn West Energy Trust
AltaLink Management	Dow Chemical	Powerex Corp.
Apache Canada Ltd.	Enbridge	Precision Drilling Trust
ARC Resources	Encana Corporation	Saskpower
ATCO Electric	Enmax Corporation	Shell Canada Limited
ATCO Energy Solutions	EPCOR Utilities	Siemens Canada
ATCO Gas	ExxonMobil	Spectra Energy
ATCO Group	ExxonMobil Business Support Centre Canada	Statoil Canada
ATCO Pipelines	FortisAlberta	Suncor Energy
ATCO Power	Gaz Metro	Syncrude Canada Ltd.
Aux Sable Canada	GDF SUEZ Energy North America	Talisman Energy
BP Canada Energy Company	Husky Energy	Tenaris Canada
British Columbia Hydro and Power Authority	Hydro-Québec	Toronto Hydro Electric Systems
Bruce Power	Imperial Oil Limited	TransAlta Corporation
Canadian Natural Resources Limited	INEOS Canada Partnership	TransCanada
Canadian Oil Sands	Irving Oil Commercial G.P	Valero Energy
Canexus Corporation	Kinder Morgan Canada (Pipelines)	Weatherford International
Capital Power Corporation	MEG Energy	Williams Companies
Cenovus Energy	Nexen	Ontario Power Generation
Chevron Canada Limited (Downstream)	NextEra Energy, Inc.	
Chevron Canada Resources (Upstream)	Niko Resources	
City of Medicine Hat (Hydro Division)	NOVA Chemicals Corporation	

Named general industry peer group

Organizations within the Towers Watson 2013 General Industry MMPS Survey were chosen based upon the following criteria:

- Located within the GTA
- Organizations of comparable size ((e.g. revenues between $1B and $5B) to THESL; and
- A headcount between of 1000 to 2000 employees

%HORZ LV 7RURQWR +\GUR¶V QDPHG SHHU JURXS IURP 7RZHUV :DWVR Survey:

Allstate	Fortis Alberta	Ontario Power Generation
AstraZeneca	General Electric Canada	Owens Corning Canada
ATCO Electric	Graham Group Ltd.	PCL Constructors
AlttaLink	Homes by Avi Canada Inc.	Saskpower
British Columbia Hydro and Power Authority	Huskey Injection Molding Systems Ltd.	Siemens Canada Lts.
Bruce Power	Hydro-Quebec	SNC Lavalin Group Inc.
Cadillac Fairview Corporation Limited	Ledcor Group of Companies	Spectra Energy Transmission
Cisco Systems	Lehich Hanson Canada	State Farm Insurance
City of Medicine Had (Hydro Division)	Mattamy Homes Limited	The Shaw Group Ltd
Enbridge Inc.	Microsoft	TransCanada
Enmax Corporation	Northbridge	Unilever
EPCOR Utilities	Omicron Canada Inc.	

Where we observed insufficient data availability from the above peer group, a whole sample General Industry survey peer group was used (a full listing of over 300 organizations can be provided separately if required).

Named Hay Group peer group

Organizations within the Hay Group 2013 Energy Industry Compensation Survey were selected based on the following criteria:

- Utility Sector Organizations with revenue above 205 million

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Bruce Power L.P.	Hydro One Brampton
Capital Power Corporation	Hydro One Inc.
Enersource Hydro Mississauga Inc	Hydro Ottawa Limited
Fortis Inc.	NB Power Holding Corporation
FortisAlberta Inc.	Newfoundland Power Inc.
FortisBC Energy Inc.	Ontario Power Generation Inc.
FortisBC Inc.	SaskEnergy Incorporated
GDF SUEZ Energy North America, Inc.	SaskPower

Benefits peer group criteria

Organizations within the Towers Watson 2013 Benefits Data Source were selected based on the following criteria:

- Electricity or gas organizations
- Vertically integrated electricity company
- Energy company operating solely in Ontario

%HORZ LV 7RURQWR+\GUR¶V SHHUV JURXS IURP 7RZHUV :DWVRQ¶V %HQH

Alberta Electric System Operator	Fortis Alberta
AltaLink Management Ltd.	Hydro One
ATCO Group	Hydro-Quebec
British Columbia Hydro and Power Authority	Independent Electricity System Operator
Bruce Power	Manitoba Hydro
Capital Power Generation	Newfoundland Power Inc.
City of Medicine Hat	Ontario Power Generation Inc.
Emera Inc.	Saskpower
Enbridge Pipelines Inc.	TransAlta Corporation
ENMAX Corporation	TransCanada Pipelines Limited
EPCOR Utitlities Inc.	

Appendix 2: In-Scope Jobs

³ ,-QVFRSH´ MREV WKRVH LQFOXGHG ZHUH FDUHIXOO\ VHOHFWHG IURP WKH UHYLHZ SURYLGHG UHSUHVHQWDWLYH HPSOR\HH SRSXODWLRQ 7KURXJKRXW WKH SURFHVV group of jobs have been deliberately excluded from the scope of the review, Toronto Hydro acted on the advice of Towers Watson in ensuring that in-scope jobs did not disproportionally focus on single incumbent positions (this would weaken the extent to which the review of findings are representative of the whole organization) or include positions that are unique to Toronto Hydro and that do not have external data availability.

To guide the selection of in-scope jobs, Toronto Hydro followed two additional guidelines:

- Both corporate and operational positions
- Management, unionized, and individual contributor jobs
- Multiple incumbent jobs (i.e., single jobs that cover a population of 5 or more employees)
- Positions at each level in the organization
- Jobs across multiple functions to ensure no functional bias

,W LV 7RZHUV :DWVRQ¶V view that the jobs listed below provide an accurate reflection of the broader compensation and benefits picture at Toronto Hydro. They represent a group of driver SRVLWLRQV DQG FRYHU RI 7RURQWR +\GUR¶V HPSOR\HH-SRSXODWLRQ 75%) that we typically encourage our clients to strive for.

In scope positions are listed below:

#	Title	Current Grade
1	Director, Employee/Labour Relations	Y3
2	Director, Strategy & Enterprise Risk Management	Y3
3	Director, Power System Services	Y3
4	Controller	Y3
5	Director, Program Support Office	Y3
6	Director, IT Security, Architecture & Infrastructure Operations	Y3
7	Director, Environmental Health & Safety	Y3
8	Director, Legal Services & Corporate Secretary	Y3
9	Director, Rates & Regulatory Affairs	Y3
10	Director, Internal Audit	Y3
11	Manager, Call Centre	Y2
12	Manager, Talent Acquisition	Y2
13	Manager, Rates	Y2
14	Manager, Finance Operations	Y2
15	Manager, Project Management	Y2
16	Senior Litigation Counsel	X1
17	Lead, Regulatory Counsel	X1
18	Lead, Corporate Applications	W4
19	Lead, Legal Services, Commercial	W4
20	Lead, Project Management	W4

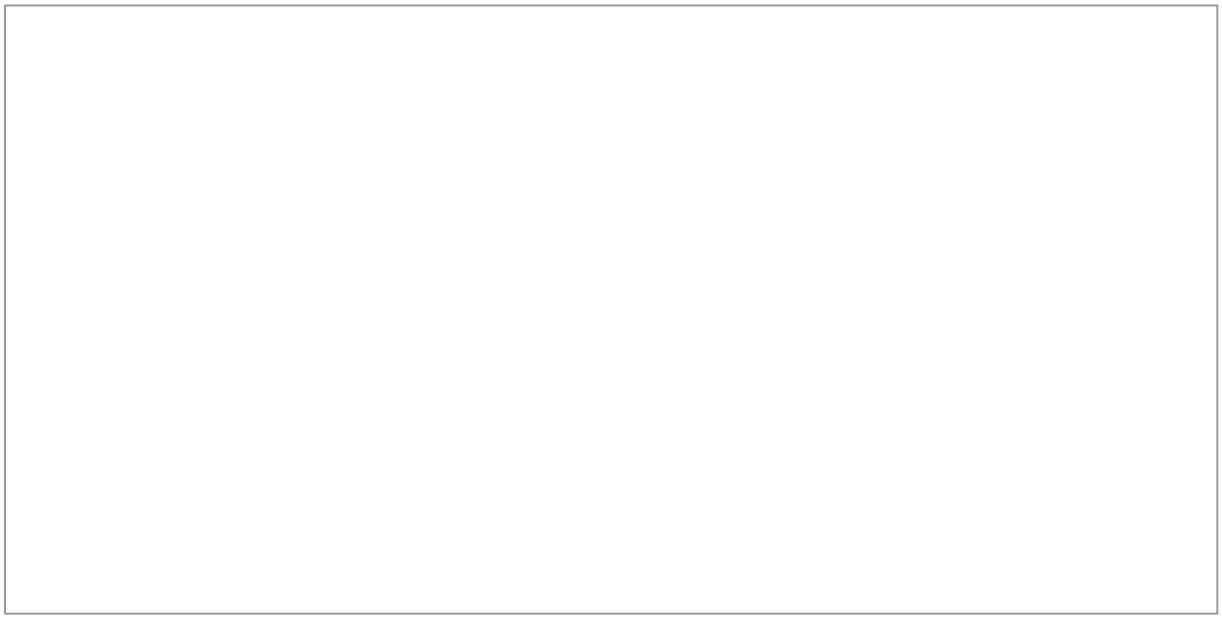
#	Title	Current Grade
21	Supervisor, Project Planning	W4
22	Supervisor, Facilities	W3
23	Supervisor, Supply Chain Services	W3
24	Supervisor, Construction & Maintenance	W3
25	Supervisor Program Management Office	W3
26	Supervisor, Design	W3
27	Supervisor, Call Centre	W2
28	Architect, Database & Integration	V4
29	Enterprise Project Management Consultant	V3
30	IT Technical Consultant	V3
31	Senior Financial Analyst	V3
32	Employee Labour Relations Consultant	V3
33	Safety & Environmental Consultant	V3
34	Senior Internal Auditor	V3
35	Strategic Planning Consultant	V3
36	Solicitor, Commercial	V3
37	Regulatory Counsel	V3
38	Program Management Consultant	V2
39	Communications Consultant	V2
40	Financial Analyst	V2

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#	Title	Current Grade
41	Talent Acquisition Consultant	V2
42	Claims Investigation Specialist	V1
43	Quality Assurance Associate	U3
44	Research Analyst	U3
45	Environmental Health & Safety Associate	U3
46	Payroll Analyst	U2
47	Staffing Associate	U2
48	Enterprise Risk Management & Policy Administration Analyst	U2
49	Executive Assistant	U1
50	Marketing Coordinator	U1
51	Service Requisition & ID Security Coordinator	U1
52	Desk Side Support	U1
53	Claims Administrator	T2
54	Organizational Development Administrator	T1
55	Administrative Assistant	T1
56	Engineer	SOCIETY
57	Senior Office Clerk 1	CUPE
58	Certified Meter Mechanic / Tester	CUPE
59	Certified Power Cable Person	CUPE
60	Crew Leader, Certified Power Cable	CUPE

#	Title	Current Grade
61	Customer Service Representative	CUPE
62	Distribution System Technologist	CUPE
63	Engineering Technologist Level 1	CUPE
64	Engineering Technologist Level 2	CUPE
65	Power System Controller	CUPE

Entire benefit program by plan: Employer provided value



Entire benefit program by plan: Total provided value



Appendix 4: Collective agreement data

	Toronto Hydro Annualized Base Pay	Collective Agreement Data (Annualized core wage rates)	*Compa-Ratio*
MIN	**$62,326**	$52,782	*18%*
AVERAGE	**$87,796**	$83,589	*5%*
MAX	**$106,309**	$121,634	*-13%*
25th Percentile	**$81,536**	$77,082	*6%*
50th Percentile	**$86,258**	$83,742	*3%*
75th Percentile	**$97,166**	$90,542	*7%*

Core wage rates for the following roles are included in the above data which is based on analysis of collective agreement data findings presented to Towers Watson by Toronto Hydro:

Toronto Hydro Job Title
Certified Power Line Person
Certified Power Cable Person
Certified Crew Leader, Line
Crew Leader, CPCP
Distribution System Technologist
System Response REP
Power System Controller
CPSL Dispatcher
Certified Meter Mechanic/Tester
Engineering Technologist - Level 1
Engineering Technologist - Level 2

Note: Annualized base pay and annualized core wage rates are calculated taking hourly rate x 2080 hours. Collective agreement data has been provided by Toronto Hydro, rendering results from 19 companies in total.

Organization
BC Hydro
Enersouce
Enmax
Epcor
Fortis Hydro
Horizon
Hydro One
Hydro One Brampton
Hydro Ottawa
Hydro Quebec
London Hydro
New Brunswick Power
Nova Scotia Power
Oakville Hydro
Oshawa
PowerStream
Veridian

Note: Organizations reported data for each role as applicable ±i.e., not all organizations reported data for all jobs

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January 16, 2014

Mr. Daniel Paquin
Toronto Hydro
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Dan:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2013 YEAR END DISCLOSURES AND ESTIMATED 2014 AND 2015 NET PERIODIC COST UNDER US GAAP

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on long-term disability;
- Dental benefits for retirees and members on long-term disability;
- Life insurance benefits for retirees;
- Vested sick leave benefits;
- OMERS top up pension; and
- Executive retirement allowances.

This letter and appendices have been prepared for the Company for the following purposes:

- Determining the final calculation of the 2013 net periodic benefit cost to be reported in the Company's 2013 financial statements;

- Providing the required information for year-end disclosure purposes as of December 31, 2013 to be reported in the Company's 2013 financial statements; and

- Determining an estimate of 2014 and 2015 net periodic benefit cost.

The information contained in this letter and appendices is presented in thousands of Canadian dollars and is in respect of the benefits mentioned above only.

All valuation results and accounting calculations presented in this letter and appendices were prepared in accordance with US GAAP (FASB Accounting Standards Codification 715).

The 2013 net periodic benefit cost is based on the 2013 net periodic benefit cost provided in our 2012 disclosure letter dated January 13, 2013, with updates for immediate recognition of the impact of the retirement allowance. The 2013 year-end disclosure obligations and extrapolations for 2014 and 2015 are based on the January 1, 2012 actuarial valuation conducted by Towers Watson.

In 2013, the Company chose to include an obligation in respect of two retiree allowances granted to one key employee. As directed by the company, the impact of this change was recognized as part of the service cost in expense as at June 30, 2013 in the financial accounting for the Plans under US GAAP for the Toronto Hydro Corporation division. Please refer to our email dated July 18, 2013 for additional information.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2012 actuarial valuation report prepared by Towers Watson for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuation.

ACTUARIAL ASSUMPTIONS AND METHODS

- The measurement date used for fiscal 2013 year-end disclosure is December 31, 2013.
- The 2013 benefit cost is based on a discount rate of 4.25% per annum and the accrued benefit obligation ("ABO") at December 31, 2013 is based on a discount rate of 4.75% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2012 and at December 31, 2013, respectively.
- Other than those noted in this letter, the actuarial methods and assumptions used for the determination of the 2013 net periodic benefit cost and the December 31, 2013 obligation are consistent with those used for the 2012 disclosures.
- The obligation as of December 31, 2013 and the 2014 and 2015 expense estimates are based on extrapolations from the January 1, 2012 valuation results for the medical, dental, life insurance, sick leave and OMERS benefit plans, and the June 30, 2013 valuation results for the retirement allowance benefit plans, assuming that there are no experience gains and losses other than from actual benefit payments being different from expected, and reflecting changes in the assumptions during the extrapolation period such as changes in the discount rate.

DISCLOSURE RESULTS SUMMARY

The summary of Fiscal 2013 net periodic benefit costs, the ABO and accumulated other comprehensive income ("AOCI") as at December 31, 2013, under US GAAP are as follows (in $000s):

	Fiscal 2013 Net Periodic Benefit Costs	ABO at December 31, 2013	AOCI at December 31, 2013
Toronto Hydro-Electric System Limited	$ 17,347	$ 232,669	$ 39,630
Toronto Hydro Corporation	341	2,233	(1,300)
Toronto Hydro-Energy Service Incorporation	259	2,811	359
Toronto Hydro-LDC Unregulated	105	1,079	92
Toronto Hydro – Consolidated	18,052	238,792	38,781

- Actual benefit payments for 2013 of $10,432,000 are based on information provided by the Company on January 9, 2013. We have projected 2014 and 2015 benefit payments based on the valuation assumptions.

ACCOUNTING METHODS

- Actuarial gains and losses will be reflected in the statement of comprehensive income. To the extent that they exceed 10% of the accumulated benefit obligation, these gains and losses will be recognized over the expected average remaining service period of active employees participating in the plans.

- Prior service costs will be reflected in the statement of comprehensive income, and recognized through expense over a straight line basis over the average service period (to full eligibility) of employees active at the date of amendment.

OTHER COMMENTS

- We understand that the post-retirement benefit plan is not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.

- A draft report on Canadian Pensioners Mortality has been published by the Canadian Institute of Actuaries. We understand that the Company will assess the appropriateness of the new mortality tables when the report is released.

- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2012 for the all benefit plans other than the retirement allowance, and since June 30, 2013 for the retirement allowance, that would materially affect the results of our valuations.

* * * * *

ACTUARIAL CERTIFICATION

The consulting actuaries are members of the Canadian Institute of Actuaries and Society of Actuaries and other professional actuarial organizations and meets their "General Qualification Standard for Statements of Actuarial Opinions" relating to pension and other postretirement benefit plans.

In preparing the results presented in this letter (including attached exhibits), we have relied upon information provided to us regarding plan provisions, actual benefit payments, historical plan costs and plan participants. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this letter is dependent upon the accuracy and completeness of the underlying information.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

The actuarial assumptions and the accounting policies and methods employed in the development of the pension and postretirement plan costs have been selected by the Toronto Hydro management as representing their best estimates of future contingent events. The assumptions are not intended to include any provision for adverse deviations, and we do not express any opinion of them. FASB ASC 715 requires that each significant assumption "individually represent the best estimate of a particular future event."

The results shown in this letter have been developed based on actuarial assumptions that are considered to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

* * * * *

The information contained in this report was prepared for Toronto Hydro, for its internal use and for the preparation of its periodic financial disclosures, and its auditors, for the preparation of its periodic financial disclosures. It is neither intended nor necessarily suitable for other purposes. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited with Towers Watson's prior written consent.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Towers Watson

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Enclosures

cc: Olga Baliakina, Mitchell Coviensky • Towers Watson

Post-Employment Benefits Plan - US GAAP - 2013 Disclosure ($'000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Funded status			January 01, 2013		
Funded status	(247,777)	(2,076)	(2,928)	(1,109)	(253,890)
Current vs. Non-Current OPEB Liability			January 01, 2013		
Current	(9,790)	(79)	(37)	(19)	(9,925)
Non-Current Liability	(237,987)	(1,997)	(2,891)	(1,090)	(243,965)
Total	(247,777)	(2,076)	(2,928)	(1,109)	(253,890)
Amounts Recognized in Accumulated Other Comprehensive Income			January 01, 2013		
Prior service (credit)/cost					
July 2000 past service costs	r		(5) r		(5)
Jan 2001 past service costs	r		r	r	r r
Jan 2003 past service costs	2	1	24		27
Net actuarial (gain)/loss	61,821	(1,195)	656	195	61,477
Total	61,823	(1,194)	675	195	61,499
Change in Accumulated Benefit Obligation (ABO)			2013		
Accumulated benefit obligation at beginning of year	247,777	2,076	2,928	1,109	253,890
Service cost	4,766	312	98	50	5,226
Interest cost	10,521	94	128	49	10,792
Actuarial (gain) loss	(20,133)	(171)	(283)	(97)	(20,684)
Benefits paid	(10,262)	(78)	(60)	(32)	(10,432)
Accumulated benefit obligation at end of year	232,669	2,233	2,811	1,079	238,792
Change in Plan Assets			2013		
Fair value of plan assets at beginning of year	r		r	r	r r
Actual return on plan assets	r		r	r	r r
Employer contribution	10,262	78	60	32	10,432
Plan participants' contributions	r		r	r	r r
Benefits paid	(10,262)	(78)	(60)	(32)	(10,432)
Fair value of plan assets at end of year	r		r	r	r r
Net Periodic Benefit Cost			2013		
Service cost	4,766	312	98	50	5,226
Interest cost	10,521	94	128	49	10,792
Amortization of prior service cost					r
July 2000 past service costs	r		(3) r		(3)
Jan 2001 past service costs	r		r	r	r r
Jan 2003 past service costs	2	1	8		11 r
Amortization of net (gain) loss	2,058	(66)	28	6	2,026
Net periodic benefit cost	17,347	341	259	105	18,052
Funded status			December 31, 2013		
Funded status	(232,669)	(2,233)	(2,811)	(1,079)	(238,792)
Current vs. Non-Current OPEB Liability			December 31, 2013		
Current	(7,855)	(88)	(39)	(21)	(8,003)
Non-Current Liability	(224,814)	(2,145)	(2,772)	(1,058)	(230,789)
Total	(232,669)	(2,233)	(2,811)	(1,079)	(238,792)
Amounts Recognized in Accumulated Other Comprehensive Income			December 31, 2013		
Prior service (credit)/cost					
July 2000 past service costs	r		(2) r		(2)
Jan 2001 past service costs	r		r	r	r r
Jan 2003 past service costs	r		16 r		16
Net actuarial (gain)/loss	39,630	(1,300)	345	92	38,767
Total	39,630	(1,300)	359	92	38,781
Additional information					
Average future working lifetime as at December 31, 2013	18	15	13	15	
Average future working lifetime as at December 31, 2012	18	15	13	15	
Key Asumptions					
Discount rate as at December 31, 2013 (used for Dec 31/13 ABO)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate as at December 31, 2012 (used for 2013 Benefit Costs)	4.25%	4.25%	4.25%	4.25%	4.25%
Assumed medical and dental cost trend rate at December 31, 2013					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Medical cost trend rate assumed for next year	6.0%	6.0%	6.0%	6.0%	6.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Medical cost trend rate assumed for next year	7.5%	7.5%	7.5%	7.5%	7.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2013					
1% point increase	2,308	(28)	40	19	2,339
1% point decrease	(2,031)	18	(35)	(15)	(2,063)
Effect on accrued benefit obligation at December 31, 2013					
1% point increase	29,559	206	458	165	30,388
1% point decrease	(25,931)	(185)	(401)	(147)	(26,664)
Sensitivity to Changes in Discount Rate Assumption					
Effect on estimated 2014 Net Periodic Benefit Cost					
1% point increase	(1,701)	(76)	(29)	(12)	(1,818)
1% point decrease	2,907	92	67	30	3,096
Effect on accrued benefit obligation at December 31, 2013					
1% point increase	(35,997)	(330)	(523)	(191)	(37,041)
1% point decrease	44,170	400	655	244	45,469
Projection of Benefit Payments					
2014	8,039	90	40	22	8,191
2015	8,238	96	44	25	8,403
2016	8,912	99	51	28	9,090
2017	9,354	100	57	30	9,541
2018	9,852	164	66	30	10,112
2019-2023	57,910	705	579	200	59,394

Post-Employment Benefits Plan - US GAAP - 2014 Estimate Expense ($'000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Funded status			January 1, 2014		
Funded status	(232,669)	(2,233)	(2,811)	(1,079)	(238,792)
Amounts Recognized in Accumulated Other Comprehensive Income			January 1, 2014		
Prior service (credit)/cost					
July 2000 past service costs			(2)		(2)
Jan 2001 past service costs					
Jan 2003 past service costs			16		16
Net actuarial (gain)/loss	39,630	(1,300)	345	92	38,767
Total	39,630	(1,300)	359	92	38,781
Change in Accumulated benefit obligation			2014		
Accumulated benefit obligation at beginning of year	232,669	2,233	2,811	1,079	238,792
Service cost	4,354	189	89	46	4,678
Interest cost	11,068	113	137	53	11,371
Actuarial (gain) loss					
Benefits paid	(8,039)	(90)	(40)	(22)	(8,191)
Accumulated benefit obligation at end of year	240,052	2,445	2,997	1,156	246,650
Change in plan assets			2014		
Fair value of plan assets at beginning of year					
Actual return on plan assets					
Employer contribution	8,039	90	40	22	8,191
Plan participants' contributions					
Benefits paid	(8,039)	(90)	(40)	(22)	(8,191)
Fair value of plan assets at end of year					
Net Periodic Benefit Cost			2014		
Service cost	4,354	189	89	46	4,678
Interest cost	11,068	113	137	53	11,371
Amortization of prior service cost					
July 2000 past service costs			(2)		(2)
Jan 2001 past service costs					
Jan 2003 past service costs			8		8
Amortization of net (gain) loss	909	(72)	5		842
Net periodic benefit cost	16,331	230	237	99	16,897
Funded status			December 31, 2014		
Funded status	(240,052)	(2,445)	(2,997)	(1,156)	(246,650)
Current vs. Non-Current OPEB Liability			December 31, 2014		
Current	(8,049)	(94)	(43)	(24)	(8,210)
Non-Current Liability	(232,003)	(2,351)	(2,954)	(1,132)	(238,440)
Total	(240,052)	(2,445)	(2,997)	(1,156)	(246,650)
Amounts Recognized in Accumulated Other Comprehensive Income			December 31, 2014		
Prior service (credit)/cost					
July 2000 past service costs					
Jan 2001 past service costs					
Jan 2003 past service costs			8		8
Net actuarial (gain)/loss	38,721	(1,228)	340	92	37,925
Total	38,721	(1,228)	348	92	37,933
Additional information					
Average future working lifetime as at December 31, 2013	18	15	13	15	
Key Asumptions					
Discount rate as at December 31, 2014 (used for Dec 31/14 APBO)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate as at December 31, 2013 (used for 2014 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%
Assumed medical and dental cost trend rate at December 31, 2013					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Medical cost trend rate assumed for next year	5.5%	5.5%	5.5%	5.5%	5.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Medical cost trend rate assumed for next year	7.0%	7.0%	7.0%	7.0%	7.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019

