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February 6, 2015

via RESS – signed original to follow by courier

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

Dear Ms. Walli:

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

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

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

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

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

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

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

In addition, enclosed are the following new Schedules:

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

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

- Issue 2B, CCC Interrogatory 24 *[corrected reference on line 19]*;
- Issue 2B, CCC Interrogatory 25 *[corrected reference on line 12]*;
- Issue 2B, VECC Interrogatory 18 *[corrected header]*;
- Issue 4A, SIA Interrogatory 39 *[corrected reference on line 12]*;
- November 17, 2014 Technical Conference Undertaking Response to J1.2-EP-50, Appendix A; and
- November 18, 2014 Technical Conference Undertaking Response to J2.29-CUPE-9, Supplemental Response.

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

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

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

Yours truly,

[original signed by]

Daliana Coban

Lead Regulatory Counsel

Toronto Hydro-Electric System Limited

regulatoryaffairs@torontohydro.com

:encl.

:JL\acc

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

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

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

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

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

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

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

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

Original Evidence (as originally filed or subsequently updated)	Revised Evidence (Filed February 6, 2015)	Numerical Differences																							
Revenue Requirement (Exhibit 6, Tab 1, Schedule 1); Revenue Requirement Workform (Exhibit 6, Tab 1, Schedule 2)	Updated the revenue requirement calculation to reflect the impact of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).	<table><tr><th colspan="3">Table 1: 2015 Revenue Requirement (\$ millions)</th></tr><tr><td>Amortization/Depreciation</td><td>~~\$208.2~~</td><td>\$206.5</td></tr><tr><td>Income Taxes (Grossed up)</td><td>~~\$22.4~~</td><td>\$22.0</td></tr><tr><td>Deemed Interest Expense</td><td>~~\$81.8~~</td><td>\$80.2</td></tr><tr><td>Return on Deemed Equity</td><td>~~\$123.3~~</td><td>\$120.8</td></tr><tr><td>Service Revenue Requirement</td><td>~~\$707.3~~</td><td>\$701.1</td></tr><tr><td>Base Revenue Requirement</td><td>~~\$661.2~~</td><td>\$655.0</td></tr></table>			Table 1: 2015 Revenue Requirement (\$ millions)			Amortization/Depreciation	~~\$208.2~~	\$206.5	Income Taxes (Grossed up)	~~\$22.4~~	\$22.0	Deemed Interest Expense	~~\$81.8~~	\$80.2	Return on Deemed Equity	~~\$123.3~~	\$120.8	Service Revenue Requirement	~~\$707.3~~	\$701.1	Base Revenue Requirement	~~\$661.2~~	\$655.0
Table 1: 2015 Revenue Requirement (\$ millions)																									
Amortization/Depreciation	~~\$208.2~~	\$206.5																							
Income Taxes (Grossed up)	~~\$22.4~~	\$22.0																							
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Return on Deemed Equity	~~\$123.3~~	\$120.8																							
Service Revenue Requirement	~~\$707.3~~	\$701.1																							
Base Revenue Requirement	~~\$661.2~~	\$655.0																							
Cost Allocation Narrative (Exhibit 7, Tab 1, Schedule 1); Cost Allocation Model (Exhibit 7, Tab 1, Schedule 2); OEB Appendix 2-P Cost Allocation (Exhibit 7, Tab 2, Schedule 1)	Updated revenue to cost ratios to reflect the impact of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).	<table><tr><th>Rate Class</th><th>2015 Model</th><th>2015 Proposed</th></tr><tr><td>Residential</td><td>N/C</td><td>~~95~~ 94</td></tr><tr><td>General Service 50-999kW</td><td>~~118~~ 119</td><td>~~118~~ 119</td></tr><tr><td>Intermediate 1000-4999kW</td><td>~~101~~ 102</td><td>~~101~~ 102</td></tr></table>			Rate Class	2015 Model	2015 Proposed	Residential	N/C	~~95~~ 94	General Service 50-999kW	~~118~~ 119	~~118~~ 119	Intermediate 1000-4999kW	~~101~~ 102	~~101~~ 102									
Rate Class	2015 Model	2015 Proposed																							
Residential	N/C	~~95~~ 94																							
General Service 50-999kW	~~118~~ 119	~~118~~ 119																							
Intermediate 1000-4999kW	~~101~~ 102	~~101~~ 102																							
Rate Design Overview (Exhibit 8, Tab 1, Schedule 1); Fixed/Variable Allocation (Exhibit 8, Tab 1, Schedule 2)	Updated distribution rates to reflect the impact of changes to the Copeland TS project schedule, as discussed in Exhibit 2B, Section 7.9 (Stations Expansion Program).	Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to updated schedule.																							

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

Daliana Coban

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February 6, 2015

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

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

Dear Ms. Walli:

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

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

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

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

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

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

Yours truly,

[original signed by]

Daliana Coban

Lead Regulatory Counsel

Toronto Hydro-Electric System Limited

regulatoryaffairs@torontohydro.com

:encl.

:JL\acc

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



1600 - 120 Adelaide Street West
Toronto, ON M5H 1T1
t 416 506 2800
www.ieso.ca

February 3, 2015

Mr. Jack Simpson
Toronto Hydro-Electric System Limited
500 Commissioners Street
Toronto, Ontario M4M 3N7

Dear Jack:

**Re: Update to July 24, 2014 Letter of Comment regarding
THESL's Renewable Energy Generation Investments Plan**

In response to your request for an update to the OPA's¹ July 24, 2014 Letter of Comment, I am pleased to provide THESL with updated information as follows.

The FIT and microFIT applications referenced in the Letter of Comment remain consistent with the renewable energy generation information that was received from THESL, as of May 31, 2014.

With respect to the Central Toronto Integrated Regional Resource Plan ("IRRP"), since July 2014, the IESO and THESL, with Hydro One Networks, have completed a stakeholder engagement process that included:

- the release of an online discussion workbook,
- two public webinars,
- three stakeholder workshops with representatives from the City of Toronto, Board of Trade, environmental non-governmental organizations and major consumers,
- focus group sessions with residential and small business customers,
- public open houses, and
- customer telephone surveys.

¹ On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

February 3, 2015
Mr. Jack Simpson
Toronto Hydro-Electric System Limited
Page 2

THESL was a full partner in developing and delivering the engagement plan. This included developing supporting materials in preparation for the stakeholder engagement, and the planning and logistics. The IESO has archived the engagement materials which can be found at the following link: <http://powerauthority.on.ca/power-planning/regional-planning/toronto/central-downtown>.

The completion date of the IRRP has been revised to April 2015 to allow time for incorporating the impact of new customer connection inquiries and meaningful consideration of input from the stakeholder engagement.

Yours truly,

A handwritten signature in dark ink, appearing to read 'Joe Toneguzzo', with a stylized flourish at the end.

Joe Toneguzzo
Director, Transmission Integration
IESO

Copied to:
Nancy Marconi, IESO
Amanda Klein, THESL Regulatory Affairs

Hydro One Network Inc.
483 Bay Street
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Toronto Hydro-Electric System Limited
EB-2014-0116
Exhibit 2B
Section B
Appendix E
Filed: 2015 Feb 6
(10 pages)



February 2, 2015

Jack Simpson

Director, Generation & Capacity Planning
Engineering and Construction
Toronto Hydro-Electric System Limited
500 Commissioners St., 3rd Floor
Toronto, ON M4M 3N7

Dear Mr. Simpson:

Subject: Regional Planning Status

In reference to your request for a Regional Planning Status Letter, please note that Toronto Hydro-Electric System Limited ("THESL") belongs to the Metro Toronto Region (Central Downtown Subregion, and Northern Subregion) and GTA North Region (Western Subregion). Both Regions are in Group 1. A map showing details with respect to the 21 Regions/Groups and a list of Local Distribution Companies in each Region is attached in Appendix A and B respectively.

Metro Toronto Region – Central Downtown Subregion

The planning activity for this Subregion was already underway prior to the new regional planning process and was deemed to be in the Integrated Regional Resource Planning ("IRRP") phase of the process. This IRRP led by the OPA is expected to be completed by Q2 2015.

Of the near-term needs identified by the study team, a special protection scheme may be implemented to comply with reliability standards, along with new transformer stations/facilities (Runnymede and Horner) in the west end of Toronto to meet transformation capacity needs in the area. The IESO (formerly OPA) has issued a handoff letter to Hydro One requesting that Hydro One further assess and develop transmission options to address the near-term transformation needs. The outcome of these assessments may require capital investments and/or contribution from THESL. In addition, THESL has indicated that they anticipate new load and that a capacity increase at transformer stations such as Copeland TS in the Downtown Area may also be required in the future. The exact timing of these investments is yet to be confirmed.

A stakeholder engagement process was undertaken in September 2014 to inform stakeholders and the public of the needs identified, and to inform them about CDM, DG, and a need for transmission and distribution system enhancements in the Subregion. These planning engagements are proceeding ahead and will be an important input to the regional planning process for the Central Downtown Subregion.

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**Metro Toronto Region – Northern Subregion**

The Need Assessment report for this Subregion was completed in June 2014 and is available on Hydro One's Regional Planning website. From a regional planning perspective, THESL has little impact from this Subregion. In addition, the study team determined that the needs identified for this Subregion can be addressed directly by Hydro One and LDCs and further regional coordination is not required.

GTA North Region – Western Subregion

The Need Assessment report for this Subregion was completed in June 2014 and is available on Hydro One's Regional Planning website. Based on the findings of the Need Assessment, the study team determined that further coordinated regional planning is required to assess load restoration issues for the loss of two radial elements (230 kV circuits V43 and V44). The IESO (formerly OPA) will coordinate the assessment of this need as part of GTA West Northern Subregion IRRP process currently underway. Other needs identified for the rest of the Subregion will be addressed directly by Hydro One and the relevant LDCs, and further regional coordination is not required.

Hydro One looks forward to working with THESL in executing the new regional planning process. If you have any further questions, please feel free to contact me.

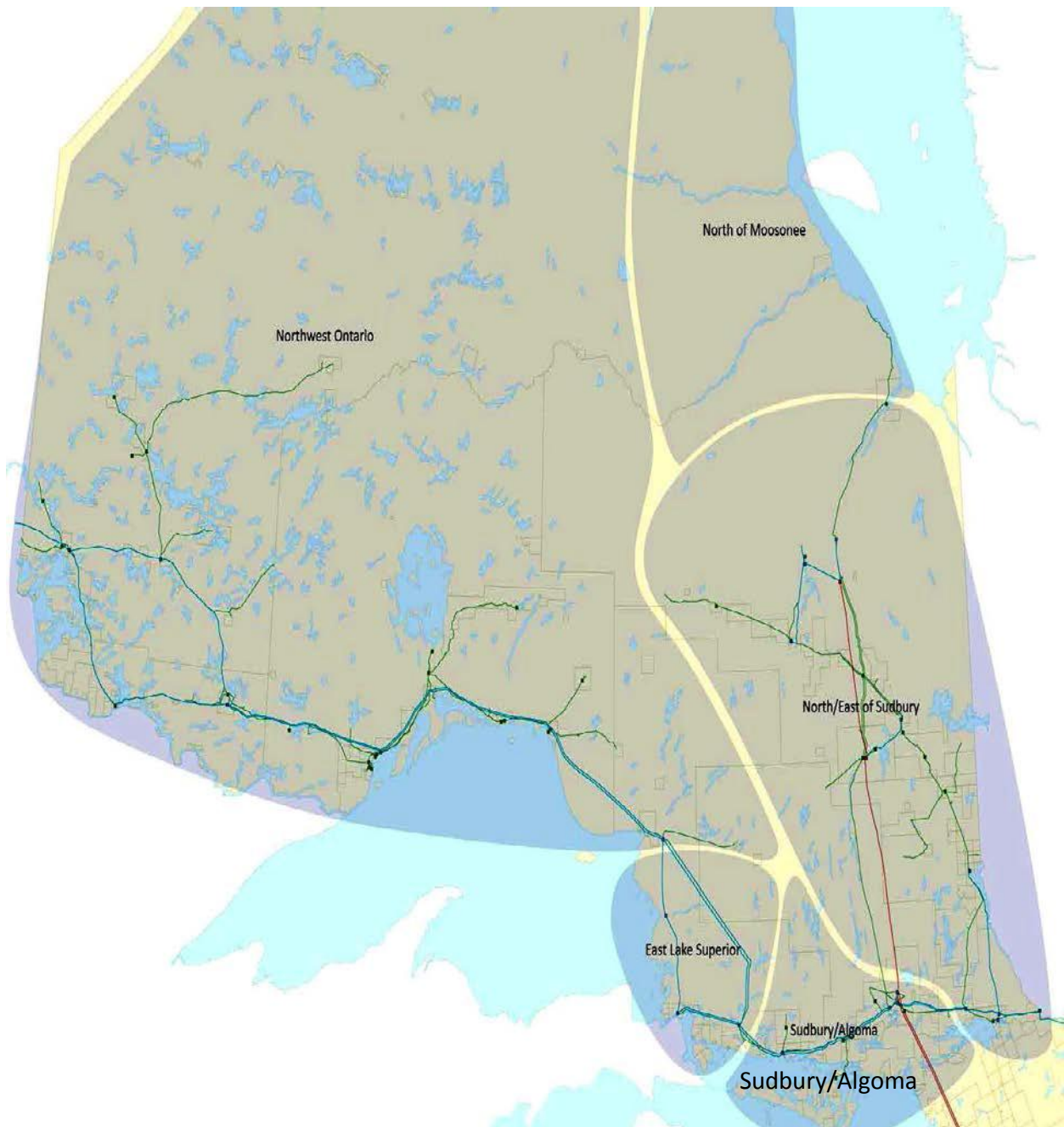
Sincerely,

A handwritten signature in black ink, appearing to be "Ajay Garg", with a long horizontal line extending to the right.

Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Southern Ontario



Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo- Cambridge-Guelph ("KWCG")		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A → This region is not within Hydro One’s territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.* • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* *Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A → This region is not within Hydro One's territory

19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

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	1	Executive Summary		/C
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	1	Administrative Information		
	2	Check List		
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	1	Application Road Map		
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		B	Review of Proposed Projects and Programs, 29 Jul 2014, prepared by Navigant Inc.	
		C	Navigant Addendum Report (Navigant Rider)	/C
	5	Productivity and Performance		
		A	Historic Performance and Productivity Initiatives	
		B	Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels, 31 Jul 2014, prepared by Power System Engineering, Inc.	
		C	PSE Reply Report to PEG's December 2014 Report	/C
	6	Annual Reporting		
	7	Customer Engagement		
		A	Letters of Support	
		B	Customer Consultation Report: DSP Review, Jul 2014, prepared by Innovative Research Group, Inc.	
		C	Sample Key Account Presentation	
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			B	Mandate of the THC Board of Directors
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			D	Code of Business Conduct
			E	Audit Committee Charter
			F	Governance Committee Charter
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			A	Prospectus, 10 December 2012
			B	8th Supplemental Trust Indenture, Nov 2011
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	A	Needs Screening Report, 11 Jun 2014, prepared by Metro Toronto Northern Sub-Region Study Team		
	B	Needs Screening Report, 27 Jun 2014, prepared by GTA North, Western Subregion Study Team		
	C	OPA Letter of Comment, 24 Jul 2014		
	D	IESO Response to OPA Letter of Comment, 03 Feb 2015		/N

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D2	Overview of Assets Managed			
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	B	Standards Review Study, 16 Jan 2014, prepared by Power System Engineering, Inc.		
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			C Toronto Hydro ERP Submission Review, 21 Jul 2014, prepared by Info-Tech Research Group	
		7	Voice Radio System Upgrade	
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			A Future Impacts of Climate Change on Toronto Hydro's Distribution System, July 2014, prepared by AECOM	

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			B1 Loads - By Class	
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		A	Report on the Response to the December 2013 Ice Storm, 19 Jun 2014, prepared by Davies Consulting	
	5	Control Centre Operations		
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	18	Legal Services		
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		A	THESL Reconciliation Report (EB-2011-0269), 3 Dec 2012	
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	4	Labour Market and Human Resources Trends, Canadian Utility Sector, 18 July 2014, prepared by Conference Board of Canada		
	5	Compensation		
	6	Compensation and Benefits Review, January 2014, prepared by Towers Watson		
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5	Shared Services			
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			B Q4 2013 OPA CDM Status Report	
	3	Rate Riders		
		1	Rate Rider Table	

**Toronto Hydro CIR Application 2015-2019
Executive Summary**

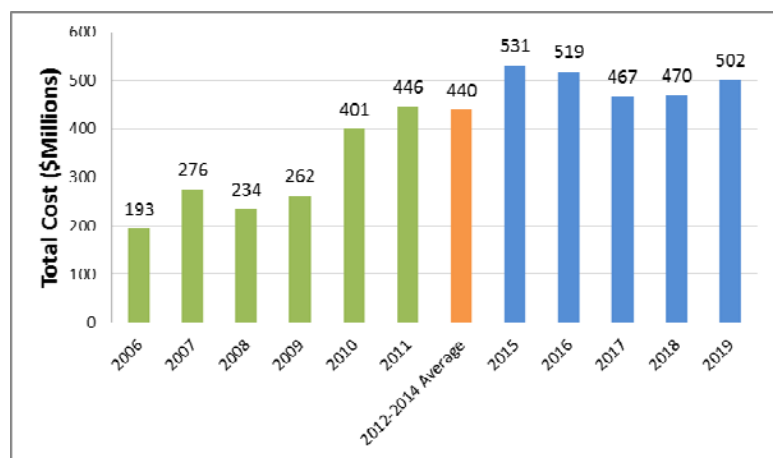
4. SUMMARY OF KEY DETAILS OF THE APPLICATION

4.1 Capital Expenditures And Rate Base

4.1.1 Capital Expenditures

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

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



/C

/C

¹⁵ EB-2012-0064, Partial Decision and Order (April 2, 2013).

¹⁶ Exhibit 1B, Tab 2, Schedule 4, Appendix B.

**Toronto Hydro CIR Application 2015-2019
Executive Summary**

million, or 40.2 percent, from the utility's last rebasing application in 2011.¹⁷ For 2016 to 2019, Toronto Hydro is proposing capital expenditures as summarized below.

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

	2016	2017	2018	2019
Capital Expenditures	518.8	467.4	470.0	502.2

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

Capital Investment Drivers

The "trigger" investment drivers of Toronto Hydro's DSP are summarized below.

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

¹⁷ EB-2010-0142

**Toronto Hydro CIR Application 2015-2019
Executive Summary**

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

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

/C

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

**Toronto Hydro CIR Application 2015-2019
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In addition to the programs listed above, Toronto Hydro's Overhead Circuit Renewal program²³ includes costs for standardizing SCADAMATE related communications technology in areas currently using an obsolete radio communication system.

Regional Planning Investments

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

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

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

/C

²³ Exhibit 2B, E6.4.

Toronto Hydro CIR Application 2015-2019
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4.1.2 Rate Base

Toronto Hydro's requested rate base for the 2015 Test Year is \$3,247.6 million, which represents an increase of approximately \$949.4 million, or 41.3%, from the rate base amount of \$2,298.2 million approved by the OEB in the utility's last rebasing application in 2011.²⁴

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

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

²⁴ EB-2010-0142.

Toronto Hydro CIR Application 2015-2019
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4.2.2 Inflation Rates and Economic Assumptions

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

4.2.3 Compensation

Toronto Hydro's forecasted total compensation cost for the 2015 test year are approximately \$225.3 million, which represents a *decrease* of approximately 9.3 million, or 4.0%, from 2011 actuals. Because Toronto Hydro's last rebasing application was settled on an envelope basis, the utility is unable to detail the OEB-approved compensation costs for 2011.²⁸

4.3 Revenue Requirement

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

/C

/C

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

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

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

Toronto Hydro CIR Application 2015-2019
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1 **4.4 Bill Impacts**

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

6
7 Table 8 below provides a summary of total bill impacts (before taxes and the Ontario
8 Clean Energy Benefit) for typical customers in all classes.

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

**Toronto Hydro CIR Application 2015-2019
Executive Summary**

1 **Table 8: Summary of Total Bill Impacts by Rate Class**

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

/C

1 **Table 1: Calculation of C_n (\$ Millions)**

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

2 The change in forecast capital related revenue requirement from 2015 to 2016 is \$29.3
3 million (\$460.9 million minus \$431.6 million). The total revenue requirement in 2015 is
4 \$655.0. C_n for 2016 is therefore:

$$C_n = (460.9 - 431.6) / 655.0 = 4.47\%.$$

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

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

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

	2016	2017	2018	2019
C_n	4.47	8.25	6.68	5.01

/C

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

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

/C

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

11
12 An efficient and principled approach is to reduce the C-factor by a capital-related
13 proportion of “I – X”. Toronto Hydro proposes that this “scaling” factor be determined

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

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

Table 4 provides the information necessary for calculating S_{cap} for 2015.¹⁰

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

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

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

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

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

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

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

3
4 **Table 5: Custom PCI Values Assuming An Inflation Factor Of 1.7% For Each Year**

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

} /C

5 **4. CONCLUSION**

6
7 **4.1. Policy Concordance**

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

19

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

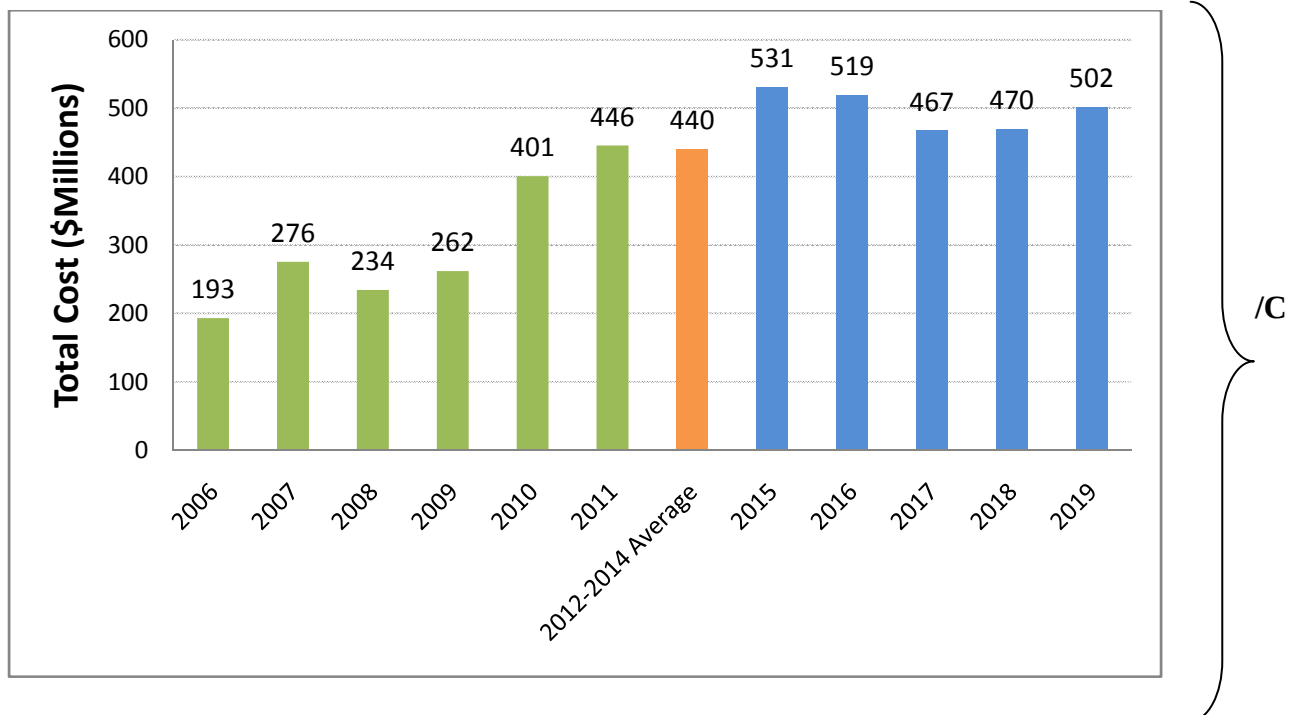
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- 1 The proposed capital programs in Table 2 are incremental to the approved OEB segments
2 from the ICM application. Toronto Hydro added these programs to the 2015-2019 capital
3 plan to accomplish one of three overarching objectives:
- 4 1) maintain responsiveness to public policy objectives and fulfil mandated service
5 obligations (e.g., Generation Protection, Monitoring and Control);
 - 6 2) address system and non-system renewal needs identified in the course of the
7 utility's long-term planning review process (e.g., Underground Legacy

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

/C

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



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

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

RIDER to Navigant Consulting Ltd. Report Titled:
INDEPENDENT ASSESSMENT OF TORONTO HYDRO BUSINESS CASES
Ontario Energy Board EB-2014-0116.

The following summarizes Navigant's review and assessment of updates for certain projects included in Toronto Hydro-Electric System Limited's (THESL) July 31, 2014 Custom Incentive Rate-setting (Custom IR) application for 2015 – 2019 Electric Distribution Rates and Charges before the Ontario Energy Board (OEB) under EB-2014-0116. The findings and conclusions presented in our report are based on our independent assessment of THESL's *Distribution System Plan* (DSP), the Schedule of Exhibits accompanying the DSP and all updated business cases for programs that THESL now seeks authorization from the OEB, and which Navigant originally evaluated in its July 29, 2014 report titled "Independent Assessment of Toronto Hydro's Distribution System Plan and Business Cases" (Exhibit 1B, Tab 02, Schedule 4, Appendix B submitted in EB-2014-0116).

The 2014 Evidence Update includes a supplemental exhibit (E.8.3) titled "*Operating Centres Consolidation Program*", which requests additional capital funds of \$52.2 million over 2015 - 2019. Navigant completed a post-filing and independent review and assessment of THESL's business case presented in E.8.3, which is attached to this rider as Attachment A. Thus, the findings and conclusions presented below are intended to amend and supplement those contained in our July 29, 2014 report with respect to the business cases and exhibits reviewed by Navigant in the 2014 Evidence Update, in addition to new evidence provided in E.8.3 justifying the consolidation of THESL operating centres.

Navigant's independent review of the Custom IR project revisions contained in THESL's September 2014 Evidence Update resulted in a determination that the conclusions we reached in our July 29, 2014 assessment have not changed. Among other findings, the total capital funds THESL now requests for 2015 – 2019 are virtually the same as the amounts that appear in our July 29, 2014 report, i.e. slightly less than \$500 million annually.

Most important, THESL's justification for each project, including costs versus expected benefits, has not materially changed. Notably, findings in our July 29, 2014 report were not premised on specific dates or times when specific projects and jobs should be completed. Rather, our report highlights on page 9 that: "*Navigant reviewed in detail*

THESL's DSP framework presented in Section A through D, and specific business cases in Section E, and has determined that THESL has developed a DSP with sufficient rigour and supporting analysis to justify the proposed levels of spending throughout the rate period [emphasis added]." The adjustments that THESL proposes are entirely consistent with this statement.

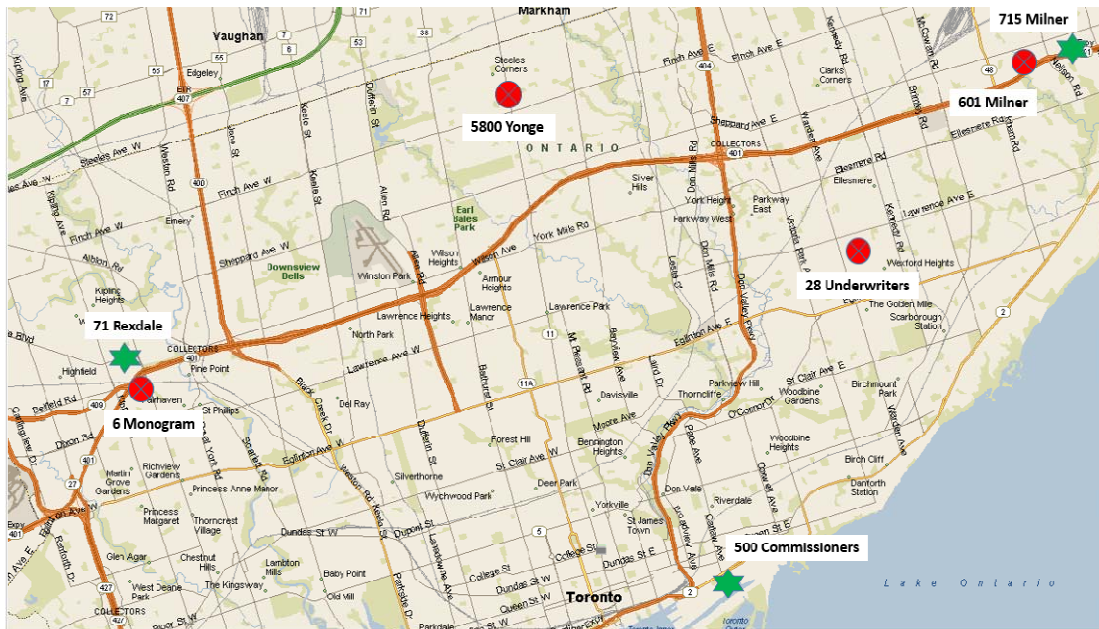
Given these facts, Navigant has no reason to change any of the key findings, conclusions or any of the findings presented in its July 29, 2014 report with respect to the business cases and exhibits reviewed by Navigant in THESL's September 2014 Evidence Update. With respect to the Operating Centres Consolidation Program, Navigant finds the proposed investments and activities associated with the reduction or relocation of THESL operating centres is warranted and will produce net economic, reliability and customer service benefits to its ratepayers.

Attachment A

Operating Centres Consolidation Program

THESL proposes to continue to invest in its Operating Centres Consolidation Program (OCCP) that it initiated prior to the Custom IR filing. The OCCP for 2015 through 2019 includes \$52.2 million of investments to fund the reduction and relocation of four operating centres at several locations. This is in addition to amounts that have been or will be spent in 2014 and prior years. Two of the operating centres (“OC”) are owned by THESL and will be sold. The other two operating centres are leased facilities that are set to expire within the 2015 through 2019 rate period. Staff, equipment and work activities from these four centres will be transferred to three existing THESL operating centres or vacant properties owned by THESL. All funds will be used for upgrading or purchasing of equipment for use in closing of the operating centres, termination of leases, transfer of staff and equipment, and the purchase of new equipment. None of the funds will be used for facilities or equipment for the delivery of electricity to THESL customers.

The following illustration highlights the location of operating centres that will be closed and the locations of existing THESL operating centres or properties that will be expanded or built to accommodate the relocations.



THESL proposes to implement the OCCP over 4 phases, the first involving the closure and sale of 5800 Yonge, with most staff, equipment and related operating functions transferred to 500 Commissioners Street. (THESL has a 99-year lease for 500 Commissioners.) Yonge Street currently houses THESL's Data Centre, the Call Centre and Control Centre. The Commissioners Street facility has sufficient space to accommodate the additional staff and activities, and will include enhancements to communications, infrastructure and security features needed for each of the three above operating functions. It includes use of highly reliable fiber optics communication systems and uninterruptible power supply at Commissioners Street for critical Control and Call Centre functions. Approximately 300 employees will transfer from 5800 Yonge to 500 Commissioners.

The second and third phases involve constructing new OC's at 715 Milner (currently a vacant building) and 74 Rexdale due to termination of leases at nearby OC's at 601 Milner and 6 Monogram. The existing OC's are used primarily as crew work centres for maintenance and construction, and are needed to serve northeastern and northwestern sections of THESL's service territory, respectively. The new OC's will provide assurance of property tenure and provide greater efficiency in building utilization and work activities. The new OC's will include more efficient space utilization and modern office facilities and equipment.

The fourth and final phase involves the permanent closure and relocation of THESL personnel, mostly restoration crews ("System Response"), from 28 Underwriters to other OC's, including the new OC's at Rexdale and Milner. The property will be completely vacated and sold. THESL expects that the de-centralization of System Response functions will reduce travel times for crews to respond to emergencies or service interruptions.

The OCCP is expected to provide benefits to THESL customers in terms of reduced cost, better reliability and improved customer service. Among these benefits is improved efficiency and asset utilization. The consolidation is expected to reduce total THESL OC square footage from 4.2 to 2.6 million, or 43%, thereby improving utilization of existing and new facilities. The sale of the 8.1 acre Yonge Street property is expected to provide direct economic benefits to ratepayers via reduced taxes, lower maintenance and proceeds from the sale of property located in a desirable, high growth area. The transfer of restoration personnel from 28 Underwriters to other OC's is expected to improve reliability as crews will require shorter travel time from the dispersed work locations to restore service. Downside risk is low as THESL owns or occupies each of the three properties where staff and operating activities will be relocated.

Navigant's experience and review of THESL's OCCP confirms the proposed consolidation is consistent with utility practices throughout North America. The reasons and analysis THESL performed to support the OCCP demonstrates that it is a better choice when compared to continuation of existing leases and facilities ("Base Case") or "Do Nothing" options. Specifically, the OCCP will provide net economic, reliability and customer service benefits to THESL's customers, and reduces the risk of higher long-term costs associated with currently leased properties when compared to other options. As a result of these findings, Navigant has determined that THESL's funding request for the OCCP is justified and warranted.



PSE Reply Report to PEG's December 2014 Report

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January 20, 2015

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1 Executive Summary

This report (the “PSE Reply Report”) is in reply to:

- PEG’s December 2014 report, “Toronto Hydro Electric System Limited Custom IR Application and PSE Report: *Econometric Benchmarking of Toronto Hydro’s Historical and Projected Total Cost and Reliability Levels*” (the “PEG Report”), and
- PEG’s corrections of errors in their PEG Report, provided in a letter on December 17, 2014 (“PEG Report Corrections”).

In the PEG Report Corrections, PEG provides a revised model (Table Three in the PEG December 2014 Report) and revised total cost results (Table Four). Using PEG’s revised model, THESL costs are 8.0% above the benchmark value for the most recent 2010-2012 time period.

In this Reply Report, PSE makes three necessary revisions to PEG’s total cost benchmarks. These changes result in THESL’s costs being 15.2% below benchmarks for the 2010-2012 period, and the 2015-2019 costs remaining within the +/- 10% band, corresponding to a 0.3% stretch factor under the 4th Generation Incentive Ratemaking framework.