Post-Employment Benefits Plan - US GAAP - 2015 Estimate Expense ($'000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated	
Funded status			January 1, 2015			
Funded status	(240,052)	(2,445)	(2,997)	(1,156)	(246,650)	
Amounts Recognized in Accumulated Other Comprehensive Income			January 1, 2015			
Prior service (credit)/cost						
July 2000 past service costs	r		r	r	r	r
Jan 2001 past service costs	r		r	r	r	r
Jan 2003 past service costs	r		8 r		8	
Net actuarial (gain)/loss	38,721	(1,228)	340	92	37,925	
Total	38,721	(1,228)	348	92	37,933	
Change in Accumulated benefit obligation			2015			
Accumulated benefit obligation at beginning of year	240,052	2,445	2,997	1,156	246,650	
Service cost	4,528	197	93	48	4,866	
Interest cost	11,422	123	146	57	11,748	
Actuarial (gain) loss	r		r	r	r	r
Benefits paid	(8,238)	(96)	(44)	(25)	(8,403)	
Accumulated benefit obligation at end of year	247,764	2,669	3,192	1,236	254,861	
Change in plan assets			2015			
Fair value of plan assets at beginning of year	r		r	r	r	r
Actual return on plan assets	r		r	r	r	r
Employer contribution	8,238	96	44	25	8,403	
Plan participants' contributions	r		r	r	r	r
Benefits paid	(8,238)	(96)	(44)	(25)	(8,403)	
Fair value of plan assets at end of year	r		r	r	r	r
Net Periodic Benefit Cost			2015			
Service cost	4,528	197	93	48	4,866	
Interest cost	11,422	123	146	57	11,748	
Amortization of prior service cost						
July 2000 past service costs	r		r	r	r	r
Jan 2001 past service costs	r		r	r	r	r
Jan 2003 past service costs	r		8 r		8	
Amortization of net (gain) loss	818	(66)	3		755	
Net periodic benefit cost	16,768	254	250	105	17,377	
Funded status			December 31, 2015			
Funded status	(247,764)	(2,669)	(3,192)	(1,236)	(254,861)	
Current vs. Non-Current OPEB Liability			December 31, 2015			
Current	(8,708)	(97)	(50)	(27)	(8,882)	
Non-Current Liability	(239,056)	(2,572)	(3,142)	(1,209)	(245,979)	
Total	(247,764)	(2,669)	(3,192)	(1,236)	(254,861)	
Amounts Recognized in Accumulated Other Comprehensive Income			December 31, 2015			
Prior service (credit)/cost						
July 2000 past service costs	r		r	r	r	r
Jan 2001 past service costs	r		r	r	r	r
Jan 2003 past service costs	r		r	r	r	r
Net actuarial (gain)/loss	37,903	(1,162)	337	92	37,170	
Total	37,903	(1,162)	337	92	37,170	
Additional information						
Average future working lifetime as at December 31, 2013	18	15	13	15		
Key Asumptions						
Discount rate as at December 31, 2015 (used for Dec 31/15 APBO)	4.75%	4.75%	4.75%	4.75%	4.75%	
Discount rate as at December 31, 2014 (used for 2015 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%	
Assumed medical and dental cost trend rate at December 31, 2013						
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%	
For pre July 2000 retirements:						
Medical cost trend rate assumed for next year	5.0%	5.0%	5.0%	5.0%	5.0%	
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%	
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016	
For other retirements:						
Medical cost trend rate assumed for next year	6.5%	6.5%	6.5%	6.5%	6.5%	
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%	
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019	

SHARED SERVICES AND CORPORATE COSTS ALLOCATIONS

In accordance with s. 2.7. 3.2 of the OEB's Filing Requirements (July 17, 2013), this schedule provides information about shared services and corporate costs allocations between Toronto Hydro and the affiliated corporate entities described below. For more information about these entities and their relationship to Toronto Hydro, please refer to Corporate Structure and Governance evidence at Exhibit 1C, Tab 2, Schedule 1:

- Toronto Hydro Corporation ("THC") – THC provides strategic direction, leadership and communication to Toronto Hydro and Toronto Hydro Energy Services Inc. ("TH Energy"). Based on THC's 2013 financial statements compiled by its auditors, its investment in Toronto Hydro represents 97 percent of its total long-term investments. THC receives shared corporate services from Toronto Hydro, and provides such services to Toronto Hydro as described above.
- TH Energy – TH Energy's primary line of business is the provision of street lighting and expressway lighting maintenance and operation services to the City of Toronto, but the company also holds electricity retailer and generator licenses. TH Energy receives shared corporate services from Toronto Hydro, and provides Toronto Hydro with emergency services including storm damage response and project design support services.

This schedule provides information about corporate cost allocations to the non-rate regulated aspects of Toronto Hydro's business (referred to as "THESU"), including Conservation Demand Management ("CDM") and generation activities. From 2012 to 2014, Toronto Hydro's non-rate regulated line of business also included activities pertaining to the former street lighting assets that were transferred to Toronto Hydro on January 1, 2012, but that were not included in the utility's rate base. Toronto Hydro proposes to transfer these assets into rate base effective January 1, 2015. Please refer to

Exhibit 2A, Tab 5 for more information about the proposed transfer of the former street lighting assets into the utility's rate base.

1. OEB APPENDIX 2-N

A completed copy of OEB Appendix 2-N is filed at Exhibit 4A, Tab 5, Schedule 2. This appendix provides cost information and allocation details relating to each shared service provided or received by Toronto Hydro in the historical years (2011 to 2013), the bridge year (2014) and the test year (2015). The amount of Board of Directors related costs included in THC's cost allocation to Toronto Hydro is also provided in this appendix.

2. SHARED SERVICE MODEL

Toronto Hydro's shared services methodology has not changed since the utility's last rebasing application (EB-2010-0142).

Each service transaction is reviewed to determine the costing formula and method of allocation. In establishing the price of a service transaction, Toronto Hydro follows the Affiliate Relationships Code ("ARC"). The ARC provides for the use of fully allocated cost based pricing ("CBP") for shared corporate services, and the use of fair market value ("FMV"), where a reasonably competitive market exists.

If a competitive market does not exist, Toronto Hydro uses fully-allocated cost-based pricing. With regard to these fundamental principles and historical information about the quantity of services provided, Toronto Hydro assesses the approximate annual cost of each service. At the end of the fiscal year, the estimated cost of providing or receiving each service is reconciled with actuals and any differences are settled.

Table 1, below provides a description of Toronto Hydro's corporate cost allocators by each functional service:

Table 1: Shared Corporate Services Primary Allocation Drivers

Functional service	Allocator	Reason
Finance (other than payroll, accounts payable, insurance)	Time allocation	Financial support, analysis, planning, calculations and reports provided for certain affiliates are more labour intensive than others.
Finance – Payroll	Headcount	Amount of payroll services required such as processing is dependent on the number of employees.
Finance –Accounts Payable	Invoices	Amount of accounts payable services required such as processing is dependent on the number of invoices.
Finance – Insurance	Usage proportion	Amount of insurance required is dependent on the coverage required.
Health and Safety	Union headcount	Services are mainly required for unionized positions as these positions typically are required to perform field work.
Information Technology & Services	By employee	Required equipment and IT services are dependent on the number of employees who need equipment/services.

Functional service	Allocator	Reason
Legal	Billable hours	Legal services and support for some affiliates are more labour intensive than others.
Organizational Effectiveness ("OE") (other than Talent Management and Administration)	Headcount	Amount of OE services required such as compensation/benefits related services is dependent on the number of employees.
OE – Talent Management and Administration	Time allocation	Services provided to certain affiliates are more labour intensive than others.
Procurement	Number of purchase orders	Amount procured for each affiliate is dependent on the number of purchase orders.
Facilities	Square footage	Amount of building space required is measured in square foot.
THC – CEO, CFO, Board of Directors	Time allocation	Services provided to certain affiliates are more labour intensive than others.

For other services, Toronto Hydro uses market price, if a reasonably competitive market exists for the service, and if it is practicable and cost efficient to undertake a market value assessment for the service.

If market price can be determined, Toronto Hydro charges the higher of fully-allocated cost or market price for any non-shared corporate services that it provides to the affiliated entities, and pays the lower of fully-allocated cost or market price for any such services that its receives from the affiliated entities.

If a market price cannot be determined, Toronto Hydro applies a fully allocated cost-based pricing, which includes direct costs, indirect cost and cost of capital, to determine the cost of providing or receiving the non-shared corporate service.

3. VARIANCE ANALYSIS

3.1. TH Energy

Further to Appendix 2-N, filed at Exhibit 4A, Tab 5, Schedule 2, the table below provides a summary of the cost of shared services provided to and received by Toronto Hydro from TH Energy. A variance analysis between 2011 actuals and 2015 test year amounts, as well as 2013 actuals and 2014 test year amounts is included after the table.

Table 2: Summary of the Cost of Shared Services Provided to and Received by Toronto Hydro from TH Energy ($ Millions)

	2011 OEB	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Services provided by Toronto Hydro	1.6	1.6	1.7	1.8	1.8	1.9
Services received by Toronto Hydro	0	0.2	0.5	0.8	0.5	0.5

3.1.1. 2011 Actual v. 2015 Test Year

- Services Provided by Toronto Hydro: The $0.3 million variance between 2011 actual amounts and the 2015 test year forecasted amounts is primarily driven by an: 1) increase in Human Resources and Organizational Effectiveness services required to support additional recruitment activities; and 2) an increase in the

forecasted cost of providing finance services is consistent with Toronto Hydro's Finance program (Exhibit 4A, Tab 2, Schedule 15).

- Services Received by Toronto Hydro: The $0.3 million variance between 2011 actual amounts and the 2015 test year forecasted amounts is primarily attributable to the provision of design services by TH Energy to Toronto Hydro. In 2011, TH Energy mainly provided emergency services to Toronto Hydro.

3.1.2. 2013 Actual v. 2015 Test Year

- Services Provided by Toronto Hydro: The $0.1 million variance from the 2013 actual amounts and the 2015 test year forecasted amounts is primarily attributable to an increase in allocated fleet services costs.
- Services Received by Toronto Hydro: The $0.3 million variance from the 2013 actual amounts and the 2015 test year forecasted amounts is primarily associated with the provision of emergency services during the December 2013 ice storm.

3.2. Non-Rate Regulated Toronto Hydro Activities

Further to Appendix 2-N, filed at Exhibit 4A, Tab 5, Schedule 2, the table below provides a summary of the cost of shared services relating to Toronto Hydro's non-rate regulated activities (i.e., CDM, generation, and street lighting assets from 2012 to 2015). A written variance analysis is provided after the table.

Table 3: Summary of the Cost of Services relating to Non-Rate Regulated Toronto Hydro activities ($ Millions)

	2011 OEB	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Services provided by Toronto Hydro	0.6	1.0	0.9	1.4	1.5	1.3

3.2.1. 2011 Actual v. 2015 Test Year

For non-rate regulated Toronto Hydro activities, the increase in the shared corporate services allocation between 2011 actual amounts and 2015 forecasts is primarily due to the following:

- the transfer of the former street lighting assets to Toronto Hydro on January 1, 2012 (refer to Exhibit 2A, Tab 5, Schedule 1 for more information about Toronto Hydro proposal to transfer these assets into the utility's rate base effective January 1, 2015);
- an increase in Human Resources and Organization Effectiveness services required to support additional recruitment activities; and
- an increase in Procurement services required due to an increase of purchase orders related to the street lighting transfer and CDM activities.

3.2.2. 2013 Actual v. 2015 Test Year

The $0.1 million variance from the 2013 actual amounts and the 2015 test year forecasted amounts is primarily due to the proposed transfer of the street lighting assets into the utility's rate base effective January 1, 2015.

3.3. THC

Further to Appendix 2-N, filed at Exhibit 4A, Tab 5, Schedule 2, the table below provides a summary of the cost of shared services provided to and received by Toronto Hydro from THC. A variance analysis between 2011 actuals and 2015 test year amounts, as well as 2013 actuals and 2014 test year amounts is included after the table .

Table 4: Summary of the Cost of Shared Services Provided to and Received by Toronto Hydro from THC ($ Millions)

	2011 OEB	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Services provided by Toronto Hydro	0.1	0.4	0.7	1.1	1.3	1.3
Services received by Toronto Hydro	2.0	3.1	3.7	4.3	4.1	4.2

3.3.1. 2011 Actual v. 2015 Test Year

- Services Provided by Toronto Hydro: The $0.9 million variance from the 2011 actual amounts and the 2015 test year forecasted amounts is primarily due to additional services provided related to finance, legal, and human resources & organizational effectiveness in 2015.
- Services Received by Toronto Hydro: The $1.1 million variance from the 2011 actual amounts and the 2015 test year forecasted amounts is primarily related to the increase in THC's costs before recoveries and related to additional governance and financial stewardship work performed by THC to support the increasing complexity of Toronto Hydro's regulated activities.

3.3.2. 2013 Actual v. 2015 Test Year

- Services Provided by Toronto Hydro: The $0.2 million variance from the 2013 actual amounts and the 2015 test year forecasted amounts is primarily attributable to an increase in the forecasted cost of providing legal services consistent with Toronto Hydro's Legal Services program (Exhibit 4A, Tab 2, Schedule 18).
- Services Received by Toronto Hydro: The $0.1 million variance from the 2013 actual amounts and the 2015 test year forecasted amounts is immaterial.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2011

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet	Fully allocated cost	0.42	0.42
THESL	THESI	Emergency Calls	Market**	0.17	0.15
THESI	THESL	Emergency	Market**	0.18	0.03

** Because of cost benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated cost	2.8%	0.50
THESL	THESI	EHS	Fully allocated cost	0.7%	0.02
THESL	THESI	Legal	Fully allocated cost	1.4%	0.07
THESL	THESI	HR&OE	Fully allocated cost	0.4%	0.04
THESL	THESI	Procurement	Fully allocated cost	5.5%	0.08
THESL	THESI	Consolidated Billing	Fully allocated cost	42.7%	0.12
THESL	THESI	IT&S	Fully allocated cost	0.2%	0.06
THESL	THESI	Facilities	Fully allocated cost	0.3%	0.06
THESL	THESU	Finance/Treasury/Insurance	Fully allocated cost	2.6%	0.47
THESL	THESU	Legal	Fully allocated cost	0.4%	0.02
THESL	THESU	HR&OE	Fully allocated cost	0.5%	0.07
THESL	THESU	Procurement	Fully allocated cost	3.7%	0.06
THESL	THESU	IT&S	Fully allocated cost	0.4%	0.12
THESL	THESU	Facilities	Fully allocated cost	1.0%	0.23
THESL	THC	Finance/Treasury/Insurance	Fully allocated cost	0.1%	0.01
THESL	THC	Legal	Fully allocated cost	4.9%	0.25
THESL	THC	Procurement	Fully allocated cost	0.3%	0.01
THESL	THC	IT&S	Fully allocated cost	0.1%	0.03
THESL	THC	Facilities	Fully allocated cost	0.3%	0.06
THC	THESL	Corporate Stewardship (CEO	Fully allocated cost	99.6%	1.85
THC	THESL	Corporate Governance (Board of Directors	Fully allocated cost	63.9%	0.20
THC	THESL	Finance Stewardship (CFO	Fully allocated cost	99.5%	1.09
THC	THESI	Corporate Governance (Board of Directors	Fully allocated cost	31.2%	0.10

Year: 2012

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESU	THESI	Fleet*	Fully allocated cost	0.30	0.30
THESU	THESI	Emergency Calls	Market**	0.32	0.27
THESI	THESU	Emergency	Market**	0.22	0.22
THESI	THESU	Sandy Storm	Market**	0.03	0.03
THESI	THESU	Design	Market**	0.25	0.25

* A portion of the fleet charge is allocated from THESU to THESI.

** Because of cost benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated cost	3.1%	0.47
THESL	THESI	EHS	Fully allocated cost	0.5%	0.01
THESL	THESI	Legal	Fully allocated cost	1.2%	0.06
THESL	THESI	HR&OE	Fully allocated cost	1.2%	0.14
THESL	THESI	Procurement	Fully allocated cost	5.0%	0.09
THESL	THESI	Consolidated Billing	Fully allocated cost	89.7%	0.14
THESL	THESI	IT&S	Fully allocated cost	0.2%	0.06
THESL	THESI	Facilities	Fully allocated cost	0.2%	0.06
THESL	THESU	Finance/Treasury/Insurance	Fully allocated cost	2.1%	0.32
THESL	THESU	Legal	Fully allocated cost	3.7%	0.17
THESL	THESU	HR&OE	Fully allocated cost	0.1%	0.01
THESL	THESU	Procurement	Fully allocated cost	8.4%	0.15
THESL	THESU	IT&S	Fully allocated cost	0.2%	0.08
THESL	THESU	Facilities	Fully allocated cost	0.7%	0.17
THESL	THC	Finance/Treasury/Insurance	Fully allocated cost	3.2%	0.49
THESL	THC	Legal	Fully allocated cost	1.8%	0.09
THESL	THC	Procurement	Fully allocated cost	0.4%	0.01
THESL	THC	IT&S	Fully allocated cost	0.1%	0.02
THESL	THC	Facilities	Fully allocated cost	0.2%	0.06
THC	THESL	Corporate Stewardship (CEO)	Fully allocated cost	100.0%	2.28
THC	THESL	Corporate Governance (Board of Directors)	Fully allocated cost	95.5%	0.33
THC	THESL	Finance Stewardship (CFO)	Fully allocated cost	100.0%	1.08
THC	THESI	Corporate Governance (Board of Directors)	Fully allocated cost	4.5%	0.02

Year: 2013

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated cost	0.26	0.26
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.34	0.34
THESI	THESL	Emergency	Market**	0.14	0.16
THESI	THESL	Ice Storm	Market**	0.27	0.30
THESI	THESL	Design	Market**	0.35	0.38

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated cost	3.3%	0.60
THESL	THESI	EHS	Fully allocated cost	0.5%	0.01
THESL	THESI	Legal	Fully allocated cost	0.9%	0.03
THESL	THESI	HR&OE	Fully allocated cost	1.6%	0.23
THESL	THESI	Procurement	Fully allocated cost	3.3%	0.10
THESL	THESI	Consolidated Billing	Fully allocated cost	65.8%	0.10
THESL	THESI	IT&S	Fully allocated cost	0.2%	0.06
THESL	THESI	Facilities	Fully allocated cost	0.2%	0.06
THESL	THESU	Finance/Treasury/Insurance	Fully allocated cost	2.0%	0.36
THESL	THESU	Legal	Fully allocated cost	1.1%	0.04
THESL	THESU	HR&OE	Fully allocated cost	1.8%	0.25
THESL	THESU	Procurement	Fully allocated cost	14.9%	0.47
THESL	THESU	IT&S	Fully allocated cost	0.2%	0.07
THESL	THESU	Facilities	Fully allocated cost	0.7%	0.17
THESL	THC	Finance/Treasury/Insurance	Fully allocated cost	3.2%	0.58
THESL	THC	Legal	Fully allocated cost	9.2%	0.33
THESL	THC	HR&OE	Fully allocated cost	0.9%	0.12
THESL	THC	Procurement	Fully allocated cost	0.4%	0.01
THESL	THC	IT&S	Fully allocated cost	0.02%	0.01
THESL	THC	Facilities	Fully allocated cost	0.2%	0.06
THC	THESL	Corporate Stewardship / CEO	Fully allocated cost	94.8%	2.66
THC	THESL	Corporate Governance / Board of Directors	Fully allocated cost	86.0%	0.26
THC	THESL	Finance Stewardship / CFO	Fully allocated cost	85.8%	1.33
THC	THESI	Corporate Governance / Board of Directors	Fully allocated cost	4.8%	0.01

Year: 2014

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated cost	0.44	0.44
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.27	0.23
THESI	THESL	Emergency	Market**	0.18	0.18
THESI	THESL	Design	Market**	0.30	0.30

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated cost	3.3%	0.64
THESL	THESI	EHS	Fully allocated cost	0.7%	0.02
THESL	THESI	Legal	Fully allocated cost	0.9%	0.04
THESL	THESI	HR&OE	Fully allocated cost	1.7%	0.24
THESL	THESI	Procurement	Fully allocated cost	3.5%	0.08
THESL	THESI	IT&S	Fully allocated cost	0.2%	0.06
THESL	THESI	Facilities	Fully allocated cost	0.1%	0.03
THESL	THESU	Finance/Treasury/Insurance	Fully allocated cost	2.4%	0.47
THESL	THESU	Legal	Fully allocated cost	1.3%	0.06
THESL	THESU	HR&OE	Fully allocated cost	1.8%	0.26
THESL	THESU	Procurement	Fully allocated cost	14.6%	0.34
THESL	THESU	IT&S	Fully allocated cost	0.2%	0.06
THESL	THESU	Facilities	Fully allocated cost	1.0%	0.27
THESL	THC	Finance/Treasury/Insurance	Fully allocated cost	3.2%	0.62
THESL	THC	Legal	Fully allocated cost	10.5%	0.49
THESL	THC	HR&OE	Fully allocated cost	0.9%	0.13
THESL	THC	Procurement	Fully allocated cost	0.4%	0.01
THESL	THC	IT&S	Fully allocated cost	0.02%	0.01
THESL	THC	Facilities	Fully allocated cost	0.3%	0.07
THC	THESL	Corporate Stewardship (CEO)	Fully allocated cost	95.0%	2.75
THC	THESL	Corporate Governance (Board of Directors)	Fully allocated cost	90.0%	0.25
THC	THESL	Finance Stewardship (CFO)	Fully allocated cost	95.0%	1.09
THC	THESI	Corporate Governance (Board of Directors)	Fully allocated cost	5.0%	0.01

Year: 2015

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated cost	0.49	0.49
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.27	0.23
THESI	THESL	Emergency	Market**	0.18	0.18
THESI	THESL	Design	Market**	0.30	0.30

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated cost	3.2%	0.66
THESL	THESI	EHS	Fully allocated cost	0.7%	0.02
THESL	THESI	Legal	Fully allocated cost	0.8%	0.04
THESL	THESI	HR&OE	Fully allocated cost	1.8%	0.26
THESL	THESI	Procurement	Fully allocated cost	3.2%	0.08
THESL	THESI	IT&S	Fully allocated cost	0.2%	0.06
THESL	THESI	Facilities	Fully allocated cost	0.1%	0.02
THESL	THESU	Finance/Treasury/Insurance	Fully allocated cost	1.8%	0.37
THESL	THESU	Legal	Fully allocated cost	1.0%	0.05
THESL	THESU	HR&OE	Fully allocated cost	2.1%	0.31
THESL	THESU	Procurement	Fully allocated cost	13.0%	0.32
THESL	THESU	IT&S	Fully allocated cost	0.2%	0.07
THESL	THESU	Facilities	Fully allocated cost	0.8%	0.24
THESL	THC	Finance/Treasury/Insurance	Fully allocated cost	3.1%	0.63
THESL	THC	Legal	Fully allocated cost	10.2%	0.49
THESL	THC	HR&OE	Fully allocated cost	1.2%	0.17
THESL	THC	Procurement	Fully allocated cost	0.4%	0.01
THESL	THC	IT&S	Fully allocated cost	0.02%	0.01
THESL	THC	Facilities	Fully allocated cost	0.0%	n
THC	THESL	Corporate Stewardship CEO	Fully allocated cost	95.0%	2.87
THC	THESL	Corporate Governance Board of Directors	Fully allocated cost	90.0%	0.25
THC	THESL	Finance Stewardship CFO	Fully allocated cost	95.0%	1.06
THC	THESI	Corporate Governance Board of Directors	Fully allocated cost	5.0%	0.01

Note:

1 This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:

· Type of Service:

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

· Pricing Methodology:

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

· % Allocation:

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

DEPRECIATION AND AMORTIZATION

This schedule provides information about Toronto Hydro's depreciation and amortization policies and expenses.

1. BACKGROUND

In 2007, Toronto Hydro commenced its International Financial Reporting Standards ("IFRS") conversion project with the intention of converting to IFRS on January 1, 2011. However, given uncertainty around the timing, scope and potential adoption of a rate-regulated accounting standard under IFRS, Toronto Hydro decided to defer the adoption of IFRS, and filed its 2011 rebasing application (EB-2010-0142) in accordance with its Canadian Generally Accepted Accounting Principles ("CGAAP") accounting practices in use at that time.

Subsequent to filing the 2011 rebasing application, Toronto Hydro continued to develop its accounting practices and operational processes to comply with IFRS. The utility also continued to assess the effect of IFRS on both financial and regulatory reporting and whether certain IFRS practices, and new information resulting from the IFRS project, would have to be implemented under CGAAP. To that extent, based on the conclusion of the independent detailed review of the useful lives conducted by Kinectrics and other third-parties, Toronto Hydro implemented certain changes in accounting estimates related to the manner in which it records and accounts for its property, plant and equipment ("PP&E").[1] Although Toronto Hydro decided to defer the adoption of IFRS, it determined that these changes were required to be applied under CGAAP as additional and more relevant information had been made available.

[1] EB-2010-0142, Application and Evidence (February 9, 2011) at Exhibit Q1, Tab 2, Schedule 7-2; and EB-2010-0142, Partial Decision & Order, (July 7, 2011) at page 41.

The changes in the estimates of useful lives of assets were reflected in the corresponding depreciation and amortization balances in Toronto Hydro's financial statements effective January 1, 2011, and the utility's last rebasing application (EB-2010-0142).[2] Toronto Hydro's external auditor acknowledged the appropriateness of the changes in accounting estimates effective January 1, 2011 under CGAAP,[3] and the Ontario Energy Board ("OEB") approved, for rate-making purposes, the depreciation and amortization expense that resulted from these changes, effective May 1, 2011.[4]

2. FILING REQUIREMENTS

Section 2.7.4 of OEB's Filing Requirements (July 17, 2013) requires an applicant to file certain information if it expects to make regulatory accounting changes regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. Because Toronto Hydro adopted changes to its depreciation and capitalization policies effective January 1, 2011, as part of its last rebasing application,[5] it did not have to make any regulatory accounting changes upon adoption of MIFRS for the 2014 bridge and 2015 test year. Consequently, the utility determined that this part of the s. 2.7.4 requirement is not applicable to Toronto Hydro in this application.

In accordance with s. 2.7.4 of the Filing Requirements, in this schedule Toronto Hydro provides the following information:

1) details regarding the Depreciation, Amortization and Depletion by Asset Group for the 2011 to 2013 historical years, 2014 bridge year and 2015 test year;

[2] EB-2010-0142 Exhibit Q1, Tab 1, Schedule 1
[3] Toronto Hydro Corporation Consolidated Financial Statements December 31, 2011
[4] See EB-2010-0142, Partial Decision & Order (July 7, 2011), Appendix C (Settlement Agreement) at page 10 of 22; EB-2010-0142, Draft Rate Order (revised July 22, 2011) at page 2 of 6; EB-2010-0142, Rate Order (July 28, 2011).
[5] Refer to EB-2010-0142 Exhibit Q1, Tab 2, Schedule 7-1 for a summary and quantification of the regulatory accounting changes applied prospectively under CGAAP commencing January 1, 2011.

2) a description of Toronto Hydro's depreciation policy and a summary of the minor change implemented since the utility's last rebasing application in 2011;
3) an explanation of Toronto Hydro's variance from the "half year rule" regarding the calculation of depreciation expense; and,
4) information about the utility's Asset Retirement Obligations ("AROs") and any associated depreciation or accretion expenses in relation to the AROs.

2.1. Depreciation Expense Details

Appendix A to this schedule provides a summary of the depreciation expense for the historical (2011 to 2013) and forecasted periods (2014 to 2019) by Uniform System of Account. The depreciation expense forecasts for 2014 and 2015 are filed under Modified International Financial Reporting Standards ("MIFRS") and include a de-recognition loss as described in Exhibit 4B, Tab 1, Schedule 2.

3. DEPRECIATION POLICY

In accordance with the APH, Toronto Hydro depreciates its assets on a straight-line basis over the estimated useful lives of the assets. Table 2 below summarizes Toronto Hydro' annual depreciation rates by asset category.

Table 1: Property Plant and Equipment (PP&E) Depreciation Rates (2011 – 2015)

Asset Category	2011 Historical	2012 Historical	2013 Historical	2014 Bridge	2015 Test
Distribution Lines	1.7% - 5.0%	1.7% - 5.0%	1.7% - 5.0%	1.7% - 5.0%	1.7% - 5.0%
Transformers	3.3% - 5.0%	3.3% - 5.0%	3.3% - 5.0%	3.3% - 5.0%	3.3% - 5.0%
Meters	2.5% - 6.7%	2.5% - 6.7%	2.5% - 6.7%	2.5% - 6.7%	2.5% - 6.7%
Stations	2.5% - 10.0%	2.5% - 10.0%	2.5% - 10.0%	2.5% - 10.0%	2.5% - 10.0%

Asset Category	2011 Historical	2012 Historical	2013 Historical	2014 Bridge	2015 Test
Buildings	1.3% - 5.0%	1.3% - 5.0%	1.3% - 5.0%	1.3% - 5.0%	1.3% - 5.0%
Rolling stock	12.5% - 25.0%	12.5% - 25.0%	12.5% - 25.0%	12.5% - 25.0%	12.5% - 25.0%
Other capital assets	4.0% - 20.0%	4.0% - 20.0%	4.0% - 20.0%	4.0% - 20.0%	4.0% - 20.0%
Equipment & tools	10.0% - 16.7%	10.0% - 16.7%	10.0% - 16.7%	10.0% - 16.7%	10.0% - 16.7%
Computer hardware	16.7% - 25.0%	16.7% - 25.0%	16.7% - 25.0%	16.7% - 25.0%	16.7% - 25.0%
Assets under capital lease	14.3% - 25.0%	14.3% - 25.0%	14.3% - 25.0%	14.3% - 25.0%	14.3% - 25.0%
Communications	10.0% - 20.0%	10.0% - 20.0%	10.0% - 20.0%	10.0% - 20.0%	10.0% - 20.0%

3.1. Intangible Assets

Table 2: Computer Software Depreciation Rates

	2011 Historical	2012 Historical	2013 Historical	2014 Bridge	2015 Test
Computer software	20.0% - 25.0%	10.0% - 25.0%	10.0% - 25.0%	10.0% - 25.0%	10.0% - 25.0%
Contributions	4.0%	4.0%	4.0%	4.0%	4.0%

Toronto Hydro reviews the useful lives of its assets annually to ensure that they remain relevant and appropriate. With the exception of the change noted below, Toronto Hydro has not made any significant material changes to its estimated useful lives since its last rebasing application (EB-2010-0142).

3.2. Depreciation Policy Change Since Last Rebasing Application In 2011

In July 2011, Toronto Hydro implemented a new Customer Information System ("CIS"), a software application called Customer Care and Billing ("CC&B"). Prior to January 1, 2012, Toronto Hydro amortized computer software over four to five years. However, through assessment and discussion with the vendor and other subject matter experts, Toronto Hydro determined that ten years was a more appropriate useful life for CC&B. This conclusion was made based on the fact that the CC&B software developers have designed an "upgrade path" whereby the software will be continually upgraded to meet new requirements, rather than having to be fully replaced, thereby extending the estimated useful life.

3.3. Variance From Half Year Rule

For the purpose of this application (as well as historically), Toronto Hydro calculates depreciation based on the month that an asset is in service, rather than on the basis of the half year rule which assumes that all asset additions are put into service in the middle of the fiscal year. Similarly, Toronto Hydro calculates depreciation associated with assets that are retired, transferred or become fully depreciated within a given year based on the month of transaction.

Depreciation reflects the pattern in which the entity expects to receive the asset's future economic benefits over the useful life of the asset. United States Generally Accepted Accounting Principles ("USGAAP") require depreciation costs to "be spread over the expected useful life of the facility in such a way as to allocate it as equitably as possible to the periods during which services are obtained from the use of the facility."[6] Likewise, IFRS (IAS 16.55) provide that "depreciation of an asset begins when it is available for use, i.e., when it is in the location and condition necessary for it to be capable of operating in the manner intended by management".

[6] USGAAP ASC 360-10-35-4

In accordance with these generally accepted accounting principles, Toronto Hydro adopted a monthly depreciation methodology because it:

1) provides a more accurate reflection of the asset's future economic benefits over its useful life, and
2) aligns the calculation of depreciation expense for rate-making purposes with Toronto Hydro's external financial reporting policies and historical practices.

4. ASSET RETIREMENT OBLIGATION

Toronto Hydro recognizes liabilities for the future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties (collectively known as "decommissioning provisions") in accordance with Article 410 of the OEB's Accounting Procedures Handbook (the "APH"). A decommissioning provision is recognized at the time that the obligation arises. Initially, Toronto Hydro measures the liability at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the utility depreciates the capitalized amount over the useful life of the related asset and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ("accretion expense") and for changes in the underlying assumptions.

Toronto Hydro's historical and forecasted decommissioning costs and the related depreciation expense for 2011-2015 ($ in millions) are summarized in Tables 3 and 4 below.

Table 3: Historical and Forecasted Decommissioning Costs and Related Depreciation Expense

	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge (USGAAP)	2014 Bridge (MIFRS)	2015 Test
Decommissioning Costs	$3.8	$4.3	$5.5	$2.4	$1.6	$0.2
Related Depreciation Expense	$0.3	$0.2	$0.3	$0.2	$0.1	$0.1

Table 4 below summarizes the corresponding decommissioning liability and related accretion expense for 2011-2015 ($ in millions):

Table 4: Historical and Forecasted Decommissioning Liability and Related Accretion Expense

	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge (USGAAP)	2014 Bridge (MIFRS)	2015 Test
Decommissioning Liability	$4.8	$5.0	$6.2	$1.5	$1.5	$1.4
Related Accretion Expense	$0.2	$0.2	$0.2	-	-	-

Table1:SummaryofDepreciation Expense

		2011CGAAP	2012UGAAP	2013 UGAAP	2014UGAAP			2014MIFRS				2015MIFRS		
OEB	**Description**	**Total Depreciation Expense**	**Total Depreciation Expense**	**Total Depreciation Expense**	**Depreciation Expense**	**Transfers**	**Total Depreciation Expense**	**Depreciation Expense**	**Transfers**	**Derecognition**	**Total Depreciation Expense**	**Depreciation Expense**	**Derecognition**	**Total Depreciation Expense**
1611	Computer Software (Formally known as Account 1925)	$ 24,893,304	$ 20,224,259	$ 17,210,554	$ 19,182,023	($ 17,128)	$ 19,164,895	$ 19,182,937	($ 17,170)	$ r	$ 19,165,768	$ 21,011,750	$ r	$ 21,011,750
1612	Land Rights	$ r	$ r	$ r	$ r	$ r	$ r	$ 89,423	$ r	$ r	$ 89,423	$ 89,423	$ r	$ 89,423
1805	Land	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r
1808	Buildings	$ 1,550,177	$ 1,495,626	$ 1,866,209	$ 2,023,489	($ 316,955)	$ 1,706,533	$ 2,034,879	($ 316,976)	$ r	$ 1,717,903	$ 2,164,056	$ r	$ 2,164,056
1815	TransformerStation Equipment>50kV	$ 380,940	$ 402,730	$ 404,101	$ 410,092	($ 3,623)	$ 406,469	$ 410,099	($ 3,630)	$ r	$ 406,469	$ 433,082	$ 38,849	$ 471,931
1820	Distribution Station Equipment <50 kV	$ 7,083,676	$ 6,499,970	$ 6,699,017	$ 7,040,253	($ 342,531)	$ 6,697,722	$ 7,040,476	($ 342,783)	$ 78,054	$ 6,775,747	$ 8,071,762	$ 82,859	$ 8,154,621
1830	Poles,Towers&Fixtures	$ 5,824,614	$ 6,469,781	$ 6,883,833	$ 7,596,852	($ 603,230)	$ 6,993,622	$ 7,597,440	($ 603,611)	$ 9,218,952	$ 16,212,780	$ 9,383,299	$ 12,792,932	$ 22,176,231
1835	OverheadConductors &Devices	$ 4,341,875	$ 5,152,543	$ 5,922,635	$ 6,901,315	($ 518,672)	$ 6,382,643	$ 6,906,901	($ 519,020)	$ 2,422,530	$ 8,810,411	$ 8,010,517	$ 2,404,482	$ 10,414,999
1840	UndergroundConduit	$ 31,948,117	$ 32,737,980	$ 34,220,426	$ 36,940,621	($ 2,658,269)	$ 34,282,352	$ 36,952,150	($ 2,660,137)	$ 324,832	$ 34,616,844	$ 40,909,577	$ r	$ 40,909,577
1845	UndergroundConductors &Devices	$ 13,844,464	$ 14,554,813	$ 16,600,725	$ 17,590,134	($ 1,777,485)	$ 15,812,649	$ 17,441,988	($ 1,777,944)	$ 3,266,345	$ 18,930,388	$ 18,874,495	$ 6,327,408	$ 25,201,903
1850	LineTransformers	$ 21,426,917	$ 20,415,257	$ 21,501,170	$ 22,171,293	($ 1,181,371)	$ 20,989,923	$ 22,237,759	($ 1,181,907)	$ 9,507,212	$ 30,563,065	$ 22,574,248	$ 9,755,037	$ 32,329,284
1855	Services(Overhead &Underground)	$ 1,433,856	$ 1,552,305	$ 1,651,822	$ 1,874,227	($ 154,401)	$ 1,719,826	$ 1,874,323	($ 154,539)	$ r	$ 1,719,784	$ 2,235,152	$ 446	$ 2,235,598
1860	Meters	$ 9,162,626	$ 9,461,636	$ 9,864,020	$ 12,464,057	($ 139,433)	$ 12,324,624	$ 12,464,374	($ 139,514)	$ r	$ 12,324,860	$ 13,258,376	$ 546,556	$ 13,804,932
1905	Land	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r
1908	Buildings&Fixtures	$ 6,395,106	$ 5,597,338	$ 5,715,814	$ 6,377,509	($ 143)	$ 6,377,366	$ 6,377,517	($ 143)	$ 12,500	$ 6,389,874	$ 6,162,152	$ 596,416	$ 6,758,568
1910	LeaseholdImprovements	$ 5,993,705	$ 604,412	$ 284,866	$ 314,340	$ r	$ 314,340	$ 314,340	$ r	$ r	$ 314,340	$ 305,716	$ r	$ 305,716
1915	OfficeFurniture &Equipment	$ 1,452,357	$ 1,695,701	$ 2,321,386	$ 2,128,106	$ r	$ 2,128,106	$ 2,128,107	$ r	$ 357	$ 2,128,464	$ 1,988,900	$ 12,017	$ 2,000,917
1920	ComputerEquipment rHardware	$ 4,373,915	$ 4,401,165	$ 4,595,199	$ 7,028,006	($ 16,303)	$ 7,011,702	$ 7,028,569	($ 16,343)	$ r	$ 7,012,227	$ 12,430,692	$ r	$ 12,430,692
1930	TransportationEquipment	$ 7,074,141	$ 7,499,760	$ 7,148,702	$ 6,558,032	($ 218)	$ 6,557,814	$ 6,558,138	($ 218)	$ r	$ 6,557,920	$ 6,376,745	$ r	$ 6,376,745
1935	StoresEquipment	$ 7,709	$ 7,709	$ 7,709	$ 7,066	$ r	$ 7,066	$ 7,066	$ r	$ r	$ 7,066	$ r	$ r	$ r
1940	Tools,Shop &Garage Equipment	$ 1,924,584	$ 2,006,371	$ 2,188,127	$ 2,216,738	$ r	$ 2,216,738	$ 2,216,753	$ r	$ r	$ 2,216,753	$ 2,220,076	$ r	$ 2,220,076
1945	Measurement&TestingEquipment	$ 1,086,963	$ 2,061,676	$ 2,081,814	$ 2,032,666	$ r	$ 2,032,666	$ 2,032,667	$ r	$ r	$ 2,032,667	$ 2,028,389	$ r	$ 2,028,389
1955	CommunicationsEquipment	$ 2,899,180	$ 2,684,558	$ 1,901,560	$ 1,855,881	$ r	$ 1,855,881	$ 1,855,881	$ r	$ r	$ 1,855,881	$ 1,924,002	$ r	$ 1,924,002
1960	Miscellaneous Equipment	$ 25,285	$ 36,918	$ 36,918	$ 36,918	$ r	$ 36,918	$ 36,918	$ r	$ r	$ 36,918	$ 37,146	$ r	$ 37,146
1970	LoadManagement Controls Customer Premises	$ 1,025,729	$ 1,082,077	$ 1,082,077	$ 1,082,077	$ r	$ 1,082,077	$ 1,082,077	$ r	$ r	$ 1,082,077	$ 1,070,206	$ r	$ 1,070,206
1975	LoadManagement Controls Utility Premises	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r	$ r
1980	SystemSupervisor Equipment	$ 1,763,841	$ 1,761,636	$ 1,814,662	$ 2,048,691	($ 72,158)	$ 1,976,533	$ 2,048,748	($ 72,168)	$ 904,959	$ 2,881,540	$ 2,137,803	$ 1,375,389	$ 3,513,193
1995	Contributions&Grants	($ 8,200,745)	($ 9,011,788)	($ 9,836,203)	($ 10,351,884)	$ 18,199	($ 10,333,685)	($ 10,369,809)	$ 18,239	$ r	($ 10,351,570)	($ 10,852,528)	$ r	($ 10,852,528)
1609	CapitalContributions Paid	$ 916,010	$ 734,850	$ 901,706	$ 955,031	$ 36,296	$ 991,327	$ 955,180	$ 36,296	$ r	$ 991,476	$ 1,150,182	$ r	$ 1,150,182
2005	PropertyUnderCapital Leases	$ r	$ r	$ r	$ 1,712,109	$ r	$ 1,712,109	$ 1,712,109	$ r	$ r	$ 1,712,109	$ 190,234	$ r	$ 190,234
		$ 148,628,347	$ 140,129,282	$ 143,068,846	$ 158,195,645	($ 7,747,425)	$ 150,448,220	$ 158,217,010	($ 7,751,568)	$ 25,735,741	$ 176,201,183	$ 174,185,452	$ 33,932,393	$ 208,117,844
	Less: FullyAllocated Depreciation													
	Transportation	($ 2,189,844)	($ 1,620,301)	($ 2,314,931)	($ 2,342,979)	$ r	($ 2,342,979)	($ 2,342,979)	$ r		($ 2,342,979)	($ 1,671,045)		($ 1,671,045)
	StoresEquipment				$ r	$ r	$ r	$ r	$ r		$ r	$ r		$ r
	NetDepreciation asperAppendix 2rBA	$ 146,438,503	$ 138,508,981	$ 140,753,915	$ 155,852,666	($ 7,747,425)	$ 148,105,240	$ 155,874,031	($ 7,751,568)	$ 25,735,741	$ 173,858,204	$ 172,514,406	$ 33,932,393	$ 206,446,799
	OtherReconciliating Items:													
	Less: 2014Derecognition in transition year transferredto1575: IFRSrUGAAP Transitional PPEAmounts				$ r						($ 25,735,741)			
	Add: StrandedMeter Depreciation				$ 2,472,404						$ 2,472,404			
	Add: SmartMeter Clearance			$ 28,733,065										
	TotalDepreciation Expense	$ 146,438,503	$ 138,508,981	$ 169,486,980	$ 150,577,644						$ 150,594,867			$ 206,446,799

DERECOGNITION OF ASSETS

1. INTRODUCTION

Upon implementation of Modified International Financial Reporting Standards ("MIFRS"), Article 410 of the Ontario Energy Board ("OEB") Accounting Procedures Handbook for Electricity Distributors requires Property, Plant & Equipment ("PP&E") assets to be derecognized when they are disposed of or when their use is no longer expected to offer future economic benefits. The gain or loss arising from the derecognition of an item of PP&E is calculated as the difference between the net disposal proceeds (if any) and the carrying amount of the item of PP&E. The gain or loss arising from the derecognition of an item of PP&E is included in the utility's profit or loss during the period in which the item is derecognized.

To comply with MIFRS, Toronto Hydro has recorded the gains resulting from the disposal of land and buildings in profit or loss. Losses resulting from the disposition of assets with a carrying amount are recorded as depreciation expense as shown in Exhibit 4B, Tab 1, Schedule 1.

2. DERECOGNITION PROCESS

To facilitate the derecognition process, Toronto Hydro has leveraged a number of the systems that it uses to manage the construction, capitalization, maintenance and monitoring of assets, namely: the Geodetically Enabled Asset Registry ("GEAR"), Ellipse, the Customer, Care & Billing system ("CC&B"), and SAP.

- GEAR is a geospatial information system that provides a graphic representation of distribution assets and their relationship to other assets within Toronto Hydro's network. To facilitate derecognition, GEAR was enhanced to capture specific asset details on the removal of distribution assets such as asset type and nature of the record change by unique asset identifiers.

- Ellipse is what Toronto Hydro's uses as an Enterprise Resource Planning ("ERP") application. It performs critical back-office business functions within finance, enterprise asset management, human resources, work management and supply chain. Ellipse is the main source of data for Stations, Fleet and Facilities assets.
- CC&B is Toronto Hydro's Customer Information System. It facilitates all customer related information as well as customer billing. It also stores metering asset information.
- SAP's fixed assets module tracks the cost, accumulated depreciation and net book value of PP&E assets. Toronto Hydro uses this information to calculate derecognition losses. SAP provides a unique asset identifier for each Toronto Hydro asset, which relates the data captured from GEAR and the other processes to the assets in SAP and establishes a reasonable match to the asset costs and related accumulated depreciation that should be derecognized.

3. FORECASTS OF LOSSES ON DERECOGNTION

Table 1 below summarizes Toronto Hydro's forecasted derecognition losses under MIFRS over the 2014 to 2019 period. These forecasts are informed by the utility's capital expenditure proposals as outlined in its Distribution System Plan ("DSP"), filed at Exhibit 2B, Section E, and are calculated on the basis of the net book values associated with assets that the utility forecasts to be taken out-of-service as part of its planned capital program.

Table 1: MIFRS Losses on Derecognition 2014 to 2019 ($ in millions)

	2014 Bridge	2015 Test	2016 Test	2017 Test	2018 Test	2019 Test
Loss on Derecognition	25.7	33.9	26.6	28.0	29.4	32.6

4. REQUEST FOR VARIANCE ACCOUNT

Due to the dynamic nature of Toronto Hydro's capital program and operating environment, the utility is likely to experience significant ongoing volatility in year over year losses on derecognition over the 2015-2019 period. To manage this volatility prudently, Toronto Hydro requests a variance account to track the actual costs associated with derecognition of assets (see Exhibit 9A). Toronto Hydro's request is based on the OEB's IFRS Report Addendum which specifically considered the issue of volatility with respect to certain expenses (including depreciation losses) arising from the application of IFRS. In its Report, the OEB concluded that a utility-specific variance account is appropriate in circumstances where there is the probability that the utility will experience significant ongoing volatility.[1]

5. PROBABILITY OF VOLATILITY

Toronto Hydro submits that it is likely to encounter significant ongoing volatility from its forecasted derecognition losses over the 2015-2019 period for the following reasons:

1) The variety of asset ages in its distribution system;
2) The dynamic nature of its capital program; and
3) The materialization of external factors and constraints.

Given the probability of volatility, Toronto Hydro submits that a utility-specific variance account to capture the difference between forecast and actual losses on derecognition would protect both the interest of rate payers and the utility. If the utility's actual derecognition losses are lower than its forecast, rate payers would be protected from overpaying the depreciation expense associated with the utility's forecasted losses. Likewise, if the utility's forecasts are lower than its actual derecognition losses, the utility would be protected from incurring additional losses.

[1] EB-2008-0408, Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment (June 13, 2011), at pages 23.

5.1. Asset Variety in Toronto Hydro's Distribution System

Toronto Hydro determined its forecast derecognition losses by the duration, age and type of assets to be removed as part of Toronto Hydro's planned five-year capital program (as set out in the DSP). Because Toronto Hydro's distribution system is the product of the amalgamation of six different utilities in 1998, the age, type and mix of its assets varies significantly depending on the location. Figure 1 below is a geographical representation of all Toronto Hydro's assets and the respective vintage which illustrates the wide range of asset age throughout the City of Toronto.

Figure 1: Age of Major Assets in Toronto Hydro's Distribution System

5.2. Dynamic Nature of Capital Program

Toronto Hydro's capital program is dynamic in that a number of factors, such as work permits, weather conditions, reprioritization of jobs due to system needs or external

obligations, may lead to annual substitutions, deletions and additions to the utility's plan.[2] These changes could result in notable variances from the assets that were originally forecasted for removal and the associated net book values on the basis of which derecognition losses are forecast for a given year.

For example, during the CIR rate period (2015-2019), Toronto Hydro may be required to substitute certain projects in the east side of the City as part of Underground Infrastructure program to complete another project in the west side of the City within the same program. Such a change may be necessary to allow the City of Toronto to proceed with road reconstruction in the west end and to enable Toronto Hydro to avoid future construction moratoriums in this area. This change could, in turn, expose the assets to a higher risk of failure if the utility has to wait until the moratoriums expire to proceed with the work. Although the projects would be within the same program, and the assets to be removed would be similar in nature, the change in location of the projects could have a notable effect on the derecognition losses incurred by the utility in that given year.

5.3. External Factors and Constraints

Toronto Hydro's DSP also contains certain work programs (for example, Reactive Capital, Externally Initiated Plant Relocations, Customer Connections) that are largely driven by external circumstances, such as storms, asset malfunction, customer and third party requests, which are especially difficult to forecast. Because the actual assets to be removed and associated net book values are specific to each location, the materialization of any one or more of these externally-driven events could have a material and significant effect on the utility's derecognition losses for that year.

An example of this potential source of volatility is the Metrolinx Union Station – Pearson Airport electrification project and other externally initiated plant relocations which could

[2] For more information about Toronto Hydro's need for flexibility over the rate period with respect to the execution of its capital program, please refer to Exhibit 1B, Tab 2, Schedule 4.

materialize during the 2015-2019 rate period, as detailed in Toronto Hydro's Externally Initiated Plant Relocations capital program (Exhibit 2B, E5.3). Due to uncertainty as to whether and when these projects will materialize during the rate period, the utility requests a variance account to capture the derecognition losses associated with these capital expenditures (see Exhibit 9A). Derecognition losses associated with these projects have not been included in the forecasted amounts in Table 1. Therefore, if these projects materialize during the rate period, Toronto Hydro will incur additional losses that have not been built into its derecognition forecasts.

The Dundas West overhead to underground conversion project is a good example of the uncertainty that Toronto Hydro may encounter over the rate period. This project is on Dundas Street West from Bathurst Street to University Avenue and it is part of City of Toronto revitalization capital program. The City of Toronto plans to rebuild a watermain and completing a sidewalk replacement along this stretch of road and originally requested that Toronto Hydro relocate its overhead infrastructure underground. Subsequently, the City determined that Toronto Hydro can keep most of the infrastructure as overhead with some minor adjustments; however, these adjustments will not be known until the City completes its design concepts. Therefore, the scope of Toronto Hydro's relocations in relation to the Dundas West project are still unknown. Although this project was filed in the 2012 IRM application, it has not yet materialized. As a result of the continuous uncertainty, this specific project was not filed as part of the 2015 capital forecast and the related derecognition loss associated with this project has not been built into the forecast. Should this project, or other externally driven projects materialize in 2015, the forecasted derecognition loss will necessarily be higher.

Another example is the North West PATH project was initiated by the City of Toronto requiring a new underground extension to the City of Toronto underground PATH network from Union Station to Wellington Street via York Street. This expansion will provide additional capacity to accommodate the growing numbers of pedestrians

accessing Union Station from the downtown core. The City of Toronto requires Toronto Hydro to relocate any infrastructure that is in conflict with proposed work, from the intersection of York Street and Front Street to York Street and Wellington Street. This project was filed in the 2012 IRM application because the City is intended to complete this project prior to the Pan Am Games. Due to construction delays, the City has modified its objectives to have only Phase 1 completed prior to the Pan Am Games. Toronto Hydro expects that Phase 2 construction will begin in 2015. As a result, Phase 2 of the North West PATH project was included as part of this application. This project accounts for approximately $0.2 million of the 2015 derecognition forecast; however, if the work is delayed, this cost may not actually be incurred in 2015.