The changes are:

1. PSE made THESL’s projected costs comparable to its past costs and the U.S. sample by excluding bad debt expenses that were included in THESL’s 2015-2019 projections in the original September 2014 PSE report,
2. PSE made cost definitions comparable and more comprehensive between THESL and the U.S. sample, by adding in THESL’s CDM costs and re-inserting customer service and information expenses for the U.S. sample, and
3. PSE re-included into the model the logical, properly signed, and statistically significant urban core variable, and excluded the incorrectly signed and statistically insignificant high voltage variable proposed by PEG.

The findings using the revised model are consistent with PSE’s September 2014 report, “Econometric Benchmarking of Toronto Hydro’s Historical and Projected Total Cost and Reliability Levels” (“PSE September Report”).

PSE also finds that the PEG Report substantiates PSE’s reliability benchmarking results found in PSE’s September 2014 Report, when the results are compared over the same timeline. Given the consistency in the total cost results between this PSE Reply Report and the PSE September Report, and the substantiation by PEG of PSE’s reliability results, the key findings and recommendations found in PSE’s September Report remain intact.

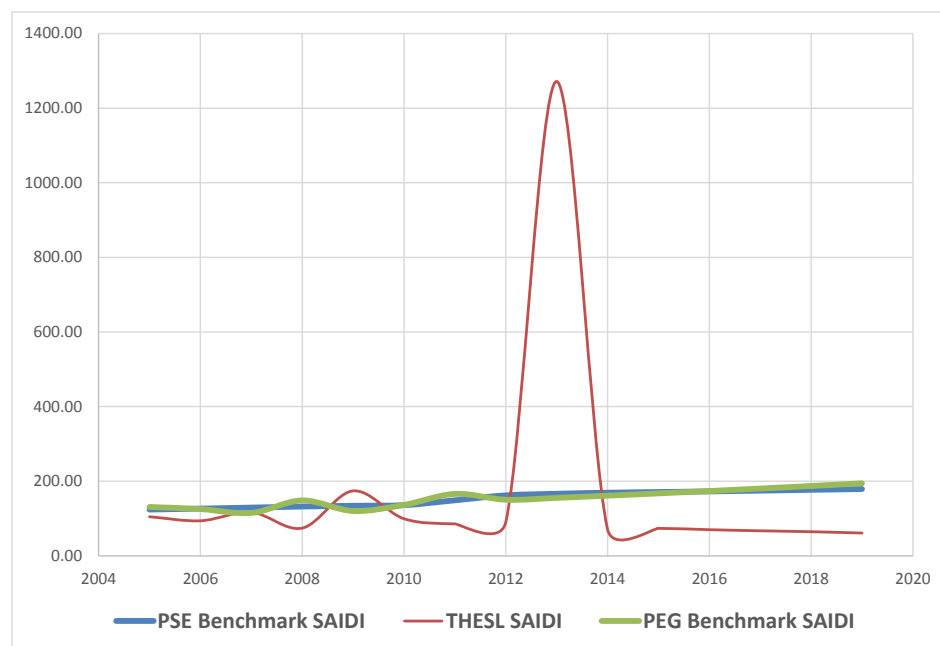
The next chapter explains in further detail how PEG’s reliability research supports PSE’s findings. Chapter Three provides the adjusted total cost model and results. In Chapter Four, PSE responds to some of the statements and other conclusions found throughout PEG’s Report. Chapter Five provides PSE’s recommendations to the Board.

2 PEG and PSE Reliability Results Are Very Similar

PEG states that PEG and PSE agree regarding THESL's SAIFI benchmarking, yet PEG states that "findings differ somewhat with respect to SAIDI".¹ PSE estimates that THESL's SAIDI is well below expected levels. PEG finds THESL's SAIDI is also below benchmarks, but not as far below as PSE found. However, the results seemingly differ because in the PEG Report, PEG was referring to the more dated time period of 2009-2011, and in the PSE September Report, we used the most recent time period of 2010-2012. When PEG's model is applied to the same time period of 2010-2012, it has THESL at 49% below SAIDI benchmark values, as compared to the 48% below in the PSE September Report. Both PSE and PEG find that THESL's SAIDI is projected to be over 100% below benchmark values by 2019.

The fact that PEG's results are nearly indistinguishable to PSE's is best illustrated by slightly modifying the graph that PSE provided in its September Report, comparing THESL's SAIDI values to benchmarks (see Figure 5 in PSE's September Report). PSE has now inserted the PEG-calculated SAIDI benchmarks (green line). PSE's September Report benchmarks are the blue line, THESL's actual and projected values are the red line. Figure 1 below shows the three values and illustrates there is little to no difference in PEG's SAIDI benchmarks and PSE's SAIDI benchmarks.

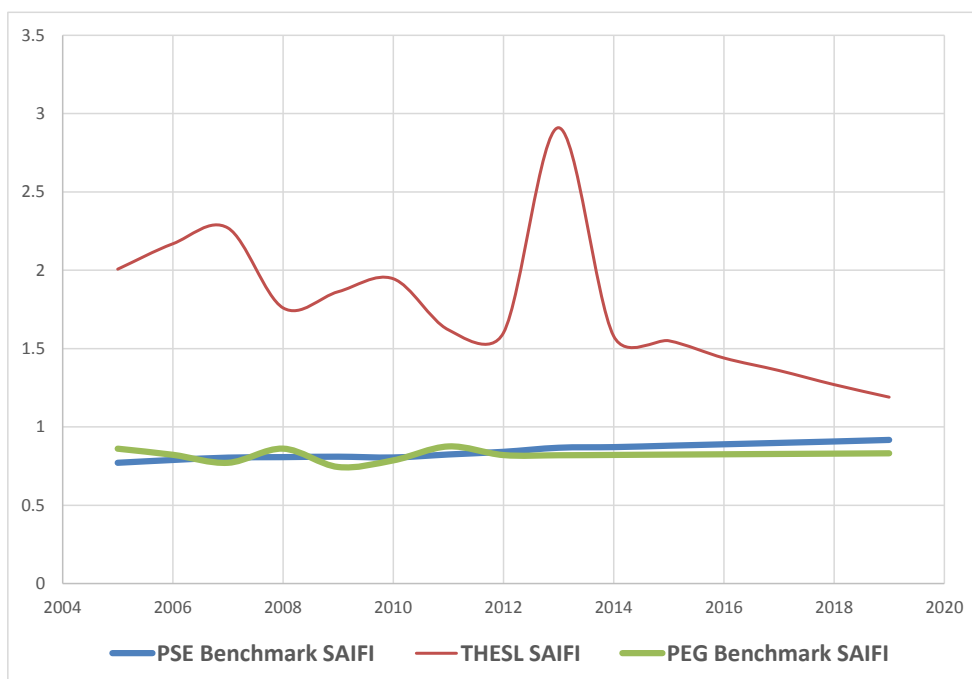
Figure 1 SAIDI: PSE, PEG, and Actual



Although PEG has already confirmed PSE's SAIFI finding, in Figure 2 we show PEG's SAIFI benchmarks (green line) compared to PSE's (blue line) and THESL's actual/projected results (red line). Notice again how similar the PEG and PSE reliability results are.

¹ Page 5 of the PEG Report.

Figure 2 SAIFI: PSE, PEG, and Actual



Despite PEG’s contention to the contrary, there is actually no meaningful difference between PEG’s SAIFI benchmarks and those of PSE’s. The only difference arises from the different time periods being compared. The PEG Report focused on the reliability performance scores in the past (2009-2011) rather than using the Custom IR projections to formulate conclusions. Although PEG has conducted this analysis, the PEG Report did not display the future reliability projections (THESL is projected to improve in this area). This is inconsistent with PEG’s analysis of THESL’s total costs, where PEG’s conclusions were based on THESL’s results through 2019.

PEG notes that it made a number of reliability data set revisions and exclusions to PSE’s data, based on whether the data could be verified with the source document, or whether the value aligned with the current document. PEG states on page 38: “In PEG’s opinion, these are serious errors and omissions.” PEG’s statement is exaggerated. The adjustments PEG made to PSE’s reliability data are minor revisions. PSE made a good faith effort to gather data from hundreds of sources scattered around the internet over the course of many years. PEG made minor changes that did not have a meaningful impact on the results. The fact that PEG’s results are so similar to PSE’s testifies to this fact.

The consistency in THESL’s reliability results is notable, given that two separate experts used different data sets, time periods, and models to derive them. While PSE is unconvinced that PEG’s included variables should have replaced those in PSE’s September model, the issue is of little consequence in this case, given the extreme similarity of results.² The similar results should provide the Board with a high level of confidence in the reliability benchmarking provided by PSE in this proceeding.

² PEG inserted cooling degree days, heating degree days, undergrounding, and precipitation into the models and took out percent forestation, customer density, wind, and the number of customers from the PSE models.

3 Total Cost Results and Model

As the experience of incentive regulation in Ontario has shown, benchmarking tends to be an iterative process. Putting together data sets, explanatory variables, and models takes time and requires input from multiple stakeholders. Throughout this process, benchmarking evaluations tend to become more accurate, comprehensive, and trustworthy, resulting in improved evidence to better inform decisions.

Relative to PEG's 4th Generation Incentive Regulation benchmarking model, the PEG Report made strides in conducting a fair total cost benchmarking evaluation in relation to THESL. This was primarily done by using the U.S. data set.³ PSE agrees with PEG that excluding uncollectible account expenses from the U.S. data is appropriate, given that bad debt expenses were excluded for all of the Ontario utilities.⁴ PEG also included THESL's smart meter expenses in its cost definition. While this is unfair to THESL, since only a handful of U.S. utilities in the dataset have fully deployed smart meters, in an effort to only focus on major issues, PSE will not modify PEG's treatment of smart meters in the Reply Report results.

However, three adjustments to PEG's Research are necessary to make cost definitions comparable and to make the model align with benchmarking best practices. These are:

1. Make THESL's forecasted costs comparable to past costs by excluding bad debt expenses,
2. Make cost definitions comparable and more comprehensive between THESL and the U.S. sample by adding in THESL's CDM costs and re-inserting customer service and information expenses for the U.S. sample, and
3. Re-introduce in the model the logical, properly signed, and statistically significant urban core variable, and exclude the incorrectly signed and statistically insignificant high voltage variable.

These three adjustments are discussed in the following sections.

3.1 Adjustment #1: Bad Debt Expenses

PEG correctly states that uncollectible account expenses should be subtracted for the U.S. sample. PSE agrees that this improves the comparability of costs, but we note that PEG should also subtract out bad debt expenses for THESL's forecasted time period of 2013 to 2019 (PEG did not do this). PSE requested this data from THESL and has subtracted bad debt expenses, along with other non-comparable costs such as property taxes that were previously in the forecasted cost data. This was done in an effort to define forecasted costs in the same way in THESL's and U.S. utilities' historical costs.

³ Recall that PSE did estimate two models, a U.S. only and a combined U.S. and Ontario model. Both models showed similar results for THESL. In the interests of brevity and time, we only discuss the U.S. model in this report. PSE does dispute, however, PEG's statement in its Responses to Interrogatories (1-THESL-60) that "PEG believes there is no value in PSE's Ontario benchmarking, because PSE selected the TFP-based cost measure for THESL while the Ontario distributors were intentionally benchmarked using a different, benchmarking-based cost measure." This is incorrect; PSE used the same cost definition for both THESL and the rest of the Ontario distributors. The only exception to this is THESL's cost 2013-2019 projections included the added costs of bad debt expenses.

⁴ PSE used PEG's data set found in the 4th Generation IR to attempt to replicate PEG's cost definitions as closely as possible. In doing that, PSE was unaware that bad debt expenses were excluded (which is why THESL's projected costs include bad debt expenses). PEG made it clear that these were excluded; thus, excluding those same type of expenses from the U.S. data set and from THESL's 2013-2019 cost projections is appropriate.

In PEG's response to THESL's Interrogatories, 1-THESL-23, PEG asserts that its estimates of THESL's 2013-2019 projected costs "implicitly" subtract bad debt expenses. This is incorrect. PEG takes its 2012 costs, which excluded bad debt, and for projected costs for 2013-2019 adjusts it by PSE's annual percentage change (from Table 6 of the PSE September Report). This method does not explicitly or implicitly exclude bad debt expenses for the 2013-2019 period, because PSE's 2013-2019 costs include THESL's bad debt expenses, whereas the historical 2002-2012 costs do not.

As an illustration, PEG's 2013 total cost value is calculated using PEG's 2012 cost value and then escalated by the growth rate in PSE's total costs from 2012 to 2013. PEG believes this in some way "implicitly" subtracts out bad debt expenses. However, in the PSE total cost measure the 2012 value excludes bad debt expenses, whereas the 2013 value includes bad debt expenses. By escalating PEG's 2012 total costs by this growth rate, PEG is implicitly adding bad debt expenses into their total cost projections for THESL, creating a mismatch in costs between THESL's projected costs and those of the rest of the sample. The PSE approach is to simply subtract out bad debt expenses in the projected data so the cost definition matches the rest of the sampled data.

3.2 Adjustment #2: Conservation Demand Management Expenses

PEG excluded the entirety of the "customer service and information expenses" for all of the U.S. utilities, in an effort to exclude CDM expenses for U.S. utilities, similar to the Ontario cost definition. However, three problems arise with this: 1) THESL and other Ontario utilities also incur non-CDM customer service expenses that are not being excluded by PEG, creating a cost comparability problem and making the treatment advantageous to the U.S. and disadvantageous to THESL; 2) Eliminating a large expense category makes the total cost definition far less comprehensive, despite the Board's preference for comprehensive total cost benchmarking; and 3) There is no assurance that U.S. utilities record all of their CDM expenses within the customer service and information cost category.⁵

To solve the first two problems, PSE added in THESL's CDM expenses and re-added customer service and information expenses back into the total cost definition for U.S. utilities. This made the cost definitions comparable between THESL and the U.S. sample, addressed PEG's concern, and made the cost definitions far more comprehensive than the definition used by PEG (which excludes all customer service and information expenses).

It is not known if all U.S. utilities report CDM costs in the customer service category. PEG claims on page 25 of its Report that CDM often constitutes the largest expense for the customer service and information expenses, thus somehow justifying the exclusion of the entire cost category for the U.S. sample only (THESL non-CDM customer service and information expenses are still included in the PEG definition). However, PEG does not provide any evidence that CDM constitutes the largest expense component of the customer service and information category, when asked in 1-THESL-24 (d).

To assist with this issue, PSE contacted FERC directly; the "FERC Form 1 team" explained to PSE that each state records these expenses differently, and there is no clear guidance on the issue. More specifically, the FERC Form 1 team stated:

⁵ PEG claims in its response to 1-THESL-24 (a) to have subtracted out all of the customer service and information expenses not related to CDM for both the historical and projected THESL costs. This statement is incorrect, based on PSE's review of PEG's working materials, where no such adjustment is apparent nor mentioned in the PEG Report.

Demand-side management (DSM) is a distribution activity regulated at the local jurisdictional level, not at the Federal level. Each jurisdiction sets its own methods for the accounting for and recovery of DSM activities, including direct expensing or recovery through of some or all of the costs in a regulatory asset. They may also have specific reporting requirements for DSM activities. Look to each company's tariff, and the local jurisdictional authority, for specific information on the treatment of DSM activities, and in which regulatory accounts such activity is charged.⁶

In an effort to provide conservative evidence in this proceeding and only address clear-cut necessary changes, PSE will assume that U.S. utilities report all CDM activities in the customer service and information expense category (even though this is likely not the case for all U.S. utilities). Thus, PSE included all of THESL's CDM expenses, which are projected at \$51 million in 2015. Along with the smart meter expense inclusions for THESL, this assumption also makes the PSE Reply Report less favorable to THESL (e.g., if we were able to ascertain all CDM expenses for each utility and how they were recorded, THESL's results would most likely be better).

3.3 Adjustment #3: Model Specification with Urban Core and High Voltage Variables

PEG modified PSE's U.S. model by removing the urban core variable and including a high voltage capacity variable.⁷ In this PSE Reply Report, following established industry practice, PSE removed PEG's high voltage variable, which is statistically insignificant and incorrectly signed, and re-included PSE's urban core variable, which is logical, signed correctly and statistically significant at a 99% confidence level.

The fact that the high voltage variable is signed incorrectly (it should be positive, but is negative in the PEG Report Corrections) and statistically insignificant at even the 90% confidence level disqualifies the variable from being included. Business condition variables that are incorrectly signed or statistically insignificant are not included in econometric benchmarking models. PEG's use of this variable, and its exclusion of the urban core variable, are not in-line with benchmarking best practices. PEG has stated the need for business condition variables to be correctly signed and statistically significant in a report to the Board. In a report dated March 20, 2008 "Benchmarking the Costs of Ontario Power Distributors" on page 52, PEG writes:

All included business conditions were required to have elasticity estimates that were plausible (e.g. sensibly signed) and significantly different from zero. All variables found to be statistically significant were included in the final model. Since, additionally, we consider for inclusion only variables that are predicted by theory or that seem relevant on the basis of our industry experience, the model is not a 'black box' that confounds attempts at earnest appraisal.

In this proceeding, PEG has provided conflicting models with different signs for the high voltage variable, but in both models the variable is statistically insignificant. PEG's original December 2014 Report provided a model in Table Three that showed a statistically insignificant high voltage variable, but one that was positively signed. Then in PEG Report Corrections, PEG submitted a revised Table Three; this time the high voltage variable was negatively signed, but still statistically

⁶ Correspondence from FERC.

⁷ PEG also removed the percent undergrounding variable, although failed to mention this change or explain why the change occurred in the PEG Report.

insignificant. Neither model meets the benchmarking best practice principles previously stated by PEG.⁸

The Appendix of PSE's September Report provided an engineering analysis showing that utilities will have different cost challenges based on the development characteristics of their service territories. Costs are found to be well over double for urban service territories, relative to suburban ones. Excluding the urban variable creates an omitted variable bias in PEG's model and unfairly disadvantages THESL in the process.

Excluding the urban core variable also violates benchmarking best practice. PEG wrote in a 2010 report written on behalf of Public Service Company of Colorado:

One important result is that an econometric cost model can yield *biased* predictions of the true benchmark if relevant business condition variables are excluded from the model. It is therefore desirable to include in an econometric benchmarking model all business conditions which are believed to be relevant, for which good data are available at reasonable cost, and which have plausible and statistically significant parameter estimates.⁹

The PSE urban core variable is necessary to include and meets PEG's stated requirements for inclusion. PEG's high voltage variable does not meet those same requirements. Substituting the high voltage variable for the urban core variable is, therefore, a necessary change to the total cost model and one that is made in this PSE Reply Report.

PEG summarizes this issue by writing the following on page 3 and 4 of the PEG Report:

The third stage of PEG's review examined PSE's business condition variables. PEG made two necessary changes to PSE's selected business conditions. The first was adding a variable to reflect MVA of transformer capacity for stations with primary voltage levels at or above 50 kV. This variable is necessary to control for US utilities' costs of owning high voltage assets. The second was eliminating the urban core dummy variable from PSE's model because it is redundant, inappropriate in electricity distribution benchmarking, and appears to distort the estimated impact of other business condition variables (especially undergrounding).

PEG seems to have added new requirements for including business condition variables. PEG claims that the urban variable is "redundant, inappropriate in electricity distribution benchmarking, and appears to distort the estimated impact of other business condition variables (especially undergrounding)". PSE addresses each of these concerns in turn below.

3.3.1 The Urban Core Variable Is Not Redundant

On page 29 of the PEG Report, PEG states: "Since PSE's model already includes a percent of plant underground variable, including an 'urban core dummy' would be redundant at best." PEG appears

⁸ PSE also notes that the high-voltage expenses are included in the "TFP-based" cost measure used by PSE. PEG incorrectly criticizes PSE's use of a TFP-based cost in its Responses to Interrogatories (1-THESL-61) and in the PEG Report. The TFP-based costs capture the high-voltage costs that PEG is describing in its response. The TFP-based cost definition also excludes contributions in aid of construction (CIAC), which PEG itself subtracts from their cost definition for THESL (see PEG's response to 1-THESL-20). Besides adding smart meter expenses, the rationale for which PEG fails to empirically substantiate in its response to 1-THESL-19, PEG is effectively advocating for the cost definition used by PSE, while at the same time criticizing PSE for its use.

⁹ PEG Report of Dr. Mark Newton Lowry, President of PEG, filed on Behalf of Public Service Company of Colorado on December 17, 2010. Report title, "Statistical Analysis of Public Service of Colorado's Forward Test Year Proosal".

to be saying that the percent underground variable should be sufficient to pick up the impacts of higher costs for urban areas. This is incorrect for several reasons.

1. In our experience with hundreds of distributors, undergrounding tends to cost a great deal more in urban centers than in rural or suburban settings. In more rural and suburban settings, direct bury cables with pad mounted equipment are typically used. These are much less expensive than concrete-encased duct bank installations with underground vaults, submersible equipment and massive civil infrastructure, which are found in urban settings.
2. Similarly, overhead line construction can be found within all service area environments, but will also cost a great deal more in urban settings; these costs are not captured by an undergrounding variable.
3. The underground variable is not found in PEG's final model or in PSE's Reply model. PEG states in 1-THESL-32 the undergrounding variable was excluded because it was either statistically insignificant or had the wrong sign. It is not sensible to exclude the urban variable on the basis it is "redundant," but then also exclude the variable PEG claims serves as its replacement.

The costs of all types of construction based on the developed areas are laid out in the Appendix to the PSE September Report. PEG's statement that the percent underground variable will pick up the cost variations for an urban utility is not correct. In the end, serving an urban core simply increases costs, and our report shows that the urban core variable captures this fact.

3.3.2 The Urban Core Variable Is Not Inappropriate

We now move to PEG's claim that the urban core variable is "inappropriate in electricity distribution benchmarking." This statement is contrasted with PEG's own use of an urban core variable in prior gas distribution cost benchmarking studies. On page 28 of the PEG Report it lays out its rationale for this statement as follows:

Some PEG studies have used this variable in gas distribution models, but the rationale for using such a dummy variable is much stronger for gas distribution because essentially all gas distribution assets are underground. A dummy variable is one means of distinguishing between the higher costs of installing and maintaining underground gas distribution assets in densely-populated, mature urban areas compared with "greenfield" suburban territories.

The reasons that costs increase for urban gas distributors are the exact same reasons costs increase for urban electric distributors. Constructing and maintaining either underground or overhead assets in a densely-populated and mature urban area will cost considerably more than constructing and maintaining either overhead or underground power lines in a suburban environment. This is the same message in the PSE September Report Appendix.

3.3.3 The Urban Core Does Not Distort the Impact of Other Variables

PEG's last criticism of the urban core variable is that it "appears to distort the estimated impact of the other business condition variables (especially undergrounding)." Recall that PEG has already eliminated the undergrounding variable from their model. Eliminating the undergrounding variable vitiates the distortion argument (similar to PEG's redundancy concerns). Furthermore, using econometrics, any included variable will change the estimated impacts of the other business condition variables. This is why there needs to be a theoretical basis for including variables, and they must be correctly signed and statistically significant. To not include a variable that is predicted by theory, correctly signed, and statistically significant because it will change the other business condition variables would distort the model by creating what is known in econometrics

as an “omitted variable bias.” By excluding the urban core variable, PEG’s model suffers from this bias.¹⁰

The system R-squared statistics of PEG’s model and PSE’s Reply Report model can be compared. R-squared statistics are measures of “goodness of fit” and basically present how much of the variation in the dependent variable (total cost) is explained by the model. PEG’s R-squared is 0.926, implying that 92.6% of the variation in the data set is explained in their model. After making the three adjustments to PEG’s model, the R-squared of the resulting model increases to 0.962. This supports PSE’s position on the need to include variables that are logical, statistically significant, and properly signed.

In summary, standard industry practice results in including the urban core variable and excluding PEG’s high voltage variable. This will also capture a highly relevant cost driver (serving an urban core), which is necessary to provide a fair and accurate model to evaluate THESL’s cost performance.

3.4 PSE Reply Total Cost Model after Adjustments

The model estimates are provided in Table 1. All first order and business condition variables are logical, correctly signed, and statistically significant at a 95% level of confidence.

The PSE Reply Report total cost results are provided in Figure 3 and Table 2. THESL’s costs are under the PSE Reply Report total cost benchmarks until 2015, when the company’s cost is projected to move higher than its benchmarks by around four percent. THESL’s projected costs assume that the company’s proposed Custom IR plan is approved in full. Table 2 shows the numerical PSE Reply Report model results. THESL Custom IR projections remain within the 4th Generation IR 0.3% stretch factor range of +/- 10%.

¹⁰ Please see PEG’s statement on the prior page regarding what causes bias and how it can be prevented by including all business conditions that are plausibly signed, can have data gathered, and are statistically significant.

Table 1 PSE Reply Report Cost Model

			WK= Capital Price		
			N= Number Retail Customers		
			D= Peak Demand		
			UD= Urban Core Dummy		
			PCE= Percent Electric Customers in Gas & Electric Customers		
			PRV= Percent Residential Deliveries in Total Deliveries		
			PDE= Percent Distribution Plant in Total Electric Plant		
			ED= Elevation Standard Deviation		
			PF= Percent Forestation		
EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
WK	0.585	161.579	PDE	0.109	6.409
KK	0.062	3.472			
KN	-0.034	-3.051	ED	0.016	2.386
KD	0.042	3.626			
			PF	0.018	3.242
N	0.738	28.283			
NN	0.583	6.354	Trend	0.003	2.727
ND	-0.495	-5.394			
D	0.208	7.566			
DD	0.455	4.580	Constant	20.052	1418.424
UD	0.014	4.625	System Rbar-Squared	0.962	
PCE	0.122	4.238	Sample Period:	2002-2012	
PRV	0.037	2.133	Number of Observations	805	

Figure 3 PSE Reply Report Cost Model Results

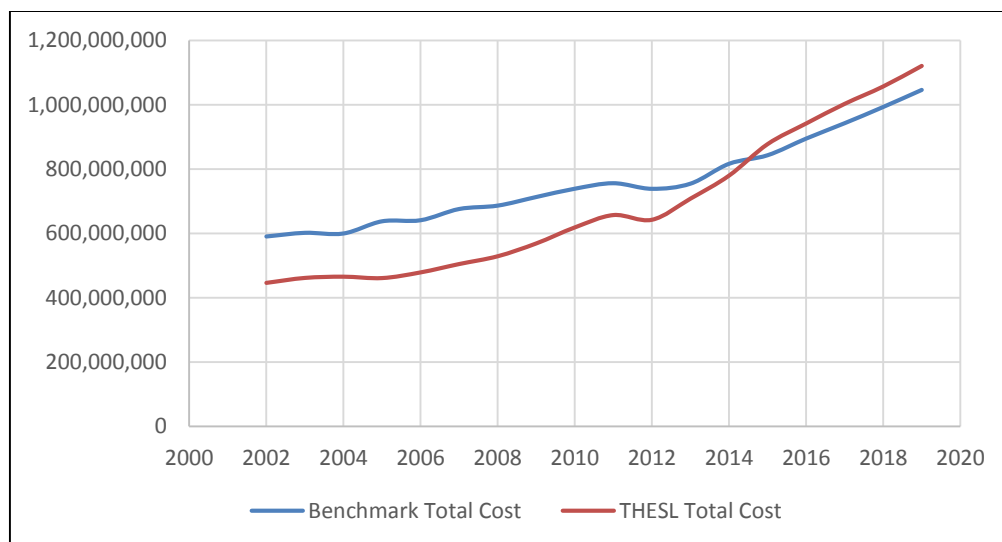


Table 2 PSE Reply Report Cost Model Results

Year	Percent of U.S. Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, \$M	Total Cost THESL, \$M
2002	-28.0%	\$591	\$446
2003	-26.5%	\$602	\$462
2004	-25.4%	\$600	\$466
2005	-32.4%	\$638	\$461
2006	-29.2%	\$641	\$479
2007	-29.2%	\$676	\$505
2008	-26.0%	\$687	\$529
2009	-22.6%	\$713	\$569
2010	-17.8%	\$739	\$619
2011	-14.0%	\$756	\$657
2012	-13.9%	\$739	\$643
2013	-6.3%	\$755	\$708
2014	-4.6%	\$816	\$780
2015	4.1%	\$843	\$878
2016	5.2%	\$895	\$942
2017	6.2%	\$943	\$1,003
2018	6.3%	\$993	\$1,057
2019	7.0%	\$1,046	\$1,121

4 PSE Response to PEG's Statements on General Benchmarking Practices

The PEG Report embarked on some discussions that did not directly pertain to the cost and reliability models. This section provides PSE's response to some of these general topics.

4.1 Response to PEG's Chapter Five, "Simultaneous Cost and Reliability Benchmarking"

In Chapter 5 of its report ("Simultaneous Cost and Reliability Benchmarking"), PEG attempts to replicate a reliability impact analysis that PSE conducted for Wisconsin Public Service ("WPS").¹¹ In 2013, WPS proposed a large 5-year reliability-driven spending program to its Wisconsin regulator. WPS named this spending program the "System Modernization Reliability Project" ("SMRP"). In that proceeding, Dr. Kaufmann of PEG provided testimony on behalf of WPS regarding the quantification of consumer benefits to improving reliability and compared these benefits to the five-year costs of the spending program. Mr. Fenrick of PSE also testified on behalf of WPS and presented PSE's reliability impact benchmarking model.

PSE found that the SMRP beat industry benchmarks for reliability-improvement spending. The study showed increasing net distribution plant by 43% for an average utility would improve SAIDI by around 12%. Thus, the projected SAIDI improvement of 20 to 25% for WPS would beat industry benchmarks.

In Chapter 5 of the PEG Report in this proceeding, PEG implemented PSE's model in the WPS case incorrectly. PEG inserted the growth rate in capital expenditures, rather than the increase in distribution net plant, over the life of the plan. PSE explicitly stated in the WPS case that we used distribution net plant as the basis for the calculation. This statement can be found in Mr. Fenrick's sur-surrebuttal testimony in Case 6690-CE-198 on May 6, 2013, page 2.

When asked in the THESL interrogatories about why PEG used annual capital expenditures rather than electric net distribution plant (1-THESL-52), PEG stated that it did not use the correct input because PSE had not provided the relevant WPS testimony. However, this testimony is on the public record, and PEG was aware of it, having been involved in the WPS case. In its report in this proceeding, PEG did not correctly reproduce PSE's prior research. When questioned in Interrogatory 1-THESL-52, PEG did not acknowledge nor correct this error in its reply, despite having access to the above-noted information that demonstrates that the error was made.

Given that THESL's net plant increase is projected to be less than WPS's (around 25% for THESL's five-year plan) with reliability improvement estimated to be very similar to WPS's (at 18.7% for THESL), we expect THESL to have a better finding than WPS did. In trying to replicate PSE's study, PEG found that THESL's SAIDI projections fall a bit short of the impact benchmarks. This conclusion is based on an incorrect implementation of PSE's prior research and should be disregarded.

4.2 PEG's "Zone of Continuous Improvement" and Eight Year Custom IR Plan

PSE's September Report states: "Based on the projections, the projected spending should result in a utility more aligned with its externally-derived benchmark values from both a total cost and

¹¹ PSE did not put forth this model in its September report, it was only brought up in interrogatories by Board Staff, in questioning by Dr. Kaufmann to Mr. Fenrick at the Technical Conference, and then in PEG's Report.

SAIFI perspective.”¹² PEG discusses how a utility should strive to improve benchmark evaluations in both cost and reliability simultaneously. PEG illustrates this on page 19 with a graph that implies that a distributor should find ways to improve both total costs and reliability at the same time, thus entering the PEG concept of the “zone of continuous improvement.”

PEG’s assertion is inconsistent with industry practices; all utilities know there are trade-offs between improving reliability and costs. PEG acknowledges this later on page 43, when it states there is a “common-sense linkage” between costs and reliability levels.¹³

PEG has not provided any detailed plans on how THESL can actually improve both reliability and their total cost performance at the same time. PEG’s proposition that this is possible is pure speculation, not likely to be possible in practice, and ignores the “common-sense linkage” between costs and reliability. Of course, it would be desirable if all utilities could simply reduce costs and enhance reliability, but in the real world, that is not feasible for the vast majority of utilities. Benchmarking can serve as a guide to help answer what is in the best interests of a utility’s customers, thus offering customers with a better balance between two competing interests (low costs and high quality service).¹⁴

As discussed in the prior section, it appeared that Dr. Kaufmann of PEG had no issue with WPS ramping up capital spending for a five-year period in order to improve reliability. In fact, he estimated that the benefits outweighed the added costs. On page 8 of Dr. Kaufmann’s rebuttal testimony on behalf of WPS, he states:

Nevertheless, with an estimated value of more than \$21 million per year to WPS customers after 2019, I believe the benefits generated because of the SMRP will certainly exceed the total costs of the program in less than 20 years, which is less than half of the 60-year expected life of the assets to be installed under the program.¹⁵

By conducting this capital spending program, WPS’s total cost benchmarks would suffer. Yet Dr. Kaufmann firmly rejected the idea that the program should be stretched out beyond the proposed five years. Dr. Kaufmann on behalf of WPS stated:

Delaying the implementation of the SMRP would reduce benefits to customers. If the project’s implementation was extended to 10 years, customers would receive some of the benefits later. Because there is a time value of money, this would reduce the project’s benefits to customers.¹⁶

¹² Page 12 of the PSE September Report.

¹³ PEG clarified its agreement in its Responses to Interrogatory (1-THESL-48); it did not dispute the common-sense linkage, as described the last sentence in paragraph 2 on page 43 of the PEG Report, which states that:

Since ‘old and failing infrastructure’ can be remedied by purchasing and installing new infrastructure, PSE posits a relationship between changes in THESL costs (especially the investment costs associated with installing new capital) and future changes in its SAIFI.”

(Emphasis added). In other words, as costs go up (especially new capital costs), SAIFI improves.