CORPORATE TAXES (PILs)

1. INTRODUCTION

The Revenue Requirement filed at Exhibit 6, Tab 1, Schedule 1 of this Application reflects amounts for Payments in Lieu of Taxes ("PILs") recovery of $24,045,463 /C (excluding investment tax credits of $2,000,000 reallocated to OM&A), for the 2015 Test Year. The 2015 PILs tax models are filed at Exhibit 4B, Tab 2, Schedule 2.[1]

2. PRUDENT MANAGEMENT OF PILS/TAXES

The amount of PILs paid by Toronto Hydro in any given year is strongly correlated with its net income. Toronto Hydro manages its tax costs diligently in an effort to keep the effective rate of tax as low as possible. A dedicated group of tax personnel administers Toronto Hydro's taxes and helps ensure that the PILs are managed prudently. Where it can, Toronto Hydro takes advantage of available tax deductions and tax credits, such as research and development tax credits, to minimize its tax burden.

3. METHODOLOGY

The methodology for calculating PILs is consistent with the principles set out in Chapter 2 of the OEB's Filing Requirements, and reflects appropriate legislative changes that have been enacted, such as changes to corporate tax rates and capital cost allowance rates. Toronto Hydro confirms that non-recoverable expenses and expenses disallowed for regulatory purposes have been excluded from the regulatory tax calculation.

4. DISCLOSURE OF PILS TAX ADMINISTRATION AND TAX RULINGS

Toronto Hydro has not received any specific tax rulings that are inconsistent with Toronto Hydro's previously filed and approved tax model except for reassessments received in respect of post employment benefit plan costs. Toronto Hydro amended its tax returns for the years 2006 to 2010 in respect of its tax treatment of post employment

[1] The formatting of Toronto Hydro's PILs model for the 2015 test year differs from the OEB model.

benefit plan costs. Previously, these costs were capitalized for tax purposes and deducted as capital cost allowance. Toronto Hydro amended its position by deducting amounts paid in respect of post employment benefits from taxable income. The revision of tax position resulted in favourable reassessments received in 2011 to 2013. As a result, Toronto Hydro proposes to include the refunds received in a rate rider to customers (see Exhibit 8, Tab 1, Schedule 1).

5. TAX REASSESSMENTS

The Ministry of Finance has most recently completed its review of Toronto Hydro's 2009 PILs return. The PILs amount computed includes methodologies approved by the Ministry of Finance through its audits.

6. TAX TREATMENT OF DIVIDENDS PAID IN PRIOR YEARS

Dividends paid in the historical year were treated as payments out of tax paid retained earnings and therefore were not treated as deductible for tax purposes.

7. CAPITAL TAX

The Ontario capital tax rate was reduced to zero effective July 1, 2010. Ontario capital taxes are therefore not included in this application.

8. LOSS CARRY-FORWARDS

Toronto Hydro does not have any non-capital loss carry-forwards as of the end of December 2013, and does not expect to have such loss carry-forwards as of the end of December 2014.

9. CAPITAL COST ALLOWANCE ("CCA")

Because Toronto Hydro is filing this application on a Future Test Year ("FTY") basis, CCA is computed for 2015 based on projections of the change in capital assets from the

2013 historical year. A separate schedule is prepared to compute the projected CCA for 2014 and to derive the projected undepreciated capital cost balances at January 1, 2015 (Exhibit 4B, Tab 2, Schedule 2). In doing so, the maximum CCA is claimed in the 2015 Test Year. Any projected additions are subject to the half-year rule in the year of acquisition.

10. REGULATORY TAX TREATMENT OF ELIGIBLE CAPITAL EXPENDITURE ("ECE")

The amount of ECE deduction is based on the projected balance of cumulative eligible capital in each relevant year. A separate completed schedule for the 2014 year is used to derive the projected 2015 opening balance of CEC (Exhibit 4B, Tab 2, Schedule 2). The maximum ECE deduction is claimed for all years.

11. INTEREST DEDUCTION

Actual interest expense is greater than the deemed interest expense calculated by the 2015 model filed at Exhibit 4B, Tab 2, Schedule 2. Therefore the difference between actual and deemed interest expense has been deducted in calculating taxable income in the Tax Models for that year.

12. CAPITALIZED INTEREST

Interest is not capitalized to construction work in progress ("CWIP") for tax purposes. However, interest is capitalized for accounting purposes in the 2015 projection.

13. NON-DISTRIBUTION ELIMINATION

Toronto Hydro has included only income from the distribution of electricity in this application.

14. TAX CREDITS

Toronto Hydro expects that the level of expenditures qualifying for Scientific Research and Experimental Development ("SRED") in 2015 will continue to decrease. Federal investment tax credits arising from expenditures on qualifying SRED projects carried on by Toronto Hydro in 2011 to 2013 decreased from $2.10 million to $1.26 million. In addition, the 2012 Federal Budget (Bill C-45) reduced the SRED investment tax credit rate from 20% to 15% for taxation years ending after 2013. Reductions in the overhead proxy rate and eligible expenditures to contractors were also implemented as part of this Bill. Toronto Hydro has therefore used the 2013 historical SRED credit and the future reductions in rate and eligible expenditure to derive the 2015 credit ($1.2M). **/C** **/C**

Toronto Hydro has also included the Federal Apprenticeship Job Creation Tax Credit, the Ontario Apprenticeship Training Tax Credit and the Ontario Co-Operative Education Tax Credit in its PILs revenue requirement. A projected tax credit of $1.06 million, based on the average benefit of 2011 through 2013 claims, has been included in the 2015 Tax Models.

15. CAPITAL LEASES

Appropriate adjustments have been made in determining taxable income in the 2015 Tax Model with respect to leases capitalized for accounting purposes.

16. INTEGRITY CHECKS

The following integrity checks have been completed in respect of the PILs model:

- Depreciation and amortization added back agrees with the numbers disclosed in the rate base section of the application;
- Capital additions and deductions agree with the rate base section for historical, bridge and test years;

- Schedule 8 of the most recent tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st. A reconciliation has been provided to remove the non distribution amounts in Exhibit 4B, Tab 2, Schedule 2;
- The CCA deductions in the application's PILs tax model for historical, bridge and test years agree with the numbers in Schedule 8;
- Accounting OPEB and pension amounts added back on Schedule 1;
- Reconciliation of accounting income to net income for tax purposes, agree with the OM&A analysis for compensation and are reasonable when compared with the notes to the audited financial statements, and the actuarial valuations; and
- The income tax rate used to calculate the tax expense is consistent with the current legislated rate.

17. TAX PAYABLE FILINGS

Details of actual taxes paid by Toronto Hydro from 2008 to 2013, as well as the forecasted taxes to be paid for 2014, are outlined in the tables below. Explanations of the variances for the forecasted years are also provided. Tax return copies for the historical year 2013 are in Exhibit 4B, Tab 2, Schedule 3.

Table 1: Summary of PILs by Year ($ Millions)

	2008 Historic	2009 Historic	2010 Historic	2011 Historic	2012 Historic	2013 Historic	2014 Bridge	2015 Test	
Income Taxes	28.21	17.56	17.89	9.44	3.62	7.99	9.52	24.05	/C
Capital Tax	5.50	5.58	2.06	-	-	-	-	-	
Total PILs	33.71	23.14	19.95	9.44	3.62	7.99	9.52	24.05	/C

17.1. 2013 to 2014

The increase in PILs of approximately $1.53 million is mainly due to differences between the tax and book treatment of various costs. /C

17.2. 2014 to 2015

The increase in PILs of approximately $14.53 million is mainly attributable to increased return on a larger capital base and differences between the tax and book treatment of various costs. /C

18. PROPERTY TAX

Property taxes are included in the Facilities Management program (Exhibit 4A, Tab 2, Schedule 11).

Ontario Energy Board

Version 3.0

Utility Name	Toronto Hydro-Electric System Limited
Assigned EB Number	EB-2014-0116
Name and Title	
Phone Number	
Email Address	
Date	
Last COS Re-based Year	2011

Note: Drop-down lists are shaded blue; Input cells are shaded green.

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While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Toronto Hydro-Electric System Limited
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H. PILS, Tax Provision Historic					

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Toronto Hydro-Electric System Limited
Data Input Sheet - Applicant's Rate Base

Rate Base			**$**	**3,247,562,846**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	129,902,514	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	1,818,635,194	*X = S * U*
Deemed Equity %	40.00%	V	$	1,299,025,138	*Y = S * V*
Short Term Interest Rate	1.38%	Z	$	1,792,655	*AC = W * Z*
Long Term Interest	4.31%	AA	$	78,383,177	*AD = X * AA*
Return on Equity ( )	9.30%	AB	**$**	**120,809,338**	*AE = Y * AB*
Return on Rate Base			**$**	**200,985,169**	*AF = AC + AD + AE*

Questions that must be answered

	Historical	**Bridge**	**Test Year**
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	Yes	Yes	Yes
3. Does the applicant have any Capital Gains or Losses for tax purposes?	Yes	Yes	Yes
4. Does the applicant have any Capital Leases?	Yes	Yes	Yes
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	No	No
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

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Toronto Hydro-Electric System Limited

Tax Rates & Exemptions

Tax Rates

Federal & Provincial As of June 20, 2012	Effective 1-Jan-11	Effective 1-Jan-12	Effective 1-Jan-13	Effective 1-Jan-14	Effective 1-Jan-15
Federal income tax					
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business					
Federal small business threshold	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	4.50%

Ontario Energy Board

Toronto Hydro-Electric System Limited
Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	1,063,314,440	39,676,106	1,023,638,334
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988	309,715,644		309,715,644
8	General Office/Stores Equip	29,425,312	2,407	29,422,905
10	Computer Hardware/ Vehicles	14,046,718		14,046,718
10.1	Certain Automobiles	0		0
12	Computer Software	7,858,379		7,858,379
13 1	Lease # 1	21,146		21,146
13 2	Lease #2	93,505		93,505
13 3	Lease # 3	95,911		95,911
13 4	Lease # 4	411,224		411,224
13 5	Lease # 5			0
13 6	Lease # 6			0
13 7	Lease # 7			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	19,030,639		19,030,639
42	Fibre Optic Cable	37,410		37,410
43.1	Certain Energy-Efficient Electrical Generating Equipment	0		0
43.2	Certain Clean Energy Generation Equipment	2,943,069	2,943,069	0
45	Computers & Systems Software acq'd post Mar 22/04	81,658		81,658
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0		0
47	Distribution System - post February 2005	1,310,574,811		1,310,574,811
50	Data Network Infrastructure Equipment - post Mar 2007	7,935,901	2,809	7,933,092
52	Computer Hardware and system software			0
95	CWIP	407,559,080	1,749,681	405,809,399
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	**3,173,144,847**	**44,374,072**	**3,128,770,775**

Ontario Energy Board

Toronto Hydro-Electric System Limited
Schedule 10 CEC - Historical Year

Cumulative Eligible Capital - Beginning of Year				21,595,209
Additions				
Cost of Eligible Capital Property Acquired during Historical Year	2,489,752			
Other Adjustments	0			
Subtotal	2,489,752	x 3/4 =	1,867,314	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			1,867,314	1,867,314
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				23,462,523
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Historical Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance				23,462,523
Current Year Deduction		23,462,523	x 7% =	1,642,377
Cumulative Eligible Capital - Closing Balance				21,820,146

Ontario Energy Board

Toronto Hydro-Electric System Limited
Schedule 13 Tax Reserves - Historical Year

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost	490,000		490,000
- Other Post-Employment Benefits	238,792,000	1,079,000	237,713,000
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	239,282,000	1,079,000	238,203,000

Ontario Energy Board

Toronto Hydro-Electric System Limited
Schedule 7-1 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Ontario Energy Board

Toronto Hydro-Electric System Limited
Adjusted Taxable Income - Historical Year

See Exhibit 4B, Tab 2, Schedule 3 for copy of the 2013 tax return.

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	118,861,874	231,840	118,630,034
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	171,474,771	1,987,699	169,487,072
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112	31,343		31,343
Taxable Capital Gains	113	573,891		573,891
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118	2,592,851		2,592,851
Capitalized interest	119			0
Non-deductible club dues and fees	120	376,763	6,624	370,139
Non-deductible meals and entertainment expense	121	270,680	2,005	268,675
Non-deductible automobile expenses	122	5,438		5,438
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126	239,282,000	1,079,000	238,203,000
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208	1,038,109		1,038,109
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293	10,176		10,176
	294			0
	295			0
ARO Accretion expense		176,603		176,603
Capital Contributions Received (ITA 12(1)(x))		25,535,013	2,380,830	23,154,183
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))		20,020,088	19,850,819	169,269
Prior Year Investment Tax Credits received				0
Other Post-Employment Benefits adjustments		21,626,492	103,000	21,523,492
Investment Tax Credits taxed in the year		1,125,451		1,125,451
Regulatory item adjustments		35,240,637		35,240,637
Current year expense deducted in prior year for tax		3,123		3,123
				0
				0
				0
				0
				0
				0
Total Additions		519,383,429	25,409,977	493,973,452

Ontario Energy Board

Toronto Hydro-Electric System Limited
Adjusted Taxable Income - Historical Year

See Exhibit 4B, Tab 2, Schedule 3 for copy of the 2013 tax return.

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Deductions:				
Gain on disposal of assets per financial statements	401	1,279,608		1,279,608
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	202,449,164	3,336,173	199,112,991
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	1,642,377		1,642,377
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411	3,824,233		3,824,233
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414	258,462,000	1,109,000	257,353,000
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391	15,181		15,181
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid		572,285		572,285
ITA 13(7.4) Election - Capital Contributions Received		25,535,013	2,380,830	23,154,183
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve		20,020,088	19,850,819	169,269
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)		2,015,708		2,015,708
Capitalized Other Post-Employment Benefits adjustment		5,836,577		5,836,577
Regulatory items adjustments		70,384,166		70,384,166
Deferred legal costs and lease cancellation		157,289		157,289
Prior year Investment tax credits taxed in prior year		905,145		905,145
Other Post-Employment Benefits adjustments		964,495		964,495
Gain on sale of shares		10,647		10,647
Capitalized interest not taxable for tax				0
Total Deductions		594,073,976	26,676,822	567,397,154
Net Income for Tax Purposes		44,171,327	-1,035,005	45,206,332
Charitable donations from Schedule 2	311	31,343		31,343
Taxable dividends deductible under section 112 or 113, from Schedule 3	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		44,139,984	-1,035,005	45,174,989

Ontario Energy Board

Toronto Hydro-Electric System Limited
PILs Tax Provision - Historical Year

See Exhibit 4B, Tab 2, Schedule 3 for copy of the 2013 tax return.

Toronto Hydro-Electric System Limited
Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 1,023,638,334	$ 29,559,048	-$ 169,047	$ 1,053,028,335	$ 14,695,001	$ 1,038,333,335	4%	$ 41,533,333	$ 1,011,495,002
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 309,715,644			$ 309,715,644	$ -	$ 309,715,644	6%	$ 18,582,939	$ 291,132,705
8	General Office/Stores Equip	$ 29,422,905	$ 3,601,232		$ 33,024,137	$ 1,800,616	$ 31,223,521	20%	$ 6,244,704	$ 26,779,433
10	Computer Hardware/ Vehicles	$ 14,046,718	$ 4,217,708	-$ 31,575	$ 18,232,851	$ 2,093,067	$ 16,139,785	30%	$ 4,841,935	$ 13,390,916
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 7,858,379	$ 14,299,598		$ 22,157,977	$ 7,149,799	$ 15,008,178	100%	$ 15,008,178	$ 7,149,799
13 1	Lease # 1	$ 21,146			$ 21,146	$ -	$ 21,146	SL	$ 21,146	$ -
13 2	Lease #2	$ 93,505			$ 93,505	$ -	$ 93,505	SL	$ 62,337	$ 31,168
13 3	Lease # 3	$ 95,911			$ 95,911	$ -	$ 95,911	SL	$ 38,365	$ 57,546
13 4	Lease # 4	$ 411,224			$ 411,224	$ -	$ 411,224	SL	$ 117,492	$ 293,732
13 5	Lease # 5		$ 387,591		$ 387,591	$ 193,796	$ 193,796	SL	$ 38,759	$ 348,832
13 6	Lease # 6				$ -	$ -	$ -	SL	$ -	$ -
14	Franchise				$ -	$ -	$ -	SL	$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 19,030,639			$ 19,030,639	$ -	$ 19,030,639	8%	$ 1,522,451	$ 17,508,188
42	Fibre Optic Cable	$ 37,410			$ 37,410	$ -	$ 37,410	12%	$ 4,489	$ 32,921
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -	$ -		$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 81,658			$ 81,658	$ -	$ 81,658	45%	$ 36,746	$ 44,912
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 1,310,574,811	$ 372,420,620		$ 1,682,995,431	$ 186,210,310	$ 1,496,785,121	8%	$ 119,742,810	$ 1,563,252,621
50	Data Network Infrastructure Equipment - post Mar 2007	$ 7,933,092	$ 32,091,583		$ 40,024,675	$ 16,045,792	$ 23,978,884	55%	$ 13,188,386	$ 26,836,289
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 405,809,399			$ 405,809,399	$ -	$ 405,809,399		$ -	$ 405,809,399
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 3,128,770,775	$ 456,577,380	-$ 200,622	$ 3,585,147,533	$ 228,188,379	$ 3,356,959,154		$ 220,984,071	$ 3,364,163,462

Ontario Energy Board

Toronto Hydro-Electric System Limited
Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**21,820,146**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	1,705,181			
Other Adjustments	0			
Subtotal	1,705,181	**x 3/4 =**	1,278,886	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			1,278,886	**1,278,886**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**23,099,032**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**23,099,032**
Current Year Deduction		**23,099,032**	**x 7% =**	**1,616,932**
Cumulative Eligible Capital - Closing Balance				**21,482,100**

OntarioEnergyBoard

Toronto Hydro-Electri c System Limited

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for acc ounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	0	0	0	0	0	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	490,000		490,000		490,000	0	-490,000	
- Other Post-Employment Benefits	237,713,000	-2,743,000	234,970,000	8,070,000		243,040,000	8,070,000	
	0		0			0		
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0				0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
Total	238,203,000	-2,743,000	235,460,000	8,070,000	490,000	243,040,000	7,580,000	0

Ontario Energy Board

Toronto Hydro-Electric System Limited
Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Yea r

Non-Capital Loss Carry Forward Deduction	Total
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	Total
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Ontario Energy Board

Toronto Hydro-Electric System Limited
Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
	A	
Income before PILs/Taxes		108,739,493
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	150,406,396
Amortization of intangible assets	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	145,900
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	364,296
Non-deductible meals and entertainment expense	121	121,681
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	
Reserves from financial statements- balance at end of year	126	243,040,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	919,144
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
ARO Accretion expense		23,685
Capital Contributions Received (ITA 12(1)(x))		17,521,727
Deferred Revenue (ITA 12(1)(a))		793,994
Non-deductible portion of auto leases (>$800/month)		
Investment Tax Credits taxed in the year		2,263,000
Total Additions		**415,599,823**

Ontario Energy Board

Toronto Hydro-Electric System Limited
Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Deductions:		
Gain on disposal of assets per financial statements	401	453,469
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	220,984,071
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	1,616,932
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	
Reserves from financial statements - balance at beginning of year	414	235,460,000
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
Financing Fees for Tax Under S.20(1)(e) / 20(1)(e.1)		1,961,842
Excess Interest (see Tab "Sch 7-3 Interest Bridge"		0
ARO Payments - Deductible for Tax when Paid		1,555,139
ARO provision credit to income		292,382
ITA 13(7.4) Election - Capital Contributions Received		17,521,727
Deferred Revenue - ITA 20(1)(m) reserve		793,994
Land Lease payment capitalized for accounting		89,423
Lease payment capitalized for accounting		3,483,931
Other Post-Employment Benefits adjustment - change in balance with no Income Statement Impact		422,000
Other Post-Employment Benefits adjustment - current year capitalized portion with no Income Statement Impact		6,295,217
Other Post-Employment Benefits adjustment - sick leave payment credit to income		206,000
Lease Cancellation payment		46,154
Total Deductions		**491,182,281**
Net Income for Tax Purposes		**33,157,035**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**33,157,035**

Note: Schedule is unchanged from Update provided in September 2014 except the following:

- Amortization of tangible assets, Capital Contributions Received (ITA 12(1)(x)), Capital cost allowance from Schedule 8, Cumulative eligible capital deduction from Schedule 10 and ITA 13(7.4) Election - Capital Contributions Received

Ontario Energy Board

Toronto Hydro-Electric System Limited
Excess Interest Expense - Bridge Year

Calculated Deemed Interest Expense	88,126,662
Bridge Year Actual Interest Expense	70,364,323
Bridge Year Capitalized Interest (USoA 6040)	
Bridge Year Capitalized Interest (USoA 6042)	0
Bridge Year Actual Interest	70,364,323
Interest Forecast for Tier 1 or 2 Adjustments	
Total Interest	70,364,323
Excess Interest Expense for Bridge Year PILs	0

Note: Bridge Year Actual Interest Expense is updated

Ontario Energy Board

Toronto Hydro-Electric System Limited
PILS Tax Provision - Bridge Year

						Wires Only	
Regulatory Taxable Income						$ 33,157,035	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 3,813,059	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-7.00%	**E**	-$ 35,000	**F = D * E**		
Ontario Income tax						$ 3,778,059	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.39%	**K = J / A**		
	Federal tax rate (Maximum 15%)			15.00%	**L**		
	Combined tax rate					26.39%	**M = K + L**
Total Income Taxes						**$ 8,751,614**	**N = A * M**
Investment Tax Credits						$ 1,206,000	**O**
Miscellaneous Tax Credits						$ 1,057,000	**P**
Total Tax Credits						**$ 2,263,000**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year						**$ 6,488,614**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				73.61%	**S = 1 - M**	**$ 2,326,772**	**T = R / S - R**
Income Tax (grossed-up)						**$ 8,815,386**	**U = R + T**
Tax credits reclass to OM&A						**$ 700,000**	**V**
Income Tax (grossed-up)						**$ 9,515,386**	**W = U + V**

Note:

1. This is for the derivation of Brdige year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

Toronto Hydro-Electric System Limited

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance (note 1)	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 1,051,152,700	59,888,497	-16,318,959	$ 1,094,722,238	$ 21,784,769	$ 1,072,937,469	4%	$ 42,917,499	$ 1,051,804,739
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 291,132,705			$ 291,132,705	$ -	$ 291,132,705	6%	$ 17,467,962	$ 273,664,743
8	General Office/Stores Equip	$ 26,779,433	3,415,063		$ 30,194,496	$ 1,707,532	$ 28,486,964	20%	$ 5,697,393	$ 24,497,103
10	Computer Hardware/ Vehicles	$ 13,390,916	3,876,736		$ 17,267,652	$ 1,938,368	$ 15,329,284	30%	$ 4,598,785	$ 12,668,867
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 7,149,799	23,681,726		$ 30,831,525	$ 11,840,863	$ 18,990,662	100%	$ 18,990,662	$ 11,840,863
13 1	Lease # 1	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 2	Lease #2	$ 31,168			$ 31,168	$ -	$ 31,168	SL	$ 31,169	$ -
13 3	Lease # 3	$ 57,546			$ 57,546	$ -	$ 57,546	SL	$ 38,365	$ 19,181
13 4	Lease # 4	$ 293,732			$ 293,732	$ -	$ 293,732	SL	$ 117,492	$ 176,240
13 5	Lease # 5	$ 348,832			$ 348,832	$ -	$ 348,832	SL	$ 77,518	$ 271,314
13 6	Lease # 6	$ -	43,066		$ 43,066	$ 21,533	$ 21,533	SL	$ 4,307	$ 38,759
13 7	Lease # 7	$ -			$ -	$ -	$ -	SL	$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 17,508,188		-1,034,729	$ 16,473,459	$ -	$ 16,473,459	8%	$ 1,317,877	$ 15,155,582
42	Fibre Optic Cable	$ 32,921			$ 32,921	$ -	$ 32,921	12%	$ 3,951	$ 28,969
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 44,912			$ 44,912	$ -	$ 44,912	45%	$ 20,210	$ 24,702
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -	196,970		$ 196,970	$ 98,485	$ 98,485	30%	$ 29,546	$ 167,425
47	Distribution System - post February 2005	$ 1,563,252,621	372,624,511		$ 1,935,877,132	$ 186,312,256	$ 1,749,564,877	8%	$ 139,965,190	$ 1,795,911,942
50	Data Network Infrastructure Equipment - post Mar 2007	$ 26,836,289	13,139,757		$ 39,976,046	$ 6,569,879	$ 33,406,168	55%	$ 18,373,392	$ 21,602,654
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 405,809,399			$ 405,809,399	$ -	$ 405,809,399	0%	$ -	$ 405,809,399
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 3,403,821,160	$ 476,866,326	-$ 17,353,688	$ 3,863,333,798	$ 230,273,684	$ 3,633,060,115		$ 249,651,318	$ 3,613,682,481

Note 1 - UCC Opening balance for Class 1	
UCC ending balance per 2014 Bridge Year Schedule 8	1,011,495,002
UCC re: Transfer of Streetlighting assets per OEB's decision	39,657,698
Adjusted UCC opening balance for Class 1	**1,051,152,700**

Ontario Energy Board

Toronto Hydro-Electric System Limited
Schedule 10 CEC - Test Year

Cumulative Eligible Capital - Beginning of Year				**21,482,100**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	46,291,502			
Other Adjustments	0			
Subtotal	46,291,502	**x 3/4 =**	34,718,627	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			34,718,627	**34,718,627**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**56,200,726**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**

Cumulative Eligible Capital Balance			**56,200,726**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")	**56,200,726**	**x 7% =**	**3,934,051**
Cumulative Eligible Capital - Closing Balance			**52,266,676**

OntarioEnergyBoard

Toronto Hydro-Electric System Limited

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

				Test Year Adjustments				
Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Additions	Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	0	0	0	0	0	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)								
			0			0		
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	243,040,000		243,040,000	8,521,000		251,561,000	8,521,000	
	0		0			0		
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
Total	243,040,000	0	243,040,000	8,521,000	0	251,561,000	8,521,000	0

OntarioEnergyBoard

Toronto Hydro-Electric System Limited

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Ontario Energy Board

Toronto Hydro-Electric System Limited
Taxable Income - Test Year

	T2 S1 line #	Test Year	Taxable Income
Net Income Before Taxes			**120,809,338**

Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	172,608,641
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	0
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	370,489
Non-deductible meals and entertainment expense	121	123,687
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	
Reserves from financial statements- balance at end of year	126	251,561,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	1,028,805
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
ARO Accretion expense		7,461
Capital Contributions Received (ITA 12(1)(x))		15,244,339
Deferred Revenue (ITA 12(1)(a))		387,306
Non-deductible portion of auto leases (>$800/month)		
Investment Tax Credits taxed in the year		2,263,000
Derecognition of tangible assets		33,932,393
Total Additions		**477,527,121**

Ontario Energy Board

Toronto Hydro-Electric System Limited
Taxable Income - Test Year

	T2 S1 line #	Test Year	Taxable Income
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403		249,651,318
Terminal loss from Schedule 8	404		
Cumulative eligible capital deduction from Schedule 10 CEC	405		3,934,051
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413		
Reserves from financial statements - balance at beginning of year	414		243,040,000
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
Financing Fees for Tax Under S.20(1)(e) / S.20(1)(e.1)			1,865,108
Excess Interest (see Tab "Sch 7-3 Interest Test Year")			3,037,819
ARO Payments - Deductible for Tax when Paid			52,000
ITA 13(7.4) Election - Capital Contributions Received			15,244,339
Deferred Revenue - ITA 20(1)(m) reserve			387,306
Land Lease payment capitalized for accounting			89,423
Lease payment capitalized for accounting			2,492,112
Other Post-Employment Benefits adjustment - change in balance with no Income Statement Impact			446,000
Other Post-Employment Benefits adjustment - current year capitalized portion with no Income Statement Impact			6,519,410
Lease Cancellation payment			1,719,231
Total Deductions			**528,478,118**
NET INCOME FOR TAX PURPOSES			**69,858,341**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331		
Net-capital losses of preceding taxation years (Please show calculation)	332		
Limited partnership losses of preceding taxation years from Schedule 4	335		
REGULATORY TAXABLE INCOME			**69,858,341**

Ontario Energy Board

Toronto Hydro-Electric System Limited
Excess Interest Expense - Test Year

Calculated Deemed Interest Expense	80,175,832
Test Year Actual Interest Expense	83,213,651
Test Year Capitalized Interest (USoA 6040)	
Test Year Capitalized Interest (USoA 6042)	0
Test Year Actual Interest	83,213,651
Interest Forecast for Tier 1 or 2 Adjustments	
Total Interest	83,213,651
Excess Interest Expense for Test Year PILs	3,037,819

Ontario Energy Board

Toronto Hydro-Electric System Limited
PILS Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$ 69,858,341	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 8,033,709	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-7.00%	**E**	-$ 35,000	**F = D * E**		
Ontario Income tax						$ 7,998,709	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.45%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					26.45%	**M = K + L**
Total Income Taxes						**$ 18,477,460**	**N = A * M**
Investment Tax Credits						$ 1,206,000	**O**
Miscellaneous Tax Credits						$ 1,057,000	**P**
Total Tax Credits						**$ 2,263,000**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 16,214,460**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				73.55%	**S = 1 - M**	**$ 5,831,003**	**T = R / S - R**
Income Tax (grossed-up)						**$ 22,045,463**	**U = R + T**
Tax credits reclass to OM&A						**$ 2,000,000**	**V**
Income Tax (grossed-up)						**$ 24,045,463**	**W = U + V**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

TAX RETURNS

In accordance with s. 2.7.5 of the OEB's Filing Requirements (July 17, 2013), the following documents are attached to this schedule:

- 2013 T2 Corporation Income Tax Return (Appendix A); and
- 2013 Scientific Research and Experimental Development (SR&ED) Expenditures Claim (Appendix B).

[redacted] 200

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

055 **Do not use this area**

Identification

Business number (BN) 001 [redacted]

Corporation's name
002 TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Address of head office
Has this address changed since the last time we were notified? 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 14 CARLTON STREET
012

City	Province, territory, or state
015 TORONTO	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 M5B 1K5

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o [redacted]
022 14 CARLTON STREET
023 5TH FLOOR -CORPORATE TAX DEPT

City	Province, territory, or state
025 TORONTO	026 ON
Country (other than Canada)	**Postal code/Zip code**
027	028 M5B 1K5

Location of books and records
Has the location of books and records changed since the last time we were notified? 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 14 CARLTON STREET
032

City	Province,territory, or state
035 TORONTO	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 M5B 1K5

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change 043 _____ YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year-end
060 2013-01-01	061 2013-12-31
YYYY MM DD	YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? 063 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired 065 _____ YYYY MM DD

Is the date on line 061 a deemed tax year-end in according to subsection 249(3.1)? 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? 070 1 Yes [ ] 2 No [X]
Amalgamation? 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079 _____

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 _____

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [X] Exempt under other paragraphs of section 149

Do not use this area
095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170	X	29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134
Did the corporation have any controlled foreign affiliates?	258		T1134
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	ELECTRICITY DISTRIBUTION	285 100.000 %
286		287 %
288		289 %

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes	2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300		44,171,327	A
Deduct: Charitable donations from Schedule 2	311	31,343		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		31,343	31,343	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			44,139,984	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		44,139,984	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			44,139,984	Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	43,597,436	A
Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 1/(0.38 - X**) 4 times the amount on line 636*** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	44,139,984	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 **** 2,447,197 / 11,250 D = 108,764,311 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425		F

Small business deduction

Amount A, B, C, or F, whichever is the least _____ x 17 % = 430 _____ G

Enter amount G on line 1 on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

**** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)					44,139,984	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27				B		
Amount QQ from Part 13 of Schedule 27				C		
Personal service business income	432			D		
Amount used to calculate the credit union deduction (amount F from Schedule 17)				E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least				F		
Aggregate investment income from line 440 on page 6*			573,891	G		
Total of amounts B to G			573,891	▶	573,891	H
Amount A **minus** amount H (if negative, enter "0")					43,566,093	I

Amount I	43,566,093	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365	x 11.5 %	=		J
Amount I	43,566,093	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365 / 365	x 13 %	=	5,663,592	K

General tax reduction for Canadian-controlled private corporations – Amount J **plus** amount K . . . . . 5,663,592 L

Enter amount L on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)						M
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27				N		
Amount QQ from Part 13 of Schedule 27				O		
Personal service business income	434			P		
Amount used to calculate the credit union deduction (amount F from Schedule 17)				Q		
Total of amounts N to Q				▶		R
Amount M **minus** amount R (if negative, enter "0")						S

Amount S		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365	x 11.5 %	=		T
Amount S		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365 / 365	x 13 %	=		U

General tax reduction – Amount T **plus** amount U V

Enter amount V on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 — 440 — 573,891 × 26 2 / 3 % = 153,038 A

Foreign non-business income tax credit from line 632 on page 7 — B

Deduct:

Foreign investment income from Schedule 7 — 445 — × 9 1 / 3 % = C

(if negative, enter "0") ▶ D

Amount A **minus** amount D (if negative, enter "0") — 153,038 E

Taxable income from line 360 on page 3 — 44,139,984 F

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least — G

Foreign non-business income tax credit from line 632 on page 7 — × 100 / 35 = H

Foreign business income tax credit from line 636 on page 7 — × 1(0.38 – X*) / 4 = I

Subtotal ▶ J

44,139,984 K

× 26 2 / 3 % = 11,770,662 L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) — 5,456,096 M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least — 450 — 153,038 N

* General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year — 460 — 979,825

Deduct: Dividend refund for the previous tax year — 465

979,825 ▶ 979,825 O

Add the total of:

Refundable portion of Part I tax from line 450 above — 153,038 P

Total Part IV tax payable from Schedule 3 — Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation — 480

153,038 ▶ 153,038 R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R — 485 — 1,132,863

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 — 40,000,000 × 1 / 3 = 13,333,333 S

Refundable dividend tax on hand at the end of the tax year from line 485 above — 1,132,863 T

Dividend refund – Amount S or T, whichever is less (enter this amount on line 784 on page 8) — 1,132,863

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % . . .			550	16,773,194 A
Recapture of investment tax credit from Schedule 31			602	B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6		573,891	i
Taxable income from line 360 on page 3	44,139,984		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	44,139,984 ▶	44,139,984	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604	38,259	C
Subtotal (**add** amounts A to C)		16,811,453	D

Deduct:

Small business deduction from line 430 on page 4			1	
Federal tax abatement	608	4,413,998		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount L on page 5	638	5,663,592		
General tax reduction from amount V on page 5	639			
Federal logging tax credit from Schedule 21	640			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652	1,277,767		
Subtotal		11,355,357 ▶		11,355,357 E

Part I tax payable – Amount D **minus** amount E		5,456,096 F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	5,456,096
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		5,456,096

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	3,671,315	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
(The Nova Scotia tax on large corporations is eliminated effective July 1, 2012.)			
Total provincial or territorial tax		3,671,315 ▶	3,671,315
Total tax payable	770		9,127,411 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784	1,132,863	
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	9,929,129	
Total credits	890	11,061,992 ▶	11,061,992 B

Refund code 894 2 Overpayment 1,934,581

Balance (amount A **minus** amount B) -1,934,581

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920

Certification

I, 950 COUILLARD (Last name (print)) 951 JS (First name (print)) 954 CFO (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2014-06-27 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation

956 (416) 542-3100 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☐ 2 No ☒

958 [redacted] Name (print) 959 [redacted] Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Privacy Act, personal information bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				115,739,021 A
Add:				
Provision for income taxes – current	101	3,122,853		
Amortization of tangible assets	104	171,474,771		
Charitable donations and gifts from Schedule 2	112	31,343		
Taxable capital gains from Schedule 6	113	573,891		
Scientific research expenditures deducted per financial statements	118	2,592,851		
Non-deductible club dues and fees	120	376,763		
Non-deductible meals and entertainment expenses	121	270,680		
Non-deductible automobile expenses	122	5,438		
Reserves from financial statements – balance at the end of the year	126	239,282,000		
Subtotal of additions		417,730,590	▶	417,730,590
Other additions:				
Debt issue expense	208	1,038,109		
Miscellaneous other additions:				
600 See attached	290	102,649,786		
603 Ontario Co-op Credit 801,687				
OITC/ORDTC/BCRDTC/ABRDTC from prior year - 12(1)(x) 79,124				
Total 880,811	293	880,811		
604 Ontario apprenticeship credit 206,986				
Total 206,986	294	206,986		
Subtotal of other additions	199	104,775,692	▶	104,775,692
Total additions	500	522,506,282	▶	522,506,282 B
Amount A **plus** amount B				638,245,303

Deduct:

Gain on disposal of assets per financial statements	401	1,279,608	
Capital cost allowance from Schedule 8	403	202,449,164	
Cumulative eligible capital deduction from Schedule 10	405	1,642,377	
SR&ED expenditures claimed in the year from Form T661 (line 460)	411	3,824,233	
Reserves from financial statements – balance at the beginning of the year	414	258,462,000	
Subtotal of deductions		467,657,382 ▶	467,657,382

Other deductions:

Miscellaneous other deductions:

700	See attached	390	126,416,594	
704				
	Total	394		
	Subtotal of other deductions	499	126,416,594 ▶	126,416,594
	Total deductions	510	594,073,976 ▶	594,073,976
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				44,171,327

T2 SCH 1 E (12)

Canada

Attached Schedule with Total

Line 390 -- Amount for line 700

Title Line 390 – Amount for line 700

Explanatory note

Other deductions to Schedule 1

Description	Amount
13(7.4) election regarding contributed capital	25,535,013 00
Capitalized POEB for actg not for tax	5,836,577 00
Principal lease payments	15,181 00
ARO payments deductible for tax purposes	572,285 00
Deferred revenue - 20(1)(m) deduct	20,020,088 00
Smart Meter OPEX recorded as Reg Asset, deductible in 2013	179,106 00
Smart Meters revenue recorded in I/S in 2013	58,128,533 00
Contact Voltage equipment lease payment capitalized for actg;deduct for tax	929,991 00
Legal Costs deferred for accounting	141,905 00
2012 Ontario Apprenticeship ITC, taxed in 2012, recorded for actg in 2013	311,800 00
2012 Ontario Co-op ITC, taxed in 2012, recorded for actg in 2013	593,345 00
Cogeco payment for lease cancellation incurred in 2013	15,384 00
Impact on 1562 Contingent Liability trued up to OEB approved amount	732,618 00
Debt financing under 20(1)(e)	2,015,708 00
POEB liability transfer from THC	157,000 00
POEB impact relating to restructuring costs	807,495 00
PILs variance acct 1562 clearance, approved by OEB	7,091,418 00
AFUDC income that is not taxable	3,322,500 00
Acctg gain of sale of Dylex Ltd shares recorded as bad debt expense	10,468 00
Acctg gain on sale of Quad Graphics shares recorded as misc interest exp	179 00
Total	126,416,594 00

Attached Schedule with Total

Line 290 – Amount for line 600

Title Line 290 – Amount for line 600

Explanatory note

Other additions to Schedule 1

Description	Amount
Smart Meter revenue recorded as Reg assets in 2013 but taxable in 2013	6,008,336 00
Reverse Smart Meters OPEX recorded in I/S per Smart Meter Clearance entries	7,105,084 00
Smart Meters Carrying Charges recorded in I/S	529,375 00
Reverse Smart Meters Carrying Charges added as reduction of revenue	646,300 00
ARO Accretion expense	176,603 00
Deferred revenue - 12(1)(a) add back	20,020,088 00
Fixed asset capital contributions under 12(1)(x)	25,535,013 00
HST cc recorded as Reg liab for acctg in 2012 [Not yet approved by OEB]	16,169 00
Reversal of PILs Regulatory Variance 1562 deducted for accounting	34,020 00
Reverse the I/S Impact on the Regulatory Liability for income tax	19,421,104 00
Late payment charges recorded as Reg Asset for acctg in 2010	1,433,445 00
Interest Expense impact on the 1562 Contingent Liability CC	46,804 00
Interest Expense re: NRWHT	169 00
Change in AOCI recorded in OPEX for accounting	1,279,492 00
POEB transferred from THESI	117,000 00
POEB change in AOCI	20,230,000 00
2012 Federal Apprenticeship credit not included in income for tax or actg	37,654 00
Interest Expense re: CRA HST Audit	10,007 00
2013 expense deducted already in 2012 for tax	3,123 00
Total	102,649,786 00

Toronto Hydro Electric System Limited

Taxation year ended: December 31, 2013
C.R.A. Bus#: [redacted]
MOF A/C# (Hydro PILs #): [redacted]

Election under subsection 13(7.4)

The company hereby elects under subsection 13(7.4) of the Income Tax Act to reduce the capital cost of depreciable property of class 47 acquired in the taxation year by a total amount of $25,535,013 received in the taxation year in respect of that property that would otherwise be included in income under paragraph 12(1)(x).

Authorized Signing Officer

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- For use by corporations to claim any of the following:
  - charitable donations to qualified donees;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the federal *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- The eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- A gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Humanitarian Coalition	250
Fatal Light Awareness Program Inc.	10,000
HOPE Inc.	100
Missionaries of Charity Inc.	200
Sick Kids Foundation	200
The Salvation Army	200
Daily Bread Food Bank	100
Canadian Cancer Society	140
Greater Toronto Apartment Association	200
The Princess Margaret Cancer Foundation	200
Tides Canada Foundation	2,000
Variety Village	400
Canadian Breast Cancer Foundation	100
Canadian Breast Cancer Foundation	5,500
Canadian Breast Cancer Foundation	190
The Peer Project - Youth Assisting Youth	200
The Peer Project - Youth Assisting Youth	200
The Peer Project - Youth Assisting Youth	200
Tony Stacey Centre for Veterans Care	100
Sierra Club Canada Foundation	200
Sick Kids Foundation	150
Parents for Community Living KW Inc.	100
Special Olympics Canada	200
Free the Children	125
The Princess Margaret Cancer Foundation	200
The Princess Margaret Cancer Foundation	200
Art House	100
Canadian Cancer Society	200
Alzheimer Society Ontario	200
Toronto Kiwanis Boys and Girls Club	1,000
Toronto Kiwanis Boys and Girls Club	500
Canadian Red Cross	1,045
The Salvation Army	100

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Movember Canada	4,653
St. Bernadette's Family Resource Centre	200
Subtotal	29,653
Add: Total donations of less than $100 each	1,690
Total donations in current tax year	31,343

			Federal		Québec		Alberta
Charitable donations at the end of the previous tax year		A		A			
Deduct: Charitable donations expired after five tax years*	239						
Charitable donations at the beginning of the tax year	240	B		B			
Add:							
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250						
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1)	210		31,343		31,343		31,343
Subtotal (line 250 **plus** line 210)		C	31,343	C	31,343		31,343
Subtotal (amount B **plus** amount C)		D	31,343	D	31,343		31,343
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255						
Total charitable donations available (amount D **minus** amount on line 255)		E	31,343	E	31,343		31,343
Deduct: Amount applied against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return)	260		31,343		31,343		31,343
Charitable donations closing balance (amount E **minus** amount on line 260)	280						

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2012-12-31			
2nd prior year	2011-12-31			
3rd prior year	2010-12-31			
4th prior year	2009-12-31			
5th prior year	2008-12-31			
6th prior year*	2007-12-31			
7th prior year	2006-12-31			
8th prior year	2005-12-31			
9th prior year	2004-12-31			
10th prior year	2003-12-31			
11th prior year	2002-12-31			
12th prior year	2001-12-31			
13th prior year	2001-09-30			
14th prior year	2000-09-30			
15th prior year	1999-09-30			
16th prior year	1998-09-30			
17th prior year	1997-09-30			
18th prior year	1996-09-30			
19th prior year	1995-09-30			
20th prior year	1994-09-30			
21st prior year*	1993-09-30			
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes * **multiplied** by 75 % . . . . . 33,128,495 F

Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** . . . . . 225 G

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) . . . . . 227 H

The amount of the recapture of capital cost allowance in respect of charitable gifts 230

Proceeds of disposition, less outlays and expenses ** I

Capital cost ** . . . . . J

Amount I or J, whichever is less 235

Amount on line 230 or 235, whichever is less . . . . . K

Subtotal (**add** amounts G, H, and K) L

Amount L **multiplied** by 25 % M

Subtotal (amount F **plus** amount M) 33,128,495 N

Maximum allowable deduction for charitable donations (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less) . . . . . 31,343 O

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year . . . . . A

Deduct: Gifts to Canada, a province, or a territory expired after five tax years 339

Gifts to Canada, a province, or a territory at the beginning of the tax year . . . . . 340 B

Add:

Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary 350

Total current-year gifts made to Canada, a province, or a territory * 310

Subtotal (line 350 **plus** line 310) ▶ C

Subtotal (amount B **plus** amount C) D

Deduct:

Adjustment for an acquisition of control (for gifts made after March 22, 2004) 355

Amount applied against taxable income (enter this amount on line 312 of the T2 return) 360

Subtotal (line 355 **plus** line 360) ▶ E

Gifts to Canada, a province, or a territory closing balance (amount D **minus** amount E) 380

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			F		
Deduct: Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the tax year	440		G		
Add:					
Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450				
Total current-year gifts of certified cultural property	410				
Subtotal (line 450 **plus** line 410)			H		
Subtotal (amount G **plus** amount H)			I		
Deduct:					
Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455				
Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			J		
Gifts of certified cultural property closing balance (amount I **minus** amount J)	480				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2012-12-31			
2nd prior year	2011-12-31			
3rd prior year	2010-12-31			
4th prior year	2009-12-31			
5th prior year	2008-12-31			
6th prior year*	2007-12-31			
7th prior year	2006-12-31			
8th prior year	2005-12-31			
9th prior year	2004-12-31			
10th prior year	2003-12-31			
11th prior year	2002-12-31			
12th prior year	2001-12-31			
13th prior year	2001-09-30			
14th prior year	2000-09-30			
15th prior year	1999-09-30			
16th prior year	1998-09-30			
17th prior year	1997-09-30			
18th prior year	1996-09-30			
19th prior year	1995-09-30			
20th prior year	1994-09-30			
21st prior year*	1993-09-30			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			K		
Deduct: Gifts of certified ecologically sensitive land expired*	539				
Gifts of certified ecologically sensitive land at the beginning of the tax year	540		L		
Add:					
Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550				
Gifts of certified ecologically sensitive land made before February 11, 2014					
Gifts of certified ecologically sensitive land made after February 10, 2014	+			+	
Total current-year gifts of certified ecologically sensitive land	510				
Subtotal (line 550 **plus** line 510)			M		
Subtotal (amount L **plus** amount M)			N		
Deduct:					
Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555				
Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			O		
Gifts of certified ecologically sensitive land closing balance (amount N **minus** amount O)	580				

* For the federal and Alberta, gifts made before February 11, 2014 , expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made during a tax year that ended after March 23, 2006 expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2012-12-31			
2nd prior year	2011-12-31			
3rd prior year	2010-12-31			
4th prior year	2009-12-31			
5th prior year	2008-12-31			
6th prior year*	2007-12-31			
7th prior year	2006-12-31			
8th prior year	2005-12-31			
9th prior year	2004-12-31			
10th prior year	2003-12-31			
11th prior year*	2002-12-31			
12th prior year	2001-12-31			
13th prior year	2001-09-30			
14th prior year	2000-09-30			
15th prior year	1999-09-30			
16th prior year	1998-09-30			
17th prior year	1997-09-30			
18th prior year	1996-09-30			
19th prior year	1995-09-30			
20th prior year	1994-09-30			
21st prior year*	1993-09-30			
Total				

* For the federal and Alberta, gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to determine the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years.
For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Part 6 – Additional deduction for gifts of medicine

		Federal	Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			P	
Deduct: Additional deduction for gifts of medicine expired after five tax years	639			
Additional deduction for gifts of medicine at the beginning of the tax year	640		Q	
Add:				
Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650			
Additional deduction for gifts of medicine for the current year:				
Proceeds of disposition	602	1	1	1
Cost of gifts of medicine	601	2	2	2
Subtotal (line 1 **minus** line 2)		3	3	3
Line 3 **multiplied** by 50 %		4	4	4
Eligible amount of gifts	600	5	5	5

Federal

a _____ x (b _____ / c) = Additional deduction for gifts of medicine for the current year 610 _____

Québec

a _____ x (b _____ / c) = Additional deduction for gifts of medicine for the current year _____

Alberta

a _____ x (b _____ / c) = Additional deduction for gifts of medicine for the current year _____

where:

a is the **lesser** of line 2 and line 4

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)			R	
Subtotal (amount Q **plus** amount R)			S	
Deduct:				
Adjustment for an acquisition of control	655			
Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Subtotal (line 655 **plus** line 660)			T	
Additional deduction for gifts of medicine closing balance (amount S **minus** amount T)	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2012-12-31			
2nd prior year	2011-12-31			
3rd prior year	2010-12-31			
4th prior year	2009-12-31			
5th prior year	2008-12-31			
6th prior year*	2007-12-31			
Total				

* These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
	Subtotal (line D **plus** line E)	F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2012-12-31	
2nd prior year	2011-12-31	
3rd prior year	2010-12-31	
4th prior year	2009-12-31	
5th prior year	2008-12-31	
6th prior year*	2007-12-31	
7th prior year	2006-12-31	
8th prior year	2005-12-31	
9th prior year	2004-12-31	
10th prior year	2003-12-31	
11th prior year	2002-12-31	
12th prior year	2001-12-31	
13th prior year	2001-09-30	
14th prior year	2000-09-30	
15th prior year	1999-09-30	
16th prior year	1998-09-30	
17th prior year	1997-09-30	
18th prior year	1996-09-30	
19th prior year	1995-09-30	
20th prior year	1994-09-30	
21st prior year*	1993-09-30	
Total		

* These gifts expired in the current year.

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A – Enter "X" if dividends received from a foreign source (connected corporation only).
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.
- Column F3 – Enter if dividends have been received or not after December 20, 2012. This information is required for corporations that must complete Schedules 71 and 72. For more details with regards to this column, consult the Help.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

		Complete if payer corporation is connected			
Name of payer corporation (from which the corporation received the dividend)	A	B Enter 1 if payer corporation is connected	C Business Number of connected corporation	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD (See note)	E Non-taxable dividend under section 83
200		205	210	220	230
				Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation. For more details, consult the Help.

				Complete if payer corporation is connected		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)*	F1 Eligible dividends (included in column F)	F2	F3	G Total taxable dividends paid by connected payer corporation (for tax year in column D)	H Dividend refund of the connected payer corporation (for tax year in column D)**	I Part IV tax before deductions F x 1 / 3 ***
240				250	260	270
						J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . . _____

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax . . . . . 320 _____

Subtotal _____

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax . . . . . 330 _____

Non-capital losses from previous years claimed to reduce Part IV tax . . . . . 335 _____

Current-year farm loss claimed to reduce Part IV tax . . . . . 340 _____

Farm losses from previous years claimed to reduce Part IV tax . . . . . 345 _____

Total losses applied against Part IV tax _____ x 1 / 3 = _____

Part IV tax payable (enter amount on line 712 of the T2 return) . . . . . 360 _____

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A Name of connected recipient corporation 400	B Business Number 410	C Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note) 420	D Taxable dividends paid to connected corporations 430	D1 Eligible dividends (included in column D)
1	Toronto Hydro Corporation	[redacted]	2013-12-31	40,000,000	40,000,000

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation. For more details, consult the Help.

Total 40,000,000

Total taxable dividends paid in the tax year to other than connected corporations . . . . . 450 _____

Eligible dividends (included in line 450) . . . . . 450a _____

Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450) 460 40,000,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 40,000,000

Other dividends paid in the tax year (total of 510 to 540) . . . . . _____

Total dividends paid in the tax year 500 40,000,000

Deduct:

Dividends paid out of capital dividend account . . . . . 510 _____

Capital gains dividends . . . . . 520 _____

Dividends paid on shares described in subsection 129(1.2) . . . . . 530 _____

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . . 540 _____

Subtotal _____ ▶ _____

Total taxable dividends paid in the tax year that qualify for a dividend refund 40,000,000

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Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 _____ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia Offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
44,139,984		44,139,984	5,041,098

Ontario basic income tax (from Schedule 500)	270	5,076,098		
Deduct: Ontario small business deduction (from Schedule 500)	402	35,000		
	Subtotal	5,041,098	5,041,098	A6
Add:				
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
	Subtotal			B6
		Subtotal (amount A6 **plus** amount B6)	5,041,098	C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414	25,249		
Ontario political contributions tax credit (from Schedule 525)	415			
Other Ontario non-refundable credits				
	Subtotal	25,249	25,249	D6
		Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")	5,015,849	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416		295,861	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			4,719,988	F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)	418			
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			4,719,988	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
	Subtotal			H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			4,719,988	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	801,687		
Ontario apprenticeship training tax credit (from Schedule 552)	454	206,986		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470	40,000		
	Subtotal	1,048,673	1,048,673	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		3,671,315	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 3,671,315

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 6

Summary of Dispositions of Capital Property

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Also use this schedule to make a designation under paragraph 111(4)(e) of the *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in Guide T4012, *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the *Income Tax Act*

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . . 050 1 Yes ☐ 2 No ☒

If **yes**, attach a statement specifying which properties such a designation applies to.