¹⁴ Other tools are also helpful to find the best balance between costs and reliability. THESL’s Feeder Investment Model (“FIM”) is an example of the utility attempting to find the most advantageous balance between capital investment and customer preferences for reliability.

¹⁵ Case 6690-CE-198 Pre-filed Rebuttal Testimony of Lawrence Kaufmann for Wisconsin Public Service Corporation, April 23, 2013.

¹⁶ Page 13 and 14, Case 6690-CE-198 Pre-filed Sur-Sur-Rebuttal Testimony of Lawrence Kaufmann for Wisconsin Public Service Corporation, May 6, 2013.

PSE believes this same logic is applicable in THESL's Custom IR proposal. The "zone of continuous improvement" is a standard for THESL that is likely to be impossible to achieve and, if attempted, would very likely result in far worse reliability than what would occur if the Custom IR plan is approved in full.

Furthermore, PSE sees no rationale for lengthening the Custom IR period from five years to eight years, as suggested by PEG. Improved reliability offers substantial benefits to customers. Even if THESL could deliver the same reliability outcomes in eight years rather than five (which is unrealistic given the reduced investment per year), there is little reason to delay a reliability outcome that is in the interests of customers. Dr. Kaufmann of PEG agrees in his WPS testimony quoted above. Providing a better alignment between costs and reliability is improvement.

4.3 The Meaning of the Benchmark Results

PEG states on page 12 of its Report: "PSE's conclusion that 'the company's capital was in need of investment' is simply speculation; this conclusion does not follow logically or empirically from the benchmark studies it presented." PSE would like to make it clear that we never concluded that "the company's capital was in need of investment."

What the PSE September Report actually stated was that PSE's benchmarking results are "suggestive" of this. PEG is correct in saying there is no statistically-derived basis for concluding with certainty that "the company's capital was in need of investment." But logic and common-sense "suggest" certain statements, even if they are not strictly empirical conclusions. A benchmarking result that shows a utility with lower than expected costs, yet higher than expected SAIFI, suggests to PSE that the capital infrastructure is failing more often than expected, and is likely in need of added investment.¹⁷

There is a common-sense linkage between cost management and reliability outcomes. The total cost benchmarking results show the expected total costs for each utility in the sample, given their business condition variable values. One method of increasing the cost efficiency benchmarking score is to have older infrastructure. All else being equal, older infrastructure will increase total costs less than newer infrastructure. Yet there are limits on increasing cost efficiency in this manner. At some point, investment is needed to renew the infrastructure.

PSE's benchmarking results found that THESL is historically a cost efficient firm, and its system is failing more often than our models suggest. Based on the common-sense linkage between costs and reliability, this result suggests to PSE that THESL's capital is in need of investment.

¹⁷ It should also be noted that PEG, in both its Report (p. 14) and its Response to Interrogatories (1-THESL-8) mischaracterizes PSE's position on SAIFI and capital spending. It is not the case that "...PSE finds THESL's SAIFI to be reasonable because it is declining under Custom IR..." PSE never states or implies THESL's SAIFI is reasonable; instead, PSE finds THESL's plan to increase capital spending is a reasonable plan to improve SAIFI.

5 PSE Conclusions

After making the three straightforward adjustments previously discussed, PSE finds that THESL's total costs are 15.2% below benchmarks in 2010-2012. During the Custom IR period, THESL's costs remain within the 4th Generation IR 0.3% stretch factor range. THESL's SAIFI is historically above benchmarks, but converges towards benchmarks during the Custom IR period. THESL's SAIDI is below benchmarks, and is projected to continue to be lower during the Custom IR period.

Based on these results and the discussions throughout this Reply Report, PSE's conclusions are:

- A stretch factor during THESL's Custom IR plan of 0.3% is consistent with 4th Generation IR. THESL's total cost results remain in the "normal" range of +/- 10% and implies the 0.3% value. Reliability is mixed, with SAIFI being worse and SAIDI being better than expected. Throughout the Custom IR period, however, SAIDI is projected to be over 100% below benchmarks and statistically superior, whereas THESL's SAIFI is projected to converge towards the benchmark and be statistically average during the Custom IR period.
- PEG's suggestion of lengthening the Custom IR plan to eight years from five should be rejected. THESL's 5-year Custom IR proposal provides an improved alignment between reliability and costs while maintaining total cost levels within the "normal" range. Lengthening the time period will stunt this improved alignment.
- THESL's 2015 test year total cost levels are reasonable from a benchmark perspective. Even with the conservative nature of PSE's Reply Report results, THESL's 2015 total costs are in the "normal" range.
- Given the enhancement in reliability resulting from THESL's proposal (in particular for SAIFI), the Custom IR plan will better align THESL with its total cost and SAIFI benchmarks. This is an improvement and is likely to provide value to THESL customers.

RATE BASE OVERVIEW

In accordance with s. 2.5.1.1 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements"), this schedule provides an overview of Toronto Hydro's rate base and year-over year variance analysis of rate base and distribution assets for the following years: 2011 OEB-approved, 2011 to 2013 historical actuals, 2014 bridge year forecast, and 2015 test year forecasts. Continuity statements for Toronto Hydro's fixed assets, including interest during construction and all overheads, are filed at Exhibit 2A, Tab 1, Schedule 2.

1. RATE BASE

Table 1 below summarizes Toronto Hydro's rate base values for the historical (2011 to 2013), bridge (2014), and test year (2015), including opening and closing balances, the average of opening and closing balances for gross assets and accumulated depreciation, and the utility's working capital allowance.

Table 1: Rate Base Overview (\$ Millions)

	2011 OEB Approved	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2015 Test MIFRS
Opening PP&E NBV	1,897.8	1,895.8	2,183.5	2,251.9	2,356.0	2,436.6
ICM	-	-	-	-	-	372.6
Street Lighting	-	-	-	-	-	39.8
Opening PP&E NBV Adjusted	1,897.8	1,895.8	2,183.5	2,251.9	2,356.0	2,849.0
Closing PP&E NBV	2,105.1	2,183.5	2,251.9	2,356.0	2,456.3 ¹	3,161.0
Average PP&E NBV	2,001.5	2,039.7	2,217.7	2,304.0	2,406.1	3,005.0
Working Capital Allowance	296.7	318.1	316.6	354.4	369.5	241.5
Rate Base	2,298.2	2,357.7	2,534.3	2,658.4	2,775.6	3,246.5

¹ The 2014 financial results have not been closed out and audited. However, Toronto Hydro's assessment is that the 2014 closing PP&E NBV is within approximately 1% of the forecast.

1 lead lag study conducted by Navigant Consulting Inc. Further details on WCA are
2 provided at Exhibit2A, Tab 3 and Schedules 1 and 2.

3 4 5 **2. RATE BASE VARIANCE ANALYSIS**

6 7 **2.1. 2011 OEB Approved vs. 2015 Test Year**

8 Toronto Hydro's requested rate base for the 2015 test year is \$3,246.7 million, which /C
9 represents an increase of \$948.5 million or 41.3 percent from the rate base amount of /C
10 \$2,298.2 million approved by the OEB in the utility's last rebasing application (EB-2010-
11 0142). The average net book value ("NBV") of PP&E increased by \$1,003.5 million and /C
12 the WCA component of rate base decreased by approximately \$55.0 million from that
13 approved by the OEB.

14 15 **2.2. 2011 OEB Approved vs. 2011 Actual**

16 Toronto Hydro's 2011 actual rate base was \$38.2 million less than the 2011 OEB-
17 approved amount. Average NBV of PP&E in 2011 was \$38.2 million higher than the
18 OEB-approved level, primarily due to higher in-service additions than originally assumed
19 and additional 2011 capital expenditure. Toronto Hydro's actual 2011 WCA was \$21.4
20 million higher than OEB-approved because the cost of power expenses were \$170.2
21 million higher than the original forecast, with most of the increase being attributable to
22 commodity price increases.

23 24 **2.3. 2011 Actual vs. 2012 Actual**

25 Toronto Hydro's rate base increased by \$176.6 million from 2011 to 2012. The net
26 increase in average PP&E was \$178.1 million. Continued investment in distribution
27 assets contributed to this increase. WCA decreased by \$1.5 million in 2012 primarily due
28 to reduction in OM&A in 2012 compared to 2011.

1

2 **2.4. 2013 Actual vs. 2012 Actual**

3 In 2013, rate base increased by \$124.1 million over 2012 levels. In 2013, the average
4 PP&E NBV increased by \$86.2 million. Continued investment in distribution assets
5 contributed to this increase. In addition, in 2013, Toronto Hydro applied for and received
6 approval for final disposition of its smart metering costs and investments. As a result of
7 this decision, a total of \$46.8 million in smart meter assets were transferred to rate base.
8 The net book value of stranded meters related to the deployment of smart meters was also
9 reclassified to regulatory assets resulting in a decrease in net assets of \$17.3 million.
10 WCA increased by \$37.8 million due to cost of power expenses, which were \$292.3
11 million higher in 2013 than the 2012, with most of the increase being attributable to
12 commodity price increases.

13

14 **2.5. 2013 Actual vs. 2014 Bridge Year**

15 In 2014, rate base is forecasted to increase by \$117.2 million. Average NBV of PP&E is /C
16 expected to increase by \$102.1 million due to increased investment in the distribution /C
17 system. The level of increases in average NBV of PP&E is offset by the 2013 removal of
18 the NBV of stranded meters related to Toronto Hydro's smart metering program. In this
19 application, Toronto Hydro is proposing disposition of its stranded meter assets (Exhibit
20 2B, Tab 4, Schedule 1) and therefore has removed the amounts from the ending 2013
21 (opening 2014) NBV of PP&E. WCA increases by \$15.1 million, primarily due to rising
22 commodity costs.

23

24 **2.6. 2014 Bridge Year vs. 2015 Test Year**

25 In 2015 rate base is forecasted to increase by \$471.1 million. Average NBV of PP&E /C
26 increases by \$598.9 million, while WCA decreases by \$127.8 million. The increase in /C
27 PP&E includes \$372.6 million towards board approved ICM of 2013-2014 and \$39.8 /C

million towards street lighting assets. Toronto Hydro has included ICM and street lighting in the opening balance of PP&E to capture the full year return.

3. DISTRIBUTION ASSETS

Table 2A below presents a summary of Toronto Hydro's distribution assets net of accumulated depreciation (excluding construction work-in-progress), based on the OEB's minimum reporting groups for the historical (2011 to 2013), bridge (2014), and test (2015) years.

Table 2A: Net Assets (2011-2015) – Years Ending December 31 (\$ millions)

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Land and Buildings	61.3	63.1	67.3	69.1	68.7	110.0
TS Primary Above 50	10.5	11.0	11.0	11.1	11.1	12.3
Distribution System	222.6	226.5	229.3	245.5	244.2	291.4
Poles and Wires	2,893.6	3,037.9	3,179.0	3,300.4	3,253.5	3,824.2
Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
Services and Meters	303.7	317.2	278.1	298.7	298.7	349.0
General Plant	130.1	134.4	141.6	167.2	167.1	153.3
Equipment	180.1	178.5	181.8	189.7	189.7	197.1
IT Assets	44.6	50.5	56.3	87.4	87.4	98.9
Other Distribution Assets	323.9	348.9	380.2	402.4	404.9	477.3
Contributions and Grants	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
Gross Assets	4,607.8	4,809.0	4,977.7	5,227.6	5,150.5	5,976.5
Accumulated Depreciation	(2,424.2)	(2,557.1)	(2,621.7)	(2,771.3)	(2,713.9)	(2,815.6)
Net Assets	2,183.5	2,251.9	2,356.0	2,456.3	2,436.6	3,161.0

/C

The major drivers of the changes from 2011 to 2015 include:

- Continued investment in distribution assets;
- Inclusion of OEB-approved smart meter expenditures in net assets;
- Reclassification of stranded meters from net assets to regulatory assets;
- Inclusion of 2013 and 2014 ICM eligible in-service capital expenditures;

- Adjustments to decrease net assets related to the transition from UGAAP to MIFRS; and
- Completion of the Phase 1 Copeland TS project.

As directed by the OEB in its Partial Decision and Order in EB-2012-0064, Toronto Hydro transferred Incremental Capital Module (“ICM”) in-service capital additions in the year 2013 and 2014 to a regulatory asset account. For the purpose of 2015 opening rate base, Toronto Hydro has included forecasted ICM in-service assets as at the end of 2014. To illustrate, Tab 2B below provides a separate view of net assets which includes ICM in-service additions in 2013 and 2014. For more information about Toronto Hydro’s ICM True-Up process proposal, please refer to Exhibit 2A, Tab 9, Schedule 1.

Table 2B: Net Assets (2011-2015) – Years Ending December 31 (\$ millions)
Including Eligible ICM In-Service Capital Expenditures

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Land and Buildings	61.3	63.1	67.8	69.8	69.3	110.0
TS Primary Above 50	10.5	11.0	11.0	11.4	11.4	12.3
Distribution System	222.6	226.5	234.7	264.6	263.3	291.4
Poles and Wires	2,893.6	3,037.9	3,312.1	3,599.0	3,552.4	3,824.2
Line Transformers	731.7	757.4	813.3	860.2	829.6	835.5
Services and Meters	303.7	317.2	282.6	314.9	315.0	349.0
General Plant	130.1	134.4	141.6	167.2	167.1	153.3
Equipment	180.1	178.5	181.8	189.7	189.7	197.1
IT Assets	44.6	50.5	56.3	87.7	87.7	98.9
Other Distribution Assets	323.9	348.9	381.2	402.2	404.7	477.3
Contributions and Grants	(294.5)	(316.6)	(339.6)	(357.2)	(357.2)	(372.5)
Gross Assets	4,607.8	4,809.0	5,142.9	5,609.5	5,532.9	5,976.5
Accumulated Depreciation	(2,424.2)	(2,557.1)	(2,623.7)	(2,781.1)	(2,723.8)	(2,815.6)
Net Assets	2,183.5	2,251.9	2,519.1	2,828.4	2,809.2	3,161.0

/C

were offset by an increase in net assets of \$46.8 million related to the OEB ruling on smart meters permitting the recovery of the utility's allowed cost of capital on smart meters since 2008.

Table 4: 2012 Historical (UGAAP) versus 2013 Historical (UGAAP) (\$ millions)

	2012 Historical UGAAP	2013 Historical UGAAP	Variance (\$)	Variance (%)
Land and Buildings	63.1	67.3	4.1	6.6
TS Primary Above 50	11.0	11.0	(0.0)	(0.0)
Distribution System	226.5	229.3	2.8	1.2
Poles and Wires	3,037.9	3,179.0	141.0	4.6
Line Transformers	757.4	791.9	34.5	4.6
Services and Meters	317.2	278.1	(39.2)	(12.3)
General Plant	134.4	141.6	7.2	5.4
Equipment	178.5	181.8	3.3	1.9
IT Assets	50.5	56.3	5.8	11.5
Other Distribution Assets	348.9	380.2	31.2	9.0
Contributions and Grants	(316.6)	(338.8)	(22.2)	7.0
Gross Assets	4,809.0	4,977.7	168.7	3.5
Accumulated Depreciation	(2,557.1)	(2,621.7)	(64.6)	2.5
Net Assets	2,251.9	2,356.0	104.1	4.6

Note: Variances due to rounding may exist

Table 4 above reflects a reduction in net assets by \$163.1 million related to ICM in-service capital expenditures, which were transferred to a regulatory asset account, as directed by the OEB in EB-2012-0064.⁴

3.4. 2013 Actual vs. 2014 Bridge

As Table 5 below illustrates, Toronto Hydro forecasts 2014 net assets at \$2,456.3 million compared to historical 2013 net assets of \$2,356.0 million, representing an increase of \$100.3 million or 4.3 percent. Capital additions are forecasted at \$470.6 million and accumulated depreciation additions are forecasted at \$158.2 million in 2014. For more information,

/C

} /C

⁴ EB-2012-0064, Partial Decision and Order (April 2, 2013).

refer to the fixed asset continuity statement for 2014 USGAAP (Exhibit 2A, Tab 1, Schedule 2, Appendix 2-BA). Continued investment in distribution assets contributed to this increase. The primary driver contributing to the increase is poles and wires assets.

Table 5: 2013 Historical (UGAAP) versus 2014 Bridge (UGAAP) (\$ millions)

	2013 Historical UGAAP	2014 Bridge UGAAP	Variance (\$)	Variance (%)
Land and Buildings	67.3	69.1	1.9	2.8
TS Primary Above 50	11.0	11.1	0.2	1.4
Distribution System	229.3	245.5	16.1	7.0
Poles and Wires	3,179.0	3,300.4	121.5	3.8
Line Transformers	791.9	810.3	18.3	2.3
Services and Meters	278.1	298.7	20.7	7.4
General Plant	141.6	167.2	25.6	18.1
Equipment	181.8	189.7	7.8	4.3
IT Assets	56.3	87.4	31.1	55.2
Other Distribution Assets	380.2	402.4	22.2	5.8
Contributions and Grants	(338.8)	(354.3)	(15.5)	4.6
Gross Assets	4,977.7	5,227.6	249.9	5.0
Accumulated Depreciation	(2,621.7)	(2,771.3)	(149.6)	5.7
Net Assets	2,356.0	2,456.3	100.2	4.3

Note: Variances due to rounding may exist

Table 5 above, reflects a reduction in net assets by \$214.6 million related to forecasted ICM eligible in-service capital expenditures, which were transferred to a regulatory asset account as directed by the OEB.

3.5. 2014 Bridge vs. 2015 Test Year

Toronto Hydro forecasts 2015 net assets under MFIRS at \$3,161.0 million compared to forecasted 2014 net assets of \$2,456.3 million under UGAAP, representing an increase of \$704.7 million or 28.7 percent. The 2015 opening balance net assets are adjusted for the following items, representing \$393.3 million of the total net asset increase:

- 1 • \$372.6 million increase related to the addition of 2013 and 2014 ICM eligible in- /C
- 2 service capital expenditures presented in the regulatory asset account for the
- 3 duration of the IRM period.
- 4 • \$39.8 million increase for the transfer of former street lighting assets, which as
- 5 proposed in Exhibit 2A, Tab 5, Schedule 1, will have a neutral effect on the
- 6 utility's test year revenue requirement;
- 7 • \$19.1 million decrease related to the transition from UGAAP to MIFRS.
- 8

9 **Table 5A: 2014 Bridge (UGAAP) versus 2015 Test (MIFRS) (\$ millions)**

	2014 Bridge UGAAP	2015 Test MIFRS	Variance (\$)	Variance (%)
Land and Buildings	69.1	110.0	40.9	59.1
TS Primary Above 50	11.1	12.3	1.2	10.4
Distribution System	245.5	291.4	45.9	18.7
Poles and Wires	3,300.4	3,824.2	523.8	15.9
Line Transformers	810.3	835.5	25.3	3.1
Services and Meters	298.7	349.0	50.2	16.8
General Plant	167.2	153.3	(13.9)	(8.3)
Equipment	189.7	197.1	7.4	3.9
IT Assets	87.4	98.9	11.4	13.1
Other Distribution Assets	402.4	477.3	75.0	18.6
Contributions and Grants	(354.3)	(372.5)	(18.2)	5.1
Gross Assets	5,227.6	5,976.5	749.0	14.3
Accumulated Depreciation	(2,771.3)	(2,815.6)	(44.3)	1.6
Net Assets	2,456.3	3,161.0	704.7	28.7

Note: Variances due to rounding may exist

- 10 Capital additions are forecasted at \$539.7 million. The increase in net assets is driven by /C
- 11 the capital investments outlined in the Distribution System Plan (Exhibit 2B, Section E).
- 12
- 13 Land and Buildings are expected to increase \$40.9 million or 59.1 percent and TS /C
- 14 Primary Above 50 assets are expected to increase \$1.2 million or 10.4 percent. The /C

1 increase in both of these major plant accounts is primarily due to the Phase 1 Copeland
2 TS project which includes the station facility construction and installation of high voltage
3 transmission connections. The Copeland TS project was approved by the OEB under the
4 Toronto Hydro's 2012-2014 ICM application.⁵ Refer to the Station Expansion Program
5 (Exhibit 2B, E7.9) for additional details relating to this project.

6
7 Distribution System assets are expected to increase \$45.9 million or 18.7 percent. The
8 increase in distribution system assets is primarily due to the forecasted in-service stations
9 switchgear projects. Municipal Station Switchgear and Transformer Switchgear work
10 was filed and approved as part of Toronto Hydro's 2012-2014 ICM application and will
11 continue as a program in 2015 to replace existing obsolete switchgear with a modern arc-
12 resistant design. Refer to the Switchgear Renewal Program (Exhibit 2B, E6.13) for more
13 information about this project.

} /C

14
15
16
17 Capital investment in poles and wires is expected to increase by \$523.8 million or 15.9
18 percent and investment in line transformer assets are expected to increase by \$25.3
19 million or 3.1 percent. The increase in these major plant categories is primarily attributed
20 to the Underground Circuit Renewal (Exhibit 2B, E6.1), Overhead Circuit Renewal
21 (Exhibit 2B, E6.4), Reactive Capital (Exhibit 2B, E6.20) and Customer Connections
22 (Exhibit 2B, E5.2) programs.

} /C

- 23 • The Underground and Overhead Circuit Renewal programs are required to replace
- 24 end of life and obsolete assets to mitigate failure and safety risks.
- 25 • The Reactive Capital program is required to restore power to customers and
- 26 maintain system performance and reliability when assets fail.

⁵ EB-2012-0064, Partial Decision and Order (April 2, 2013) at page 53.

- The Customer Connection program allows Toronto Hydro to satisfy its obligation to connect new customers in its service area.

Net additions to poles and wires and line transformers includes the 2013 and 2014 ICM eligible in-service capital expenditures presented in the regulatory asset account for the duration of the IRM period. Former street lighting assets are also included as part of the net addition increase to poles and wires.

Services and meter assets are expected to increase \$50.2 million or 16.8 percent. The increase in services and meter assets is primarily related to the Metering program (Exhibit 2B, E6.1), the objective of which is to ensure compliance with Measurement Canada, OEB and IESO rules and regulations.

} /C

Equipment assets are expected to increase \$7.4 million or 3.9 percent. The increase in equipment is primarily due to fleet. Refer to the Fleet and Equipment Services program (Exhibit 2B, E8.1) for additional details.

/C
/C

IT assets are expected to increase \$11.4 million or 13.1 percent primarily due to computer hardware equipment investment which enables Toronto Hydro to efficiently and effectively plan and execute capital and operational programs and fulfill its obligations to customers and regulatory bodies. Refer to the IT Hardware program (Exhibit 2B, E8.4) for more information.

Other distribution assets are expected to increase \$75.0 million or 18.6 percent primarily due to the in-service amount for computer software additions. For additional details related to the computer software investments refer to the IT Software program (Exhibit 2B, E8.5).

} /C

1

2

3

4 Contributions and grants are expected to increase \$18.2 million or 5.1 percent related to
5 realized contributions related to in-service assets.

6

7 The forecasted accumulated depreciation additions is \$208.1 million in 2015, and /C
8 includes \$33.9 million of losses on derecognition of assets. For more information about
9 Toronto Hydro's depreciation expense and derecognition losses, refer to Exhibit 4B, Tab
10 1, Schedules 1 and 2, respectively.

11

12 Net assets were reduced by \$4.6 million related to eligible investment for the purpose of
13 enabling the connection of a renewable energy generation facility to its distribution
14 system. In accordance with s. 79.1 of the *Ontario Energy Board Act, 1998* and s. 2.5.2.5
15 of the OEB's Filing Requirements (July 17, 2013), Toronto Hydro proposes to recover
16 the cost incurred for these investments from all provincial ratepayers. Refer to Exhibit
17 2A, Tab 8, Schedule 1 for more information about Toronto Hydro's proposed treatment
18 of renewable enabling eligible investments.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - CGAAP

Year 2011

CCA Class	OEB	Description	Cost					Accumulated Depreciation					
			Opening Balance	Additions	Retirement	Transfers	Closing Balance	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	\$ 172,691,847	\$ 53,066,537	\$ -	(\$ 3,159,693)	\$ 222,598,691	(\$ 129,292,640)	(\$ 24,893,304)	\$ -	\$ -	(\$ 154,185,944)	\$ 68,412,747
N/A	1805	Land	\$ 7,670,263	(\$ 1,535)	(\$ 58,892)	\$ -	\$ 7,609,837	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,609,837
1	1808	Buildings	\$ 45,857,359	\$ 2,530,944	(\$ 3,761,399)	(\$ 45,048)	\$ 44,581,856	(\$ 17,441,185)	(\$ 1,550,177)	\$ 1,151,042	\$ 6,334	(\$ 17,833,986)	\$ 26,747,870
47	1815	Transformer Station Equipment >50 kV	\$ 9,869,059	\$ 623,021	\$ -	\$ -	\$ 10,492,080	(\$ 3,945,111)	(\$ 380,940)	\$ -	\$ -	(\$ 4,326,051)	\$ 6,166,029
47	1820	Distribution Station Equipment <50 kV	\$ 199,481,416	\$ 23,105,699	\$ -	\$ -	\$ 222,587,114	(\$ 88,643,689)	(\$ 7,083,676)	\$ -	\$ -	(\$ 95,727,365)	\$ 126,859,750
47	1830	Poles, Towers & Fixtures	\$ 350,090,188	\$ 28,998,242	\$ -	\$ -	\$ 379,088,430	(\$ 171,015,223)	(\$ 5,824,614)	\$ -	\$ -	(\$ 176,839,838)	\$ 202,248,592
47	1835	Overhead Conductors & Devices	\$ 378,085,017	\$ 34,893,995	\$ -	\$ -	\$ 412,979,013	(\$ 240,607,561)	(\$ 4,341,875)	\$ -	\$ -	(\$ 244,949,436)	\$ 168,029,576
47	1840	Underground Conduit	\$ 1,178,820,486	\$ 134,109,241	\$ -	\$ -	\$ 1,312,929,727	(\$ 588,742,455)	(\$ 31,948,117)	\$ -	\$ -	(\$ 620,690,572)	\$ 692,239,156
47	1845	Underground Conductors & Devices	\$ 722,435,297	\$ 66,209,802	\$ -	\$ -	\$ 788,645,099	(\$ 377,725,469)	(\$ 13,844,464)	\$ -	\$ -	(\$ 391,569,933)	\$ 397,075,166
47	1850	Line Transformers	\$ 682,649,674	\$ 49,044,127	\$ -	\$ -	\$ 731,693,800	(\$ 356,892,831)	(\$ 21,426,917)	\$ -	\$ -	(\$ 378,319,748)	\$ 353,374,052
47	1855	Services (Overhead & Underground)	\$ 72,596,667	\$ 2,896,736	\$ -	\$ -	\$ 75,493,402	(\$ 13,025,365)	(\$ 1,433,856)	\$ -	\$ -	(\$ 14,459,221)	\$ 61,034,181
47	1860	Meters	\$ 210,553,546	\$ 17,674,856	\$ -	\$ -	\$ 228,228,402	(\$ 115,000,783)	(\$ 9,162,626)	\$ -	\$ -	(\$ 124,163,409)	\$ 104,064,992
N/A	1905	Land	\$ 1,889,782	\$ 7,261,212	\$ -	\$ -	\$ 9,150,994	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,150,994
1	1908	Buildings & Fixtures	\$ 105,685,557	\$ 4,619,112	\$ -	\$ 45,048	\$ 110,349,717	(\$ 38,167,505)	(\$ 6,395,106)	\$ -	(\$ 6,334)	(\$ 44,568,945)	\$ 65,780,772
13	1910	Leasehold Improvements	\$ 19,460,717	\$ 294,610	\$ -	\$ -	\$ 19,755,328	(\$ 12,768,075)	(\$ 5,993,705)	\$ -	\$ -	(\$ 18,761,779)	\$ 993,548
8	1915	Office Furniture & Equipment	\$ 16,398,277	\$ 4,106,766	\$ -	\$ -	\$ 20,505,043	(\$ 7,024,507)	(\$ 1,452,357)	\$ -	\$ -	(\$ 8,476,864)	\$ 12,028,179
52	1920	Computer Equipment - Hardware	\$ 40,633,537	\$ 3,991,660	\$ -	\$ -	\$ 44,625,197	(\$ 31,228,484)	(\$ 4,373,915)	\$ -	\$ -	(\$ 35,602,399)	\$ 9,022,798
10	1930	Transportation Equipment	\$ 73,748,754	\$ 11,490,148	(\$ 7,257,634)	\$ 34,362	\$ 78,015,630	(\$ 43,208,343)	(\$ 7,074,141)	\$ 7,185,827	(\$ 57,374)	(\$ 43,154,031)	\$ 34,861,599
8	1935	Stores Equipment	\$ 5,506,283	\$ -	\$ -	\$ -	\$ 5,506,283	(\$ 5,476,091)	(\$ 7,709)	\$ -	\$ -	(\$ 5,483,800)	\$ 22,484
8	1940	Tools, Shop & Garage Equipment	\$ 36,736,912	\$ 2,646,528	\$ -	(\$ 192,000)	\$ 39,191,440	(\$ 25,431,593)	(\$ 1,924,584)	\$ -	\$ -	(\$ 27,356,177)	\$ 11,835,262
8	1945	Measurement & Testing Equipment	\$ 4,866,897	\$ 13,567,209	\$ -	(\$ 13,417,930)	\$ 5,016,176	(\$ 4,300,071)	(\$ 1,086,963)	\$ -	\$ 958,424	(\$ 4,428,611)	\$ 587,566
8	1955	Communications Equipment	\$ 26,817,595	\$ 1,368,039	\$ -	\$ 3,351,693	\$ 31,537,327	(\$ 21,012,708)	(\$ 2,899,180)	\$ -	\$ -	(\$ 23,911,888)	\$ 7,625,439
8	1960	Miscellaneous Equipment	\$ 170,801	\$ 197,257	\$ -	\$ -	\$ 368,058	(\$ 2,911)	(\$ 25,285)	\$ -	\$ -	(\$ 28,196)	\$ 339,863
47	1970	Load Management Controls Customer Premises	\$ 15,181,181	(\$ 338,086)	\$ -	\$ -	\$ 14,843,095	(\$ 8,630,378)	(\$ 1,025,729)	\$ -	\$ -	(\$ 9,656,107)	\$ 5,186,988
47	1975	Load Management Controls Utility Premises	\$ 554,382	\$ -	\$ -	\$ -	\$ 554,382	(\$ 554,382)	\$ -	\$ -	\$ -	(\$ 554,382)	\$ -
47	1980	System Supervisor Equipment	\$ 56,427,608	\$ 1,154,182	\$ -	\$ -	\$ 57,581,790	(\$ 36,171,073)	(\$ 1,763,841)	\$ -	\$ -	(\$ 37,934,914)	\$ 19,646,876
47	1995	Contributions & Grants	(\$ 258,098,313)	(\$ 36,381,079)	\$ -	\$ -	(\$ 294,479,391)	\$ 53,243,868	\$ 8,200,745	\$ -	\$ -	\$ 61,444,613	(\$ 233,034,778)
N/A	1609	Capital Contributions Paid	\$ 2,042,507	\$ 12,016,399	\$ -	\$ -	\$ 14,058,906	(\$ 524,244)	(\$ 916,010)	\$ -	\$ -	(\$ 1,440,253)	\$ 12,618,653
N/A	2005	Property Under Capital Leases	\$ 885,800	\$ -	\$ -	\$ 13,383,568	\$ 14,269,368	(\$ 350,415)	\$ -	\$ -	(\$ 901,049)	(\$ 1,251,464)	\$ 13,017,904
							\$ -					\$ -	\$ -
		Sub-Total	\$ 4,179,709,098	\$ 439,145,621	(\$ 11,077,924)	\$ -	\$ 4,607,776,794	(\$ 2,283,939,224)	(\$ 148,628,347)	\$ 8,336,869	\$ -	(\$ 2,424,230,701)	\$ 2,183,546,093
		Less Socialized Renewable Energy Generation Investments (input as negative)					\$ -					\$ -	\$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					\$ -					\$ -	\$ -
		Total PP&E	\$ 4,179,709,098	\$ 439,145,621	(\$ 11,077,924)	\$ -	\$ 4,607,776,794	(\$ 2,283,939,224)	(\$ 148,628,347)	\$ 8,336,869	\$ -	(\$ 2,424,230,701)	\$ 2,183,546,093
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							\$ -				\$ -
		Total							(\$ 148,628,347)				

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation

Transportation

(\$ 2,189,844)

Stores Equipment

Net Depreciation

(\$ 146,438,503)

Notes:

1 The below CCA classes have been updated or added for these OEB Accounts:

CCA Class	OEB	Description	Explanation for Change
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
52	1920	Computer Equipment - Hardware	Class 52 (with 100% CCA rate with no half-year rule) was added to Schedule II of Income Tax Regulations on April 30, 2009 - for eligible computers acquired after January 27, 2009 and before February, 2011.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - UGAAP