Part 1 – Shares

	1 Number of shares 100	2 Name of corporation in which the shares are held 105	3 Class of shares 106	4 Date of Acquisition YYYY/MM/DD 110	5 Proceeds of disposition 120	6 Adjusted cost base 130	7 Outlays and expenses from disposition 140	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 150	Foreign source
1	9,495	Dylex Ltd	Common		10,468			10,468	
2	8	Quad Graphics	Common		179			179	
				Totals	10,647			10,647	

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 160

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) . . . . . 10,647 A

Part 2 – Real estate (Do not include losses on depreciable property)

	1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	2 Date of Acquisition YYYY/MM/DD 210	3 Proceeds of disposition 220	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250	Foreign source
1	3077 Kingston Road		136,990		11,350	125,640	
2	104A Hollis Ave -Birchmount MS		400,000		24,879	375,121	
3	327 Cedarvale Avenue-East York		500,000		25,009	474,991	
4	450 Commissioner Street		225,000	150,820	13,019	61,161	
5	84 North Queen Street		218,817	104,000	14,595	100,222	
		Totals	1,480,807	254,820	88,852	1,137,135	B

Part 3 – Bonds

1 Face value of bonds 300	2 Maturity date YYYY/MM/DD 305	3 Name of bond issuer 307	4 Date of Acquisition YYYY/MM/DD 310	5 Proceeds of disposition 320	6 Adjusted cost base 330	7 Outlays and expenses from disposition 340	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 350	Foreign source
			Totals					C

Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property 400	2 Date of Acquisition YYYY/MM/DD 410	3 Proceeds of disposition 420	4 Adjusted cost base 430	5 Outlays and expenses from disposition 440	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 450	Foreign source
	Totals					D

Note

Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property 500	2 Date of Acquisition YYYY/MM/DD 510	3 Proceeds of disposition 520	4 Adjusted cost base 530	5 Outlays and expenses from disposition 540	6 Gain only (column 3 **minus** columns 4 and 5; if negative, enter "0") 550	Foreign source
	Totals					E

Note

You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property 600	2 Date of Acquisition YYYY/MM/DD 610	3 Proceeds of disposition 620	4 Adjusted cost base 630	5 Outlays and expenses from disposition 640	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 650	Foreign source
	Totals					

Deduct: Unapplied listed personal property losses from other years 655

Net gains (or losses) from the disposition of listed personal property (total of column 6 **minus** line 655) . . . . . F

Note

Net listed personal property losses can only be applied against listed personal property gains.
The amount on line 655 is from line 530 in Part 5 of Schedule 4, *Corporation Loss Continuity and Application*.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation	2 Shares, enter 1; debt, enter 2	3 Date of Acquisition YYYY/MM/DD	4 Proceeds of disposition	5 Adjusted cost base	6 Outlays and expenses from disposition	7 Loss only (column 4 **minus** columns 5 and 6)	Foreign source
900	905	910	920	930	940	950	
		Totals					

Allowable business investment losses (ABILs) . . . . . Total of Column 7 _____ x 50.0000 % = _____ G

Enter amount G on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.

Note

Properties listed in Part 7 should not be included in any other parts of this schedule.

Part 8 – Capital gains or losses

Total of amounts A to F (do not include amount F if it is a loss) . . . . . 1,147,782 H

Add: Foreign source

Capital gains dividend received in the year . . . . . 875 _____ I ☐

Capital gains reserve opening balance (from Schedule 13, *Continuity of Reserves*) . . . . . 880 _____ J

Subtotal (total of amounts H to J) 1,147,782 K

Deduct: Capital gains reserve closing balance (from Schedule 13) . . . . . 885 _____ L

Capital gains or losses, excluding ABILs (amount K **minus** amount L) . . . . . 890 1,147,782 M

Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8) . . . . . 1,147,782 N

Deduct the following amounts included in amount N, that are subject to the zero inclusion rate:

Note

When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only part of the taxpayer's capital gain on disposition of the property. See section 38.2 of the Act for more information.

Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under subparagraphs 38(a.1)(i) and (iii) of the Act . . . . . 895 _____ a Foreign source ☐

Gain on the donation to a qualified donee of ecologically sensitive land under paragraph 38(a.2) of the Act* . . . . . 896 _____ b Foreign source ☐

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) . . . . . _____ b-2 Foreign source ☐

Subtotal (amount a **plus** amount b **plus** b-2) _____ ▶ _____ O

Subtotal (amount N **minus** amount O) 1,147,782 P

Add:

Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12) of the Act:

Exemption threshold at time of disposition . . . . . 897 _____ c Foreign source ☐

The total of all capital gains from the disposition of the actual property . . . . . 898 _____ d Foreign source ☐

Amount c or amount d, whichever is less _____ Q

Total capital gains or losses (amount P **plus** amount Q) 1,147,782 R

Taxable capital gains or total capital losses:

Total capital losses (from amount R, if amount R is negative; if amount R is positive, enter "0") . . . . . _____ S

Enter amount S on line 210 of Schedule 4.

Taxable capital gains (amount R, if amount R is positive, multiplied 1,147,782 by 50.0000 %; if amount R is negative, enter "0") . . . . . 573,891 T

Enter amount T on line 113 of Schedule 1.

* Do not include gains on donations of ecologically sensitive land to a private foundation.

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Schedule 7

Aggregate Investment Income and Active Business Income

Corporation's name	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- This schedule is for the use of Canadian-controlled private corporations to calculate:
  - aggregate investment income and foreign investment income for the purpose of determining the refundable portion of Part I tax, as defined in subsection 129(4) of the *Income Tax Act;*
  - specified partnership income for members of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part I Tax" in Guide T4012, *T2 Corporation – Income Tax Guide.*

Part 1 – Aggregate investment income

The aggregate investment income is the aggregate **world** source income.

The eligible portion of taxable capital gains included in income for the year	002			573,891 A
Deduct:				
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	012		a	
Net capital losses of other years claimed on line 332 on the T2 return	022		b	
Amount a **plus** amount b				B
Amount A **minus** amount B (if negative, enter "0")				573,891 C
Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada)	032		c	
Deduct:				
Exempt income	042		1	
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year	052		2	
Taxable dividends deductible (total of Column F on Schedule 3)	062		3	
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	072		4	
Total of amounts 1 to 4			d	
Subtotal (amount c **minus** amount d)				D
Amount C **plus** amount D				573,891 E
Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)	082			F
Amount E **minus** amount F (if negative, enter "0")	092			573,891 G

Enter amount G on line 440 of the T2 return.

Part 2A – Canadian investment income calculation

Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13	573,891	1.1	
Reserve's eligible portion (addition/deduction)		1.2	
The eligible portion of taxable capital gains included in income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts 1.1 and 1.2)	573,891		573,891 1a
Deduct:			
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		2a	
Net capital losses of other years claimed on line 332 on the T2 return		3a	
Total of amounts 2a and 3a			4a
Amount 1a **minus** amount 4a (if negative, enter "0")			573,891 5a

Part 2A – Canadian investment income calculation (continued)

Taxable dividends	6.1		
Real estate rental properties (under regulation 1100(11))	6.2		
Other property income	6.3		
Total income from property from a source **Canadian**	▶		6a
Deduct:			
Exempt income	7a		
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year	8a		
Taxable dividends deductible (total of Column F on Schedule 3)	9a		
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	10a		
Total of amounts 7a to 10a	▶		11a
Amount 6a **minus** amount 11a			12a
Amount 5a **plus** amount 12a		573,891	13a
Losses from rental properties (under regulation 1100(11))	14.1		
Other losses from property	14.2		
Total losses from property from a source **Canadian**	▶		14a
Amount 13a **minus** amount 14a (if negative, enter "0")		573,891	15a

Part 2 – Foreign investment income

The foreign investment income is all income from sources **outside of Canada**.

Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13	H1			
Reserve's eligible portion (addition/deduction)	H2			
The eligible portion of taxable capital gains included in income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts H1 and H2)	▶	001		H
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		009		I
Subtotal (amount H **minus** amount I) (if negative, enter "0")				J
Taxable dividends	e1			
Real estate rental properties (under regulation 1100(11))	e2			
Other property income	e3			
Total income from property from a source **outside Canada**	▶	019		e
Deduct:				
Exempt income	029		5	
Taxable dividends deductible (total of Column F on Schedule 3)	049		6	
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	059		7	
Total of amounts 5 to 7	▶			f
Subtotal (amount e **minus** amount f)	▶			K
Amount J **plus** amount K				L
Losses from rental properties (under regulation 1100(11))	M1			
Other losses from property	M2			
Total losses from property from a source **outside Canada**	▶	069		M
Amount L **minus** amount M (if negative, enter "0")		079		N

(enter amount N on line 445 of the T2 return)

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

A	B	C
Partnership name 200	Total income (loss) of partnership from an active business 300	Corporation's share of amount in column B 310

D	E	F	G	H	I
Adjustments (add or deduct the prorated amounts calculated under section 34.2* and deduct expenses incurred by the corporation to earn partnership income) 315	Corporation's income (loss) of the partnership (column C **plus** column D) 320	Number of days in the partnership's fiscal period 325	Prorated business limit (column C ÷ column B) x [$500,000 x (column F ÷ 365)] (if column C is negative, enter "0")** 330	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0") 340
Total 350				Total 385	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . . 370 _____ g

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) . . . . . 380 _____ h

Subtotal (amount g **plus** amount h) _____ i

Amount at line 385 or amount i, whichever is less . . . . . 390 _____ O

Specified partnership income (line 360 **plus** amount O) . . . . . 400 _____ P

Enter amount P at line T in Part 4.

* In general, amounts included or deducted under subsections 34.2(2), 34.2(3), 34.2(4), 34.2(11), and 34.2(12) are deemed to have the **same character** and be in the **same proportions** as the partnership income to which they relate. For example, if a corporation receives $100,000 of partnership income for the partnership's fiscal period ending in its tax year, and that income is made up of $40,000 of active business income, $30,000 of income from property, and $30,000 as a taxable capital gain, the corporation's adjusted stub period accrual (ASPA) in respect of the partnership would be 40% active business income, 30% property income, and 30% taxable capital gains. Add or deduct **only the proportion** of the following amounts that is deemed under subsection 34.2(5) to be **active business income**:

add:

- the ASPA under subsection 34.2(2) (column 4 of Schedule 73);
- the income inclusion for a new corporate member of a partnership under subsection 34.2(3) (column 6 of Schedule 73);
- the previous-year transitional reserve under subsection 34.2(12) (column 12 of Schedule 73);

deduct:

- the previous-year ASPA under subsection 34.2(4) (column 5 of Schedule 73);
- the previous-year income inclusion for a new corporate member of a partnership under subsection 34.2(4) (column 7 of Schedule 73); and
- the current-year transitional reserve under subsection 34.2(11) (column 11 of Schedule 73).

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income for the purpose of calculating the prorated business limit in column G. Enter on line h the total of all loss from column E.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 in Part 3 (if the net amount is negative, enter "0" on line U)			Q
Specified partnership loss (from amount h in Part 3)			R
	Subtotal (amount Q **plus** amount R)		S
Deduct:			
Specified partnership income (from amount P in Part 3)			T
Partnership income (amount S **minus** amount T) (enter on line p in Part 5)	450		U

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return		44,171,327	j	
Plus:				
Allowable business investment loss from line 406 of Schedule 1			k	
	Subtotal (amount j **plus** amount k)	44,171,327 ▶		44,171,327 V
Deduct:				
Foreign business income after deducting related expenses*	500		l	
Taxable capital gains from line 113 of Schedule 1		573,891	m	
Net property income [amount c **minus** (amounts 1, 2, and F* in Part 1)]			n	
Personal services business income and other income after deducting related expenses*	520		o	
	Total of amounts l to o	573,891 ▶		573,891 W
Net amount (amount V **minus** amount W)				43,597,436 X
Deduct:				
Partnership income (amount U in Part 4)			p	
Income allocated to the corporation under subsection 96(1.1)	530		q	
	Subtotal (amount p **plus** amount q)	▶		Y
Income from active business carried on in Canada (amount X **minus** amount Y) (enter amount Z on line 400 of the T2 return - if negative, enter "0")				43,597,436 Z

* If negative, enter amount in brackets, and **add** instead of **subtracting**.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? 101 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Adjustments and transfers** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		1,100,418,576	7,194,064		140,384	3,526,840	1,103,945,416	4	0	0	44,157,817	1,063,314,439
2.	8		33,672,787	2,866,524		103,100	1,381,712	35,054,499	20	0	0	7,010,900	29,425,311
3.	10		19,745,958	337,366		73,193	132,087	19,878,044	30	0	0	5,963,413	14,046,718
4.	12		8,216,569	15,716,758		0	7,858,379	16,074,948	100	0	0	16,074,948	7,858,379
5.	17		15,752,835	4,734,238		7,123	2,363,558	18,116,392	8	0	0	1,449,311	19,030,639
6.	2		329,484,728			0		329,484,728	6	0	0	19,769,084	309,715,644
7.		CWIP	341,002,149	66,556,931		0	33,278,466	374,280,614	0	0	0		407,559,080
8.	45	computer hardware	148,469			0		148,469	45	0	0	66,811	81,658
9.	47	ELECTRICITY DISTRIBUTION EC	1,089,839,519	320,752,556		0	160,376,278	1,250,215,797	8	0	0	100,017,264	1,310,574,811
10.	13	2006 Additions				0			NA	0	0		
11.	13	2007 Additions				0			NA	0	0		
12.	42	Fibre	42,511			0		42,511	12	0	0	5,101	37,410
13.	50	Computers acquired after March	7,374,672	6,368,688		0	3,184,344	10,559,016	55	0	0	5,807,459	7,935,901
14.	13	2008 Additions	175,636			0		175,636	NA	0	0	175,636	
15.	13	2009 Additions	63,439			0		63,439	NA	0	0	42,293	21,146
16.	13	2010 Additions	155,842			0		155,842	NA	0	0	62,337	93,505
17.	43.2		2,129,728	2,504,274		0	1,252,137	3,381,865	50	0	0	1,690,933	2,943,069
18.	13	2011 Additions	134,276			0		134,276	NA	0	0	38,365	95,911
19.	13	2012 additions	556,825		-28,109	0		528,716	NA	0	0	117,492	411,224
		Totals	2,948,914,519	427,031,399	-28,109	323,800	213,353,801	3,162,240,208				202,449,164	3,173,144,845

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost:
- Amounts transferred under section 85, or transferred on amalgamation and winding-up of a subsidiary.

Items that **reduce** the undepreciated capital cost:
- Government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80.

See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (13)

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	TORONTO HYDRO CORPORATION		[redacted]	1					
2.	TORONTO HYDRO ENERGY SERVIC		[redacted]	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	21,595,209 A
Add: Cost of eligible capital property acquired during the taxation year	222	2,489,752			
Other adjustments	226				
Subtotal (line 222 plus line 226)		2,489,752	x 3 / 4 =	1,867,314 B	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1 / 2 =	C	
amount B minus amount C (if negative, enter "0")		1,867,314	▶		1,867,314 D
Amount transferred on amalgamation or wind-up of subsidiary				224	E
Subtotal (add amounts A, D, and E)				230	23,462,523 F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242			G	
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244			H	
Other adjustments	246			I	
(add amounts G,H, and I)			x 3 / 4 =	248	J
Cumulative eligible capital balance (amount F minus amount J)					23,462,523 K
(if amount K is negative, enter "0" at line M and proceed to Part 2)					
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business	249				
amount K	23,462,523				
less amount from line 249					
Current year deduction	23,462,523	x 7.00 % =	250	1,642,377 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)		1,642,377	▶		1,642,377 L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	21,820,146 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4	
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409	▶	9	
Line 6 minus line 9 (if negative, enter "0")		▶		O
Line N minus line O (if negative, enter "0")				P
Line 5 _____ x 1 / 2 =				Q
Line P minus line Q (if negative, enter "0")				R
Amount R _____ x 2 / 3 =				S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	POEB	253,890,000			15,098,000	238,792,000
2	Termination Accrual	4,572,000			4,082,000	490,000
	Reserves from Part 2 of Schedule 13					
	Totals	258,462,000			19,180,000	239,282,000

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 — Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 — Year: 2013

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 — 1 Yes ☐ 2 No ☒

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	1	500,000	100.0000	500,000
2	TORONTO HYDRO CORPORATION	[redacted]	1	500,000		
3	TORONTO HYDRO ENERGY SERVICES INC.	[redacted]	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

  Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (09)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 29

PAYMENTS TO NON-RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- A corporation that makes payments or credits amounts to non-residents under subsections 202(1) and 105(1) of the *Income Tax Regulations* has to file the applicable information return.
- The corporation has to complete the information below for all amounts paid or credited to non-residents that are listed in Note 1. If the total amount paid or credited is less than $100, you do not have to complete the information for that payee.

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
1	Bloomberg LP	731 Lexington Avenue Attention: Tax Department NewYork NY US 10022	02	1,826
2	AIHce	3141 Fairview Park Drive Suite 777 Falls Church VA US 22042	09	832
3	Assoc. of North American Independent Lab	Skarskaug Testing Lab 505 South Bell Avenue Ames IA US 50010	09	2,900
4	[redacted]	[redacted]	09	143,063
5	Exl Service Holdings Inc	280 Park Ave 38th Floor NewYork NY US 10017	09	11,765
6	EUCI	4601 DTC Blvd Suite 800 Denver OH US 80237	09	2,458
7	Hannon Electric Company	1605 Waynesbury Drive SE Carlton OH US 44707	09	3,681
8	IAPP Symposium	75 RochesterAve Suite 4 Portsmouth NH US 03801	09	1,288
9	Innovative Engineering Solution	PO Box 41 Napoleon MI US 49261	09	6,132
10	MTG	PO Box 340 Elk River MN US 55330	09	20,000

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	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
11	Power System Engineering Inc.	1532 West Broadway Madison WI US 53713	09	54,505
12	ProMark Solutions LLC	901 Mopac Expressway South Barton Oaks Plaza One Suite300 Austin TX US 78746	09	377,585
13	RMSI Private Limited	A-8 Sector 16 Noida IN 201301	09	119,363
14	Robert Jones & Associates	54 Knob Hill Orchard Park NY US 14127	09	19,739
15	Schweitzer Engineering Laboratories	2350 NE Hopkins Court Pullman WA US 99163	09	119,920
16	Scroggie Creek Consulting Inc.	6935 Wisconsin Ave Suite 600 Chevy Chase MD US 20815	09	16,699
17	Skillpath Seminars	PO Box 997 Mission KS US 66201	09	1,210
18	Smartsphere Inc	617 Broadway #1975 Sonoma CA US 95476	09	40,877
19	TDWI Symposium	1201 Monster Road SW Suite 250 Renton WA US 98057	09	2,709
20	Timelink	2975 Wesrchester Ave 2nd Floor Purchase NY US 10577	09	195,914
21	Toshiba	13131 West Liitle York Houston TX US 77041	09	255,289
22	TPSCO LLC	2961 Kendrick St Golden CO US 80401	09	12,373
23	The Colt Group	4135 Industry Way Flowery Branch GA US 30542	09	139,058

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	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
24	UMS	Morris Corporate Center 1300 Interpace Pkwy Parsippany NJ US 07054	09	38,000
25	Writing Assistance	3140 Harbor Lane Suite 130 Plymouth MN US 55447	09	37,991

Note 1: Enter the applicable payment code in column 300:

1 – Royalties
2 – Rents
3 – Management fees/commissions
4 – Technical assistance fees
5 – Research and development fees
6 – Interest
7 – Dividends
8 – Film payments: – motion picture film, or
– a film or video tape for use in connection with television
9 – Other services

T2 SCH 29 (99)

Canada

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Canada Revenue Agency / Agence du revenu du Canada

Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim;*
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada*, and T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21 of the Act), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) of the Act for more information.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) of the Act for more information.

Detailed information (continued)

- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013***	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****:	
– after March 28, 2012, and before 2014****	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015****	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more information. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . 101 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . 102 1 Yes ☐ 2 No ☒

Contributions to agricultural organizations for SR&ED* . . . . . 103 _____

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see Guide RC4088, *General Index of Financial Information (GIFI)*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661. Include all of the contributions made before 2013 and 80% of the contributions made after 2012.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125

Total of investments for qualified property and qualified resource property _____ A

* CCA: capital cost allowance

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year . . . . . B

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal (line 210 **plus** line 215) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part of amount A from Part 4) . . . . . x 10 % = 240

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part of amount A from Part 4) . . . . . x 5 % = 242

Credit allocated from a partnership 250

Subtotal (total of lines 230 to 250) ▶ D

Total credit available (line 220 **plus** amount D) . . . . . E

Deduct:

Credit deducted from Part I tax (enter at amount D in Part 30) 260

Credit carried back to the previous year(s) (amount H from Part 6) . . . . . a

Credit transferred to offset Part VII tax liability 280

Subtotal (total of line 260, amount a, and line 280) ▶ F

Credit balance before refund (amount E **minus** amount F) . . . . . G

Deduct:

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) 310

ITC closing balance of investments from qualified property and qualified resource property (amount G **minus** line 310) 320

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter at amount a in Part 5) H

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 from Part 5) I

Credit balance before refund (amount G from Part 5) . . . . . J

Refund (40 % of amount I or J, whichever is less) . . . . . K

Enter amount K or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)	6,233,799		
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (line 557 on Form T661 **plus** line 103 from Part 3)*	6,233,799 ▶	350	6,233,799
Capital expenditures incurred **before** 2014 (from line 558 on Form T661)**		360	45,034
Repayments made in the year (from line 560 on Form T661)		370	
Qualified SR&ED expenditures (total of lines 350 to 370)		380	6,278,833

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates an SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [X] 2 No [ ]

Complete lines 390 and 398 if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) 390

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million 398

* If either of the tax years referred to at line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone corporation: $ 8,000,000

Deduct:

Taxable income for the previous tax year (line 390 from Part 9) or $500,000, whichever is more _____ x 10 = _____ A

Excess ($8,000,000 **minus** amount A; if negative, enter "0") _____ B

$ 40,000,000 **minus** line 398 from Part 9 _____ a

Amount a **divided** by $ 40,000,000 _____ C

Expenditure limit for the stand-alone corporation (amount B **multiplied** by amount C) _____ D*

For an associated corporation:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 400 _____ E*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D or E _____ x Number of days in the tax year / 365 = 365 _____ F

Your SR&ED expenditure limit for the year (enter the amount from line D, E, or F, whichever applies) 410 _____

* Amount D or E cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10), whichever is less*	420		x	35 %	=		G
Line 350 **minus** line 410 (if negative, enter "0")**	430	6,233,799	x	20 %	=	1,246,760	H
Line 410 **minus** line 350 (if negative, enter "0")			b				
Capital expenditures (line 360 from Part 8) or amount b above, whichever is less*	440		x	35 %	=		I
Line 360 **minus** amount b above (if negative, enter "0")**	450	45,034	x	20 %	=	9,007	J
Repayments (amount from line 370 in Part 8)							
If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.**	460		x	35 %	=		c
	480		x	20 %	=		d
			Subtotal (amount c **plus** amount d)		▶		K
Current-year SR&ED ITC (total of amounts G to K; enter on line 540 in Part 12)						1,255,767	L

* For corporations that are not CCPCs, enter "0" for amounts G and I.

** For tax years that end after 2013, the general SR&ED rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year					M
Deduct:					
Credit deemed as a remittance of co-op corporations	510				
Credit expired	515				
		Subtotal (line 510 **plus** line 515)	▶		N
ITC at the beginning of the tax year (amount M **minus** amount N)			520		
Add:					
Credit transferred on amalgamation or wind-up of subsidiary	530				
Total current-year credit (from amount L in Part 11)	540	1,255,767			
Credit allocated from a partnership	550				
		Subtotal (total of lines 530 to 550)	1,255,767 ▶	1,255,767	O
Total credit available (line 520 **plus** amount O)				1,255,767	P
Deduct:					
Credit deducted from Part I tax (enter at amount E in Part 30)	560	1,255,767			
Credit carried back to the previous year(s) (amount S from Part 13)			e		
Credit transferred to offset Part VII tax liability	580				
		Subtotal (total of line 560, amount e, and line 580)	1,255,767 ▶	1,255,767	Q
Credit balance before refund (amount P **minus** amount Q)					R
Deduct:					
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)			610		
ITC closing balance on SR&ED (amount R **minus** line 610)			620		

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

Credit to be applied 911 _____
Credit to be applied 912 _____
Credit to be applied 913 _____
Total (enter at amount e in Part 12) _____ S

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? 650 1 Yes ☐ 2 No ☒

Current-year ITC (lines 540 **plus** 550 from Part 12 **minus** amount K from Part 11) _____ f

Refundable credits (amount f above or amount R from Part 12, whichever is less)* _____ T

Deduct:

Amount T or amount G from Part 11, whichever is less _____ U

Net amount (amount T **minus** amount U; if negative, enter "0") _____ V

Amount V **multiplied** by 40 % _____ W

Add:

Amount U _____ X

Refund of ITC (amount W **plus** amount X – enter this, or a lesser amount, on line 610 in Part 12) _____ Y

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined at line 101 in Part 2.

Credit balance before refund (amount R from Part 12) _____ Z

Deduct:

Amount Z or amount G from Part 11, whichever is less _____ AA

Net amount (amount Z **minus** amount AA; if negative, enter "0") _____ BB

Amount BB or amount I from Part 11, whichever is less _____ CC

Amount CC **multiplied** by 40 % _____ DD

Add :

Amount AA _____ EE

Refund of ITC (amount DD **plus** amount EE) _____ FF

Enter FF, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal (enter this amount at amount C in Part 17) A

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B in Part 16 on page 9.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B below.

D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (enter this amount at amount D in Part 17) B

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760 below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported at amount E in Part 17) **760** _____

Part 17 – Total recapture of SR&ED investment tax credit

Recapturated ITC for calculation 1 from amount A in Part 16	_____	C
Recapturated ITC for calculation 2 from amount B in Part 16	_____	D
Recapturated ITC for calculation 3 from line 760 in Part 16	_____	E
Total recapture of SR&ED investment tax credit – total of amounts C to E	_____	F

Enter amount F at amount A in Part 29.

Pre-Production Mining

Part 18 -- Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810	
Geological, geophysical, or geochemical surveys	811	
Drilling by rotary, diamond, percussion, or other methods	812	
Trenching, digging test pits, and preliminary sampling	813	

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820	
Sinking a mine shaft, constructing an adit, or other underground entry	821	

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts in column 826 ▶ A

Total pre-production mining expenditures (total of lines 810 to 821 and amount A)	830	

Deduct:

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832	
Excess (line 830 **minus** line 832) (if negative, enter "0")		B

Add:

Repayments of government and non-government assistance	835	
Pre-production mining expenditures (amount B **plus** line 835)		C

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year . . . . . D

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal (line 841 **plus** line 845) ▶ E

ITC at the beginning of the tax year (amount D **minus** amount E) 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part of amount C from Part 18)	870	x	10 %	=	a
Pre-production mining exploration expenditures incurred in 2013 (applicable part of amount C from Part 18)	872	x	5 %	=	b
Pre-production mining development expenditures incurred in 2014 (applicable part of amount C from Part 18)	874	x	7 %	=	c
Pre-production mining development expenditures incurred in 2015 (applicable part of amount C from Part 18)	876	x	4 %	=	d

Current year credit (total of amounts a to d) 880 ▶ F

Total credit available (total of lines 850, 860, and amount F) . . . . . G

Deduct:

Credit deducted from Part I tax (enter at amount F in Part 30) 885

Credit carried back to the previous year(s) (amount I from Part 20) . . . . . e

Subtotal (line 885 **plus** amount e) ▶ H

ITC closing balance from pre-production mining expenditures (amount G **minus** amount H) 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	921	
2nd previous tax year				Credit to be applied	922	
3rd previous tax year				Credit to be applied	923	

Total (enter at amount e in Part 19) I

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	PC3467	LINEWORKER	33,855	3,386	2,000
2.	PB1829	LINEWORKER	30,480	3,048	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
3.	PC3468	LINEWORKER	31,756	3,176	2,000
4.	PC3401	LINEWORKER	32,722	3,272	2,000
5.	PC3465	LINEWORKER	29,925	2,993	2,000
6.	PC3466	LINEWORKER	29,982	2,998	2,000
7.	PA8747	LINEWORKER	32,525	3,253	2,000
8.	PC3470	LINEWORKER	31,642	3,164	2,000
9.	PC3463	LINEWORKER	32,341	3,234	2,000
10.	PC3469	LINEWORKER	34,239	3,424	2,000
11.	PC7706	LINEWORKER	32,221	3,222	2,000

Total current-year credit (enter at line 640 in Part 22) 22,000 A

* Net of any other government or non-government assistance received or to be received.

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year . . . . . B

Deduct:

Credit deemed as a remittance of co-op corporations 612

Credit expired after 20 tax years 615

Subtotal (line 612 **plus** line 615) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) 625

Add:

Credit transferred on amalgamation or wind-up of subsidiary 630

ITC from repayment of assistance 635

Total current-year credit (amount A from Part 21) 640 22,000

Credit allocated from a partnership 655

Subtotal (total of lines 630 to 655) 22,000 ▶ 22,000 D

Total credit available (line 625 **plus** amount D) . . . . . 22,000 E

Deduct:

Credit deducted from Part I tax (enter at amount G in Part 30) 660 22,000

Credit carried back to the previous year(s) (amount G from Part 23) . . . . . a

Subtotal (line 660 **plus** amount a) 22,000 ▶ 22,000 F

ITC closing balance from apprenticeship job creation expenditures (amount E **minus** amount F) 690

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	931
2nd previous tax year				Credit to be applied	932
3rd previous tax year				Credit to be applied	933

Total (enter at amount a in Part 22) G

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year 715 _____

Add:

Specified child care start-up expenditures from the current tax year . . . . . 705 _____

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . _____ A

Deduct:

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line A . . . . . 725 _____

Excess (amount A **minus** line 725) (if negative, enter "0") . . . . . _____ B

Add:

Repayments by the corporation of government and non-government assistance . . . . . 735 _____

Total eligible expenditures for child care spaces (amount B **plus** line 735) . . . . . 745 _____

* CCA: capital cost allowance

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745) . . . . . _____ x 25 % = _____ C

Number of child care spaces . . . . . 755 _____ x $ 10,000 = _____ D

ITC from child care spaces expenditures (amount C or D, whichever is less) . . . . . _____ E

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year . . . . . F

Deduct:

Credit deemed as a remittance of co-op corporations 765

Credit expired after 20 tax years 770

Subtotal (line 765 **plus** line 770) ▶ G

ITC at the beginning of the tax year (amount F **minus** amount G) 775

Add:

Credit transferred on amalgamation or wind-up of subsidiary 777

Total current-year credit (amount E from Part 25) 780

Credit allocated from a partnership 782

Subtotal (total of lines 777 to 782) ▶ H

Total credit available (line 775 **plus** amount H) I

Deduct:

Credit deducted from Part I tax (enter at amount H in Part 30) 785

Credit carried back to the previous year(s) (amount K from Part 27) . . . . . a

Subtotal (line 785 **plus** amount a) ▶ J

ITC closing balance from child care spaces expenditures (amount I **minus** amount J) 790

Part 27 – Request for carryback of credit from child care space expenditures

	Year	Month	Day
1st previous tax year	2012-12-31		
2nd previous tax year	2011-12-31		
3rd previous tax year	2010-12-31		

. . . . . Credit to be applied 941

. . . . . Credit to be applied 942

. . . . . Credit to be applied 943

Total (enter at amount a in Part 26) K

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) 792

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC 795

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property 797

Amount from line 795 or line 797, whichever is less . . . . . A

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC 799

Total recapture of child care spaces investment tax credit (total of line 792, amount A, and line 799) . . . . . B

Enter amount B at amount B in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F in Part 17) . . . . . A

Recaptured child care spaces ITC (from amount B in Part 28) . . . . . B

Total recapture of investment tax credit (amount A **plus** amount B) C

Enter amount C on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		D
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	1,255,767	E
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		F
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	22,000	G
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		H
Total ITC deducted from Part I tax (total of amounts D to H)	1,277,767	I

Enter amount I at line 652 of the T2 return.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	TORONTO HYDRO CORPORATION	[redacted]			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

On: 2013-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Has the corporation wound-up a subsidiary in the preceding taxation year? ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	281,748,452 A
Taxable income for the year (DICs enter "0") *		110 44,139,984 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140	573,891		
Subtotal (**add** lines 120, 130, and 140)		573,891 ▶ 573,891 C		
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")		150 43,566,093		
After-tax income (line 150 x general rate factor for the tax year ** 0.72)			190	31,367,587 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (**add** lines 200 and 210)		▶		E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (**add** lines 220, 230, and 240)		▶	290	F
Subtotal (**add** lines A, D, E, and F)				313,116,039 G
Eligible dividends paid in the previous tax year	300	40,000,000		
Excessive eligible dividend designations made in the previous tax year	310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.				
Subtotal (line 300 **minus** line 310)		40,000,000 ▶		40,000,000 H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)			490	273,116,039
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	273,116,039

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2012-12-31

Taxable income before specified future tax consequences from the current tax year	24,673,909 J1		
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	696,346 M1		
Subtotal (**add** lines K1, L1, and M1)	696,346 ▶	696,346 N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")	23,977,563 ▶		23,977,563 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (**add** lines Q1, R1, and S1) ▶ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ▶ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.72) 500

Second previous tax year 2011-12-31

Taxable income before specified future tax consequences from the current tax year 46,068,513 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) 1,575,637 M2

Subtotal (**add** lines K2, L2, and M2) 1,575,637 ▶ 1,575,637 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 44,492,876 ▶ 44,492,876 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Subtotal (**add** lines Q2, R2, and S2) ▶ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ▶ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.7) 520

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year 68,995,269 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ L3

Aggregate investment income (line 440 of the T2 return) 492,758 M3

Subtotal (**add** lines K3, L3, and M3) 492,758 ▶ 492,758 N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 68,502,511 ▶ 68,502,511 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . . _____ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ R3

Aggregate investment income (line 440 of the T2 return) . . . . . _____ S3

Subtotal (**add** lines Q3, R3, and S3) _____ ▶ _____ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") _____ ▶ _____ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") _____ V3

GRIP adjustment for specified future tax consequences to the third previous tax year

(line V3 **multiplied by** the general rate factor for the tax year 0.69) . . . . . 540 _____

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . _____ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . AA

Eligible dividends paid by the corporation in its last tax year . . . . . _____ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . _____ CC

Subtotal (line BB **minus** line CC) _____ ▶ _____ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

(line AA **minus** line DD) . . . . . _____ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . ☐ Post amalgamation . . . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year		FF
The corporation's money on hand immediately before the end of its previous/last tax year		GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses		
Net capital losses		
Farm losses		
Restricted farm losses		
Limited partnership losses		
Subtotal	▶	HH
Subtotal (**add** lines FF, GG, and HH)		II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		JJ
Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		KK
All the corporation's reserves deducted in its previous/last tax year		LL
The corporation's capital dividend account immediately before the end of its previous/last tax year		MM
The corporation's low rate income pool immediately before the end of its previous/last tax year		NN
Subtotal (**add** lines JJ, KK, LL, MM, and NN)	▶	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")		PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	×	number of days in the tax year before January 1, 2010 / number of days in the tax year	365	. . . . .	=		QQ
0.69	×	number of days in the tax year in 2010 / number of days in the tax year	365	. . . . .	=		RR
0.7	×	number of days in the tax year in 2011 / number of days in the tax year	365	. . . . .	=		SS
0.72	×	number of days in the tax year after December 31, 2011 / number of days in the tax year	365 / 365	. . . . .	=	0.720000000	TT

General rate factor for the tax year (total of lines QQ to TT) . . . . . 0.72000 UU

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		40,000,000	
Total taxable dividends paid in the tax year	100	40,000,000	
Total eligible dividends paid in the tax year	150	40,000,000	A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160	273,116,039	B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200		
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or are claiming the Ontario transitional tax credit.
- Unless otherwise noted, all legislative references are to the federal *Income Tax Act*.
- File this schedule with the *T2 Corporation Income Tax Return*.
- Unless otherwise noted, terms on this page are defined under subsection 46(1) of the *Taxation Act, 2007* (Ontario).
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal Act;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal Act;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part II of the *Corporations Tax Act* (Ontario) for that tax year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of *the Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the tax year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the tax year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the tax year; or
  - the corporation has an unused transitional tax credit balance from previous tax years.
- **Transition time** means:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on December 31, 2008, or
  - the beginning of the corporation's tax year that includes January 1, 2009, in any other case.
- An **eligible amalgamation** means an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An **eligible post-2008 windup** means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year (during which it received the assets of the subsidiary) ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An **eligible pre-2009 windup** means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year (during which it received the assets of the subsidiary) ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year (during which it received the assets of the subsidiary) ended after December 31, 2008.
- The **completion time** of a windup means the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A **specified pre-2009 transfer** under section 52 of the *Taxation Act, 2007* (Ontario) means a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	110	
Charitable donations not yet deducted from income (from line 280 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	112	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	114	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	116	
Gifts of certified ecologically sensitive land (from line 580 of Schedule 2) (see Note 1)	118	
Gifts of medicine (from line 680 of Schedule 2) (see Note 1)	120	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	122	
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	124	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	128	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	130	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	132	

Federal balances at the beginning of the current tax year

Non-capital losses (line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	134	
Net capital losses (from line 200 of Schedule 4 of the current tax year x 50 %) (see Note 2 and Note 4)	136	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	150	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	152	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	154	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act, at the beginning of the tax year (see Note 5)	160	
Gain from a negative adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	162	
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	164	
Federal balance before election (total of lines 110 to 164)		A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	170	

Total federal balance (amount A **minus** line 170) 180

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 2 – Total Ontario balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*)	210	
Charitable donations (amount I from Ontario *Schedule 2, Ontario Charitable Donations and Gifts*) (see Note 1)	212	
Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1)	214	
Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1)	216	
Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1)	218	
Gifts of medicine (see Note 1)	220	
Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*)	222	
Ontario SR&ED expenditure pool (line 480 from Ontario *CT23 Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3)	224	
Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5)	226	
Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2)	228	
Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2)	230	
Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2)	232	
Non-capital losses (from line 709 of Ontario *Corporations Tax Return CT8* or *CT23 Corporations Tax and Annual Return*) (see Note 2 and Note 4)	234	
Net capital losses (from line 719 of CT8 or CT23 x 50 %) (see Note 2 and Note 4)	236	

Amounts included in the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv)	250	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii)	252	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year (see Note 6)	260	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year	262	
Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	264	
Total Ontario balance (total of lines 210 to 264)	280	

Enter amount on line 340 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:

- have been earned and are available without restriction to the corporation;
- are attributable to qualifying Ontario SR&ED expenditures;
- have not been deducted under subsection 127(5) or (6) of the federal Act at the end of the corporation's tax year ending immediately before its transition time; and
- do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor as calculated in Part 11.

Note 6: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 3 – Total federal balance and total Ontario balance at the end of the tax year

Total federal balance:

Total federal balance (amount from line 180 in Part 1, or amount from line 330 in Part 3 of Schedule 506 for the previous tax year)	300	959,662,508		
Add:				
Amount from eligible amalgamation*	310			
Amount from eligible post-2008 windup*	315			
Amount from eligible pre-2009 windup*	320			
Amount from specified pre-2009 transfers*	325			
Total federal balance at the end of the tax year		959,662,508 ▶	330	959,662,508

Total Ontario balance:

Total Ontario balance (amount from line 280 in Part 2, or amount from line 370 in Part 3 of Schedule 506 for the previous tax year)	340	960,101,610		
Add:				
Amount from eligible amalgamation*	350			
Amount from eligible post-2008 windup*	355			
Amount from eligible pre-2009 windup*	360			
Amount from specified pre-2009 transfers*	365			
Total Ontario balance at the end of the tax year		960,101,610 ▶	370	960,101,610
Transitional balance at the end of the tax year (line 330 **minus** line 370)			390	-439,102

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation.*

Part 4 – Election to reduce federal SR&ED expenditure pool

The corporation may make this election if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? 400 1 Yes ☐ 2 No ☒

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1)			B
Deduct:			
Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2)	1		
Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2)	2		
Subtotal (amount 1 **plus** amount 2)	▶		C
Subtotal (amount B **minus** amount C) (if negative, enter "0")			D
Federal balance before election (amount A from Part 1)			
Deduct:			
Total Ontario balance (amount from line 280 in Part 2)			
Subtotal (if negative, enter "0")			E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period starts at the beginning of the corporation's first tax year ending after December 31, 2008, and ends on whichever date is earlier:

- five calendar years after the time immediately before the start of the corporation's reference period; or
- December 31, 2013.

Number of days in the corporation's reference period* (do not include February 29, 2008, and February 29, 2012) . . **410** 730

* The number of days in the corporation's reference period is 1825 unless:

- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or
- the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:

- the end of the corporation's reference period; or
- the early termination date as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) **420** 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:

- the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or
- the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period ends, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a PE in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debit.
Note: The Ontario Allocation Factor, calculated in Part 6, has to be at least 90% or the amount on line 390 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 8 cannot be more than $1,000.

If you ticked one of the above boxes:

- enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 . . . . . **435**
- enter the number of days from the first day of the tax year to the end of the corporation's reference period (do not include February 29, 2008, or February 29, 2012) **440**

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line F:

Ontario taxable income* / Taxable income** =

Ontario allocation factor (OAF) . . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If taxable income is nil, calculate the amount in column F as if taxable income were $1,000.

** Enter taxable income from line 360 or amount Z of the T2 return, whichever applies. If taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3			G
Amount G x Ontario basic rate of tax*	11.5 % =		H
Amount H x OAF (from line F in Part 6)	1.00000		I

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period from line 410 in Part 5: 365 / 730 = 0.50000 J

Transitional tax debit before tax on elected reduced SR&ED pool (amount I **multiplied** by amount J) K

Post-2008 SR&ED balance at the end of the year (amount HH from Part 12) 460

Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14) 470

Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470) L

Total transitional tax debits (amount K **plus** amount L) M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5 5,041,098 N

Deduct:

Ontario resource tax credit (from line 404 of Schedule 5)

Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)

Ontario foreign tax credit (from line 408 of Schedule 5)

Ontario credit union tax reduction (from line 410 of Schedule 5)

Subtotal O

Subtotal (amount N **minus** amount 0) 5,041,098 P

Number of days from line 420 in Part 5 / Number of days in the tax year (do not include February 29, 2008, or February 29, 2012): 365 / 365 = 1.00000 Q

Ontario tax payable for purposes of the current year transitional tax credit (amount P **multiplied** by amount Q) 510 5,041,098

Amount from line 390 in Part 3 (enter as a positive amount)		439,102	R
Amount R x Ontario basic rate of tax*	11.5 % =	50,497	S
Amount S x OAF (from line F in Part 6)		50,497	T

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period on line 410 in Part 5: 365 / 730 = 0.50000 U

Current-year transitional tax credit (amount T **multiplied** by amount U) 520 25,249

Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0") 530 5,015,849

Transitional tax credit:

Lesser of amounts on line 510 and 520 25,249 V

Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530 W

Transitional tax credits (amount V **plus** amount W) 25,249 X

Enter amount X on line 414 of Schedule 5.

* Enter the rate calculated in Part 1 of Schedule 500, *Ontario Corporation Tax Calculation*.

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)* 1

Add:

Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2008 windup* 560 2

Unused transitional tax credit available (amount 1 **plus** amount 2) . . . . . Y

Add:

Current-year transitional tax credit (amount from line 520 in Part 8) . . . . . 25,249 Z

Subtotal (amount Y **plus** amount Z) 25,249 3

Deduct:

Transitional tax credit applied (amount X from Part 8) . . . . . 25,249 AA

Unused transitional tax credit (available for later years) (amount 3 **minus** amount AA) 580

* Enter "0" if this is the first tax year ending after 2008.

Complete parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a) 610

Capital SR&ED expenditures in the year under paragraph 37(1)(b) 614

Repayment of assistance under paragraph 37(1)(c) 618

Investment tax credit recaptured under subsections 127(27), (29), and (34) in the previous tax year 624

Subtotal (total of lines 610 to 624) BB

Deduct:

Assistance under paragraph 37(1)(d) 638

Investment tax credits deducted under paragraph 37(1)(e) 644

Subtotal (line 638 **plus** line 644) CC

Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC) 650

If the amount on line 650 is positive, enter it on line II in Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

- the corporation's OAF for the tax year that includes its transition time (from line F in Part 6) . . . . . %
- the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) . . . . . %
- the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008 . . . . . %

Relevant OAF . . . . . 660 %

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

- the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;
2) a corporation that wound up into the particular corporation under subsection 88(1); or
3) a designated corporation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . . DD

SR&ED expenditure amount deducted in the year under subsection 37(1) 670

Deduct:

Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) 675

Subtotal (line 670 **minus** line 675) (if negative, enter "0") ▶ EE

Subtotal (amount DD **plus** amount EE) FF

Amount FF x 14 % GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 660 from Part 11) . . . . . HH

Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) II

Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 700

Subtotal (line II **plus** line 700) JJ

Total of all amounts deducted under subsection 37(1) for previous tax years ending after December 31, 2008 705

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) 710

Deduct:

Amounts included in line 710 that are reasonably attributable to the federal current SR&ED deficit for the year 715

Subtotal (line 710 **minus** line 715) 720

Line 720 = ... KK

Relevant OAF (from line 660 in Part 11) x 14 %

Subtotal (line 705 **minus** amount KK) ▶ 730

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") LL

Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1 (see Note) . . . . . 735 MM

Relevant OAF (from line 660) (see Note) **multiplied** by amount MM . . . . . NN

Amount NN x 14 % . . . . . ▶ OO

Federal SR&ED transitional balance transferred on an eligible amalgamation or an eligible post-2008 wind-up 740

Subtotal (amount OO **plus** line 740) PP

Deduct:

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) 750

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . . QQ

Enter amount QQ on line 470 in Part 7.

Note: For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

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SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return*.

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	6,659,771 A	
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	85,077 B	
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		6,574,694 C	
Add: Eligible expenditures transferred to the corporation by another corporation	110	D	
Subtotal (amount C **plus** amount D)		6,574,694 ▶	6,574,694 E
Deduct: Eligible expenditures the corporation transferred to another corporation	115		F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")	120		6,574,694 G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)	6,574,694	x	4.50 %	=	200	295,861 H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					205	I
* If there is a disposal or change of use of eligible property, see Part 6						
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment	210	x	4.50 %	=	215	J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220	x 1 / 4 =	x 4.50 %	=	225	K
Current part of the ORDTC (total of amounts H to K)					230	295,861 L

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year			M
Deduct: ORDTC expired after 20 tax years	300		N
ORDTC at the beginning of the tax year (amount M **minus** amount N)	305		O
Add:			
ORDTC transferred on amalgamation or windup	310		P
Current part of ORDTC (amount L in Part 2)		295,861	Q

Are you waiving all or part of the current part of the ORDTC? 315 Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	320		R	
Subtotal (amount Q **minus** amount R)		295,861 ▶	295,861	S
ORDTC available for deduction (total of amounts O, P and S)		295,861 ▶	295,861	T
Deduct:				
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)		295,861	U	
ORDTC carried back to a previous tax year (from Part 4)			V	
Subtotal (amount U **plus** amount V)		295,861 ▶	295,861	W
ORDTC balance at the end of the tax year (amount T **minus** amount W)	325			X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year	Month	Day			
1st previous tax year	2012-12-31			Credit to be applied	901	
2nd previous tax year	2011-12-31			Credit to be applied	902	
3rd previous tax year	2010-12-31			Credit to be applied	903	
				Total (enter amount on line V in Part 3)		

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available
1994-09-30	
1995-09-30	
1996-09-30	
1997-09-30	
1998-09-30	
1999-09-30	
2000-09-30	
2001-09-30	
2001-12-31	
2002-12-31	

Tax year of origin (earliest tax year first) Year Month Day	Credit available
2003-12-31	
2004-12-31	
2005-12-31	
2006-12-31	
2007-12-31	
2008-12-31	
2009-12-31	
2010-12-31	
2011-12-31	
2012-12-31	
Current tax year 2013-12-31	

Total (equals line 325 in Part 3) _____

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Z Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) _____ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred 750	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) _____ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . . 760 _____ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . . _____ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . . _____ LL

Amount KK **plus** amount LL . . . . . _____ x 23.56 % = _____ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . . _____ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . . _____ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation.**

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures		Capital Expenditures
Total expenditures for SR&ED		5,756,477		47,156
Add				
• payment of prior years' unpaid expenses (other than salary or wages)	+			
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	1,466,035		
• expenditures on shared-use equipment			+	
• other additions	+		+	
Subtotal	=	7,222,512	=	47,156
Less				
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	−			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	−			
• 20% of contract expenditures for SR&ED performed on your behalf	−	609,897		
• prescribed expenditures not allowed by regulations	−		−	
• other deductions	−		−	
• non-arm's length transactions				
– expenditures for non-arm's length SR&ED contracts	−			
– purchases (limited to costs) of goods and services from non-arm's length suppliers	−		−	
Subtotal	=	6,612,615 I	=	47,156 II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			=	6,659,771 III

Enter amount III on line 100 of Schedule 508.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	3,775,449,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	2,884,593,000
Total assets (total of lines 112 to 116)		6,660,042,000
Total revenue of the corporation for the tax year **	142	3,187,743,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	205,636,000
Total revenue (total of lines 142 to 146)		3,393,379,000

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

*** Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

**** Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	115,739,021
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	3,122,853		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281 _____	282			
283 _____	284			
Subtotal		3,122,853 ▶		3,122,853 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381 _____	382			
383 _____	384			
385 _____	386			
387 _____	388			
389 _____	390			
Subtotal		▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	118,861,874

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

*** Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)	515	118,861,874	
Deduct:			
CMT loss available (amount R from Part 7)			
Minus: Adjustment for an acquisition of control *	518		
Adjusted CMT loss available			C
Net income subject to CMT calculation (if negative, enter "0")	520	118,861,874	

Amount from line 520: 118,861,874 × (Number of days in the tax year before July 1, 2010 / Number of days in the tax year: 365) × 4 % = 1

Amount from line 520: 118,861,874 × (Number of days in the tax year after June 30, 2010: 365 / Number of days in the tax year: 365) × 2.7 % = 3,209,271 2

Subtotal (amount 1 **plus** amount 2) 3,209,271 3

Gross CMT: amount on line 3 above x OAF **	540	3,209,271	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		3,209,271	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		4,719,988	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

**** Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G
Deduct:			
CMT credit expired *	600		
CMT credit carryforward at the beginning of the current tax year * (see note below)		620	
Add:			
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)	650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)			H
Deduct:			
CMT credit deducted in the current tax year (amount P from Part 5)			I
Subtotal (amount H **minus** amount I)			J
Add:			
Net CMT payable (amount E from Part 3)			
SAT payable (amount O from Part 6 of Schedule 512)			
Subtotal			K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)	670		L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)	4,719,988	1		
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)	3,209,271	2		
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)		3		
Gross SAT (line 460 from Part 6 of Schedule 512)		4		
The **greater** of amounts 3 and 4		5		
Deduct: line 2 or line 5, whichever applies:	3,209,271	6		
Subtotal (if negative, enter "0")	1,510,717		1,510,717	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)	4,719,988			
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)	1,048,673			
Subtotal (if negative, enter "0")	3,671,315		3,671,315	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin		CMT credit balance *
10th previous tax year	680	
9th previous tax year	681	
8th previous tax year	682	
7th previous tax year	683	
6th previous tax year	684	
5th previous tax year	685	
4th previous tax year	686	
3rd previous tax year	687	
2nd previous tax year	688	
1st previous tax year	689	
Total **		

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year	[redacted]	829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return*.