Year 2012

			Cost					Accumulated Depreciation							
CCA Class	OEB	Description	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Net Book Value		
12	1611	Computer Software (Formally known as Account 1925)	\$ 222,598,691	\$ 19,655,588	\$ -	\$ -	\$ 242,254,279	(\$ 154,185,944)	(\$ 20,224,259)	\$ -	\$ -	(\$ 174,410,203)	\$ 67,844,075		
N/A	1805	Land	\$ 7,609,837	\$ -	(\$ 13,989)	\$ -	\$ 7,595,848	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,595,848		
1	1808	Buildings	\$ 44,581,856	\$ 2,314,871	(\$ 566,615)	\$ 45,048	\$ 46,375,160	(\$ 17,833,986)	(\$ 1,495,626)	\$ 247,655	(\$ 3,983)	(\$ 19,085,940)	\$ 27,289,220		
47	1815	Transformer Station Equipment >50 kV	\$ 10,492,080	\$ 525,966	\$ -	(\$ 43,688)	\$ 10,974,359	(\$ 4,326,051)	(\$ 402,730)	\$ -	\$ -	(\$ 4,728,781)	\$ 6,245,578		
47	1820	Distribution Station Equipment <50 kV	\$ 222,587,114	\$ 3,874,905	\$ -	\$ 77,169	\$ 226,539,188	(\$ 95,727,365)	(\$ 6,499,970)	\$ -	\$ -	(\$ 102,227,335)	\$ 124,311,853		
47	1830	Poles, Towers & Fixtures	\$ 379,088,430	\$ 13,535,315	\$ -	\$ -	\$ 392,623,745	(\$ 176,839,838)	(\$ 6,469,781)	\$ -	\$ -	(\$ 183,309,619)	\$ 209,314,126		
47	1835	Overhead Conductors & Devices	\$ 412,979,013	\$ 20,008,279	\$ -	\$ 84,573	\$ 433,071,865	(\$ 244,949,436)	(\$ 5,152,543)	\$ -	\$ -	(\$ 250,101,980)	\$ 182,969,885		
47	1840	Underground Conduit	\$ 1,312,929,727	\$ 65,155,008	\$ -	(\$ 424,660)	\$ 1,377,660,076	(\$ 620,690,572)	(\$ 32,737,980)	\$ -	(\$ 1,119)	(\$ 653,429,670)	\$ 724,230,405		
47	1845	Underground Conductors & Devices	\$ 788,645,099	\$ 45,810,001	\$ -	\$ 134,998	\$ 834,590,098	(\$ 391,569,933)	(\$ 14,554,813)	\$ -	(\$ 1,599)	\$ 406,126,346)	\$ 428,463,752		
47	1850	Line Transformers	\$ 731,693,800	\$ 25,553,462	\$ -	\$ 184,160	\$ 757,431,422	(\$ 378,319,748)	(\$ 20,415,257)	\$ -	\$ 1,599	(\$ 398,733,406)	\$ 358,698,016		
47	1855	Services (Overhead & Underground)	\$ 75,493,402	\$ 4,880,163	\$ -	\$ 119,394	\$ 80,492,959	(\$ 1,552,305)	(\$ -	\$ -	\$ -	(\$ 16,011,525)	\$ 64,481,434		
47	1860	Meters	\$ 228,228,402	\$ 8,583,433	\$ -	(\$ 71,512)	\$ 236,740,323	(\$ 124,163,409)	(\$ 9,461,636)	\$ -	\$ -	(\$ 133,625,046)	\$ 103,115,277		
N/A	1905	Land	\$ 9,150,994	\$ -	\$ -	\$ -	\$ 9,150,994	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,150,994		
1	1908	Buildings & Fixtures	\$ 110,349,717	\$ 3,688,811	\$ -	(\$ 45,048)	\$ 113,993,480	(\$ 44,568,945)	(\$ 5,597,338)	\$ -	\$ 3,983	(\$ 50,162,300)	\$ 63,831,180		
13	1910	Leasehold Improvements	\$ 19,755,328	\$ 628,396	\$ -	\$ -	\$ 20,383,723	(\$ 18,761,779)	(\$ 604,412)	\$ -	\$ -	(\$ 19,366,191)	\$ 1,017,532		
8	1915	Office Furniture & Equipment	\$ 20,505,043	\$ 1,213,915	\$ -	\$ -	\$ 21,718,959	(\$ 1,695,701)	(\$ 8,476,864)	\$ -	\$ -	(\$ 10,172,565)	\$ 11,546,394		
50	1920	Computer Equipment - Hardware	\$ 44,625,197	\$ 5,897,757	\$ -	(\$ 20,079)	\$ 50,502,876	(\$ 35,602,399)	(\$ 4,401,165)	\$ -	\$ 418	(\$ 40,003,146)	\$ 10,499,730		
10	1930	Transportation Equipment	\$ 78,015,630	\$ 2,116,290	(\$ 7,623,507)	\$ 731,156	\$ 73,239,570	(\$ 43,154,031)	(\$ 7,499,760)	\$ 7,039,462	(\$ 220,097)	(\$ 43,834,426)	\$ 29,405,144		
8	1935	Stores Equipment	\$ 5,506,283	\$ -	\$ -	\$ -	\$ 5,506,283	(\$ 5,483,800)	(\$ 7,709)	\$ -	\$ -	(\$ 5,491,508)	\$ 14,775		
8	1940	Tools, Shop & Garage Equipment	\$ 39,191,440	\$ 1,104,891	\$ -	\$ -	\$ 40,296,331	(\$ 27,356,177)	(\$ 2,006,371)	\$ -	\$ -	(\$ 29,362,549)	\$ 10,933,782		
8	1945	Measurement & Testing Equipment	\$ 5,016,176	\$ 298,172	\$ -	\$ -	\$ 5,314,349	(\$ 2,061,676)	(\$ 4,428,611)	\$ -	\$ 1,916,847	(\$ 4,573,439)	\$ 740,910		
8	1955	Communications Equipment	\$ 31,537,327	\$ 522,839	\$ -	\$ 20,079	\$ 32,080,245	(\$ 23,911,888)	(\$ 2,684,558)	\$ -	(\$ 418)	(\$ 26,596,864)	\$ 5,483,380		
8	1960	Miscellaneous Equipment	\$ 368,058	\$ 1,043	\$ -	\$ -	\$ 369,101	(\$ 28,196)	(\$ 36,918)	\$ -	\$ -	(\$ 65,113)	\$ 303,988		
47	1970	Load Management Controls Customer Premises	\$ 14,843,095	\$ -	\$ -	\$ -	\$ 14,843,095	(\$ 9,656,107)	(\$ 1,082,077)	\$ -	\$ -	(\$ 10,738,184)	\$ 4,104,911		
47	1975	Load Management Controls Utility Premises	\$ 554,382	\$ -	\$ -	\$ -	\$ 554,382	(\$ 554,382)	\$ -	\$ -	\$ -	(\$ 554,382)	\$ -		
47	1980	System Supervisor Equipment	\$ 57,581,790	\$ 526,532	\$ -	(\$ 19,082)	\$ 58,089,239	(\$ 37,934,914)	(\$ 1,761,636)	\$ -	\$ -	(\$ 39,696,550)	\$ 18,392,689		
47	1995	Contributions & Grants	(\$ 294,479,391)	(\$ 22,061,046)	\$ -	(\$ 41,353)	(\$ 316,581,790)	\$ 61,444,613	\$ 9,011,788	\$ -	\$ 1,119	\$ 70,457,520	(\$ 246,124,270)		
N/A	1609	Capital Contributions Paid	\$ 14,058,906	\$ 5,590,059	\$ -	\$ -	\$ 19,648,965	(\$ 1,440,253)	(\$ 734,850)	\$ -	\$ -	(\$ 2,175,104)	\$ 17,473,861		
N/A	2005	Property Under Capital Leases	\$ 14,269,368	\$ -	\$ -	(\$ 731,156)	\$ 13,538,213	(\$ 1,251,464)	\$ -	\$ -	(\$ 1,696,751)	(\$ 2,948,215)	\$ 10,589,998		
							\$ -					\$ -	\$ -		
		Sub-Total	\$ 4,607,776,794	\$ 209,424,649	(\$ 8,204,110)	\$ -	\$ 4,808,997,333	(\$ 2,424,230,701)	(\$ 140,129,282)	\$ 7,287,117	\$ -	(\$ 2,557,072,867)	\$ 2,251,924,467		
		Less Socialized Renewable Energy Generation Investments (input as negative)					\$ -					\$ -	\$ -		
		Less Other Non Rate-Regulated Utility Assets (input as negative)					\$ -					\$ -	\$ -		
		Total PP&E	\$ 4,607,776,794	\$ 209,424,649	(\$ 8,204,110)	\$ -	\$ 4,808,997,333	(\$ 2,424,230,701)	(\$ 140,129,282)	\$ 7,287,117	\$ -	(\$ 2,557,072,867)	\$ 2,251,924,467		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							\$ -			\$ -			
		Total						(\$ 140,129,282)							

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation

Transportation

(\$ 1,620,301)

Stores Equipment

Net Depreciation

(\$ 138,508,981)

Notes:

1 The below CCA classes have been updated for these OEB Accounts:

CCA Class	OEB	Description	Explanation for Change
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included in Class 52.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - UGAAP

Year 2013

CCA Class	OEB	Description	Cost					Accumulated Depreciation					
			Opening Balance	Additions	Retirement	Transfers	Closing Balance	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	\$ 242,254,279	\$ 17,872,360	\$ -	\$ 8,261,966	\$ 268,388,604	(\$ 174,410,203)	(\$ 17,210,554)	\$ -	(\$ 7,195,178)	(\$ 198,815,935)	\$ 69,572,669
N/A	1805	Land	\$ 7,595,848	\$ -	(\$ 7,317)	\$ -	\$ 7,588,531	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,588,531
1	1808	Buildings	\$ 46,375,160	\$ 4,942,504	(\$ 246,793)	(\$ 541,000)	\$ 50,529,871	(\$ 19,085,940)	(\$ 1,866,209)	\$ 37,334	\$ 225,417	(\$ 20,689,399)	\$ 29,840,472
47	1815	Transformer Station Equipment >50 kV	\$ 10,974,359	\$ 4,172	\$ -	(\$ 5,874)	\$ 10,972,657	(\$ 4,728,781)	(\$ 404,101)	\$ -	\$ 180	(\$ 5,132,702)	\$ 5,839,955
47	1820	Distribution Station Equipment <50 kV	\$ 226,539,188	\$ 8,271,011	\$ -	(\$ 5,464,410)	\$ 229,345,789	(\$ 102,227,335)	(\$ 6,699,017)	\$ -	\$ 182,105	(\$ 108,744,247)	\$ 120,601,543
47	1830	Poles, Towers & Fixtures	\$ 392,623,745	\$ 30,383,301	\$ -	(\$ 16,170,543)	\$ 406,836,503	(\$ 183,309,619)	(\$ 6,883,833)	\$ -	\$ 87,033	(\$ 190,106,418)	\$ 216,730,084
47	1835	Overhead Conductors & Devices	\$ 433,071,865	\$ 43,696,424	\$ -	(\$ 14,172,386)	\$ 462,595,902	(\$ 250,101,980)	(\$ 5,922,635)	\$ -	\$ 90,213	(\$ 255,934,401)	\$ 206,661,501
47	1840	Underground Conduit	\$ 1,377,660,076	\$ 100,436,340	\$ -	(\$ 57,235,826)	\$ 1,420,860,590	(\$ 653,429,670)	(\$ 34,220,426)	\$ -	\$ 582,669	(\$ 687,067,427)	\$ 733,793,163
47	1845	Underground Conductors & Devices	\$ 834,590,098	\$ 99,691,661	\$ -	(\$ 45,594,739)	\$ 888,687,020	(\$ 406,126,346)	(\$ 16,600,725)	\$ -	\$ 578,583	(\$ 422,148,488)	\$ 466,538,532
47	1850	Line Transformers	\$ 757,431,422	\$ 55,799,337	\$ -	(\$ 21,304,392)	\$ 791,926,367	(\$ 398,733,406)	(\$ 21,501,170)	\$ -	\$ 228,732	(\$ 420,005,844)	\$ 371,920,523
47	1855	Services (Overhead & Underground)	\$ 80,492,959	\$ 6,704,765	\$ -	(\$ 3,072,213)	\$ 84,125,511	(\$ 16,011,525)	(\$ 1,651,822)	\$ -	\$ 13,170	(\$ 17,650,177)	\$ 66,475,334
47	1860	Meters	\$ 236,740,323	\$ 13,604,147	\$ -	(\$ 56,391,064)	\$ 193,953,406	(\$ 133,625,046)	(\$ 9,864,020)	\$ -	\$ 83,356,734	(\$ 60,132,332)	\$ 133,821,074
N/A	1905	Land	\$ 9,150,994	\$ -	\$ -	\$ -	\$ 9,150,994	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,150,994
1	1908	Buildings & Fixtures	\$ 113,993,480	\$ 7,241,269	\$ -	\$ -	\$ 121,234,749	(\$ 50,162,300)	(\$ 5,715,814)	\$ -	\$ -	(\$ 55,878,114)	\$ 65,356,634
13	1910	Leasehold Improvements	\$ 20,383,723	(\$ 31,233)	\$ -	\$ -	\$ 20,352,491	(\$ 19,366,191)	(\$ 284,866)	\$ -	\$ -	(\$ 19,651,057)	\$ 701,434
8	1915	Office Furniture & Equipment	\$ 21,718,959	\$ 577,423	\$ -	\$ -	\$ 22,296,381	(\$ 10,172,565)	(\$ 2,321,386)	\$ -	\$ -	(\$ 12,493,951)	\$ 9,802,431
50	1920	Computer Equipment - Hardware	\$ 50,502,876	\$ 5,275,147	\$ -	\$ 550,474	\$ 56,328,497	(\$ 40,003,146)	(\$ 4,595,199)	\$ -	(\$ 537,522)	(\$ 45,135,867)	\$ 11,192,631
10	1930	Transportation Equipment	\$ 73,239,570	\$ 337,366	(\$ 832,365)	\$ 120,283	\$ 72,864,854	(\$ 43,834,426)	(\$ 7,148,702)	\$ 773,987	(\$ 72,944)	(\$ 50,282,085)	\$ 22,582,769
8	1935	Stores Equipment	\$ 5,506,283	\$ -	\$ -	\$ -	\$ 5,506,283	(\$ 5,491,508)	(\$ 7,709)	\$ -	\$ -	(\$ 5,499,217)	\$ 7,066
8	1940	Tools, Shop & Garage Equipment	\$ 40,296,331	\$ 2,291,332	\$ -	\$ -	\$ 42,587,663	(\$ 29,362,549)	(\$ 2,188,127)	\$ -	\$ -	(\$ 31,550,676)	\$ 11,036,987
8	1945	Measurement & Testing Equipment	\$ 5,314,349	\$ 304,913	(\$ 194,000)	(\$ 304,913)	\$ 5,120,349	(\$ 4,573,439)	(\$ 2,081,814)	\$ 54,843	\$ 1,960,406	(\$ 4,640,005)	\$ 480,344
8	1955	Communications Equipment	\$ 32,080,245	\$ 1,011,467	\$ -	\$ -	\$ 33,091,712	(\$ 26,596,864)	(\$ 1,901,560)	\$ -	\$ -	(\$ 28,498,424)	\$ 4,593,288
8	1960	Miscellaneous Equipment	\$ 369,101	\$ -	\$ -	\$ -	\$ 369,101	(\$ 65,113)	(\$ 36,918)	\$ -	\$ -	(\$ 102,031)	\$ 267,071
47	1970	Load Management Controls Customer Premises	\$ 14,843,095	\$ -	\$ -	\$ -	\$ 14,843,095	(\$ 10,738,184)	(\$ 1,082,077)	\$ -	\$ -	(\$ 11,820,262)	\$ 3,022,834
47	1975	Load Management Controls Utility Premises	\$ 554,382	\$ -	\$ -	\$ -	\$ 554,382	(\$ 554,382)	\$ -	\$ -	\$ -	(\$ 554,382)	\$ -
47	1980	System Supervisor Equipment	\$ 58,089,239	\$ 3,405,676	\$ -	(\$ 1,013,175)	\$ 60,481,740	(\$ 39,696,550)	(\$ 1,814,662)	\$ -	\$ 14,286	(\$ 41,496,926)	\$ 18,984,815
47	1995	Contributions & Grants	(\$ 316,581,790)	(\$ 23,083,937)	\$ -	\$ 858,765	(\$ 338,806,962)	\$ 70,457,520	\$ 9,836,203	\$ -	(\$ 13,004)	\$ 80,280,719	(\$ 258,526,243)
N/A	1609	Capital Contributions Paid	\$ 19,648,965	\$ 2,532,156	\$ -	\$ -	\$ 22,181,121	(\$ 2,175,104)	(\$ 901,706)	\$ -	\$ -	(\$ 3,076,809)	\$ 19,104,312
N/A	2005	Property Under Capital Leases	\$ 13,538,213	\$ -	\$ -	\$ 184,630	\$ 13,722,843	(\$ 2,948,215)	\$ -	\$ -	(\$ 1,887,462)	(\$ 4,835,677)	\$ 8,887,166
							\$ -					\$ -	\$ -
		Sub-Total	\$ 4,808,997,333	\$ 381,267,602	(\$ 1,280,474)	(\$ 211,294,417)	\$ 4,977,690,044	(\$ 2,557,072,867)	(\$ 143,068,846)	\$ 866,164	\$ 77,613,418	(\$ 2,621,662,131)	\$ 2,356,027,913
		Less Socialized Renewable Energy Generation Investments (input as negative)					\$ -					\$ -	\$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					\$ -					\$ -	\$ -
		Total PP&E	\$ 4,808,997,333	\$ 381,267,602	(\$ 1,280,474)	(\$ 211,294,417)	\$ 4,977,690,044	(\$ 2,557,072,867)	(\$ 143,068,846)	\$ 866,164	\$ 77,613,418	(\$ 2,621,662,131)	\$ 2,356,027,913
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						\$ -				\$ -	
		Total						(\$ 143,068,846)					

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation

Transportation	(\$ 2,314,931)
Stores Equipment	
Net Depreciation	(\$ 140,753,915)

Notes:

1	The below CCA classes have been updated for these OEB Accounts		
CCA Class	OEB	Description	Explanation for Change
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included in Class 52.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - UGAAP

Year 2014

		Cost						Accumulated Depreciation					
CCA Class	OEB	Description	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Opening Balance	Additions	Retirement	Transfers	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	\$ 268,388,604	\$ 15,168,023	\$ -	(\$ 330,435)	\$ 283,226,192	(\$ 198,815,935)	(\$ 19,182,023)	\$ -	\$ 17,128	(\$ 217,980,830)	\$ 65,245,361
N/A	1805	Land	\$ 7,588,531	\$ -	(\$ 3,288)	\$ -	\$ 7,585,243	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,585,243
1	1808	Buildings	\$ 50,529,871	\$ 4,340,259	(\$ 2,379,439)	(\$ 78,322)	\$ 52,412,370	(\$ 20,689,399)	(\$ 2,023,489)	\$ 381,380	\$ 316,955	(\$ 22,014,552)	\$ 30,397,818
47	1815	Transformer Station Equipment >50 kV	\$ 10,972,657	\$ 473,723	\$ -	(\$ 321,055)	\$ 11,125,325	(\$ 5,132,702)	(\$ 410,092)	\$ -	\$ 3,623	(\$ 5,539,171)	\$ 5,586,154
47	1820	Distribution Station Equipment <50 kV	\$ 229,345,789	\$ 29,848,866	\$ -	(\$ 13,711,927)	\$ 245,482,729	(\$ 108,744,247)	(\$ 7,040,253)	\$ -	\$ 342,531	(\$ 115,441,968)	\$ 130,040,760
47	1830	Poles, Towers & Fixtures	\$ 406,836,503	\$ 36,083,610	(\$ 1,575,844)	(\$ 26,984,374)	\$ 414,359,894	(\$ 190,106,418)	(\$ 7,596,852)	\$ 421,813	\$ 603,230	(\$ 196,678,227)	\$ 217,681,668
47	1835	Overhead Conductors & Devices	\$ 462,595,902	\$ 49,556,844	\$ -	(\$ 25,230,128)	\$ 486,922,618	(\$ 255,934,401)	(\$ 6,901,315)	\$ -	\$ 518,672	(\$ 262,317,044)	\$ 224,605,574
47	1840	Underground Conduit	\$ 1,420,860,590	\$ 143,831,357	\$ -	(\$ 84,834,206)	\$ 1,479,857,741	(\$ 687,067,427)	(\$ 36,940,621)	\$ -	\$ 2,658,269	(\$ 721,349,779)	\$ 758,507,962
47	1845	Underground Conductors & Devices	\$ 888,687,020	\$ 58,960,887	\$ -	(\$ 28,340,892)	\$ 919,307,016	(\$ 422,148,488)	(\$ 17,590,134)	\$ -	\$ 1,777,485	(\$ 437,961,137)	\$ 481,345,879
47	1850	Line Transformers	\$ 791,926,367	\$ 46,968,875	\$ -	(\$ 28,636,422)	\$ 810,258,820	(\$ 420,005,844)	(\$ 22,171,293)	\$ -	\$ 1,181,371	(\$ 440,995,767)	\$ 369,263,053
47	1855	Services (Overhead & Underground)	\$ 84,125,511	\$ 17,455,197	\$ -	(\$ 9,502,810)	\$ 92,077,897	(\$ 17,650,177)	(\$ 1,874,227)	\$ -	\$ 154,401	(\$ 19,370,003)	\$ 72,707,894
47	1860	Meters	\$ 193,953,406	\$ 14,882,921	\$ -	(\$ 2,182,077)	\$ 206,654,251	(\$ 60,132,332)	(\$ 12,464,057)	\$ -	\$ 139,433	(\$ 72,456,955)	\$ 134,197,295
N/A	1905	Land	\$ 9,150,994	\$ -	\$ -	\$ -	\$ 9,150,994	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,150,994
1	1908	Buildings & Fixtures	\$ 121,234,749	\$ 25,218,362	\$ -	\$ 3,515	\$ 146,456,626	(\$ 55,878,114)	(\$ 6,377,509)	\$ -	\$ 143	(\$ 62,255,481)	\$ 84,201,145
13	1910	Leasehold Improvements	\$ 20,352,491	\$ 387,591	\$ -	\$ -	\$ 20,740,081	(\$ 19,651,057)	(\$ 314,340)	\$ -	\$ -	(\$ 19,965,397)	\$ 774,685
8	1915	Office Furniture & Equipment	\$ 22,296,381	\$ 2,347,858	\$ -	\$ -	\$ 24,644,239	(\$ 12,493,951)	(\$ 2,128,106)	\$ -	\$ -	(\$ 14,622,057)	\$ 10,022,182
50	1920	Computer Equipment - Hardware	\$ 56,328,497	\$ 31,340,289	\$ -	(\$ 252,540)	\$ 87,416,246	(\$ 45,135,867)	(\$ 7,028,006)	\$ -	\$ 16,303	(\$ 52,147,569)	\$ 35,268,677
10	1930	Transportation Equipment	\$ 72,864,854	\$ 4,223,323	\$ -	(\$ 1,307)	\$ 77,086,870	(\$ 50,282,085)	(\$ 6,558,032)	\$ -	\$ 218	(\$ 56,839,900)	\$ 20,246,970
8	1935	Stores Equipment	\$ 5,506,283	\$ -	\$ -	\$ -	\$ 5,506,283	(\$ 5,499,217)	(\$ 7,066)	\$ -	\$ -	(\$ 5,506,283)	\$ -
8	1940	Tools, Shop & Garage Equipment	\$ 42,587,663	\$ 472,026	\$ -	\$ -	\$ 43,059,688	(\$ 31,550,676)	(\$ 2,216,738)	\$ -	\$ -	(\$ 33,767,414)	\$ 9,292,274
8	1945	Measurement & Testing Equipment	\$ 5,120,349	\$ 2,101,186	\$ -	(\$ 2,092,578)	\$ 5,128,956	(\$ 4,640,005)	(\$ 3,744,776)	\$ -	\$ 3,744,029	(\$ 4,640,751)	\$ 488,205
8	1955	Communications Equipment	\$ 33,091,712	\$ 773,912	\$ -	\$ -	\$ 33,865,625	(\$ 28,498,424)	(\$ 1,855,881)	\$ -	\$ -	(\$ 30,354,306)	\$ 3,511,319
8	1960	Miscellaneous Equipment	\$ 369,101	\$ -	\$ -	\$ -	\$ 369,101	(\$ 102,031)	(\$ 36,918)	\$ -	\$ -	(\$ 138,948)	\$ 230,153
47	1970	Load Management Controls Customer Premises	\$ 14,843,095	\$ -	\$ -	\$ -	\$ 14,843,095	(\$ 11,820,262)	(\$ 1,082,077)	\$ -	\$ -	(\$ 12,902,339)	\$ 1,940,757
47	1975	Load Management Controls Utility Premises	\$ 554,382	\$ -	\$ -	\$ -	\$ 554,382	(\$ 554,382)	\$ -	\$ -	\$ -	(\$ 554,382)	\$ -
47	1980	System Supervisor Equipment	\$ 60,481,740	\$ 1,924,300	\$ -	(\$ 215,829)	\$ 62,190,211	(\$ 41,496,926)	(\$ 2,048,691)	\$ -	\$ 72,158	(\$ 43,473,459)	\$ 18,716,753
47	1995	Contributions & Grants	(\$ 338,806,962)	(\$ 17,584,653)	\$ -	\$ 2,123,873	(\$ 354,267,741)	\$ 80,280,719	\$ 10,351,884	\$ -	(\$ 18,199)	\$ 90,614,404	(\$ 263,653,337)
N/A	1609	Capital Contributions Paid	\$ 22,181,121	\$ 1,798,200	\$ -	\$ 1,761,108	\$ 25,740,429	(\$ 3,076,809)	(\$ 955,031)	\$ -	(\$ 36,296)	(\$ 4,068,136)	\$ 21,672,292
N/A	2005	Property Under Capital Leases	\$ 13,722,843	\$ -	\$ -	\$ 2,092,578	\$ 15,815,421	(\$ 4,835,677)	\$ -	\$ -	(\$ 3,744,029)	(\$ 8,579,706)	\$ 7,235,715
			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
		Sub-Total	\$ 4,977,690,044	\$ 470,572,957	(\$ 3,958,571)	(\$ 216,733,828)	\$ 5,227,570,601	(\$ 2,621,662,131)	(\$ 158,195,645)	\$ 803,193	\$ 7,747,425	(\$ 2,771,307,158)	\$ 2,456,263,443
		Less Socialized Renewable Energy Generation Investments (input as negative)					\$ -					\$ -	\$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					\$ -					\$ -	\$ -
		Total PP&E	\$ 4,977,690,044	\$ 470,572,957	(\$ 3,958,571)	(\$ 216,733,828)	\$ 5,227,570,601	(\$ 2,621,662,131)	(\$ 158,195,645)	\$ 803,193	\$ 7,747,425	(\$ 2,771,307,158)	\$ 2,456,263,443
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						\$ -				\$ -	
		Total						(\$ 158,195,645)					

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation

Transportation	(\$ 2,342,979)
Stores Equipment	
Net Depreciation	(\$ 155,852,666)

Notes:

1	The below CCA classes has been updated or added for these OEB Accounts:		
CCA Class	OEB	Description	Explanation for Change
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included in Class 52.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2014

Cost									Accumulated Depreciation						
CCA Class	OEB	Description	Opening Balance	Additions	Retirement	Transfers	Derecognition	Closing Balance	Opening Balance	Additions	Retirement	Transfers	Derecognition	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	\$ 268,388,604	\$ 15,177,636	\$ -	(\$ 331,236)	\$ -	\$ 283,235,005	(\$ 198,815,935)	(\$ 19,182,937)	\$ -	\$ 17,170	\$ -	(\$ 217,981,703)	\$ 65,253,302
N/A	1612	Land Rights	\$ 7,191,090	\$ -	\$ -	\$ -	\$ -	\$ 7,191,090	\$ -	(\$ 89,423)	\$ -	\$ -	\$ -	(\$ 89,423)	\$ 7,101,667
N/A	1805	Land	\$ 7,588,531	\$ -	(\$ 3,288)	\$ -	\$ -	\$ 7,585,243	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,585,243
1	1808	Buildings	\$ 50,051,442	\$ 4,342,809	(\$ 2,379,439)	(\$ 80,876)	\$ -	\$ 51,933,935	(\$ 20,689,399)	(\$ 2,034,879)	\$ 381,380	\$ 316,976	\$ -	(\$ 22,025,922)	\$ 29,908,013
47	1815	Transformer Station Equipment >50 kV	\$ 10,972,657	\$ 474,187	\$ -	(\$ 321,661)	\$ -	\$ 11,125,183	(\$ 5,132,702)	(\$ 410,099)	\$ -	\$ 3,630	\$ -	(\$ 5,539,171)	\$ 5,586,012
47	1820	Distribution Station Equipment <50 kV	\$ 229,345,789	\$ 29,862,940	\$ -	(\$ 13,738,605)	(\$ 1,289,203)	\$ 244,180,921	(\$ 108,744,247)	(\$ 7,040,476)	\$ -	\$ 342,783	\$ 1,211,150	(\$ 114,230,790)	\$ 129,950,132
47	1830	Poles, Towers & Fixtures	\$ 406,937,426	\$ 36,102,639	(\$ 1,575,844)	(\$ 27,039,814)	(\$ 19,700,692)	\$ 394,723,714	(\$ 190,106,418)	(\$ 7,597,440)	\$ 421,813	\$ 603,611	\$ 10,481,739	(\$ 186,196,694)	\$ 208,527,020
47	1835	Overhead Conductors & Devices	\$ 462,595,902	\$ 49,585,933	\$ -	(\$ 25,282,689)	(\$ 5,667,212)	\$ 481,231,934	(\$ 255,934,401)	(\$ 6,906,901)	\$ -	\$ 519,020	\$ 3,244,682	(\$ 259,077,600)	\$ 222,154,334
47	1840	Underground Conduit	\$ 1,420,860,590	\$ 143,930,570	\$ -	(\$ 85,058,238)	(\$ 744,800)	\$ 1,478,988,122	(\$ 687,067,427)	(\$ 36,952,150)	\$ -	\$ 2,660,137	\$ 419,968	(\$ 720,939,472)	\$ 758,048,650
47	1845	Underground Conductors & Devices	\$ 888,938,892	\$ 59,003,468	\$ -	(\$ 28,397,701)	(\$ 20,974,613)	\$ 898,570,047	(\$ 422,148,488)	(\$ 17,441,988)	\$ -	\$ 1,777,944	\$ 17,708,268	(\$ 420,104,264)	\$ 478,465,783
47	1850	Line Transformers	\$ 791,192,942	\$ 47,004,173	\$ -	(\$ 28,690,543)	(\$ 29,945,614)	\$ 779,560,959	(\$ 420,005,844)	(\$ 22,237,759)	\$ -	\$ 1,181,907	\$ 20,438,401	(\$ 420,623,295)	\$ 358,937,664
47	1855	Services (Overhead & Underground)	\$ 84,125,511	\$ 17,465,910	\$ -	(\$ 9,521,934)	\$ -	\$ 92,069,487	(\$ 17,650,177)	(\$ 1,874,323)	\$ -	\$ 154,539	\$ -	(\$ 19,369,961)	\$ 72,699,526
47	1860	Meters	\$ 193,953,406	\$ 14,890,821	\$ -	(\$ 2,186,247)	\$ -	\$ 206,657,980	(\$ 60,132,332)	(\$ 12,464,374)	\$ -	\$ 139,514	\$ -	(\$ 72,457,191)	\$ 134,200,789
N/A	1905	Land	\$ 9,150,994	\$ -	\$ -	\$ -	\$ -	\$ 9,150,994	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,150,994
1	1908	Buildings & Fixtures	\$ 121,234,749	\$ 25,218,671	\$ -	\$ 3,506	(\$ 125,000)	\$ 146,331,925	(\$ 55,878,114)	(\$ 6,377,517)	\$ -	\$ 143	\$ 112,500	(\$ 62,142,988)	\$ 84,188,937
13	1910	Leasehold Improvements	\$ 20,352,491	\$ 387,591	\$ -	\$ -	\$ -	\$ 20,740,081	(\$ 19,651,057)	(\$ 314,340)	\$ -	\$ -	\$ -	(\$ 19,965,397)	\$ 774,685
8	1915	Office Furniture & Equipment	\$ 22,296,381	\$ 2,347,871	\$ -	\$ -	(\$ 3,842)	\$ 24,640,411	(\$ 12,493,951)	(\$ 2,128,107)	\$ -	\$ -	\$ 3,485	(\$ 14,618,572)	\$ 10,021,839
50	1920	Computer Equipment - Hardware	\$ 56,328,497	\$ 31,345,390	\$ -	(\$ 253,152)	\$ -	\$ 87,420,735	(\$ 45,135,867)	(\$ 7,028,569)	\$ -	\$ 16,343	\$ -	(\$ 52,148,093)	\$ 35,272,642
10	1930	Transportation Equipment	\$ 72,864,854	\$ 4,225,151	\$ -	(\$ 1,307)	\$ -	\$ 77,088,698	(\$ 50,282,085)	(\$ 6,558,138)	\$ -	\$ 218	\$ -	(\$ 56,840,005)	\$ 20,248,692
8	1935	Stores Equipment	\$ 5,506,283	\$ -	\$ -	\$ -	\$ -	\$ 5,506,283	(\$ 5,499,217)	(\$ 7,066)	\$ -	\$ -	\$ -	(\$ 5,506,283)	\$ -
8	1940	Tools, Shop & Garage Equipment	\$ 42,587,663	\$ 472,378	\$ -	\$ -	\$ -	\$ 43,060,041	(\$ 31,550,676)	(\$ 2,216,753)	\$ -	\$ -	\$ -	(\$ 33,767,429)	\$ 9,292,612
8	1945	Measurement & Testing Equipment	\$ 5,120,349	\$ 2,101,189	\$ -	(\$ 2,092,578)	\$ -	\$ 5,128,960	(\$ 4,640,005)	(\$ 3,744,776)	\$ -	\$ 3,744,029	\$ -	(\$ 4,640,751)	\$ 488,208
8	1955	Communications Equipment	\$ 33,091,712	\$ 773,912	\$ -	\$ -	\$ -	\$ 33,865,625	(\$ 28,498,424)	(\$ 1,855,881)	\$ -	\$ -	\$ -	(\$ 30,354,306)	\$ 3,511,319
8	1960	Miscellaneous Equipment	\$ 369,101	\$ -	\$ -	\$ -	\$ -	\$ 369,101	(\$ 102,031)	(\$ 36,918)	\$ -	\$ -	\$ -	(\$ 138,948)	\$ 230,153
47	1970	Load Management Controls Customer Premises	\$ 14,843,095	\$ -	\$ -	\$ -	\$ -	\$ 14,843,095	(\$ 11,820,262)	(\$ 1,082,077)	\$ -	\$ -	\$ -	(\$ 12,902,339)	\$ 1,940,757
47	1975	Load Management Controls Utility Premises	\$ 554,382	\$ -	\$ -	\$ -	\$ -	\$ 554,382	(\$ 554,382)	\$ -	\$ -	\$ -	\$ -	(\$ 554,382)	\$ -
47	1980	System Supervisor Equipment	\$ 60,481,740	\$ 1,925,700	\$ -	(\$ 216,297)	(\$ 4,680,597)	\$ 57,510,547	(\$ 41,496,926)	(\$ 2,048,748)	\$ -	\$ 72,168	\$ 3,775,638	(\$ 39,697,869)	\$ 17,812,678
47	1995	Contributions & Grants	(\$ 338,806,962)	(\$ 17,605,144)	\$ -	\$ 2,129,381	\$ -	(\$ 354,282,725)	\$ 80,280,719	\$ 10,369,809	\$ -	(\$ 18,239)	\$ -	\$ 90,632,289	(\$ 263,650,436)
N/A	1609	Capital Contributions Paid	\$ 22,181,121	\$ 1,803,632	\$ -	\$ 1,761,108	\$ -	\$ 25,745,861	(\$ 3,076,809)	(\$ 955,180)	\$ -	(\$ 36,296)	\$ -	(\$ 4,068,286)	\$ 21,677,575
N/A	2005	Property Under Capital Leases	\$ 13,722,843	\$ -	\$ -	\$ 2,092,578	\$ -	\$ 15,815,421	(\$ 4,835,677)	\$ -	\$ -	(\$ 3,744,029)	\$ -	(\$ 8,579,706)	\$ 7,235,715
			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
		Sub-Total	\$ 4,984,022,075	\$ 470,837,428	(\$ 3,958,571)	(\$ 217,226,307)	(\$ 83,131,571)	\$ 5,150,543,054	(\$ 2,621,662,131)	(\$ 158,217,010)	\$ 803,193	\$ 7,751,568	\$ 57,395,830	(\$ 2,713,928,550)	\$ 2,436,614,504
		Less Socialized Renewable Energy Generation Investments (input as negative)						\$ -						\$ -	\$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						\$ -						\$ -	\$ -
		Total PP&E	\$ 4,984,022,075	\$ 470,837,428	(\$ 3,958,571)	(\$ 217,226,307)	(\$ 83,131,571)	\$ 5,150,543,054	(\$ 2,621,662,131)	(\$ 158,217,010)	\$ 803,193	\$ 7,751,568	\$ 57,395,830	(\$ 2,713,928,550)	\$ 2,436,614,504
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							\$ -					\$ -	
		Total							(\$ 158,217,010)						