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	TORONTO HYDRO CORPORATION	[redacted]	2,854,213,000	189,462,000
2	TORONTO HYDRO ENERGY SERVICES INC.	[redacted]	30,380,000	16,174,000
		Total 450	2,884,593,000	550 205,636,000

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2012-01-01	1864665

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
14	Carlton Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Toronto	ON	CA	M5B 1K5

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 COUILLARD (Last name) **451** JS (First name)

454 _____ (Middle name(s))

460 [2] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering 1 for English or 2 for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	[redacted]	2013-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return.*
- File this schedule with the *T2 Corporation Income Tax Return.*

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
[redacted]	[redacted]

Is the claim filed for a CETC earned through a partnership?* . . . . . 150 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . 160 _____

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . 170 _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . 200 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . 210 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

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Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * 300 1,000,000

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \frac{\text{amount on line 300 minus } \$\ 400{,}000}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . 310 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \frac{\text{amount on line 300 minus } \$\ 400{,}000}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . 312 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
1.	Waterloo	Management Engineering
2.	Mohawk	Eng Tech
3.	McMaster	Electrical Engineering
4.	McMaster	Civil Eng/Management
5.	McMaster	Electrical Engineering
6.	UOIT	Engineering
7.	U of T	Professional Experience Year
8.	McMaster	Electrical Engineering
9.	UTSC	Management
10.	Seneca	Computer Systems Technology
11.	UofT PEY	Professional Experience Year
12.	UTSC	Management
13.	UTSC	Management
14.	Seneca	Human Resources
15.	U of T	Professional Experience Year
16.	Centennial	Electronics Eng Technology
17.	Waterloo	Environment & Business
18.	UofT PEY	Professional Experience Year
19.	U of T	Professional Experience Year
20.	U of T PEY	Professional Experience Year
21.	UofT PEY	Professional Experience Year
22.	U of T	Professional Experience Year
23.	York	Information Technology

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	Ryerson	Industrial Internship Program
25.	U of T	Professional Experience Year
26.	UofT PEY	Professional Experience Year
27.	Ryerson	Business Tech Management
28.	UofT PEY	Professional Experience Year
29.	Seneca	Accounting and Finance
30.	Waterloo	Electrical Engineering
31.	U of T	Professional Experience Year
32.	Ryerson University	Electrical & Computer Engineering
33.	U of T PEY	Professional Experience Year
34.	U of T PEY	Professional Experience Year
35.	U of T	Professional Experience Year
36.	Western	Mechanical Engineering
37.	Mohawk	Eng-Tech
38.	Georgian	Electrical Engineering Technology
39.	UofT Scarborough	Management
40.	McMaster University	Computer Engineering
41.	UofT PEY	Professional Experience Year
42.	U of T	Professional Experience Year
43.	McMaster	Electrical Engineering
44.	U of T	Professional Experience Year
45.	Georgian	Electrical Engineering Technology
46.	Ryerson	Computer Science
47.	Waterloo	Electrical Engineering
48.	U of T	Professional Experience Year
49.	UofT PEY	Professional Experience Year
50.	Georgian	Electrical Engineering Technology
51.	Georgian	Electrical Engineering Technology
52.	UofT PEY	Professional Experience Year
53.	UofT PEY	Professional Experience Year
54.	UofT PEY	Professional Experience Year
55.	U of T	Professional Experience Year
56.	Georgian	Electrical Engineering Technology
57.	Queens	Undergraduate Internship Program
58.	U of T	Professional Experience Year
59.	UofT PEY	Professional Experience Year
60.	Georgian	Electrical Engineering Technology
61.	Waterloo	Electrical Engineering
62.	Waterloo	Science & Business
63.	Ryerson	Industrial Internship Program
64.	McMaster	Engineering Physics
65.	Georgian	Electrical Engineering Technology
66.	Waterloo	Electrical Engineering
67.	UTSC	Management
68.	Waterloo	Electrical Engineering
69.	UOIT	Engineering
70.	U of T	Professional Experience Year
71.	Mohawk	Electrical Engineering Technology
72.	Ryerson University	Electrical & Computer Engineering
73.	U of T	Professional Experience Year
74.	Georgian	Electrical Engineering Technology
75.	UofT PEY	Professional Experience Year
76.	Guelph	Mechanical Engineering
77.	U of T	Professional Experience Year
78.	U of T	Professional Experience Year

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
79.	Mohawk	Electrical Engineering Technology
80.	McMaster	Business
81.	UTSC	Management
82.	Seneca	Human Resources
83.	UofT Scarborough	Management
84.	Georgian	Automotive Business Diploma
85.	Ryerson	Industrial Internship Program
86.	Seneca	Accounting and Finance
87.	York	Information Technology
88.	Ryerson	Mechanical & Industrial Engineering
89.	Ryerson	Chemical Engineering
90.	U of T PEY	Professional Experience Year
91.	Ryerson	Occupational Health & Safety
92.	Waterloo	Mechanical Engineering
93.	UofT PEY	Professional Experience Year
94.	Ryerson	Mechanical & Industrial Engineering
95.	Waterloo	Electrical Engineering
96.	U of T PEY	Professional Experience Year
97.	McMaster	Electrical Engineering
98.	Mohawk	Eng-Tech
99.	McMaster	Electrical Engineering
100.	UTSC	Management
101.	UTSC	Management
102.	Waterloo	Mechatronics Engineering
103.	U of T	Professional Experience Year
104.	Seneca	Computer Systems Technology
105.	Waterloo	Chemical Engineering
106.	Waterloo	Science& Business
107.	Waterloo	Systems Design Engineering
108	U of T	Professional Experience Year
109.	U of T	Professional Experience Year
110.	Seneca	Human Resources
111.	Georgian	Electrical Engineering Technology
112.	Waterloo	Mathematics
113.	U of T	Professional Experience Year
114.	U of T	Professional Experience Year
115.	U of T	Professional Experience Year
116.	Waterloo	Electrical Engineering
117.	Georgian	Electrical Engineering Technology
118.	Seneca	Accounting and Finance
119.	Waterloo	Electrical Engineering
120.	U of T	Electrical Engineering
121.	Ryerson University	Electrical & Computer Engineering
122.	Waterloo	Business& Mathematics
123.	Waterloo	Information Tech Mgmt
124.	Mohawk	Eng-Tech
125.	Georgian	Electrical Engineering Technology
126.	UofT Scarborough	Management
127.	McMaster University	Computer Engineering
128.	U of T	Professional Experience Year
129.	U of T	Professional Experience Year
130.	Waterloo	Electrical Engineering
131.	U of T	Professional Experience Year
132.	Waterloo	Computational Mathematics
133.	Waterloo	Environmental Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
134.	Georgian	Electrical Engineering Technology
135.	UofT Scarborough	Management
136.	U of T	Professional Experience Year
137.	Georgian	Electrical Engineering Technology
138.	Georgian	Electrical Engineering Technology
139.	U of T	Professional Experience Year
140.	Georgian	Human Resources Management
141.	Georgian	Electrical Engineering Technology
142.	Waterloo	Systems Design Engineering
143.	UofT Scarborough	Management
144.	Waterloo	Mechanical Engineering
145.	UOIT	Engineering
146.	U of T	Professional Experience Year
147.	Mohawk	Electrical Engineering Technology
148.	Ryerson University	Electrical & Computer Engineering
149.	Ryerson	Occupational Health & Safety
150.	U of T	Professional Experience Year
151.	Georgian	Electrical Engineering Technology
152.	Guelph	Mechanical Engineering
153.	Seneca	Business
154.	Waterloo	Systems Design Engineering
155.	U of T	Professional Experience Year
156.	Mohawk	Electrical Engineering Technology
157.	Waterloo	Electrical Engineering
158.	Georgian	Electrical Engineering Technology
159.	Georgian	Electrical Engineering Technology
160.	Georgian	Electrical Engineering Technology
161.	UofT Scarborough	Management
162.	Waterloo	Management Engineering
163.	UofT Scarborough	Management
164.	U of T Scarborough	Management
165.	Seneca	Accounting and Finance
166.	Waterloo	Nanotechnology Engineering
167.	Waterloo	Electrical Engineering
168.	Ryerson	Electrical Engineering Technology
169.	Georgian	Electrical Engineering Technology
170.	Waterloo	Electrical Engineering
171.	Mohawk	Eng-Tech
172.	Waterloo	Electrical Engineering
173.	Waterloo	Electrical Engineering
174.	McMaster	Electrical Engineering
175.	Brock	Business Administration
176.	McMaster	Civil Eng/Management
177.	McMaster	Electrical Engineering
178.	U of T	Professional Experience Year
179.	Georgian College	Electrical Engineering Technology
180.	UOIT	Engineering
181.	McMaster	Electrical Engineering
182.	U of T	Professional Experience Year
183.	Georgian College	Electrical Engineering
184.	Georgian College	Electrical Engineering Technology
185.	Waterloo	Civil Engineering
186.	Seneca	Computer Systems Technology
187.	UTSC	Management
188.	UTSC	Management

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
189.	UofT PEY	Professional Experience Year
190.	UTSC	Management
191.	Waterloo	Science &Business/Biotech
192.	UTSC	Management
193.	U of T	Professional Experience Year
194.	U of T	Professional Experience Year
195.	Ryerson	Public Health & Safety
196.	Waterloo	Electrical Engineering
197.	UTSC	Management
198.	Georgian College	Electrical Engineering Technology
199.	Brock	Business Administration
200.	UofT PEY	Professional Experience Year
201.	UTSC	Management
202.	U of T PEY	Professional Experience Year
203.	UofT PEY	Professional Experience Year
204.	Ryerson	Industrial Internship Program
205.	Queen's	Undergraduate Internship Program
206.	UTSC	Management
207.	UofT PEY	Professional Experience Year
208.	UTSC	Management
209.	Waterloo	Electrical Engineering
210.	Georgian College	Electrical Engineering Technology
211.	Georgian College	Human Resources Management
212.	UofT PEY	Professional Experience Year
213.	Seneca	Accounting and Finance
214.	Waterloo	Electrical Engineering
215.	U of T PEY	Professional Experience Year
216.	Brock	Business Administration
217.	UTSC	Management
218.	UTSC	Management
219.	U of T PEY	Professional Experience Year
220.	U of T	Professional Experience Year
221.	Western	Mechanical Engineering
222.	Mohawk	Eng-Tech
223.	UofT PEY	Professional Experience Year
224.	Seneca College	Accounting and Finance
225.	Ryerson	Computer Science
226.	UofT PEY	Professional Experience Year
227.	UofT PEY	Professional Experience Year
228.	Waterloo	Environmental Engineering
229.	U of T	Professional Experience Year
230.	UofT PEY	Professional Experience Year
231.	Georgian College	Electrical Engineering Technology
232.	UofT PEY	Professional Experience Year
233.	Georgian College	Electrical Engineering Technology
234.	Queens	Undergraduate Internship Program
235.	Georgian College	Electrical Engineering Technology
236.	UofT PEY	Professional Experience Year
237.	Ryerson	Industrial Internship Program
238.	Seneca	Human Resource Management
239.	McMaster	Engineering Physics
240.	U of T	Professional Experience Year
241.	Waterloo	Accounting & Finance Mgnt
242.	UTSC	Management
243.	UOIT	Engineering and Applied Science

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
244.	Mohawk	Electrical Engineering
245.	Seneca College	Corporate Communications
246.	UofT PEY	Professional Experience Year
247.	Seneca	Accounting and Finance
248.	McMaster	Electrical & Biomedical Engineering
249.	Georgian College	Electrical Engineering Technology
250.	Laurier	Business
251.	U of T	Professional Experience Year
252.	Waterloo	Science & Business/Biotech
253.	Georgian College	Electrical Engineering Technology
254.	UTSC	Management
255.	Seneca	Business Management
256.	McMaster	Business
257.	UTSC	Management
258.	Ryerson	Industrial Internship Program
259.	York	Information Technlogy
260.	Georgian College	Electrical Engineering Technology
261.	Ryerson	Chemical Engineering
262.	U of T PEY	Professional Experience Year
263.	UofT PEY	Professional Experience Year
264.	George Brown	Human Resources
265.	Ryerson	Mechanical & Industrial Engineering
266.	Waterloo	Electrical Engineering
267.	Waterloo	Economics
268.	Georgian College	Electrical Engineering Technology
269.	UTSC	Management
270.	Georgian College	Electrical Engineering Technology
271.	UTSC	Management
272.	U of T PEY	Professional Experience Year
273.	McMaster	Electrical Engineering
274.	Mohawk	Eng-Tech
275.	UTSC	Management
276.	McMaster	Electrical Engineering
277.	Waterloo	Math/Fin. Analysis & Risk Mgmt
278.	Seneca	Accounting and Finance
279.	U of T	Professional Experience Year
280.	U of T PEY	Professional Experience Year
281.	Mohawk	Electrical Engineering Technology
282.	UTSC	Management
283.	Brock	Business Administration
284.	York	Information Technology
285.	York	Accounting
286.		
287.		
288.		
289.		
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	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
299.		
300.		

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	[redacted]	2013-05-06	2013-08-30
2.	[redacted]	2013-05-06	2013-08-30
3.	[redacted]	2013-05-06	2013-08-30
4.	[redacted]	2013-05-06	2013-08-30
5.	[redacted]	2013-05-06	2013-08-30
6.	[redacted]	2013-05-06	2013-08-30
7.	[redacted]	2013-05-06	2013-08-30
8.	[redacted]	2013-05-06	2013-08-30
9.	[redacted]	2013-05-06	2013-08-30
10.	[redacted]	2013-05-06	2013-08-30
11.	[redacted]	2013-05-06	2013-08-30
12.	[redacted]	2013-05-06	2013-08-30
13.	[redacted]	2013-05-06	2013-08-30
14.	[redacted]	2013-05-06	2013-08-30
15.	[redacted]	2013-05-06	2013-08-30
16.	[redacted]	2013-05-06	2013-08-30
17.	[redacted]	2013-05-06	2013-08-30
18.	[redacted]	2013-05-06	2013-08-30
19.	[redacted]	2013-05-06	2013-08-30
20.	[redacted]	2013-05-06	2013-08-30
21.	[redacted]	2013-05-06	2013-08-30
22.	[redacted]	2013-05-06	2013-08-30
23.	[redacted]	2013-05-06	2013-08-30
24.	[redacted]	2013-05-06	2013-08-30
25.	[redacted]	2013-05-06	2013-08-30
26.	[redacted]	2013-05-06	2013-08-30
27.	[redacted]	2013-05-06	2013-08-30
28.	[redacted]	2013-05-06	2013-08-30
29.	[redacted]	2013-05-06	2013-08-30
30.	[redacted]	2013-05-06	2013-08-30
31.	[redacted]	2013-05-06	2013-08-30
32.	[redacted]	2013-05-06	2013-08-30
33.	[redacted]	2013-05-06	2013-08-30
34.	[redacted]	2013-05-06	2013-08-30
35.	[redacted]	2013-05-06	2013-08-30
36.	[redacted]	2013-05-06	2013-08-30
37.	[redacted]	2013-05-06	2013-08-30
38.	[redacted]	2013-05-06	2013-08-30
39.	[redacted]	2013-05-06	2013-08-30
40.	[redacted]	2013-05-06	2013-08-30
41.	[redacted]	2013-05-06	2013-08-30
42.	[redacted]	2013-05-06	2013-08-30
43.	[redacted]	2013-05-06	2013-08-30
44.	[redacted]	2013-05-06	2013-08-30
45.	[redacted]	2013-05-06	2013-08-30
46.	[redacted]	2013-05-06	2013-08-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
47.	[redacted]	2013-05-06	2013-08-30
48.	[redacted]	2013-05-06	2013-08-30
49.	[redacted]	2013-05-06	2013-08-30
50.	[redacted]	2013-05-06	2013-08-30
51.	[redacted]	2013-05-06	2013-08-30
52.	[redacted]	2013-05-06	2013-08-30
53.	[redacted]	2013-05-06	2013-08-30
54.	[redacted]	2013-05-06	2013-08-30
55.	[redacted]	2013-05-06	2013-08-30
56.	[redacted]	2013-05-06	2013-08-30
57.	[redacted]	2013-05-06	2013-08-30
58.	[redacted]	2013-05-06	2013-08-30
59.	[redacted]	2013-05-06	2013-08-30
60.	[redacted]	2013-05-06	2013-08-30
61.	[redacted]	2013-05-06	2013-08-30
62.	[redacted]	2013-05-06	2013-08-30
63.	[redacted]	2013-05-06	2013-08-30
64.	[redacted]	2013-05-06	2013-08-30
65.	[redacted]	2013-05-06	2013-08-30
66.	[redacted]	2013-05-06	2013-08-30
67.	[redacted]	2013-05-06	2013-08-30
68.	[redacted]	2013-05-06	2013-08-30
69.	[redacted]	2013-05-06	2013-08-30
70.	[redacted]	2013-05-06	2013-08-30
71.	[redacted]	2013-05-06	2013-08-30
72.	[redacted]	2013-05-06	2013-08-30
73.	[redacted]	2013-05-06	2013-08-30
74.	[redacted]	2013-05-06	2013-08-30
75.	[redacted]	2013-05-06	2013-08-30
76.	[redacted]	2013-05-06	2013-08-30
77.	[redacted]	2013-05-06	2013-08-30
78.	[redacted]	2013-05-06	2013-08-30
79.	[redacted]	2013-05-06	2013-08-30
80.	[redacted]	2013-05-06	2013-08-30
81.	[redacted]	2013-05-06	2013-08-30
82.	[redacted]	2013-05-06	2013-08-30
83.	[redacted]	2013-05-06	2013-08-30
84.	[redacted]	2013-05-06	2013-08-30
85.	[redacted]	2013-05-06	2013-08-30
86.	[redacted]	2013-05-06	2013-08-30
87.	[redacted]	2013-01-02	2013-08-30
88.	[redacted]	2013-05-06	2013-08-30
89.	[redacted]	2013-05-06	2013-08-30
90.	[redacted]	2013-05-06	2013-08-30
91.	[redacted]	2013-05-06	2013-08-30
92.	[redacted]	2013-05-06	2013-08-30
93.	[redacted]	2013-05-06	2013-08-30
94.	[redacted]	2013-05-06	2013-08-30
95.	[redacted]	2013-05-06	2013-08-30
96.	[redacted]	2013-05-06	2013-08-30
97.	[redacted]	2013-05-06	2013-08-30
98.	[redacted]	2013-05-06	2013-08-30
99.	[redacted]	2013-05-06	2013-08-30
100.	[redacted]	2013-05-06	2013-08-30

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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
101.	[redacted]	2013-05-06	2013-08-30
102.	[redacted]	2013-01-02	2013-04-26
103.	[redacted]	2013-01-02	2013-04-26
104.	[redacted]	2013-01-02	2013-04-26
105.	[redacted]	2013-01-02	2013-04-26
106.	[redacted]	2013-01-02	2013-04-26
107.	[redacted]	2013-01-02	2013-04-26
108.	[redacted]	2013-01-02	2013-04-26
109.	[redacted]	2013-01-02	2013-04-26
110.	[redacted]	2013-01-02	2013-04-26
111.	[redacted]	2013-01-02	2013-04-26
112.	[redacted]	2013-01-02	2013-04-26
113.	[redacted]	2013-01-02	2013-04-26
114.	[redacted]	2013-01-02	2013-04-26
115.	[redacted]	2013-01-02	2013-04-26
116.	[redacted]	2013-01-02	2013-04-26
117.	[redacted]	2013-01-02	2013-04-26
118.	[redacted]	2013-01-02	2013-04-26
119.	[redacted]	2013-01-02	2013-04-26
120.	[redacted]	2013-01-02	2013-04-26
121.	[redacted]	2013-01-02	2013-04-26
122.	[redacted]	2013-01-02	2013-04-26
123.	[redacted]	2013-01-02	2013-04-26
124.	[redacted]	2013-01-02	2013-04-26
125.	[redacted]	2013-01-02	2013-04-26
126.	[redacted]	2013-01-02	2013-04-26
127.	[redacted]	2013-01-02	2013-04-26
128.	[redacted]	2013-01-02	2013-04-26
129.	[redacted]	2013-01-02	2013-04-26
130.	[redacted]	2013-01-02	2013-04-26
131.	[redacted]	2013-01-02	2013-04-26
132.	[redacted]	2013-01-02	2013-04-26
133.	[redacted]	2013-01-02	2013-04-26
134.	[redacted]	2013-01-02	2013-04-26
135.	[redacted]	2013-01-02	2013-04-26
136.	[redacted]	2013-01-02	2013-04-26
137.	[redacted]	2013-01-02	2013-04-26
138.	[redacted]	2013-01-02	2013-04-26
139.	[redacted]	2013-01-02	2013-04-26
140.	[redacted]	2013-01-02	2013-04-26
141.	[redacted]	2013-01-02	2013-04-26
142.	[redacted]	2013-01-02	2013-04-26
143.	[redacted]	2013-01-02	2013-04-26
144.	[redacted]	2013-01-02	2013-04-26
145.	[redacted]	2013-01-02	2013-04-26
146.	[redacted]	2013-01-02	2013-04-26
147.	[redacted]	2013-01-02	2013-04-26
148.	[redacted]	2013-01-02	2013-04-26
149.	[redacted]	2013-01-02	2013-04-26
150.	[redacted]	2013-01-02	2013-04-26
151.	[redacted]	2013-01-02	2013-04-26
152.	[redacted]	2013-01-02	2013-04-26
153.	[redacted]	2013-01-02	2013-04-26
154.	[redacted]	2013-01-02	2013-04-26

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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
209.	[redacted]	2013-09-03	2013-12-20
210.	[redacted]	2013-09-03	2013-12-20
211.	[redacted]	2013-09-03	2013-12-20
212.	[redacted]	2013-09-03	2013-12-20
213.	[redacted]	2013-09-03	2013-12-20
214.	[redacted]	2013-09-03	2013-12-20
215.	[redacted]	2013-09-03	2013-12-20
216.	[redacted]	2013-09-03	2013-12-20
217.	[redacted]	2013-09-03	2013-12-20
218.	[redacted]	2013-09-03	2013-12-20
219.	[redacted]	2013-09-03	2013-12-20
220.	[redacted]	2013-09-03	2013-12-20
221.	[redacted]	2013-09-03	2013-12-20
222.	[redacted]	2013-09-03	2013-12-20
223.	[redacted]	2013-09-03	2013-12-20
224.	[redacted]	2013-09-03	2013-12-20
225.	[redacted]	2013-09-03	2013-12-20
226.	[redacted]	2013-09-03	2013-12-20
227.	[redacted]	2013-09-03	2013-12-20
228.	[redacted]	2013-09-03	2013-12-20
229.	[redacted]	2013-09-03	2013-12-20
230.	[redacted]	2013-09-03	2013-12-20
231.	[redacted]	2013-09-03	2013-12-20
232.	[redacted]	2013-09-03	2013-12-20
233.	[redacted]	2013-09-03	2013-12-20
234.	[redacted]	2013-09-03	2013-12-20
235.	[redacted]	2013-09-03	2013-12-20
236.	[redacted]	2013-09-03	2013-12-20
237.	[redacted]	2013-09-03	2013-12-20
238.	[redacted]	2013-09-03	2013-12-20
239.	[redacted]	2013-09-03	2013-12-20
240.	[redacted]	2013-09-03	2013-12-20
241.	[redacted]	2013-09-03	2013-12-20
242.	[redacted]	2013-09-03	2013-12-20
243.	[redacted]	2013-09-03	2013-12-20
244.	[redacted]	2013-09-03	2013-12-20
245.	[redacted]	2013-09-03	2013-12-20
246.	[redacted]	2013-09-03	2013-12-20
247.	[redacted]	2013-09-03	2013-12-20
248.	[redacted]	2013-09-03	2013-12-20
249.	[redacted]	2013-09-03	2013-12-20
250.	[redacted]	2013-09-03	2013-12-20
251.	[redacted]	2013-09-03	2013-12-20
252.	[redacted]	2013-09-03	2013-12-20
253.	[redacted]	2013-09-03	2013-12-20
254.	[redacted]	2013-09-03	2013-12-20
255.	[redacted]	2013-09-03	2013-12-20
256.	[redacted]	2013-09-03	2013-12-20
257.	[redacted]	2013-09-03	2013-12-20
258.	[redacted]	2013-09-03	2013-12-20
259.	[redacted]	2013-09-03	2013-12-20
260.	[redacted]	2013-09-03	2013-12-20
261.	[redacted]	2013-09-03	2013-12-20
262.	[redacted]	2013-09-03	2013-12-20

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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
155	[redacted]	2013-01-02	2013-04-26
156.	[redacted]	2013-01-02	2013-04-26
157	[redacted]	2013-01-02	2013-04-26
158	[redacted]	2013-01-02	2013-04-26
159.	[redacted]	2013-01-02	2013-04-26
160.	[redacted]	2013-01-02	2013-04-26
161.	[redacted]	2013-01-02	2013-04-26
162.	[redacted]	2013-01-02	2013-04-26
163.	[redacted]	2013-01-02	2013-04-26
164.	[redacted]	2013-01-02	2013-04-26
165.	[redacted]	2013-01-02	2013-04-26
166.	[redacted]	2013-01-02	2013-04-26
167.	[redacted]	2013-01-02	2013-04-26
168.	[redacted]	2013-01-02	2013-04-26
169.	[redacted]	2013-01-02	2013-04-26
170.	[redacted]	2013-01-02	2013-04-26
171.	[redacted]	2013-01-02	2013-04-26
172.	[redacted]	2013-01-02	2013-04-26
173.	[redacted]	2013-09-03	2013-12-20
174.	[redacted]	2013-09-03	2013-12-20
175.	[redacted]	2013-09-03	2013-12-20
176.	[redacted]	2013-09-03	2013-12-20
177.	[redacted]	2013-09-03	2013-12-20
178.	[redacted]	2013-09-03	2013-12-20
179.	[redacted]	2013-09-03	2013-12-20
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181.	[redacted]	2013-09-03	2013-12-20
182.	[redacted]	2013-09-03	2013-12-20
183.	[redacted]	2013-09-03	2013-12-20
184.	[redacted]	2013-09-03	2013-12-20
185.	[redacted]	2013-09-03	2013-12-20
186.	[redacted]	2013-09-03	2013-12-20
187.	[redacted]	2013-09-03	2013-12-20

[redacted]