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation

Transportation	(\$ 2,342,979)
Stores Equipment	
Net Depreciation	(\$ 155,874,031)

Notes:

1 The below CCA classes has been updated or added for these OEB Accounts:

CCA Class	OEB	Description	Explanation for Change
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures [“ECE”] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures [“ECE”] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included in Class 52.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2015

			Cost								
CCA Class	OEB	Description	Original Opening Balance	STL Transfer	ICM Transfer	Revised Opening Balance	Additions	Retirement	Transfers	Derecognition	Closing Balance
12	1611	Computer Software (Formally known as Account 1925)	\$ 283,235,005	\$ -	\$ 331,236	\$ 283,566,240	\$ 25,707,753	\$ -	\$ -	\$ -	\$ 309,273,993
N/A	1612	Land Rights	\$ 7,191,090	\$ -	\$ -	\$ 7,191,090	\$ -	\$ -	\$ -	\$ -	\$ 7,191,090
N/A	1805	Land	\$ 7,585,243	\$ -	\$ -	\$ 7,585,243	\$ -	\$ -	\$ -	\$ -	\$ 7,585,243
1	1808	Buildings	\$ 51,933,935	\$ -	\$ 621,876	\$ 52,555,812	\$ 42,675,695	(\$ 1,449,701)	\$ -	\$ -	\$ 93,781,805
47	1815	Transformer Station Equipment >50 kV	\$ 11,125,183	\$ -	\$ 321,661	\$ 11,446,844	\$ 928,991	\$ -	\$ -	\$ 94,141)	\$ 12,281,694
47	1820	Distribution Station Equipment <50 kV	\$ 244,180,921	\$ -	\$ 19,117,868	\$ 263,298,789	\$ 30,196,781	\$ -	(\$ 470,712)	(\$ 1,630,381)	\$ 291,394,477
47	1830	Poles, Towers & Fixtures	\$ 394,723,714	\$ 36,121,302	\$ 43,211,408	\$ 474,056,425	\$ 42,285,278	\$ -	\$ 0	(\$ 27,184,232)	\$ 489,157,471
47	1835	Overhead Conductors & Devices	\$ 481,231,934	\$ 341,869	\$ 39,460,264	\$ 521,034,068	\$ 50,220,187	\$ -	\$ -	(\$ 14,001,761)	\$ 557,252,494
47	1840	Underground Conduit	\$ 1,478,988,122	\$ 3,457,400	\$ 142,264,440	\$ 1,624,709,962	\$ 124,467,391	\$ -	\$ -	\$ -	\$ 1,749,177,353
47	1845	Underground Conductors & Devices	\$ 898,570,047	\$ 4,697,187	\$ 73,974,813	\$ 977,242,048	\$ 70,084,398	\$ -	(\$ 30,471,343)	(\$ 18,693,747)	\$ 1,028,632,698
47	1850	Line Transformers	\$ 779,560,959	\$ -	\$ 50,042,828	\$ 829,603,786	\$ 36,538,578	\$ -	\$ 0	(\$ 30,603,146)	\$ 835,539,218
47	1855	Services (Overhead & Underground)	\$ 92,069,487	\$ -	\$ 12,595,308	\$ 104,664,795	\$ 15,347,254	\$ -	\$ -	(\$ 7,152)	\$ 120,004,896
47	1860	Meters	\$ 206,657,980	\$ -	\$ 3,644,325	\$ 210,302,305	\$ 19,717,726	\$ -	\$ 0	(\$ 1,071,386)	\$ 228,948,645
N/A	1905	Land	\$ 9,150,994	\$ -	\$ -	\$ 9,150,994	\$ -	(\$ 477,212)	\$ -	\$ -	\$ 8,673,782
1	1908	Buildings & Fixtures	\$ 146,331,925	\$ -	(\$ 3,506)	\$ 146,328,420	\$ 17,921,294	(\$ 30,471,343)	\$ -	(\$ 1,287,428)	\$ 132,490,943
13	1910	Leasehold Improvements	\$ 20,740,081	\$ -	\$ -	\$ 20,740,081	\$ 43,066	\$ -	\$ -	\$ -	\$ 20,783,147
8	1915	Office Furniture & Equipment	\$ 24,640,411	\$ -	\$ -	\$ 24,640,411	\$ 210,700	\$ -	\$ -	(\$ 63,647)	\$ 24,787,464
50	1920	Computer Equipment - Hardware	\$ 87,420,735	\$ -	\$ 253,152	\$ 87,673,888	\$ 11,191,364	\$ -	\$ -	\$ -	\$ 98,865,251
10	1930	Transportation Equipment	\$ 77,088,698	\$ -	\$ 1,307	\$ 77,090,005	\$ 3,877,748	\$ -	\$ -	\$ -	\$ 80,967,753
8	1935	Stores Equipment	\$ 5,506,283	\$ -	\$ -	\$ 5,506,283	\$ -	\$ -	\$ -	\$ -	\$ 5,506,283
8	1940	Tools, Shop & Garage Equipment	\$ 43,060,041	\$ -	\$ -	\$ 43,060,041	\$ 1,832,094	\$ -	\$ -	\$ -	\$ 44,892,135
8	1945	Measurement & Testing Equipment	\$ 5,128,960	\$ -	\$ -	\$ 5,128,960	\$ -	\$ -	(\$ 0)	\$ -	\$ 5,128,960
8	1955	Communications Equipment	\$ 33,865,625	\$ -	\$ -	\$ 33,865,625	\$ 1,571,175	\$ -	\$ -	\$ -	\$ 35,436,800
8	1960	Miscellaneous Equipment	\$ 369,101	\$ -	\$ -	\$ 369,101	\$ 7,831	\$ -	\$ -	\$ -	\$ 376,932
47	1970	Load Management Controls Customer Premises	\$ 14,843,095	\$ -	\$ -	\$ 14,843,095	\$ 99,273	\$ -	\$ -	\$ -	\$ 14,942,368
47	1975	Load Management Controls Utility Premises	\$ 554,382	\$ -	\$ -	\$ 554,382	\$ -	\$ -	\$ -	\$ -	\$ 554,382
47	1980	System Supervisor Equipment	\$ 57,510,547	\$ -	\$ 1,229,472	\$ 58,740,019	\$ 7,707,664	\$ -	(\$ 4,096,668)	(\$ 7,296,713)	\$ 55,054,301
47	1995	Contributions & Grants	(\$ 354,282,725)	\$ -	(\$ 2,902,453)	(\$ 357,185,178)	(\$ 15,280,038)	\$ -	(\$ 0)	\$ -	(\$ 372,465,216)
N/A	1609	Capital Contributions Paid	\$ 25,745,861	\$ -	(\$ 1,761,108)	\$ 23,984,753	\$ 52,373,679	\$ -	(\$ 1,853,428)	\$ -	\$ 74,505,004
N/A	2005	Property Under Capital Leases	\$ 15,815,421	\$ -		\$ 15,815,421	\$ -	\$ -	\$ 0	\$ -	\$ 15,815,421
		Sub-Total	\$ 5,150,543,054	\$ 44,617,759	\$ 382,402,893	\$ 5,577,563,706	\$ 539,725,880	(\$ 32,398,256)	(\$ 6,420,808)	(\$ 101,933,734)	\$ 5,976,536,788
		Less Socialized Renewable Energy Generation Investments (input as negative)									\$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)									\$ -
		Total PP&E	\$ 5,150,543,054	\$ 44,617,759	\$ 382,402,893	\$ 5,577,563,706	\$ 539,725,880	(\$ 32,398,256)	(\$ 6,420,808)	(\$ 101,933,734)	\$ 5,976,536,788
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total									

10		Transportation
8		Stores Equipment

Notes:

1 The below CCA classes has been updated or added for these OEB Accounts:

CCA Class	OEB	Description	Explanation for Change
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included i
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

Accumulated Depreciation												
CCA Class	OEB	Description	Original Opening Balance	STL Transfer	ICM Transfer	Revised Opening Balance	Additions	Retirement	Transfers	Derecognition	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	(\$ 217,981,703)	\$ -	(\$ 17,170)	(\$ 217,998,872)	(\$ 21,011,750)	\$ -	\$ -	\$ -	(\$ 239,010,622)	\$ 70,263,371
N/A	1612	Land Rights	(\$ 89,423)	\$ -	\$ -	(\$ 89,423)	(\$ 89,423)	\$ -	\$ -	\$ -	(\$ 178,846)	\$ 7,012,244
N/A	1805	Land	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,585,243
1	1808	Buildings	(\$ 22,025,922)	\$ -	(\$ 542,392)	(\$ 22,568,314)	(\$ 2,164,056)	\$ 130,522	\$ 0	\$ -	(\$ 24,601,849)	\$ 69,179,957
47	1815	Transformer Station Equipment >50 kV	(\$ 5,539,171)	\$ -	(\$ 3,630)	(\$ 5,542,801)	(\$ 433,082)	\$ -	\$ 3	\$ 55,292	(\$ 5,920,589)	\$ 6,361,105
47	1820	Distribution Station Equipment <50 kV	(\$ 114,230,790)	\$ -	(\$ 522,081)	(\$ 114,752,870)	(\$ 8,071,762)	\$ -	\$ 4,124	\$ 1,547,522	(\$ 121,272,987)	\$ 170,121,490
47	1830	Poles, Towers & Fixtures	(\$ 186,196,694)	(\$ 3,536,803)	(\$ 690,647)	(\$ 190,424,144)	(\$ 9,383,299)	\$ -	\$ 1,211	\$ 14,391,300	(\$ 185,414,933)	\$ 303,742,539
47	1835	Overhead Conductors & Devices	(\$ 259,077,600)	(\$ 25,769)	(\$ 609,398)	(\$ 259,712,767)	(\$ 8,010,517)	\$ -	\$ 2,508	\$ 11,597,279	(\$ 256,123,497)	\$ 301,128,997
47	1840	Underground Conduit	(\$ 720,939,472)	(\$ 273,033)	(\$ 3,242,546)	(\$ 724,455,051)	(\$ 40,909,577)	\$ -	\$ 28,132	\$ -	(\$ 765,336,496)	\$ 983,840,857
47	1845	Underground Conductors & Devices	(\$ 420,104,264)	(\$ 976,046)	(\$ 2,357,313)	(\$ 423,437,622)	(\$ 18,874,495)	\$ -	\$ 8,037	\$ 12,366,339	(\$ 429,937,742)	\$ 598,694,956
47	1850	Line Transformers	(\$ 420,623,295)	\$ -	(\$ 1,434,826)	(\$ 422,058,121)	(\$ 22,574,248)	\$ -	\$ 1,019	\$ 20,848,109	(\$ 423,783,240)	\$ 411,755,978
47	1855	Services (Overhead & Underground)	(\$ 19,369,961)	\$ -	(\$ 167,709)	(\$ 19,537,670)	(\$ 2,235,152)	\$ -	\$ 169	\$ 6,706	(\$ 21,765,946)	\$ 98,238,950
47	1860	Meters	(\$ 72,457,191)	\$ -	(\$ 198,422)	(\$ 72,655,613)	(\$ 13,258,376)	\$ -	\$ 1	\$ 524,830	(\$ 85,389,159)	\$ 143,559,487
N/A	1905	Land	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 8,673,782
1	1908	Buildings & Fixtures	(\$ 62,142,988)	\$ -	(\$ 162,152)	(\$ 62,143,131)	(\$ 6,162,152)	\$ 18,990,375	\$ 0	\$ 691,012	(\$ 48,623,896)	\$ 83,867,047
13	1910	Leasehold Improvements	(\$ 19,965,397)	\$ -	\$ -	(\$ 19,965,397)	(\$ 305,716)	\$ -	\$ -	\$ -	(\$ 20,271,113)	\$ 512,034
8	1915	Office Furniture & Equipment	(\$ 14,618,572)	\$ -	\$ -	(\$ 14,618,572)	(\$ 1,988,900)	\$ -	\$ -	\$ 51,630	(\$ 16,555,842)	\$ 8,231,621
50	1920	Computer Equipment - Hardware	(\$ 52,148,093)	\$ -	(\$ 16,343)	(\$ 52,164,436)	(\$ 12,430,692)	\$ -	\$ -	\$ -	(\$ 64,595,128)	\$ 34,270,123
10	1930	Transportation Equipment	(\$ 56,840,005)	\$ -	(\$ 218)	(\$ 56,840,223)	(\$ 6,376,745)	\$ -	\$ -	\$ -	(\$ 63,216,968)	\$ 17,750,785
8	1935	Stores Equipment	(\$ 5,506,283)	\$ -	\$ -	(\$ 5,506,283)	\$ -	\$ -	\$ -	\$ -	(\$ 5,506,283)	\$ -
8	1940	Tools, Shop & Garage Equipment	(\$ 33,767,429)	\$ -	\$ -	(\$ 33,767,429)	(\$ 2,220,076)	\$ -	\$ -	\$ -	(\$ 35,987,505)	\$ 8,904,630
8	1945	Measurement & Testing Equipment	(\$ 4,640,751)	\$ -	\$ -	(\$ 4,640,751)	(\$ 2,218,623)	\$ -	\$ 2,222,154	\$ -	(\$ 4,637,220)	\$ 491,739
8	1955	Communications Equipment	(\$ 30,354,306)	\$ -	\$ -	(\$ 30,354,306)	(\$ 1,924,002)	\$ -	\$ -	\$ -	(\$ 32,278,308)	\$ 3,158,491
8	1960	Miscellaneous Equipment	(\$ 138,948)	\$ -	\$ -	(\$ 138,948)	(\$ 37,146)	\$ -	\$ -	\$ -	(\$ 176,094)	\$ 200,838
47	1970	Load Management Controls Customer Premises	(\$ 12,902,339)	\$ -	\$ -	(\$ 12,902,339)	(\$ 1,070,206)	\$ -	\$ -	\$ -	(\$ 13,972,544)	\$ 969,824
47	1975	Load Management Controls Utility Premises	(\$ 554,382)	\$ -	\$ -	(\$ 554,382)	\$ -	\$ -	\$ -	\$ -	(\$ 554,382)	\$ -
47	1980	System Supervisor Equipment	(\$ 39,697,869)	\$ -	(\$ 86,454)	(\$ 39,784,323)	(\$ 2,137,803)	\$ -	\$ 23,305	\$ 5,921,324	(\$ 35,977,498)	\$ 19,076,803
47	1995	Contributions & Grants	\$ 90,632,289	\$ -	\$ 30,491	\$ 90,662,780	\$ 10,852,528	\$ -	(\$ 17,051)	\$ -	\$ 101,498,257	(\$ 270,966,959)
N/A	1609	Capital Contributions Paid	(\$ 4,068,286)	\$ -	\$ 36,296	(\$ 4,031,989)	(\$ 1,150,182)	\$ -	\$ -	\$ -	(\$ 5,182,171)	\$ 69,322,833
N/A	2005	Property Under Capital Leases	(\$ 8,579,706)	\$ -	\$ -	(\$ 8,579,706)	\$ -	\$ -	(\$ 2,222,154)	\$ -	(\$ 10,801,861)	\$ 5,013,560
		Sub-Total	(\$ 2,713,928,550)	(\$ 4,811,651)	(\$ 9,822,504)	(\$ 2,728,562,705)	(\$ 174,185,452)	\$ 19,120,897	\$ 51,457	\$ 68,001,341	(\$ 2,815,574,461)	\$ 3,160,962,327
		Less Socialized Renewable Energy Generation Investments (input as negative)	\$ -								\$ -	\$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	\$ -								\$ -	\$ -
		Total PP&E	(\$ 2,713,928,550)	(\$ 4,811,651)	(\$ 9,822,504)	(\$ 2,728,562,705)	(\$ 174,185,452)	\$ 19,120,897	\$ 51,457	\$ 68,001,341	(\$ 2,815,574,461)	\$ 3,160,962,327
		Depreciation Expense adj. from gain or los					\$ -				\$ -	
		Total					(\$ 174,185,452)					

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	(\$ 1,671,045)
Stores Equipment	
Net Depreciation	(\$ 172,514,406)

Notes:

1 The below CCA classes has been updated or added for these			
CCA Class	OEB	Description	
N/A	1612	Land Rights	
1	1808	Buildings	
1	1908	Buildings & Fixtures	
50	1920	Computer Equipment - Hardware	n Class 52.
N/A	1609	Capital Contributions Paid	
N/A	2005	Property Under Capital Leases	

GROSS ASSETS

1. BREAKDOWN BY FUNCTION

In accordance with section 2.5.1.2 of the OEB’s Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the “Filing Requirements”), Table 1 below provides a breakdown of gross assets by function from 2011 historical actuals through to 2015 test year forecast. The amount for construction work-in-progress (“CWIP”) has also been provided. The amounts for CWIP have not been included in gross assets for rate base.

In accordance with the Uniform System of Accounts (“USoA”), Toronto Hydro has included asset accounts 1805 to 1860 in the category of distribution plant, accounts 1905 to 1980, accounts 1609 to 1612 and account 2005 in the category of general plant, and account 1995 in the category of capital contributions.

Table 1: Breakdown of Gross Assets by Function

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS	/C
Gross Assets							
Distribution Plant	4,214.3	4,404.1	4,547.4	4,726.0	4,646.6	5,413.8	
General Plant	687.9	721.5	769.2	855.8	858.2	935.2	
Capital Contributions	(294.5)	(316.6)	(338.9)	(354.3)	(354.3)	(372.5)	
Total Before CWIP	4,607.8	4,809.0	4,977.7	5,227.6	5,150.5	5,976.5	
CWIP	257.8	336.9	401.3	515.5	516.1	507.4	
Total Including CWIP	4,865.6	5,145.9	5,379.0	5,743.1	5,666.6	6,483.9	

Note: Variances due to rounding may exist

2. BREAKDOWN BY MAJOR PLANT ACCOUNT

In accordance with section 2.5.1.2 of the OEB’s Filing Requirements (July 17, 2013), Table 2 below provides a breakdown of gross assets by major plant account from 2011 to 2015.

1 **Table 2: Gross Assets Breakdown by Major Plant Account Summary**

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Land and Buildings	61.3	63.1	67.3	69.1	68.7	110.0
TS Primary Above 50	10.5	11.0	11.0	11.1	11.1	12.3
Distribution System	222.6	226.5	229.3	245.5	244.2	291.4
Poles and Wires	2,893.6	3,037.9	3,179.0	3,300.4	3,253.5	3,824.2
Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
Services and Meters	303.7	317.2	278.1	298.7	298.7	349.0
General Plant	130.1	134.4	141.6	167.2	167.1	153.3
Equipment	180.1	178.5	181.8	189.7	189.7	197.1
IT Assets	44.6	50.5	56.3	87.4	87.4	98.9
Other Distribution Assets	323.9	348.9	380.2	402.4	404.9	477.3
Contributions and Grants	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
Gross Assets	4,607.8	4,809.0	4,977.7	5,227.6	5,150.5	5,976.5

Note: Variances due to rounding may exist

/C

2 In accordance with the Uniform System of Accounts (“USoA”), Toronto Hydro’s major
3 plant categories are comprised of the following USoA accounts:

- 4 • **Land and Building:** 1805 Land; 1808 Buildings and Fixtures; 1810 Leasehold
5 Improvements; 1905 Land
- 6 • **TS Primary Above 50:** 1815 Transformer Station Equipment
- 7 • **Distribution System:** 1820 Distribution Station Equipment
- 8 • **Poles and Wires:** 1830 Poles, Towers and Fixtures; 1835 O/H Conductors and
9 Devices; 1840 U/G Conduit; 1845 U/G Conductors and Devices
- 10 • **Line Transformers:** 1850 Line Transformers
- 11 • **Services and Meters:** 1855 Services; 1860 Meters (including Smart Meters)
- 12 • **General Plant:** 1908 Buildings and Fixtures; 1910 Leasehold Improvements
- 13 • **Equipment:** 1915 Office Furniture and Equipment; 1930 Transportation
14 Equipment; 1935 Stores Equipment; 1940 Tools, Shop and Garage Equipment;
15 1945 Measures & Test Equipment; 1955 Communication Equipment; 1960
16 Miscellaneous Equipment
- 17 • **IT Assets:** 1610 Miscellaneous Intangible Plant; 1920 Computer Equipment

Appendix A. Table 2 - Gross Assets Breakdown by Major Plant Account - Detailed by Uniform System of Account

	Description	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
1905	Land	9.2	9.2	9.2	9.2	9.2	8.7
1805	Land	7.6	7.6	7.6	7.6	7.6	7.6
1808	Buildings and Fixtures	44.6	46.4	50.5	52.4	51.9	93.8
1810	Leasehold Improvements	-	-	-	-	-	-
	Subtotal Land and Buildings	61.3	63.1	67.3	69.1	68.7	110.0
1815	Transformer Station Equipment	10.5	11.0	11.0	11.1	11.1	12.3
	Subtotal TS Primary Above 50	10.5	11.0	11.0	11.1	11.1	12.3
1820	Distribution Station Equipment	222.6	226.5	229.3	245.5	244.2	291.4
	Subtotal Distribution System	222.6	226.5	229.3	245.5	244.2	291.4
1830	Poles, Towers and Fixtures	379.1	392.6	406.8	414.4	394.7	489.2
1835	O/H Conductors and Devices	413.0	433.1	462.6	486.9	481.2	557.3
1840	U/G Conduit	1,312.9	1,377.7	1,420.9	1,479.9	1,479.0	1,749.2
1845	U/G Conductors and Devices	788.6	834.6	888.7	919.3	898.6	1,028.6
	Subtotal Poles and Wires	2,893.6	3,037.9	3,179.0	3,300.4	3,253.5	3,824.2
1850	Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
	Subtotal Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
1855	Services	75.5	80.5	84.1	92.1	92.1	120.0
1860	Meters (includes Smart Meters)	228.2	236.7	194.0	206.7	206.7	229.0
	Subtotal Services and Meters	303.7	317.2	278.1	298.7	298.7	349.0
1908	Buildings and Fixtures	110.3	114.0	121.2	146.5	146.3	132.5
1910	Leasehold Improvements	19.8	20.4	20.4	20.7	20.7	20.8
	Subtotal General Plant	130.1	134.4	141.6	167.2	167.1	153.3
1915	Office Furniture and Equipment	20.5	21.7	22.3	24.6	24.6	24.8
1930	Transportation Equipment	78.0	73.2	72.9	77.1	77.1	81.0
1935	Stores Equipment	5.5	5.5	5.5	5.5	5.5	5.5
1940	Tools, Shop and Garage Equipment	39.2	40.3	42.6	43.1	43.1	44.9
1945	Measurement & Test Equipment	5.0	5.3	5.1	5.1	5.1	5.1
1955	Communication Equipment	31.5	32.1	33.1	33.9	33.9	35.4
1960	Miscellaneous Equipment	0.4	0.4	0.4	0.4	0.4	0.4
	Subtotal Equipment	180.1	178.5	181.8	189.7	189.7	197.1
1610	Miscellaneous Intangible Plant	-	-	-	-	-	-
1920	Computer Equipment	44.6	50.5	56.3	87.4	87.4	98.9
	Subtotal IT Assets	44.6	50.5	56.3	87.4	87.4	98.9
1609	Capital Contributions Paid	14.1	19.6	22.2	25.7	25.7	74.5
1611	Computer Software	222.6	242.3	268.4	283.2	283.2	309.3
1612	Land Rights	-	-	-	-	7.2	7.2
1970	Load Management-Customer	14.8	14.8	14.8	14.8	14.8	14.9
1975	Load Management-Utility	0.6	0.6	0.6	0.6	0.6	0.6
1980	System Supervisory Equipment	57.6	58.1	60.5	62.2	57.5	55.1
2005	Property Under Capital Leases	14.3	13.5	13.7	15.8	15.8	15.8
	Subtotal Other Distribution Assets	323.9	348.9	380.2	402.4	404.9	477.3
1995	Contributed Capital	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
	Subtotal Contributions and Grants	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
	GROSS FIXED ASSETS	4,607.8	4,809.0	4,977.7	5,227.6	5,150.5	5,976.5
2055	Construction Work in Process	257.8	336.9	401.3	515.5	516.1	507.4
	GROSS INCLUDING CWIP	4,865.6	5,145.9	5,379.0	5,743.1	5,666.6	6,483.9

WORKING CAPITAL ALLOWANCE (WCA)

Toronto Hydro determined the Working Capital Allowance (“WCA”) included in its 2015 ratebase based on an updated Lead-Lag Study performed by Navigant Consulting Inc. (“Navigant”), which is filed as Exhibit 2A, Tab 3, Schedule 2. Navigant used Toronto Hydro’s 2012 financial information to determine the revenue lead and expense lag for various detailed revenue and cost components. The methodology employed by Navigant in the current study is generally the same as that employed in the last Lead-Lag study which was filed in EB-2007-0680. Toronto Hydro confirms that for the purposes of the Lead-Lag Study, leads and lags were measured in days, and were dollar weighted.

The result of the Lead-Lag Study is a significant decrease in the WCA rate approved in the utility’s last rebasing application (EB-2010-0142) from 12.88% of controllable expenses plus cost of power to 7.99% for the 2015 test year. The reduction was achieved primarily as a result of two changes: /C

- 1) a significant decrease in the revenue lag due to improved billing and collection activities, and
- 2) a change in the weightings applied to revenue lag days from customers to class revenues.

Table 1 below presents a detailed calculation of the WCA for 2015. To calculate the WCA, the Cost of Power was determined by using: the split between RPP and non-RPP customers, 2015 forecast RPP, HOEP, and UTR.

1 **Table 1: Working Capital Allowance Calculation**

	2015 Expenses (\$ millions)	Working Capital Factor		Expenses * Working Capital Factor (\$ millions)	
Cost of Power	2,751.9	6.1%		167.0	
OM&A	269.5	5.8%		15.6	
Interest on Long Term Debt	82.0	2.4%		2.0	
Income and Capital Taxes	24.0	28.4%		6.8	/C
DRC	171.2	5.9%		10.2	
Sub-Total Working Capital Requirement				201.7	/C
HST at 13%		Net Lag Days	Expenses * Net Lag Days/365 * 13% HST		
Revenue	3,403.1	-5.5	-6.6		
Cost of Power	2,751.9	45.9	45.0		
OM&A Expenses	103.2	41.5	1.5		
HST Working Capital Requirement				39.9	
Total Working Capital				241.5	/C
Working Capital as % of Cost of Power and Controllable Expenses				7.99%	

2 Table 2 below provides a comparison of the Working Capital Requirements for the 2015
3 test year which have been included in the utility's rate base calculations (Exhibit 2A, Tab
4 1, Schedule 1), and the last OEB-approved WCA in 2011. This table shows that since
5 2011, Toronto Hydro has achieved a reduction of just under \$60M in its WCA.

7 **Table 2: Working Capital Allowance (\$millions)**

	2011 OEB Approved	2015 Test Year	
Working Capital Allowance	296.7	241.5	/C

OEB Appendix 2-AA

Capital Projects Table

Projects	2010	2011	2012	2013	2014 BRIDGE	2015 TEST	2016 TEST	2017 TEST	2018 TEST	2019 TEST
Reporting Basis	CGAAP	CGAAP	USGAAP	USGAAP	USGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Metering	28.4	22.1	12.1	12.2	14.0	24.7	16.6	14.7	11.7	13.7
Customer Connections	15.2	31.2	31.0	53.4	52.1	39.3	53.8	64.9	56.9	46.6
Externally-Initiated Plant Relocation & Expansion	0.7	5.0	9.8	18.6	8.8	4.0	4.0	4.0	4.0	4.0
Load Demand	-	-	0.3	2.4	1.1	12.0	13.9	14.0	15.7	19.2
Generation Projects Protection and Control	-	-	-	-	-	6.1	5.2	3.3	2.1	2.0
System Access Investments Sub-total	44.4	58.3	53.2	86.6	76.0	86.1	93.5	100.9	90.4	85.5
Underground Circuit Renewal	108.4	90.3	53.8	68.8	108.1	96.0	80.1	84.0	99.7	99.5
Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers	-	5.5	1.5	2.4	4.7	3.5	1.4	0.7	0.8	0.5
Underground Legacy Infrastructure	-	-	-	-	-	2.1	6.7	6.6	6.5	5.5
Overhead Circuit Renewal	25.8	28.3	23.2	49.0	53.3	44.0	23.0	24.9	25.3	30.3
Overhead Infrastructure Relocation	-	-	-	-	-	0.7	1.4	1.8	2.3	3.6
Rear Lot Conversion	6.9	16.6	17.5	23.8	22.7	17.0	8.1	10.3	10.3	13.6
Box Construction Conversion	5.7	7.1	0.8	13.8	23.3	16.8	20.7	21.1	21.6	22.7
SCADAMATE R1 Renewal	-	-	-	1.9	2.6	6.2	4.1	2.7	-	-
Network Vault Renewal	1.7	0.9	3.6	10.8	0.9	4.0	10.4	10.3	10.3	10.2
Network Unit Renewal	7.3	4.4	5.1	7.3	3.6	5.2	7.4	7.3	7.3	7.3
Legacy Network Equipment Renewal (ATS & RPB)	0.4	0.0	0.1	1.6	0.2	0.4	1.0	1.1	0.9	1.1
Network Circuit Reconfiguration	-	-	-	-	-	-	2.3	2.3	2.3	2.3
Stations Switchgear Renewal	14.9	12.9	11.6	7.9	24.6	11.9	18.9	25.5	27.6	22.4
Stations Power Transformer Renewal	1.8	4.0	2.7	1.7	1.3	1.7	2.6	2.6	2.7	2.7
Stations Circuit Breaker Renewal	0.0	0.9	0.2	1.0	2.1	1.7	1.8	1.8	2.1	1.8
Stations Control & Monitoring	-	-	0.1	0.5	0.2	0.1	0.9	1.1	1.5	1.4
Stations Ancillary Systems	0.1	0.1	0.2	0.6	0.2	0.7	0.6	0.4	0.3	0.4
Station Buildings	-	-	0.5	0.0	0.2	0.5	2.5	2.3	2.6	3.3
Stations DC Battery Renewal	0.2	0.2	0.4	0.3	0.6	0.3	0.7	0.7	0.7	0.7
Reactive Capital	25.1	28.6	29.2	37.4	32.1	31.9	32.7	33.1	33.6	34.2
Worst Performing Feeder	16.7	19.3	6.7	1.2	4.8	1.2	1.8	1.8	1.8	1.8
Telecom Program	-	-	-	1.0	0.9	6.1	6.0	4.0	-	-
System Renewal Investments Sub-total	215.0	219.3	157.2	231.1	286.4	251.7	235.0	246.3	260.1	265.5
Contingency Enhancement	-	-	-	-	-	10.0	5.9	9.7	9.7	13.5
Design Enhancements	-	-	-	-	-	0.4	1.7	1.7	1.7	1.7
Feeder Automation	3.3	0.9	6.2	8.8	0.8	11.1	15.1	9.4	10.0	8.5
Overhead Momentary Reduction	-	-	-	-	-	-	-	0.6	0.6	0.6
Handwell Upgrades	21.1	32.9	12.6	11.7	16.2	5.0	-	-	-	-
Polymer SMD-20 Renewal	-	-	-	0.8	2.8	4.8	-	-	-	-
Downtown Contingency	1.1	4.7	0.1	1.1	1.0	-	0.7	0.7	1.0	0.9
Customer Owned Station Protection	-	-	-	-	-	0.6	1.0	1.0	0.8	0.6
Stations Expansion	6.9	32.5	18.6	61.2	79.5	43.8	41.6	36.5	22.0	44.0
Energy Storage Systems	-	-	-	-	1.0	0.5	1.1	2.2	3.2	3.8
Local Demand Response	-	-	-	-	-	0.2	2.4	0.6	0.5	0.3
Grid Intelligence	3.0	4.8	0.8	0.1	-	-	-	-	-	-
EV	-	-	0.0	0.0	-	-	-	-	-	-
System Service Investments Sub-Total	35.3	75.6	38.4	83.7	101.3	76.5	69.6	62.5	49.5	73.9
Fleet and Equipment Services	10.6	11.8	0.8	2.2	2.6	3.9	3.2	3.7	3.5	3.6
Facilities	12.1	25.3	6.6	14.5	90.3	53.8	24.2	2.0	2.0	1.9
IT Hardware	10.6	9.4	7.4	6.0	5.2	5.9	8.0	7.4	9.8	5.6
IT Software	22.2	21.2	14.5	9.6	10.1	15.5	16.2	15.8	16.8	16.8
Radio Project	-	-	-	-	-	6.7	13.7	-	-	-
ERP*	-	-	-	1.5	0.9	17.7	33.6	-	-	-
Program Support	-	-	-	-	0.4	1.2	0.5	-	-	-
General Plant Investments Sub-Total	55.5	67.7	29.3	33.8	109.5	104.6	99.4	28.9	32.1	27.9
Miscellaneous	12.3	(4.2)	4.5	5.4	3.2	0.9	1.2	1.2	1.2	1.2
AFUDC	3.5	5.2	2.3	3.3	6.5	8.0	5.8	4.5	4.6	4.6
Roadcuts	-	-	3.1	1.8	3.0	3.3	4.1	4.1	4.1	4.1
EAR	34.5	23.6	-	-	-	-	-	-	-	-
Inflation	-	-	-	-	-	-	10.2	18.9	28.0	39.5
Other Sub-Total	50.4	24.6	9.9	10.5	12.7	12.2	21.2	28.6	37.9	49.4
Total	400.6	445.5	288.0	445.7	585.9	531.1	518.8	467.4	470.0	502.2
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-	-	(6.3)	(5.9)	(5.1)	(5.0)	(5.4)
Total	400.6	445.5	288.0	445.7	585.9	524.9	512.9	462.3	465.0	496.7

OEB Appendix 2-AB

**Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated
Distribution System Plan Filing Requirements**

First year of Forecast Period:

CATEGORY					Forecast Period (planned)					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Actual	Actual	Actual	Actual	Bridge	Test	Test	Test	Test	Test
	\$ '000	\$ '000	\$ '000	\$ '000	\$ '000	\$ '000	\$ '000	\$ '000	\$ '000	\$ '000
System Access	44.4	58.3	53.2	86.6	76.0	86.1	93.5	100.9	90.4	85.5
System Renewal	215.0	219.3	157.2	231.1	286.4	251.7	235.0	246.3	260.1	265.5
System Service	35.3	75.6	38.4	83.7	101.3	76.5	69.6	62.5	49.5	73.9
General Plant	55.5	67.7	29.3	33.8	109.5	104.6	99.4	28.9	32.1	27.9
Others	50.4	24.6	9.9	10.5	12.7	12.2	21.2	28.6	37.9	49.4
TOTAL EXPENDITURE	400.6	445.5	288.0	445.7	585.9	531.1	518.8	467.4	470.0	502.2
System O&M	\$ 114.6	\$ 111.9	\$ 109.0	\$ 119.8	\$ 118.9	\$ 128.8				

Note: Variances due to rounding may exist

Distribution System Plan 2015-2019

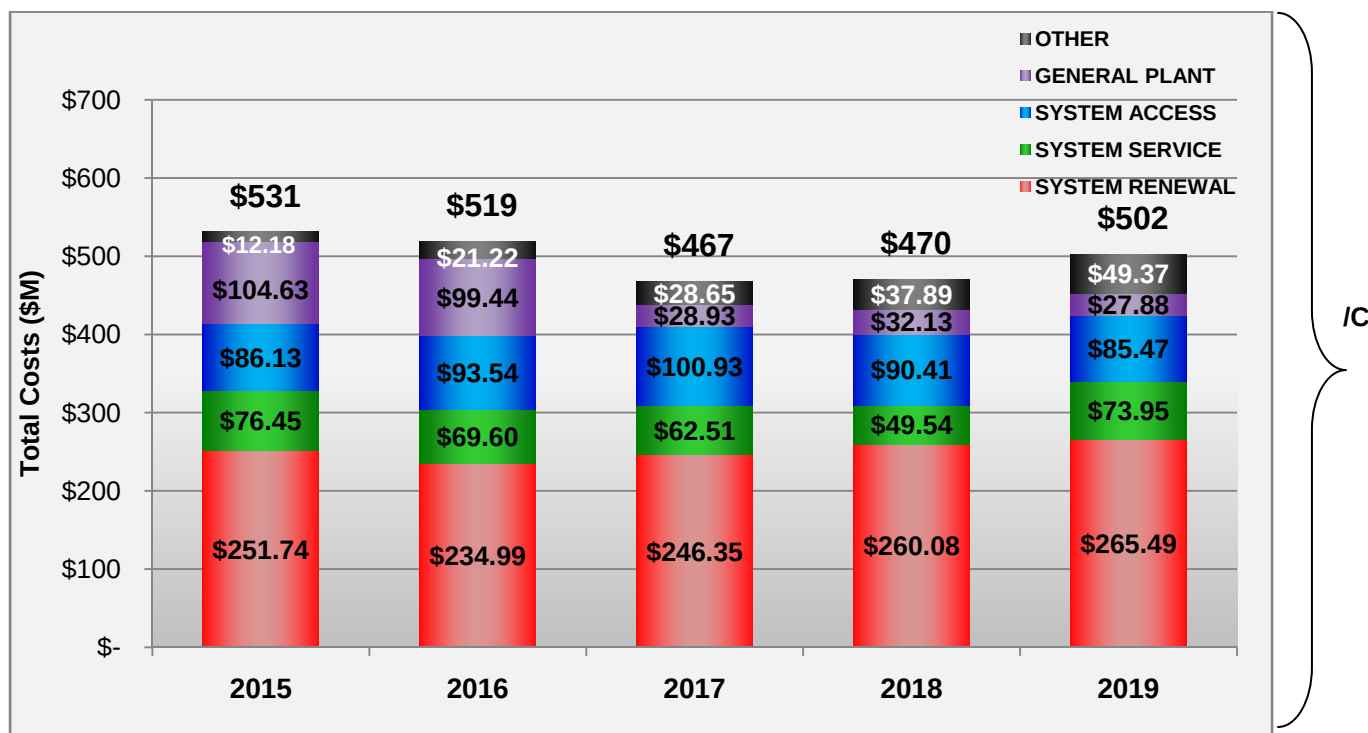


FIGURE 1: CAPITAL INVESTMENT REQUIREMENTS BY CATEGORY² (2015-2019)

2.1 Capital Investment Needs and Opportunities

This section provides an overview of the system and operational investment needs facing Toronto Hydro during the 2015-2019 forecast period and a discussion of the utility's long-term asset management objectives. For a comprehensive discussion of Toronto's existing distribution system assets, configurations, climate and utilization please refer to Section D2.

(iii) System Pressures: Aging and Obsolete Assets

Toronto Hydro's distribution system faces a number of significant and evolving challenges that necessitate the proposed level of investment. The foremost of these challenges is the large and growing backlog of in-service assets that are operating beyond their expected useful lives, which is reflected in the large percentage of System Renewal investments in all five years of the expenditure plan. To illustrate the rate of system aging, Figure 2 breaks the existing in-service asset base into three portions:

² The "Other" investment category includes forecast expenditures related to inflation, road cut repairs, and other capital expenditures that are unrelated to specific capital programs. For a complete explanation of this expenditures, refer to Section E4.2.5.

Distribution System Plan 2015-2019

- 1 Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). (A detailed
- 2 discussion of these reliability forecasts is provided in Section E2).

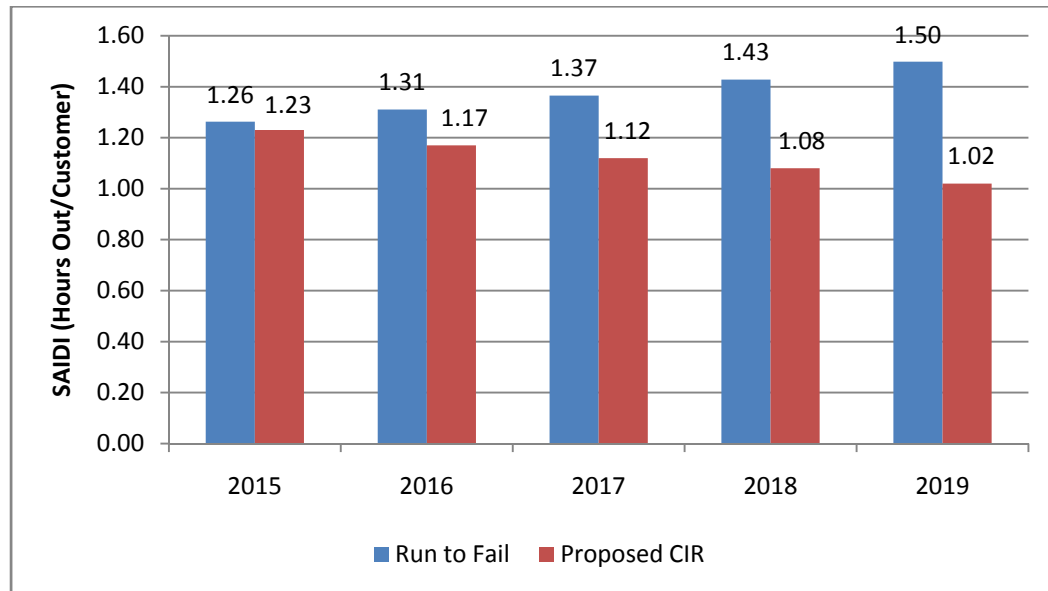


FIGURE 3: FIVE-YEAR SAIDI PROJECTION

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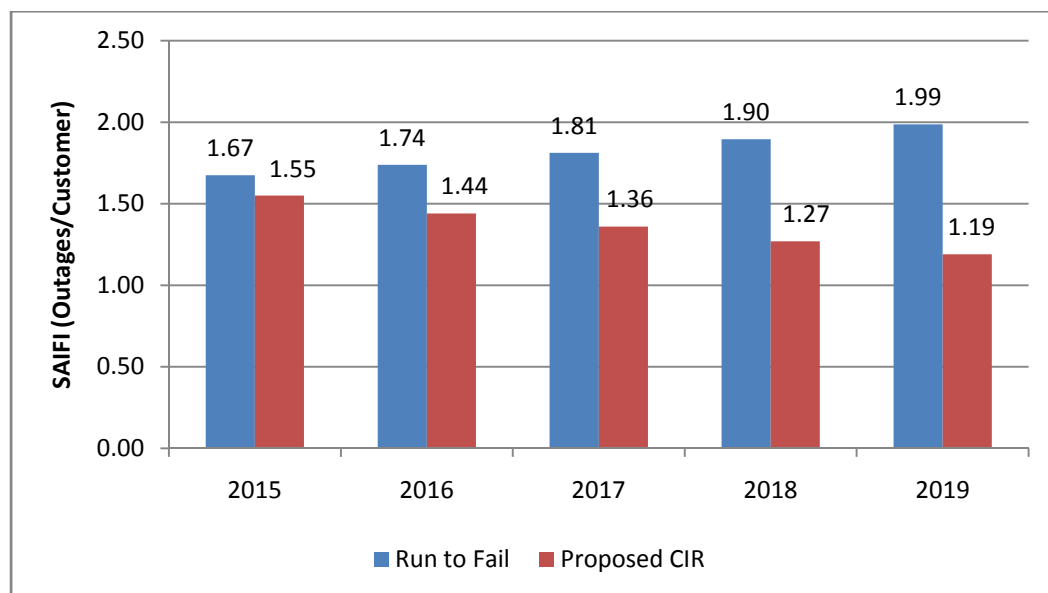


FIGURE 4: FIVE-YEAR SAIFI PROJECTION

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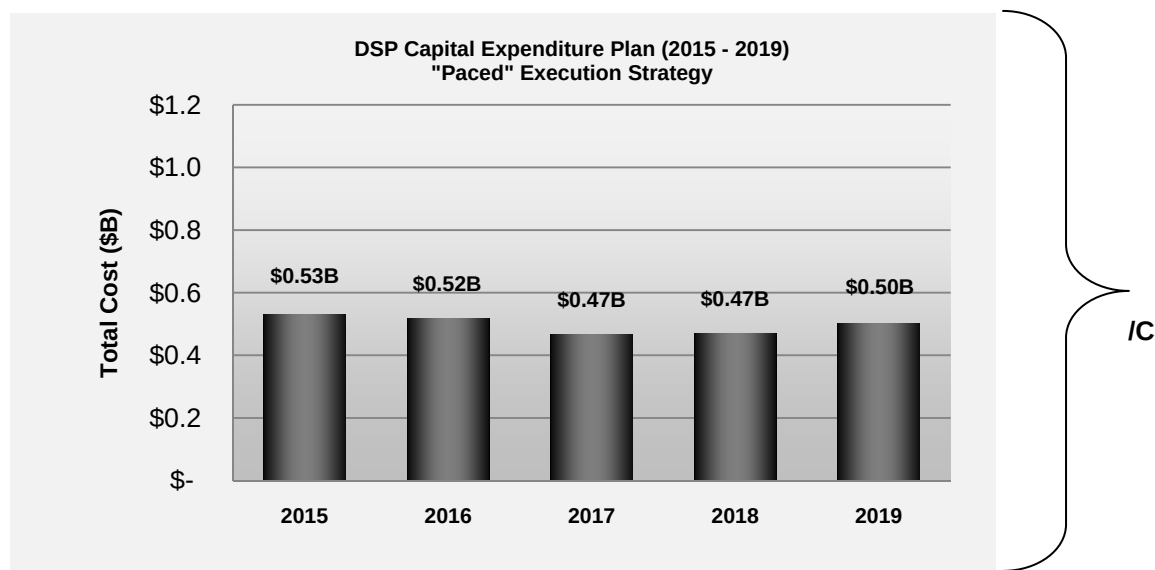


FIGURE 9: PACED CAPITAL INVESTMENT STRATEGY (2015-2019)

The paced execution strategy features an average annual investment of just under \$500 million, which, as the DSP evidence in Chapters D and E demonstrates, is the minimum level of investment that is appropriate given the magnitude of the asset backlog and other critical system issues and operational needs. If Toronto Hydro were to continue at this annual pace beyond 2019, the system is forecast to reach steady state by approximately 2037.

The disadvantage of this strategy is that customers are exposed to greater total asset lifecycle costs during the entire period of 2015 to 2037. However, this approach has the advantage of more predictable and tolerable bill increases during the 2015-2019 period and alignment with Toronto Hydro's immediate execution capacity.

The paced strategy has another significant advantage over the accelerated strategy: bill impacts and system performance are forecast to be more predictable beyond the achievement of steady-state. This is because the paced strategy takes a more gradual or dispersed approach to clearing the backlog of end-of-life assets. While achieving steady-state faster would maximize customer value sooner, the rapid renewal of aging assets would likely result in another large "lump" of end-of-life assets in the future, which would require another period of significantly large, multi-year investment needs.

To illustrate the overall impact on the system of reaching steady state, Figure 10 shows the forecast useful life demographics of the system as of 2037. The projected steady state in 2037

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TABLE 3: CAPITAL EXPENDITURE SUMMARY

CATEGORY	Historical Spend (\$M)					Forecasted Spend (\$M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System Access	\$44.37	\$58.31	\$53.15	\$86.62	\$76.01	\$86.13	\$93.54	\$100.93	\$90.41	\$85.47
System Renewal	\$215.00	\$219.25	\$157.25	\$231.08	\$286.37	\$251.74	\$234.99	\$246.35	\$260.08	\$265.49
System Service	\$35.32	\$75.63	\$38.35	\$83.67	\$101.34	\$76.45	\$69.60	\$62.51	\$49.54	\$73.95
General Plant	\$55.53	\$67.71	\$29.28	\$33.77	\$109.47	\$104.63	\$99.44	\$28.93	\$32.13	\$27.88
Other CAPEX	\$50.36	\$24.63	\$9.92	\$10.52	\$12.73	\$12.18	\$21.22	\$28.65	\$37.89	\$49.37
Total	\$400.58	\$445.53	\$287.95	\$445.66	\$585.92	\$531.13	\$518.79	\$467.36	\$470.05	\$502.16
System O&M	\$114.64	\$111.89	\$109.03	\$119.84	\$118.94	\$128.76	-	-	-	-

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The following sections provide a summary of System Access, System Service, System Renewal and General Plant programs as well as System O&M expenditures. For full details and justification of the programs listed throughout these sections, see Sections E5 through E8 of the DSP. For a detailed explanation of System O&M expenditures, see Section E4.2.6.

7.1 System Access

Toronto Hydro's capital expenditures under the System Access investment category are driven by statutory, regulatory or other obligations that require Toronto Hydro to provide customers with access to the distribution system or to otherwise respond to service requests.

TABLE 4: SUMMARY OF SYSTEM ACCESS PROGRAMS

Program Index and Name	Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E5.1 Metering	Enable Toronto Hydro to meet its mandatory service obligations with respect to revenue metering and wholesale metering. This will be accomplished by testing meters, replacing damaged and obsolete meters, and upgrading the under-capacity and obsolete collector stations. Upgrading Toronto Hydro's Interval Metering MDM software will help customers manage their energy use and costs by providing them with timely access to their data.	\$81.5 M	Mandated Service Obligations	Failure Risk

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Program Index and Name		Description	Total (5 years)	Trigger Driver	Secondary Drivers
E7.7	Downtown Contingency	Providing distribution load transfer capability between stations in the downtown Toronto area by tying feeders from one station with feeders from an adjacent station. This program addresses a risk in the downtown area where no back-up is provided for certain low probability, high impact events.	\$3.36 M	Reliability	Operational Constraints - Safety
E7.8	Customer Owned Station Protection	Installation of utility-owned protection devices upstream of customer-owned substations to isolate any faults occurring at customer owned substations.	\$4.04 M	Reliability	Safety
E7.9	Stations Expansion (including HONI contributions)	Upgrades to either Toronto Hydro or Hydro One Networks Inc. owned transformer stations. These upgrades address recent trends in customer connection requirements and loading, by mitigating system limitations imposed by existing station equipment.	\$188 M	Capacity Constraints	Reliability
E7.10	Local Demand Response	Providing medium-term capacity relief to Cecil TS by implementing a targeted and localized demand response strategy which primarily leverages new and existing demand response resources.	\$4.06 M	Capacity Constraints	Reliability
E7.11	Energy Storage Systems	To provide a conventional support for local capacity constraints and service reliability issues throughout Toronto Hydro's distribution system. These systems are also categorized as a renewable enabling improvement to accommodate the increasing numbers of renewable energy generation (REG) connections.	\$10.8 M	System Efficiency	Reliability - Power Quality

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7.4 General Plant

- 1
- 2 Capital expenditures under the General Plant investment category represent necessary routine
- 3 and one-time investments into the backbone assets that support Toronto Hydro's operational
- 4 activities. These investments are essential to the execution of the capital and O&M related
- 5 activities and expenditures discussed in the DSP and elsewhere.

1 expected to complete by April 2015 (see Exhibit 2B, Appendix D). The impact of the regional plan
2 on the Distribution System Plan is discussed in Section E1.4 - Regional Planning Considerations.

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3 **B2.2 Metro Toronto – Northern Sub-Region Needs** 4 **Screening**

5 The purpose of the Needs Screening report was to undertake an assessment of the Metro
6 Toronto Northern Sub-Region and determine if there were regional needs that require
7 coordinated regional planning. Where regional coordination is not required, and a “localized”
8 wires solution is necessary, such needs will be addressed between relevant Local Distribution
9 Companies (LDCs) and Hydro One and other parties as required. No need for coordinated
10 regional planning was identified. Impacts to the Distribution System Plan are described in
11 Section E1.4 (Regional Planning Considerations).

12 **B2.3 GTA North – Western Sub-Region Needs Screening**

13 The purpose of the Needs Screening report was to undertake an assessment of the Greater
14 Toronto Area (GTA) North, Western Sub-region and determine if there were regional needs that
15 would lead to coordinated regional planning. Where regional coordination is not required and a
16 “wires” only solution is necessary, such needs will be addressed between the relevant Local
17 Distribution Companies (LDCs) and Hydro One and other parties as required. No need for
18 coordinated regional planning was identified. Impacts to the Distribution System Plan are
19 described in Section E1.4 (Regional Planning Considerations).

E1.2 Expenditure Summary Tables

This section provides breakdowns of the investments contained within Toronto Hydro's Distribution System Plan (DSP) based upon investment categories and drivers.

E1.2.1 Expenditures by Investment Category

Table 1 shows the capital expenditure for the 2015-2019 period for each category. The System Renewal category has the highest spending of around \$1.26 billion (\$250 million annually) due to Toronto Hydro's continual renewal and replacement of aging distribution assets. The other CAPEX category has the lowest spending of around \$147 million (\$29 million annually) as it includes costs related to Engineering Capital, Road Cuts, Allowance for Funds Used During Construction (AFUDC), Major Tools and inflation. Section 4.2 provides the details around the spending profiles for all these categories and the major variances within them along with the inter-relationships between each of these elements. In addition, Sections E5-E8 provides the details of the capital programs in these categories.

TABLE 1: CAPITAL INVESTMENT BY CATEGORIES

CATEGORY	Forecasted Spend (\$M)						
	Avg.	2015	2016	2017	2018	2019	Total
System Access	\$91.29	\$86.13	\$93.54	\$100.93	\$90.41	\$85.47	\$456.47
System Renewal	\$251.73	\$251.74	\$234.99	\$246.35	\$260.08	\$265.49	\$1,258.64
System Service	\$66.41	\$76.45	\$69.60	\$62.51	\$49.54	\$73.95	\$332.05
General Plant	\$58.60	\$104.63	\$99.44	\$28.93	\$32.13	\$27.88	\$293.01
Other CAPEX	\$29.86	\$12.18	\$21.22	\$28.65	\$37.89	\$49.37	\$149.31
Total	\$497.90	\$531.13	\$518.79	\$467.36	\$470.05	\$502.16	\$2,489

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Distribution System Plan 2015-2019

E1.2.2 Expenditures by Investment Drivers

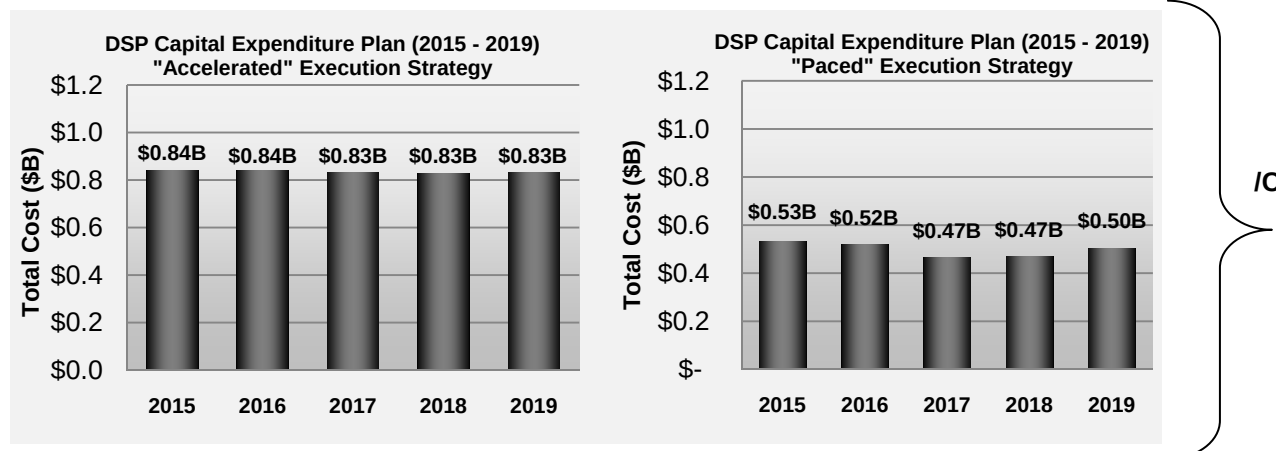
Table 2 shows the capital expenditure for the 2015-2019 period for based on the primary drivers. The three primary drivers with the highest investment are failure risk, functional obsolescence, and customer service requests. The combined investments for these drivers is approximately \$1.45 billion due to the System Renewal and System Access programs such as Overhead and Underground Circuit Renewal, Box Construction, Rear Lot Conversion, Customer Connections and Externally Initiated Plant Relocations and Expansion. Conversely, the three primary drivers with the lowest investments are Safety, System Efficiency and Reliability. However, it should be noted, as seen in Table 3, both Safety and Reliability are secondary drivers for 29 and 18 programs respectively.

TABLE 2: CAPITAL INVESTMENT BY PRIMARY DRIVERS

Drivers	Forecasted Spend (\$M)						
	Avg.	2015	2016	2017	2018	2019	Total
Customer Service Requests / Third Party Requests	\$71.27	\$55.31	\$71.74	\$82.94	\$76.58	\$69.77	\$356.34
Mandated Service Obligations	\$20.03	\$30.82	\$21.80	\$17.99	\$13.83	\$15.69	\$100.14
Functional Obsolescence	\$82.81	\$80.61	\$105.54	\$78.31	\$75.05	\$74.54	\$414.05
Failure	\$33.10	\$31.90	\$32.71	\$33.11	\$33.61	\$34.18	\$165.51
Failure Risk	\$146.07	\$156.91	\$130.31	\$134.93	\$151.42	\$156.76	\$730.33
Safety	\$15.11	\$16.50	\$13.73				\$30.22
Reliability	\$13.07	\$10.97	\$9.38	\$13.83	\$13.81	\$17.36	\$65.35
System Efficiency	\$12.99	\$11.68	\$16.20	\$11.58	\$13.23	\$12.24	\$64.93
Capacity Constraints	\$38.39	\$43.98	\$44.02	\$37.10	\$22.50	\$44.35	\$191.94
System Maintenance & Capital Investment Support	\$44.27	\$80.26	\$52.14	\$28.93	\$32.13	\$27.88	\$221.35
Other	\$29.86	\$12.18	\$21.22	\$28.65	\$37.89	\$49.37	\$149.31
Total	\$497.90	\$531.13	\$518.79	\$467.36	\$470.05	\$502.16	\$2,489.48

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Distribution System Plan 2015-2019



1 **FIGURE 5: ACCELERATED VERSUS PACED CAPITAL INVESTMENT EXECUTION STRATEGIES (2015-2019)**

2 As previously explained, the steady state is the economically optimal condition for the distribution
3 system and ratepayers. By reaching the steady state in the proposed "paced" manner, the
4 fluctuations in capital investment spending, which are driven by uneven depreciation of the asset
5 base and necessitate periods of significantly large multi-year capital investment above historic
6 levels, can be mitigated, leading to more consistent system-wide performance and smoother rate
7 impacts beyond the initial achievement of steady state in 2037. As noted in the results of Toronto
8 Hydro's customer engagement activities (Exhibit 1B, Tab 2, Schedule 7), some focus group and
9 workshop participants, while accepting of the need for significant capital investment above
10 historic levels and the associated bill impacts, felt that the uneven approach to investment over
11 time could have been avoided had Toronto Hydro been building a reserve of capital funds
12 beforehand. While Toronto Hydro is not able to operate a capital reserve fund of this nature, the
13 paced execution strategy described here could, over the long-term, help mitigate the rate
14 increases that can accompany uneven capital investment commitments.

15 Under the proposed "paced" execution strategy, SAIFI is projected to be reduced from 1.53
16 outages in 2014) to 1.13 outages in 2019, and SAIDI is projected to be reduced from 1.21 hours
17 in 2014 to 0.97 hours in 2019 respectively. In contrast, should Toronto Hydro not execute this
18 investment approach and instead adopt a run-to-failure approach, SAIFI and SAIDI are
19 forecasted to worsen by another 30%, and 24% respectively over the period from 2015 to 2019. A
20 run-to-failure approach would force Toronto Hydro to manage assets in a reactive manner,
21 exposing customers to associated outages and higher reactive costs associated with the
22 replacement of assets and the restoration of the system.

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1 peak period to date, which includes infrastructure that has reached or is exceeding its useful life
2 criteria as illustrated by the bars in red in Figure 6.

3 Figure 7 further illustrates how capital investments necessary to manage this current investment
4 peak period have been on the rise since 2006.

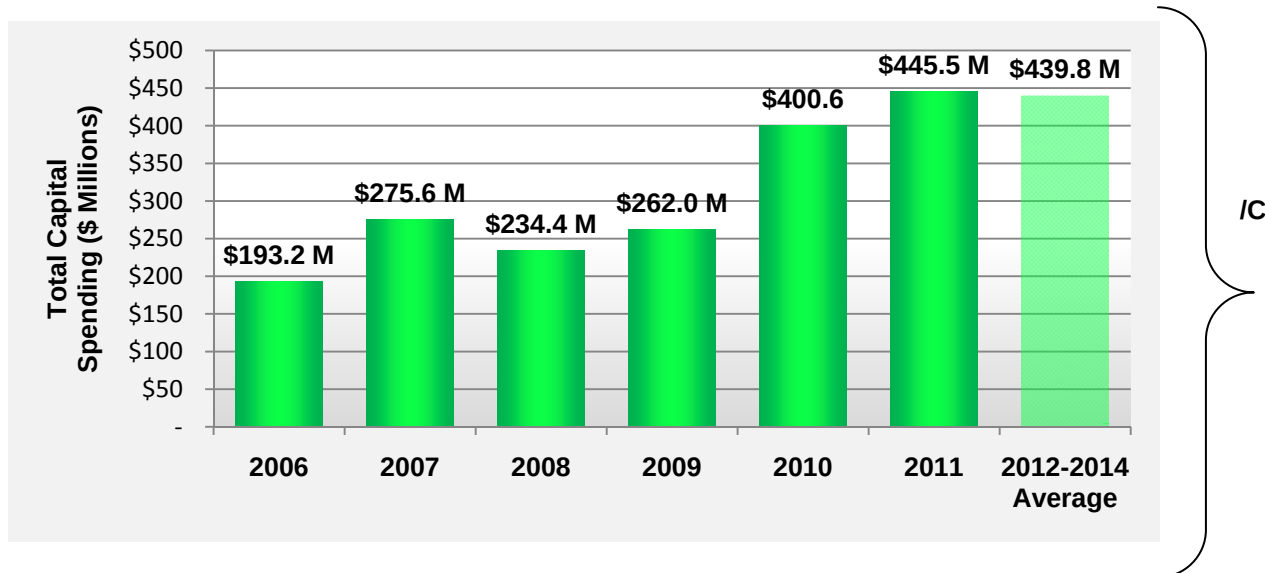


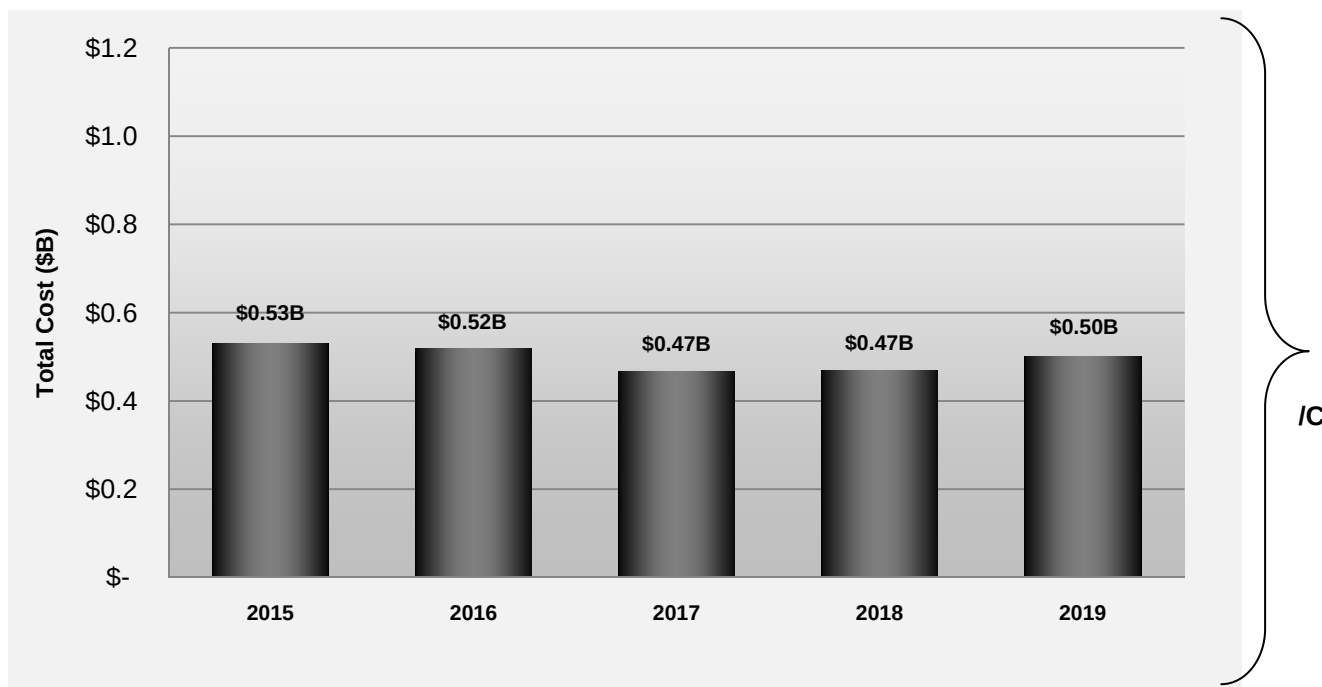
FIGURE 7: HISTORICAL SYSTEM INVESTMENT

6 From 2012 to 2014, this third peak of investments was managed through a series of OEB-
7 approved Incremental Capital Module (ICM) segments filed as part of Toronto Hydro's 2012-2014
8 rates application². Many of the DSP programs proposed for 2015-2019 include capital work that
9 is comparable to approved ICM segments, including "core" asset renewal investments for each of
10 the grid systems (overhead, underground, secondary network and stations), the replacement of
11 functionally obsolete infrastructure such as rear lot and box construction, and the replacement of
12 legacy infrastructure currently posing safety issues, including SCADAMATE R1 and Polymer
13 SMD-20 fused switches.

14 As originally further illustrated in Figure 8 below, approximately 26% of the replacement value
15 Toronto Hydro's asset base will be past its useful life criteria by 2015.

² EB-2012-0064.

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1 **FIGURE 11: CAPITAL INVESTMENT APPROACH AS PER “PACED” EXECUTION STRATEGY (2015-2019)**

2 Toronto Hydro believes that the benefits of reduced rate impacts and execution complexities
3 associated with the “Paced” execution strategy outweigh the benefits of the “Accelerated”
4 execution strategy in terms of reaching the steady state within the five-year period. Based upon
5 these results, Toronto Hydro has selected the “Paced” execution strategy as part of the 2015-
6 2019 capital investment plan. Ultimately, the execution of the capital expenditure plan as per this
7 strategy will result in predictable rates over the five-year DSP term due to the “paced” nature of
8 the investments, and will ultimately allow for steady state achievement by 2037.

9 Figure 12 illustrates the useful life demographics following the achievement of steady state as per
10 the “paced” execution strategy in 2037. The results illustrate how the replacement value
11 associated with assets past their useful life decrease from 26% as of 2015 to 11% by 2037.
12 Similarly, assets not exceeding their useful lives will increase from 67% as of 2015 to 80% by
13 2037.

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E4

CAPITAL EXPENDITURE SUMMARY

1 This section summarizes historical and forecasted system capital and system operating and
2 maintenance (O&M) expenditures and their respective drivers for the period 2010 to 2019.

E4.1 Investment Summary (10-Year Comparison)

4 Table 1 shows the level of spending for the System Access, System Renewal, System Service
5 and General Plant investment categories, as well as the System O&M expenditures, over the
6 historical period from 2010 to 2014, and over the forecasted period from 2015 to 2019. This table
7 aligns with "Table 2 – Capital Expenditure Summary" as specified in Chapter 5 of the Ontario
8 Energy Board's (OEB) *Filing Requirements for Electricity Distribution Rate Applications* (July 17,
9 2013).

TABLE 1: CAPITAL EXPENDITURE SUMMARY

CATEGORY	Historical Spend (\$M)					Forecasted Spend (\$M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System Access	\$44.37	\$58.31	\$53.15	\$86.62	\$76.01	\$86.13	\$93.54	\$100.93	\$90.41	\$85.47
System Renewal	\$215.00	\$219.25	\$157.25	\$231.08	\$286.37	\$251.74	\$234.99	\$246.35	\$260.08	\$265.49
System Service	\$35.32	\$75.63	\$38.35	\$83.67	\$101.34	\$76.45	\$69.60	\$62.51	\$49.54	\$73.95
General Plant	\$55.53	\$67.71	\$29.28	\$33.77	\$109.47	\$104.63	\$99.44	\$28.93	\$32.13	\$27.88
Other CAPEX	\$50.36	\$24.63	\$9.92	\$10.52	\$12.73	\$12.18	\$21.22	\$28.65	\$37.89	\$49.37
Total	\$400.58	\$445.53	\$287.95	\$445.66	\$585.92	\$531.13	\$518.79	\$467.36	\$470.05	\$502.16
System O&M	\$114.64	\$111.89	\$109.03	\$119.84	\$118.94	\$128.76	-	-	-	-

11 Expenditures within the 2010-2013 historical period are actual expenditures, whereas
12 expenditures for 2014 (i.e. bridge year) are planned expenditures, as the 2014 year has not yet
13 concluded as of this writing.

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performance and safety issues (e.g. Stations Expansion) and by improving system operational efficiency (e.g. Feeder Automation). System Service is further discussed in the following section.

E4.2.3 System Service Spending Profile

Toronto Hydro's capital expenditures under the System Service investment category are driven primarily by the need to resolve critical system-wide issues, including capacity and operational constraints, security-of-supply risks, potential safety risks, system reliability deficiencies and other inefficiencies within the existing grid. Beyond the safety and capacity-driven investments in this category, a number of the programs were selected as cost-effective means of delivering significant customer value (in the form of improved service and service efficiency) during the 2015-2019 period while maintaining a relatively modest pace of System Renewal work.

Key investments within the System Service investment category include:

- re-configuration and re-design of feeders to improve restoration capabilities, tree contact resistance and coordination of protective devices;
- installation of assets and technologies to improve restoration capabilities and system efficiencies and mitigate capacity constraints;
- expansion of station infrastructure to mitigate capacity constraints and security-of-supply risks;
- installation of tie points and upgrading of feeder cable sizes to improve load transfer and contingency management capabilities; and
- replacement of legacy assets that pose potential safety risks to crew workers and the general public.

Section E7 provides further details on the nature of this investment category along with full details and justification for the individual capital expenditure programs within. Table 4 outlines the year-over-year spending profile of the System Service investment category from 2010 to 2019.

TABLE 4: SYSTEM SERVICE EXPENDITURES – HISTORICAL & FORECASTED

CATEGORY	Historical Spend (\$M)					Forecasted Spend (\$M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System Service	\$35.32	\$75.63	\$38.35	\$83.67	\$101.34	\$76.45	\$69.60	\$62.51	\$49.54	\$73.95

IC

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System Service investments between 2010 and 2014 mainly consisted of investments in the Handwell Upgrades and Stations Expansions programs. There is relatively little historical System Service spending related to the overhead, underground and secondary network systems in the form of re-configuration and re-design of feeders, installation of assets and technologies, and installation of tie points and upgrading of feeder cable sizes. Investments for System Service started off at minimal levels in 2010 due to minimal spending related to Stations Expansions. Most of the 2010 spending was made up of capital expenditures in the Handwell Upgrades program.

System Service investment began to increase in 2011 and, with the exception of 2012, continued increasing through 2014, mainly due to Toronto Hydro's investments in the Stations Expansion program – in particular, Phase 1 of construction of the new Copeland Transformer Station (TS). Fluctuation in spending in the Stations Expansion program is due to the fact that the program consists of a small number of significant projects.

The decrease in spending in 2012 was due to the immediate ramp-down capital investments that year following the OEB's decision in Toronto Hydro's Cost of Service application (EB-2011-0144) in January 2012. This ramp-down had a direct impact on the scheduling, execution and resulting spend levels in 2012 associated with Copeland TS.

From 2015 onwards to 2019, System Service investments transition towards the management of critical issues within the overhead, underground and secondary network systems in the form of re-configuration and re-design of feeders, installation of assets and technologies, installation of tie points and upgrading feeder cable sizes. In this same time period, associated investments for Handwell Upgrades and Stations Expansion continue to decrease, resulting in an overall reduction of System Service investments.

The Handwell Upgrades program is planned for completion in 2015. Accordingly, Toronto Hydro does not forecast further spend for this program in the 2016 to 2019 period. The utility also forecasts a decrease in the Stations Expansion program mainly due to the anticipated completion of the Copeland Transformer Station Phase 1 project in 2016. Phase 2 of the Copeland Transformer Station is forecasted to begin in 2019, hence the increase in spending in that year.

E4.2.4 General Plant Spending Profile

Toronto Hydro's capital expenditures under the General Plant investment category represent necessary routine and one-time investments into the backbone assets that support Toronto

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1 **TABLE 6: OTHER CAPITAL EXPENDITURES (CAPEX) – HISTORICAL & FORECASTED**

CATEGORY	Historical Spend (\$M)					Forecasted Spend (\$M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
Other CAPEX	\$50.36	\$24.63	\$9.92	\$10.52	\$12.73	\$12.18	\$21.22	\$28.65	\$37.89	\$49.37

IC

2 Spending reductions in this category from 2010 to 2011 are largely attributed to reductions in
3 engineering capital spending, as certain overhead costs were deemed to be no longer directly
4 attributable to assets as per the 2011 accounting update, therefore resulting in a reduced amount
5 of engineering capital being eligible for capitalization in 2011. The full details associated with the
6 2011 accounting update and impacts are further explained and defined within Exhibit Q1, Tab 2,
7 Schedule 1 as part of Toronto Hydro's 2011 cost-of-service EDR application (EB-2010-0142).

8 Engineering capital expenditures are only included within this investment category between 2010
9 and 2011, and from 2012 and onwards, these costs are integrated within capital investment
10 programs, which therefore drives further reduction in this category between 2011 and 2012
11 respectively. Increases in this spending category from 2015 onwards to 2019 are largely the
12 product of spending inflation. Furthermore, the AFUDC rate applied by Toronto Hydro from 2010
13 onwards to 2014 is based on the OEB prescribed rate, whereas the forecasted expenditures from
14 2015 and onwards are based on MIFRS and thus include AFUDC calculated based on Toronto
15 Hydro's weighted average cost of debt.

16 From 2016 onwards to 2019, inflation costs are also included within this category, which result in
17 the year-over-year increases.

18 **E4.2.6 System Operating & Maintenance (O&M) Spending** 19 **Profile**

20 System Operational and Maintenance (O&M) expenditures represent the following five functional
21 areas:

- 22 ▪ Supply Chain Services;
- 23 ▪ Control Centre;
- 24 ▪ Operations Support;
- 25 ▪ Distribution Maintenance Programs; and

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Examples of this include capital replacements and enhancements for legacy distribution assets such as fibertop network units, reverse power breakers, and porcelain insulators. Examples also include corrective maintenance expenditures, which during the 2010 to 2013 period, experienced a reduction in part due to increases in planned capital expenditures on ageing and deteriorated assets. For 2014 and 2015, corrective maintenance is expected to rise, however it will remain below the peak levels experienced in 2011.

Although System O&M and capital investments are interrelated, a significant portion of System O&M expenditures are directed to activities that are independent of particular capital expenditure levels, including routine maintenance to preserve asset performance over its expected life; vegetation management to maintain minimum clearance requirements for overhead conductor and equipment; cyclical patrols and inspections undertaken to comply with minimum Distribution System Code requirements; corrective maintenance activities to address deficiencies caused by animal, pest, or tree contacts; and emergency maintenance following severe weather and storm damage. In addition, System O&M programs are necessary to provide the information that is used to plan Toronto Hydro's capital programs such as asset health and condition information. This is particularly important given Toronto Hydro's ageing asset base, which cannot be feasibly replaced through capital work in a short time frame due to a variety of factors such as resource and logistic constraints. The information captured through Toronto Hydro's System O&M programs is necessary to enable the prioritization of assets for capital work and to maximize the likelihood that assets that remain in-service have not surpassed end-of-life.

E4.2.6 Overall Trends

As illustrated in Table 11 above, with the exception of 2012, Toronto Hydro's historical capital expenditures have generally increased over the five-year historical period from 2010 to 2014 in the System Access, System Renewal, and System Service investment categories. This increase in investment was made because of Toronto Hydro's gradually worsening distribution system reliability due to a large number of aging and deteriorating infrastructure assets. Also, an increase in investment was required for the capacity growth seen between 2010 and 2014 and the increase in real estate developments and large infrastructure projects during that period.

General Plant spending was elevated in 2010 and 2011, partly due to the corresponding ramp-up in distribution system capital spending. Routine General Plant investments were stable from 2012-2014, but spending increase sharply in 2014 due to the initiation of the Operating Centres Consolidation Program. Spending in the General Plant category appears front-loaded during the 2015-2019 due to a number of larger, one-time investments required in the early years.

IC

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1 **TABLE 1: UNDERGROUND CIRCUIT RENEWAL PROGRAM ASSET REPLACEMENT UNITS**

Assets (Units)	2015	2016	2017	2018	2019	Total
Underground Switches	84	71	74	88	88	405
Underground Transformer	348	291	305	362	361	1,667
Underground Cable (circuit km)	149	125	131	155	155	715

IC

2 **TABLE 2: SUMMARY PROGRAM BENEFITS**

Customer Value	- Installing newer assets allows for reduced customer disruption in the event of an outage (i.e. quicker restoration due to SCADA switches and no digging for cable replacement). - Improved neighborhood aesthetics depending on the age and condition of existing assets (i.e. heavily rusted transformers and switches). - The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of \$102 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.1.7).
Reliability	Proactively replacing assets with a high risk of failure will: - Reduce customers interruptions - Mitigate safety risks to employees - Minimize reactive repair costs
Safety	- Minimize safety related issues due to flashovers (seen with pad-mounted and submersible switches and non-switchable submersible transformers). - Minimize the risk associated with dig-ins of direct buried cables and cables in direct buried PVC ducts.
Efficiency	- Improved restoration time by replacing older and unreliable assets with modern equipment capable of remote sensing and operation (i.e. switch). - Improved isolation of transformers without affecting power supply to customers on the rest of the distribution system. - Faster cable replacement of underground cables due to the concrete encased duct infrastructure.
Other (flashovers, dig-ins)	- Elimination of routine CO₂ washing used to maintain pad-mounted switches. - Complete removal of cables in duct when a feeder is abandoned rather than dead-ending the cables and leaving it in the ground where removal of direct buried cables is not economically feasible.

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TABLE 7: AVOIDED RISK COST BUSINESS CASE EVALUATION

Business Case Element	Cost (in Millions)
Asset Renewal	
Present Value of Net Cost in 2020 [PV(NET_COST(2020))]	\$192.56
Net Cost for the First Year of Activity [NET_COST(First Year of Activity)]	\$96.00
Avoided Risk Cost of Executing Work for the First Year of Activities [ARC = (PV(NET_COST(2020)) - (NET_COST(First Year of Activity)))]	\$102.93

E6.1.7 2015 Project Details

Table 9 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

- (a) previously filed projects that appeared as jobs in the OEB approved Underground Infrastructure segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and
- (b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 8: 2015 PROGRAM COSTS

2015 CAPEX (\$M)	
ICM Jobs	CIR Projects
18.6	77.3

Table 10 lists all projects that will be partially or completely executed as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

IC

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E12278 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12278 Nashdene-Tiffield UG Rebuild - Elec (NAR26M22)

Project Number: E12278

Project Year: 2015

Estimated Cost: \$3,628,734

(i) Objective

Rebuild a portion of NAR26M22 out of Malvern TS to improve reliability and service to this industrial neighborhood. E12278 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 36: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough-Rouge River
Station(s):	Malvern TS (27.6 kV)
Feeder(s):	SCNAR26M22

TABLE36A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	6,008.98 m
Underground Transformers	0
Underground Switch	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

IC

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 37: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	- Direct buried cable - Installed 1982 (32 years old)
Reliability	Reliability is getting worse.
Other (i.e. road moratoriums, etc)	This is the electrical portion of the project and needs to be completed to help improve reliability in the area

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E12477 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: E12477 Middlefield Passmore StateCrown Civ SCNAR26M21

IC

Project Number: E12477

Project Year: 2015

Estimated Cost: \$1,403,077

(i) Objective

Rebuild a portion of SCNAR26M21 containing aged direct buried cable to improve reliability and service to the customer. E12477 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 67: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough-Rouge River
Station(s):	Malvern TS (27.6 kV)
Feeder(s):	SCNAR26M21

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 68: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	- Direct buried cable - Installed 1979 (35 years old)
Reliability	- Reliability improved, but deteriorating again. - Majority of outages due to primary cable and transformer failures both of which will be targeted for replacement in the Underground

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E13621 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Brandy Court P and C Civil/Elec NY53M24

Project Number: E13621

Project Year: 2015

Estimated Cost: \$113,533

(i) Objective

Replace US96182 with an SF6, PMH-9 equivalent pad switch as the current switch has a protection/control issue. E13621 replaces assets that pose a higher reliability risk to the system. To increase efficiency, this project combines the civil and electrical work.

(ii) Scope of Work

TABLE 88: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Bermondsey II TS (27.6 kV)
Feeder(s):	NY53M24

TABLE 88A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	0
Underground Transformers	0
Underground Switch	4
Poles	0
Overhead Transformer	0
Overhead Switch	0

IC

Distribution System Plan 2015-2019

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 89: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	Non-standard vacuum switch failed, replaced with same style until civil construction completed enabling upgrade to standard SF6 type pad mount switch
Reliability	- Switch identified for upgrade to standard SF6 pad mount switch due to failure - Feeder has experienced poor reliability with 9 outages in last 2 years
Other (i.e. road moratoriums, etc)	Protection and control issue will be mitigated at location with upgrade

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 70.

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E15307, E15317, E15318 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Bridgeport UG Rebuild Ph1, 2 and 3 - Civil SCNA47M13

Project Number: E15307, E15317, E15318

Project Year: 2015

Estimated Cost: \$5,693,725

(i) Objective

Rebuild the direct buried distribution of Port Union Village. This project has been divided into three phases. E15307, E15317 and E15318 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

District Neighborhood:

Station(s):

Feeder(s):

TABLE 162: SCOPE OF WORK DETAILS

District Neighborhood	Parkdale-High Park
Station(s):	Sheppard TS (27.6 kV)
Feeder(s):	SCNA47M13

IC

1 **(iii) Justification & Benefits**

2 Supplemental details pertaining to the justification and benefits of this project are summarized as
3 follows:

4 **TABLE 163: SUPPLEMENTAL DETAILS**

Supplemental Details	Description
Age/Condition	- Direct buried cable - Installed 1988 (26 years old)
Reliability	Feeder reliability is weakening
Other (i.e. road moratoriums, etc)	N/A

5 Historical reliability including number of customers interrupted (CI), customer hours interrupted
6 (CHI) and outages along the feeder are given in Figure 103.

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E15476, E15477 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: 45 Birchmount Road UG Rebuild Civil/Electrical SCNAR43M24

Project Number: E15476, E15477

Project Year: 2015

Estimated Cost: \$185,563

(i) Objective

Replace underground assets on 43M24 that have reached and/or exceeded their useful service life. E15476 will install the civil infrastructure necessary to complete the project; E15477 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 200: SCOPE OF WORK DETAILS

District Neighborhood	Scarborough Southwest
Station(s):	Warden TS (27.6 kV)
Feeder(s):	SCNAR43M24

TABLE 201: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	82.18 m
Underground Transformers	2
Underground Switch	0
Poles	0
Overhead Transformer	0
Overhead Switch	2

(iii) Justification & Benefits

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W12077 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Hoggs Hollow PH4

Project Number: W12077

Project Year: 2015

Estimated Cost: \$1,722,014

(i) Objective

Replace the direct buried primary distribution in the area known as Hogg's Hollow to improve reliability and service to customers. W12077 will install the civil infrastructure necessary to complete the project.

(ii) Scope of Work

TABLE 221: SCOPE OF WORK DETAILS

District Neighborhood	Don Valley West
Station(s):	Fairchild II TS(27.6 kV)
Feeder(s):	NY80M30, NY55M29

TABLE 222A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	16,563.95
Underground Transformers	2
Underground Switch	1
Poles	1
Overhead Transformer	24
Overhead Switch	0

IC

(iii) Justification & Benefits

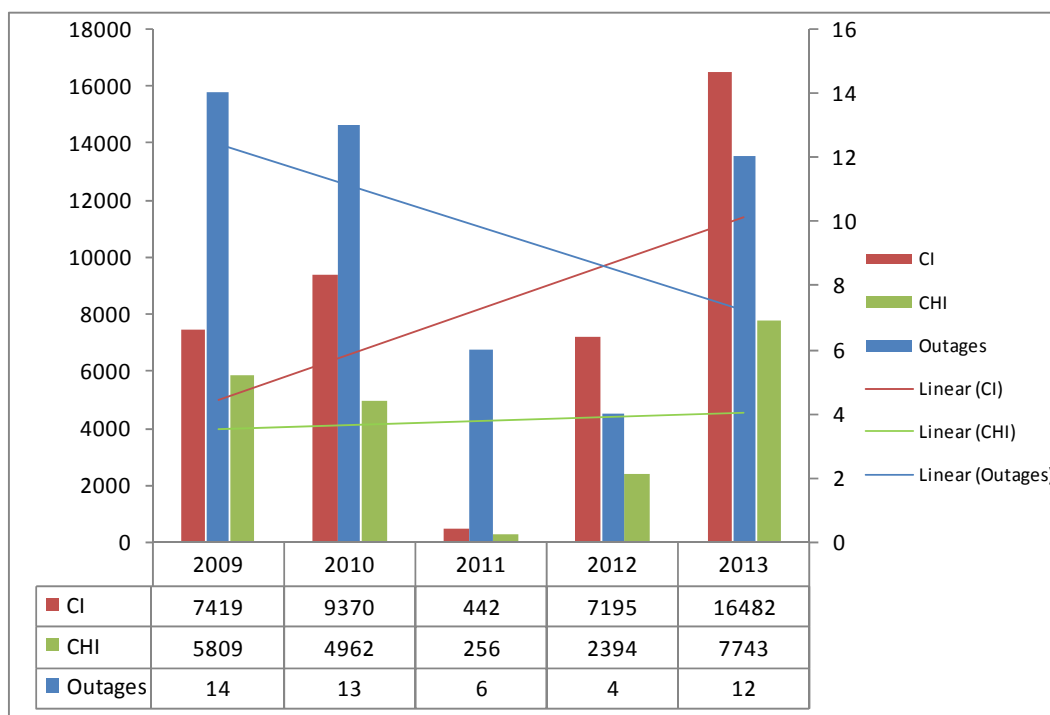
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1 Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

2 **TABLE 222: SUPPLEMENTAL DETAILS**

Supplemental Details	Description
Age/Condition	- Direct buried cable - Installed 1984 (30 years old)
Reliability	Feeder 80M30 has been performing very poorly with an average of nearly 10 power outages per year during the past 5 years
Other (i.e. road moratoriums, etc)	N/A

3 Historical reliability including number of customers interrupted (CI), customer hours interrupted
4 (CHI) and outages along the feeder are given in Figure XYZ.



5 **FIGURE 125: HISTORICAL RELIABILITY DETAILS FOR NY80M30**

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W14130 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: Rebuild Russfax & Twin Circle Crt

Project Number: W14130

Project Year: 2015

Estimated Cost: \$439,236

(i) Objective

Rebuild the OH and UG distribution on Russfax and Twin Circle Crt to improve reliability. W14130 combines both the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 232: SCOPE OF WORK DETAILS

District Neighborhood	York Centre
Station(s):	Bathurst I TS (27.6 kV)
Feeder(s):	NY85M7

TABLE 233: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	320.14 m
Underground Transformers	2
Underground Switch	0
Poles	7
Overhead Transformer	1
Overhead Switch	1

IC

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W14274 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: UG Lateral Cable Replacement -Fenmar/Ormout 55M1 Civil/Elec

IC

Project Number: W14274

Project Year: 2015

Estimated Cost: \$1,055,354

(i) Objective

Replace all XLPE UG primary service laterals in the area of Fenmar/Ormout to improve reliability and service to the customer. W14274 combines the civil and electrical work required to complete the project.

(ii) Scope of Work

TABLE 238: SCOPE OF WORK DETAILS

District Neighborhood	York West
Station(s):	Finch I TS (27.6 kV)
Feeder(s):	NY55M1

TABLE 239A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,287.39 m
Underground Transformers	12
Underground Switch	0
Poles	0
Overhead Transformer	0
Overhead Switch	0

IC

(iii) Justification & Benefits

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Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 239: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	- Combination of direct buried cable and end-of-life cable in duct - Assets installed around 1970 - 1980 (approx. between 34-44 years old)
Reliability	- Feeder has experienced several underground transformer outages - The primary failure mode of the feeder is overhead defective equipment - Due to poor conditions of the poles that have to be replaced, including riser poles, the underground XLPE cable will be replaced, along with transformers that have reached end-of-life.
Other (i.e. road moratoriums, etc)	N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 133.

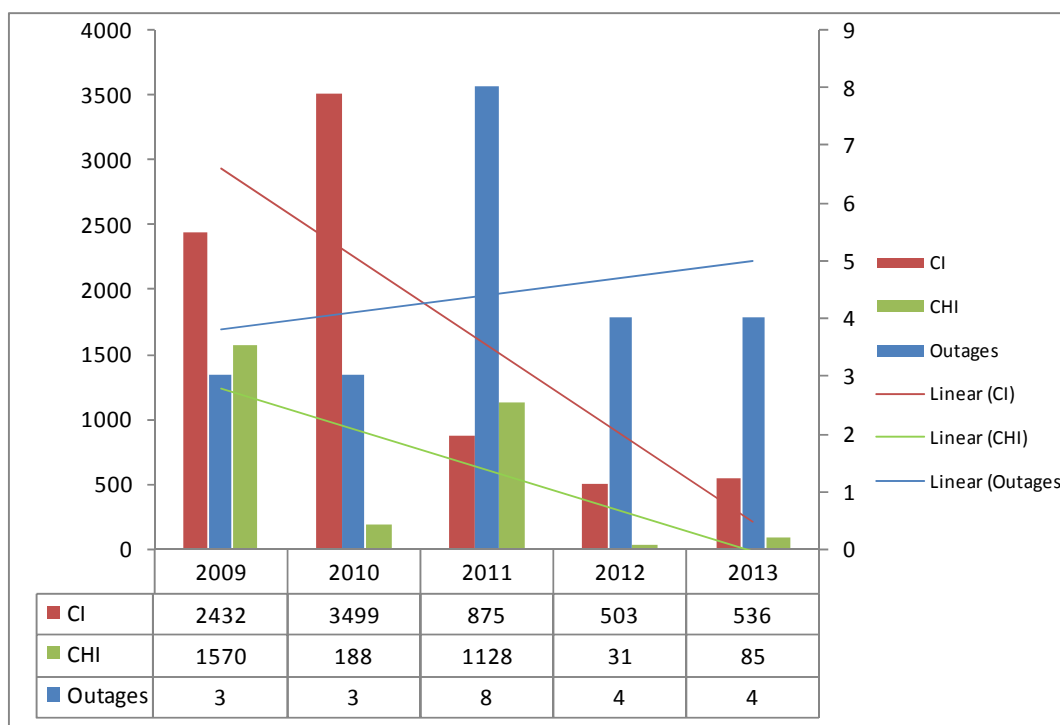


FIGURE 133: HISTORICAL RELIABILITY DETAILS FOR NY55M1

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W15268, W15269 Project Description

Investment Category: System Renewal

Program: Underground Circuit Renewal

Project Title: P01 - Red Robinway & Arnott UG Direct-Buried Cable Renewal Civil/Electrical

Project Number: W15268, W15269

Project Year: 2015

Estimated Cost: \$1,086,141

(i) Objective

Rebuild the direct-buried cable in the Robinway and Arnott area distribution, which has been subjected to multiple historical cable failures.

W15268 will install the civil infrastructure necessary to complete the project; W15269 will complete the electrical portion of the project.

(ii) Scope of Work

TABLE 245: SCOPE OF WORK DETAILS

District Neighborhood	York Centre
Station(s):	Fairchild I TS (27.6 kV)
Feeder(s):	NY80M8

TABLE 246A: ASSETS TO BE REPLACED

Assets to be Replaced	
Primary Cable	1,188.76 m
Underground Transformers	6
Underground Switch	4
Poles	3
Overhead Transformer	0
Overhead Switch	0

IC

Distribution System Plan 2015-2019

(iii) Justification & Benefits

Supplemental details pertaining to the justification and benefits of this project are summarized as follows:

TABLE 246: SUPPLEMENTAL DETAILS

Supplemental Details	Description
Age/Condition	This project replaces directly buried cable supplies Red Robinway and Arnott area that is aged and in poor condition.
Reliability	Segment of cable in the scope area had experienced multiple failures that has lasted long durations
Other (i.e. road moratoriums, etc)	N/A

Historical reliability including number of customers interrupted (CI), customer hours interrupted (CHI) and outages along the feeder are given in Figure 136.

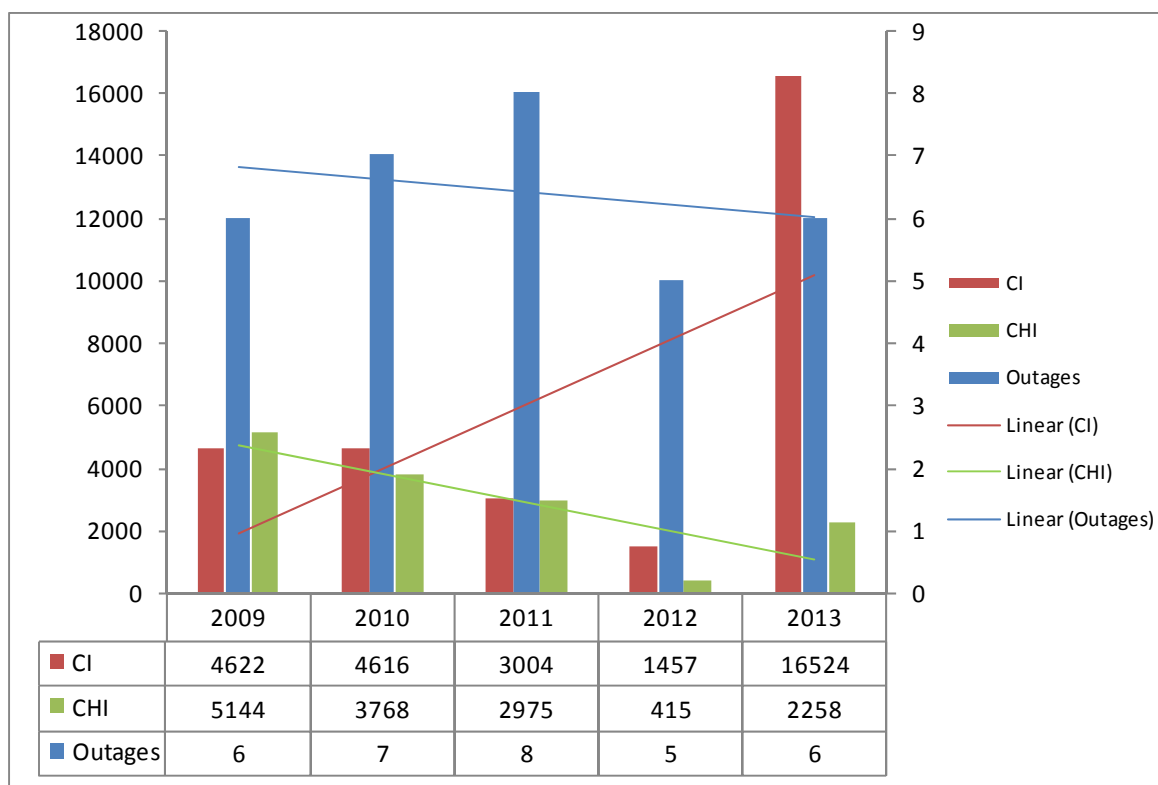


FIGURE 136: HISTORICAL RELIABILITY DETAILS FOR NY80M8

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TABLE 1: PROGRAM BENEFITS

Customer Value	- Improves service reliability for customers on the targeted feeders; the trunk-related outages to be mitigated can affect up to 7,000 customers and can cause adverse power quality issues for large industrial facilities on the same station bus. - The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of \$39.94 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.4.7).
Reliability	Improves system reliability by mitigating failure risk and limiting the frequency and impact of Overhead defective outages through the like-for-life replacement of end-of-life overhead assets
Safety	- Polymeric insulating material has less destructive failure modes than currently used porcelain material. - Prevents poles from falling due to rotting bases. - Standardized transformers have an external disconnect switch to provide a visible positive affirmation of an "open" or "close" state and longer working distances, as opposed to CSP transformers. - Avoids sub-optimal illumination for drivers and pedestrians caused by defective street light pole outages.
Efficiency	Reduces unexpected costs that are incurred for repair and restoration efforts as part of overhead defective equipment.

Table 2 below provides details of the estimated number of assets forecasted for replacement from 2015 to 2019.

TABLE 2: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Poles	2,838	1,735	1,900	1,934	2,313	11,214
Overhead Switches	218	160	166	154	207	981
Overhead Transformers	937	511	478	598	673	3,232

IC

E6.4.3 Why the Program is Needed

Toronto Hydro's Overhead Circuit Renewal program targets assets that are aged and deteriorated, leading to a high risk of failure. The failure of these assets will negatively impact service reliability to customers on the overhead system and could pose safety concerns for employees and the general public. As discussed in Section E6.4.5.2, defective overhead equipment is a significant source of outages.

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E6.6.2 Program Description

The Rear Lot Conversion program continues the activities described in the Rear Lot Construction segment of Toronto Hydro's 2012-2014 rate filing, which was approved by the OEB. Toronto Hydro estimates that the Rear Lot Conversion program will cost \$59 million over the 2015 to 2019 period, with spending averaging approximately \$12 million per year. A summary of the major assets to be replaced by asset class is shown Table 1 below and a map of the rear lot areas to be address between 2015 and 2019 can be seen in Figure 1 at the end of this section.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Asset Type	2015	2016	2017	2018	2019	Total
Pole	352	23	210	133	122	840
Transformer	99	37	64	32	51	283
Manual Switch	44	10	15	10	7	86
Fuse	48	15	27	14	29	133
Riser	32	2	27	4	25	90
Conductor (m)	18,295	2,933	9,112	6,692	9,157	46,188
Cable (m)	2,853	9,858	2,694	3,062	8,552	27,018

IC

Rear Lot Service History

Rear lot service was implemented in certain Toronto neighbourhoods in the 1950s and 1960s. At the time, this configuration was seen as more cost effective compared to front lot underground service and aesthetically superior to front lot overhead systems. The rear lot systems were constructed along the easements between customer properties at their rear lines. Toronto Hydro now considers rear lot service to be functionally obsolete due to a number of reliability, operational efficiency and safety issues associated with the configuration. Accordingly, Toronto Hydro no longer uses rear lot service for new projects and plans on converting rear lots to front lots. Rear lot conversion may also occasionally be driven by the need to replace 4 kV feeders that are connected to aging stations that are set to be decommissioned.

While there are some portions of rear lot distribution circuits that are underground, most rear lot service is overhead. These facilities consist of cable, poles, transformers, switches and overhead conductors. The system also features minor non-standard components, such as porcelain arrestors and insulators.

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1

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
OH Transformer	183	381	86	175	77	902
OH Switch	154	301	70	176	85	786
Poles	377	780	277	255	117	1,806
UG Switch	0	0	0	6	0	6
UG Transformer	20	27	9	52	17	125
OH Conductor (km)	23.5	46.2	11.4	24.4	11.5	117.1
UG Cable (km)	6.0	10.4	1.5	5.8	1.4	25.0

IC

- 2 Toronto Hydro evaluated the proposed program against the status-quo alternative of maintaining
3 and replacing (on a like-for-life basis) the equipment used in box construction, and determined
4 that proactive conversion is the best alternative. Table 2 summarizes the benefits associated with
5 the Box Construction Conversion program.

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E6.7.6.1 Proposed Work Plan

The proposed work plan in the 2015-2019 period does not necessarily follow a station-by-station approach but rather indicates a milestone year when all load will be converted at a given station. Feeders proposed for conversion in the 2015-2019 period are summarized Table 8.

Issues may arise that are specific to certain conversions; however, current planning processes have not identified any major issues in years 2015-2019 other than the continued deterioration and aging of assets.

Ultimately, work proposed for 2016 to 2019 is of the same nature as work proposed from 2015. No major change in design standards or planning methodologies that could affect the work program are anticipated.

TABLE 8: 2015-2019 LONG TERM PLAN

Year	Feeder	Station
2015	B4KS	KEELE & ST. CLAIR MS
2015	B3MD	MILLWOOD MS
2015	B1MR	MERTON MS
2015	B2MR	MERTON MS
2015	B4E	CARLAW MS
2015	B8E	CARLAW MS
2015	B1W	WILTSHIRE MS
2015	B2W	WILTSHIRE MS
2015	B3W	WILTSHIRE MS
2015	B2HS	HAMMERSMITH MS
2016	B71DU	DUPONT MS
2016	B10J	JUNCTION MS
2016	B6DU	DUPONT MS
2016	B4DU	DUPONT MS
2016	B3MR	MERTON MS
2016	B5MR	MERTON MS
2016	B4HS	HAMMERSMITH MS
2016	B13E	CARLAW MS

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Distribution System Plan 2015-2019

- 1 The project is on Christie Street and bounded by Davenport Avenue to the north and Dupont
- 2 Street to the south.

/C

Distribution System Plan 2015-2019

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Distribution System Plan 2015-2019

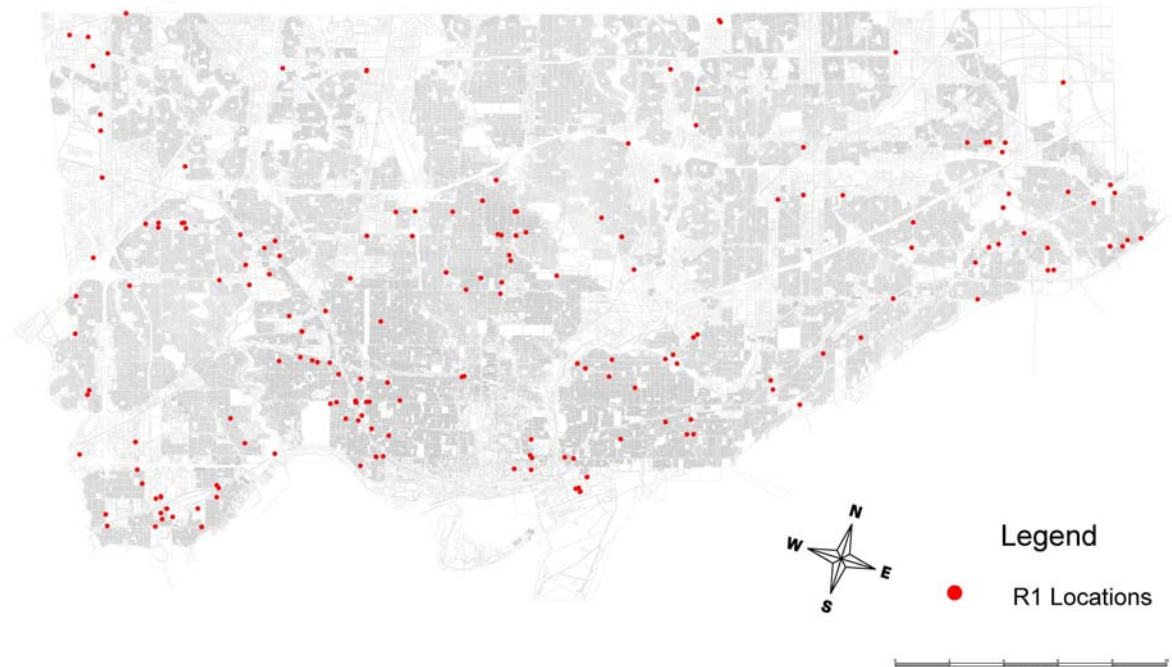


FIGURE 2: MAP OF THE REMAINING SCADA-MATE R1 SWITCHES

Toronto Hydro plans to continue replacing the remaining R1 units with the newer R2 switching units. As explained in section E6.8.3, the design of the SCADA-Mate R2 mitigates the safety risks to field crews and the public associated with operating the SCADA-Mate R1 switches.

Toronto Hydro plans to replace the remaining SCADA-Mate R1 switches from 2015-2017 at a total estimated cost of \$12.96 million. Table 1 summarizes the assets to be replaced within this program.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
R1 Switch	99	67	57	-	-	223
RTU	69	49	14	-	-	132

} /C

This program provides customer value by reducing the duration and frequency of outages and by enabling Toronto Hydro to manage and operate the distribution system more effectively. SCADA-Mate switches are an important feature of the overhead distribution system as they enable the control room to locate a fault on the feeder, isolate the affected sections of the feeder and restore

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Program Index and Name		Description	Total (5 years)
E7.4	Overhead Momentary Reduction	Installation of reclosers to provide flexibility to the system, fault protection and improve the distribution feeder reliability performance by limiting outage times and containing the outage to a minimum area.	\$1.91 M
E7.5	Handwell Upgrades	Replacing the remaining legacy handwells with new standard handwells made from non-conducting composite materials to remove the risk of contact voltage to the public.	\$4.98 M
E7.6	Polymer SMD-20 Fuses	Targets SMD-20 switches that were installed between 2006 and 2011, as breakages inhibit these switches from functioning safely as designed. New switches utilize a fiberglass core that has five times the strength of the previous design. Replacement of the switches eliminates the known safety risk to the public and Toronto Hydro employees.	\$4.84 M
E7.7	Downtown Contingency	Providing distribution load transfer capability between stations in the downtown Toronto area by tying feeders from one station with feeders from an adjacent station. This program addresses a risk in the downtown area where no back-up is provided for certain low probability, high impact events.	\$3.36 M
E7.8	Customer Owned Station Protection	Installation of utility-owned protection devices upstream of customer-owned substations to isolate any faults occurring at customer owned substations.	\$4.04 M
E7.9	Stations Expansion (including HONI contributions)	Upgrades to either Toronto Hydro or Hydro One Networks Inc. owned transformer stations. These upgrades address recent trends in customer connection requirements and loading, by mitigating system limitations imposed by existing station equipment.	\$188 M
E7.10	Local Demand Response	Providing medium-term capacity relief to Cecil TS by implementing a targeted and localized demand response strategy which primarily leverages new and existing demand response resources.	\$4.06 M
E7.11	Energy Storage Systems	To provide a conventional support for local capacity constraints and service reliability issues throughout Toronto Hydro's distribution system. These systems are also categorized as a renewable enabling improvement to accommodate the increasing numbers of renewable energy generation (REG) connections.	\$10.8 M

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- 1 The following Sections E7.1 through to E7.10 contain the details and justification for each capital investment program within the System Service investment category.
- 2

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proximity to, and the loading of, adjacent feeders for each targeted feeder trunk. The SCADA switches utilized in the automation of the Horseshoe area will include overhead and pad-mounted units, depending on whether the segments being tied are overhead or underground. Automation efforts will also include autonomous action of the station breaker in a restoration scenario.

In a number of cases, Toronto Hydro plans to leverage existing overhead SCADA switches, which will only require minor software and communication upgrades to enable desired automation. In cases where existing switches are manually operated, or where the system planners determine that additional new switching nodes are required, new SCADA switches would be installed.

Each SCADA switch requires a remote terminal unit (RTU). RTU's for existing SCADA switches that are currently utilized need to be upgraded so that the switch can operate autonomously. This upgrade consists of a new radio unit, controller faceplate and a software upgrade inside the RTU. The RTUs form an important part of the control and communication infrastructure required for the switches to report remotely and for the automated feeder network to function.

In all, the planned upgrades in the Horseshoe area would improve the operating efficiency of Toronto Hydro's 27.6 kV open loop system and will significantly improve overall system reliability at a low initial investment. Table 1 details the proposed asset installations required for the Horseshoe feeder automation program.

TABLE 1: NEW ASSETS PROPOSED FOR INSTALLATION BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
Overhead SCADA Switches	94	63	64	75	63	384
RTU	93	100	64	69	57	383
RTU Upgrade	16	40	34	68	80	238
Radio & Antenna	112	140	98	137	138	625
Underground SCADA Switches	--	31	12	16	12	71

/C

E7.3.2.2 Downtown Feeder Automation

Feeder automation in the Downtown area targets the underground residential distribution (URD) system, which is an underground configuration unique to the former City of Toronto area. The URD is a looped style system with three distinct feeder levels: a main loop, sub-loops and branch circuits (or sub-sub-loops). The main loop does not serve any customers but is equipped with

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E7.3.7.1 Feeder Automation Scarborough TS Project Description

Investment Category: System Service

Program: Feeder Automation

Project Title: Feeder Automation Scarborough TS

Project Number: E12679, E14387, E14388, E14389, E14390, E14391, E14392, E14393, E14394, E14395, E14396, E14397, E14398, E14399, E14400, E14401

Project Year: 2015

Estimated Cost: \$7.48 million

(i) Objective

The objective of this project is to automate the selected feeders being supplied from Scarborough East TS and expand the network that has been established from Cavangh and Agincourt TS.

(ii) Scope of Work

TABLE 12: SCOPE OF WORK DETAILS

District Neighborhood	SCARBOROUGH
Station(s)	SCARBOROUGH EAST TS
Feeder(s)	5M2, 5M6, 5M8, 5M10, 5M21, 5M22, 5M23, 5M24, 5M25, 5M26, 5M27, 5M29, 5M30

TABLE 13: ASSETS REPLACED

Assets (Units)	2015
SCADA-Mate Switches	62
RTU	63
RTU Upgrade	7
Radio & Antenna	71

IC

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E7.3.7.3 Feeder Automation Etobicoke Project Description

Investment Category: System Service

Program: Feeder Automation

Project Title: Feeder Automation Etobicoke

Project Number: W13379, W13381, W13383, W13384, W13483, W13485

Project Year: 2015

Estimated Cost: \$1.51 million

(i) Objective

The objective of this scope is to automate the selected feeders being supplied from Manby and Horner TS and establish a new network in Etobicoke.

(ii) Scope of Work

TABLE 16: SCOPE OF WORK DETAILS

District Neighborhood	SOUTH ETOBICOKE
Station(s)	MANBY AND HORNER TS
Feeder(s)	30M9, 38M8, 38M5, 38M4

TABLE 17: ASSETS REPLACED

Assets (Units)	2015
SCADA-Mate Switches	18
RTU	16
RTU Upgrade	0
Radio & Antenna	18

/C

E7.6.2 Program Description

The Polymer SMD-20 Switch Renewal program will continue the replacement activities that were initiated as part of the Ontario Energy Board (OEB) approved Polymer SMD-20 Switches segment of Toronto Hydro's 2012-2014 ICM application. The projects to be undertaken under this program are identical in nature to the jobs included in the 2012-2014 filing. Toronto Hydro plans to complete the replacement of defective SMD-20 switches by the end of 2015 at a total cost of \$4.84million. The program will first target switches on feeders with the worst reliability and will then replace the remaining switches. Table 1 shows the number of assets to be replaced by asset class.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Asset (Units)	2015	2016	2017	2018	2019	Total
1-Phase Units	407	-	-	-	-	407
3-Phase Units	751	-	-	-	-	751

} /C

The 1,158 defective switch locations that remain in Toronto Hydro's distribution system are made up of 407 single phase locations and 751 three phase locations (which consist of three switches clustered together). As such, a total of 2,660 discrete SMD-20 switching units is targeted for replacement as part of this program.

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The locations of switches that are scheduled to be replaced are illustrated in Figure 1 below.

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28, 2011), Toronto Hydro (November 9, 2011), Electrical Safety Authority (December 9, 2011) and the manufacturer (November 30, 2011) (See Appendix A). The insulator of the SMD-20 is bolted onto the pole and serves to isolate the live circuit from the pole and to maintain the switch's structure so that it can be operated safely. The nature of the defect causes the insulator to shear while the operating force is applied the switch, meaning that if when switch breaks, pieces of the switch could fall below onto a crew member or could be projected onto property nearby, such as parked cars.

Defective SMD-20s may also arc as the switch breaks apart, potentially causing a flashover – a safety hazard that could subject Toronto Hydro crews to risk of injury. These hazards also extend to any members of the public in the area. As well, the failure of a switch extends outage restoration time as the entire switch must be replaced in order to correct the problem instead of simply replacing the fuse.

As of 2015, Toronto Hydro expects that there will be 2,660 defective switches remaining in the distribution system at 1,158 locations. These defective switches can potentially cause interruptions for up to 26,455 customers, resulting in up to 40,809 CHI as shown in Table 4. On average, each location has the potential to interrupt 23 customers, contributing to 35 CHI. An SMD-20 on a single phase lateral can add an additional two hours of outage time to a lateral fault, while an SMD-20 on a three-phase lateral can add an additional three-and-a-half hours.

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TABLE 4: TOTAL ACCUMULATED RELIABILITY

Switch Type	Accumulated CI	Accumulated CHI
1-Phase	25,704	38,556
3-Phase	751	2,253
Total	26,455	40,809

/C

E7.6.4 Timing & Pacing of the Program

As per the table below, this program is expected to cost \$4.84 million in 2015.

TABLE 5: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX (\$M)	0	0	0	0.84	2.85	4.84	0	0	0	0

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	component is out of service) is defined based on the element with the lowest rating. ▪ Additional capacity will support planned switchgear renewal, where space limitations prevent direct load transfers from old to new equipment. ▪ Lack of spare capacity limits Toronto Hydro's ability to complete maintenance (which in turn increases failure risk) and increases the likelihood of customer outages in the event of an equipment failure.
--	--

Preferred Alternative

Toronto Hydro has identified alternative options to address several issues and evaluated the options based on current and future needs of the system. As an alternative to undertaking capital work, the potential for Conservation and Demand Management (CDM) was evaluated. However, the potential peak reduction achieved through CDM is not sufficient to materially defer or eliminate the need for the capital projects included in this program. Toronto Hydro does plan to undertake a demand reduction program to address future capacity needs at Cecil TS. The details of this program are provided in E7.10 Local Demand Response.

Timing and Pacing

Station Expansion projects generally require material capital investment, involve significant coordination with HONI and are extremely complex to execute. For these reasons, detailed project execution scheduling and feasibility is difficult to estimate until the project is underway.

The timing for projects is driven by system need (i.e., when the forecasted capacity shortfall is expected to materialize) and anticipated project lead times. Delay of the program could result in rotating blackouts, voltage reductions, inability to execute planned work (maintenance or capital) and reduced reliability (due to long feeder lengths that would be required for load transfers).

Table C provides the estimated costs of the program for the 2015-2019 period.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX (\$M)	6.9	32.5	18.6	61.2	79.5	43.8	41.6	36.5	22.0	44.0

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E7.9.2 Program Description

The objective of the Station Expansions program is to address limitations and constraints placed on the distribution system by existing transformer station infrastructure. These constraints fall into one of three categories:

- (1) Forecasted thermal capacity shortfalls due to increasing electricity demand,
- (2) Short circuit current limitation/shortfalls due to forecasted distributed generation (DG) connections, and
- (3) Requirements for additional feeder positions to connect very large customers.

In each case, Toronto Hydro has identified specific projects to mitigate these issues and ensure that the utility can continue fulfilling all of its obligations under the Distribution System Code (DSC). Each issue is described in further detail in the sections below. A summary of the projects included as part of the Stations Expansion program is provided in Table 1.

TABLE 1: SUMMARY OF STATIONS EXPANSION PROJECTS

Description	Station(s) Impacted	Need	Anticipated Project Start	Anticipated Project Finish	Cost (\$M)
Copeland TS – Phase 1 (carry over)	Copeland TS	Capacity	2013	2016	192.9
New Transformer Station in Manby TS area	Horner TS, Manby TS	Capacity	2016	2019	72
Expansion of Runnymede TS	Runnymede TS, Fairbank TS	Capacity	2016	2017	33
Copeland TS - Phase 2	Windsor TS, Esplanade TS (George and Duke MS), Copeland TS	Capacity	2019	2020	46
HONI T12 replacement and upgrade	Strachan TS	Capacity	2018	2018	0.5
Basin TS short circuit upgrades	Basin TS	Short Circuit	2015	2015	2
Bathurst – New Feeder Positions	Bathurst TS	Feeder Positions	2018	2018	1.5

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1 develop the complete scope of such projects, in particular any upstream transmission level work
2 required to enable the project benefits, and move forward towards implementation.

3 South-West Toronto

4 For the south-west Toronto area, Toronto Hydro plans to pursue implementation of two
5 independent solutions. The first solution involves the installation of an additional 27.6 kV load
6 serving bus at Runnymede TS. As this station is owned by HONI, Toronto Hydro has submitted a
7 connection application to HONI to formally identify the need for additional capacity and to request
8 a study to determine feasibility, requisite transmission upgrades and detailed project costs. This
9 request is expected to be addressed once the first phase of the Toronto Regional Plan exercise is
10 complete. The preferred option is the Runnymede TS expansion option as it is expected to
11 provide relief to both Runnymede TS and Fairbank TS load, which is isolated from adjacent
12 stations by the Humber River, Highway 401 and 13.8 kV distribution areas. In parallel, Toronto
13 Hydro also plans to pursue an entirely new transformer station in the existing Manby TS service
14 territory. This transformer station is expected to provide direct capacity relief to Manby TS and
15 Horner TS. Both areas continue to experience the redevelopment of previously vacant land with
16 large condo projects and energy intensive data centres. This new transformer station would be
17 supplied from the 230 kV transmission system, which would reduce the load on the 115 kV lines
18 currently supplying Runnymede TS, Fairbank TS and much of the 13.8 kV distribution system in
19 central Toronto.

20 Downtown Core

21 For the downtown core area encompassing the current (and planned) service territories of
22 Windsor TS, Esplanade TS, George and Duke MS (which is supplied from Esplanade TS) and
23 Copeland TS, Toronto Hydro plans to introduce additional bus and feeder capacity, additional
24 feeder positions and enhanced reliability through Phase 2 of the Copeland TS project. Phase 1,
25 which includes construction of the station facility, installation of the high voltage transmission
26 connections, two power transformers and two busses, is expected to be completed in 2016.
27 Towards the end of the 2015 to 2019 time period, Toronto Hydro anticipates needing Phase 2 to
28 address emerging and future capacity and feeder position shortages anticipated as a result of
29 current growth and planned intensification of currently vacant lands in the area. Toronto Hydro
30 proposes that Phase 2 involve the installation of three power transformers (two load serving, one
31 back up), a transfer bus to enable station to station ties and utilization of the backup transformer,

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TABLE 10: ADDITIONAL STATION-BY-STATION CONSIDERATIONS

Station	Considerations
Esplanade TS and George and Duke MS	- George and Duke MS is supplied by medium voltage express feeders from Esplanade TS. - GD supplies some network load – limits ability to install feeders back to back and thus limits overall availability of feeder positions. - Prime location for new condo or office developments. - Significant potential for redevelopment and load growth – the City of Toronto has developed long term “Precinct Plans” for area near Esplanade TS (West Don Lands, East Bayfront). - Space is available for station expansion. - A1-2GD is a four wire busses approaching 95%, which requires capacity relief in the near future. A1-2X at Esplanade TS is a 3- wire bus and therefore cannot be used to provide relief (although it is nearing 95% capacity as well).
Strachan TS	- Prime location for new condo developments (King West, Liberty Village, etc.). - Potential for generation connections (Exhibition Place, Island MS). - Significant potential for redevelopment and load growth (Exhibition Place). - Replacements of Strachan A5-6T planned, A7-8T in progress. - Space is available for station expansion. - A5-6T and A7-8T are 3-wire busses and cannot accommodate 4-wire load.
Windsor TS	- Current plan is to replace all six switchgear one after another 2015: A5-6 → 2017: A3-4 → 2019: A11-12. - This will reduce overall capacity at the station by 39 to 65 MVA for the foreseeable future. - Station is effectively at capacity due to switchgear replacements, additional loads likely to be connected to Copeland. - Prime location for new condo or office developments. - Capacity on A3-4WR and A5-6WR revised downward by HONI (from 68 to 59 MVA) as a result of an analysis of LTR rating of series reactors. - No space is available for station expansion. - Currently only three of six busses can accommodate new feeder positions.
Copeland TS (Phase 1, 144MVA)	- Will provide support for Windsor TS switchgear replacements. - Energization date of 2016. - Station built with provisions for expansion to 244 MVA. - Transmission connection work completed with Phase 1. - Will primarily service load currently supplied by Windsor TS and new customers (some load will be transferred from Esplanade TS and Terauley TS as well).

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As new load and customers materialize, Toronto Hydro anticipates having to undertake a number of load transfer projects to maintain all 11 busses located in the Windsor / Esplanade / Copeland area that are below 95% of their rated capacity. Based on the load forecast and the system limitations described throughout this section, Toronto Hydro anticipates that after 2023, there will be no feasible options to supply future load/customers. Therefore, additional capacity must be installed and available in the area no later than the end of 2023. Should peak demand growth

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In the event of a contingency (i.e., loss of any single station element due to equipment failure, planned outages, maintenance, etc), Toronto Hydro must have the ability to resupply load through an alternate path. Failure to maintain this arrangement will significantly impact the length of time required to restore power after a station outage, as Toronto Hydro could be forced to wait until the failed equipment can be procured and replaced. Additionally, operating the system at or above its rated capacity compromises Toronto Hydro's ability to isolate critical equipment for planned maintenance or capital work. This limits Toronto Hydro's overall ability to execute its planned work programs as the window of opportunity available in the year gets smaller and smaller due to switching restrictions.

Pending a formal connection request from the customer, Toronto Hydro plans to proceed with this project. The high level estimated cost is \$1.5 million, half of which is expected to be a capital contribution to HONI. Toronto Hydro is anticipating a 2018 in service date.

E7.9.4 Timing & Pacing of the Program

As per the table below, the total estimated cost for the Stations Expansion program over the 2015 to 2019 period is \$187.9 million.

TABLE 16: HISTORICAL SPENDING

Year	Historical Spending					Future Spending				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX (\$M)	6.9	32.5	18.6	61.2	79.5	43.8	41.6	36.5	22.0	44.0

The timing for projects is driven by system need (i.e., when the forecasted capacity shortfall is expected to materialize) and anticipated project lead times. Deferral of the entire program or its parts is likely to result in Toronto Hydro being forced to undertake extremely costly, complex and impractical load transfer projects, or to operate the system in violation of its design parameters (in which case Toronto Hydro would not have sufficient capacity to supply peak load under first contingency). Ultimately, delay of the program could result in rotating blackouts, voltage reductions, inability to execute planned work (maintenance or capital), reduced reliability (due to long feeder lengths that would be required for load transfers).

Future year spending on a project-by-project basis is shown in Table 18.

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TABLE 17: SPENDING BY PROJECT

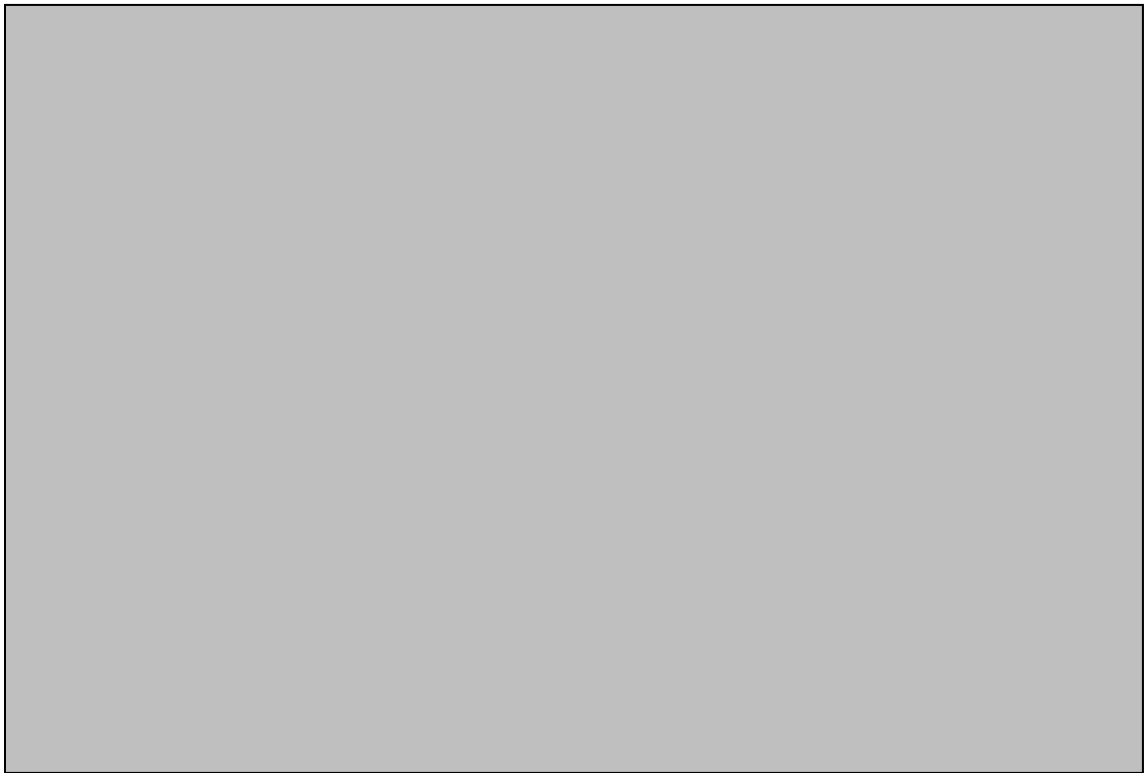
Project	2015	2016	2017	2018	2019	Future
Copeland Phase 1	\$41.8M	\$13.1M	-	-	-	-
New Transformer Station in Manby TS area	-	\$12.0M	\$20.0M	\$20.0M	\$20.0M	-
Expansion of Runnymede TS	-	\$16.5M	\$16.5M	-	-	-
Copeland TS - Phase 2	-	-	-	-	\$24.0M	\$22.0M
HONI T12 replacement and upgrade	-	-	-	\$0.5M	-	-
Basin TS short circuit upgrades	\$2.0M	-	-	-	-	-
Bathurst – New Feeder Positions	-	-	-	\$1.5M	-	-

Construction on Copeland Transformer Station (TS) began in 2013 and is expected to be completed in 2016. Copeland TS is a uniquely challenging project located in the dense urban core of the city. The station design places most of the equipment underground and includes a tunnel connection to HONI's Front Street tunnel. Excavation of the main site began in 2013 and was completed before the end of that year. Presently, civil construction is under way on the project. Cable tunnel mining is complete and concrete placement is ongoing. Major equipment orders were placed in 2013. Manufacturing, factory acceptance testing and delivery of most of the major equipment occurred in 2014 and it is now in secure storage awaiting station readiness for installation.

Initially, Toronto Hydro estimated the Copeland TS (Phase 1) project would be completed by the end of 2014. However, due to several unforeseen events and factors, Toronto Hydro now expects the construction to be completed in the second quarter of 2016. The project's overall cost is expected to remain within the OEB-approved amount; however, the timing of certain portions of those expenditures will shift given the delay to the construction completion date (i.e. some of the 2014 forecast spend is now deferred to 2015 and 2016). The delay is attributable to a variety of factors, including the effect of unusually adverse weather events, a generally harsh winter in 2014, challenging site conditions and contractor performance. Other causes of delay include unforeseen obstructions found on site (not known at time of the RFP or identified in engineering reviews of site records), and delays in securing appropriate permits for certain on-site activities (i.e. lane closure permit for tunnel boring subcontractor).

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26 In addition to Copeland Phase 1, the majority of the remaining historical spending over the 2010
27 to 2014 time period on Station Expansion type work can be attributed to the Leaside-Birch
28 transmission reinforcement project, which involved upgrades to the 115 kV transmission lines
29 between Leaside TS and Wiltshire TS, and installation of additional feeder breakers at various
30 27.6 kV stations to support load growth due to new customer connections. It should also be noted

LOADS, CUSTOMERS AND REVENUE

Toronto Hydro's total load, customer and distribution revenue forecast is summarized in Table 1. The revenue forecast is calculated based on proposed distribution rates, excluding commodity, rate riders, and all other non-distribution rates.

Table 1: Total Load, Revenues and Customers

YEAR		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue (\$M)	Total Customers
2009	Actual	25,572.8	42,754.7	\$475.2	689,399
2010	Actual	25,607.2	43,273.3	\$519.3	696,729
2011	Actual	25,419.0	43,020.2	\$522.2	705,756
2012	Actual	25,639.2	43,544.5	\$527.9	713,093
2013	Actual	25,213.2	42,658.7	\$529.5	724,144
2014	Bridge	25,018.5	42,712.7	\$539.4	736,974
2015	Test	24,993.3	42,697.2	\$655.1	749,679
2016	Test	25,027.4	42,806.2	\$692.8	763,091
2017	Test	24,841.6	42,631.3	\$754.4	773,850
2018	Test	24,696.9	42,584.4	\$810.5	785,107
2019	Test	24,611.4	42,529.2	\$857.8	796,865

Notes:

1. Total Normalized GWh are purchased GWh (before losses), and are weather normalized to the Test Year heating and cooling degree day assumptions.
2. Total Normalized MVA are weather normalized MVA.
3. Total Distribution Revenue is weather normalized and includes an adjustment for the Transformer allowance.
4. Total Customers are as of mid-year and exclude street lighting devices and unmetered load connections.

The detailed load forecasts by rate class are shown at Exhibit 3, Tab 1, Schedule 1, Appendix B. Forecasts of customers by rate class are shown at Exhibit 3, Tab 1, Schedule 1, Appendix C. Forecast of distribution revenues by rate class are shown at Exhibit 3, Tab 1, Schedule 1, Appendix E.

Table 1: Revenues by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	
1																				
2			2009 Board Approved	2009 Actual	2010 Board Approved	2010 Actual	2011 Board Approved	2011 Actual	2012 Board Approved	2012 Actual	2013 Board Approved	2013 Actual	2014 Board Approved	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	
3	Residential	Customer Charge	\$ 125,425,779	\$ 124,940,074	\$ 136,520,338	\$ 136,865,151	\$ 138,422,132	\$ 138,698,105	n/a	\$ 140,362,973	n/a	\$ 135,962,871	n/a	\$ 138,526,315	\$ 169,445,400	\$ 178,330,300	\$ 194,392,979	\$ 208,817,011	\$ 220,757,092	/C
4		Distribution Charge	\$ 77,144,817	\$ 71,970,251	\$ 79,873,771	\$ 81,851,468	\$ 75,798,884	\$ 78,624,727	n/a	\$ 78,214,821	n/a	\$ 76,164,016	n/a	\$ 75,873,988	\$ 92,109,689	\$ 96,591,666	\$ 103,826,062	\$ 110,132,442	\$ 115,299,286	/C
5	Competitive Sector Multi-Unit Residential (CSMUR)	Customer Charge	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	\$ 7,548,650	n/a	\$ 9,201,697	\$ 12,445,354	\$ 15,774,871	\$ 19,408,826	\$ 23,334,753	\$ 27,442,367	/C
6		Distribution Charge	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	\$ 2,203,832	n/a	\$ 4,497,642	\$ 6,075,961	\$ 7,645,347	\$ 9,417,386	\$ 11,315,133	\$ 13,296,204	/C
7	GS <50 kW	Customer Charge	\$ 17,266,106	\$ 17,235,623	\$ 19,438,004	\$ 19,453,474	\$ 19,451,451	\$ 19,714,238	n/a	\$ 19,927,106	n/a	\$ 20,387,603	n/a	\$ 20,786,711	\$ 25,594,485	\$ 26,908,571	\$ 29,308,812	\$ 31,447,065	\$ 33,212,422	/C
8		Distribution Charge	\$ 50,282,354	\$ 43,064,406	\$ 50,609,112	\$ 47,573,889	\$ 48,070,477	\$ 46,861,136	n/a	\$ 47,739,044	n/a	\$ 48,928,777	n/a	\$ 48,947,300	\$ 59,611,837	\$ 62,071,943	\$ 66,068,283	\$ 69,310,888	\$ 71,987,746	/C
9	GS 50-999 kW	Customer Charge	\$ 4,660,902	\$ 4,864,615	\$ 5,300,602	\$ 5,558,497	\$ 5,653,199	\$ 5,557,346	n/a	\$ 5,247,571	n/a	\$ 5,191,170	n/a	\$ 5,279,354	\$ 6,398,645	\$ 6,815,147	\$ 7,514,390	\$ 8,163,522	\$ 8,727,039	/C
10		Distribution Charge	\$ 130,888,593	\$ 134,082,058	\$ 150,096,766	\$ 151,264,158	\$ 152,811,870	\$ 152,298,566	n/a	\$ 149,830,800	n/a	\$ 148,813,053	n/a	\$ 152,151,564	\$ 183,793,699	\$ 193,295,112	\$ 209,107,303	\$ 223,516,879	\$ 235,224,656	/C
11		Transformer Allowance	(3,263,711)	(3,181,459)	(3,319,551)	(3,300,697)	(3,283,350)	(3,586,925)	n/a	(3,618,183)	n/a	(3,563,945)	n/a	(3,571,778)	(3,587,324)	(3,594,720)	(3,578,454)	(3,571,786)	(3,565,882)	/C
12	GS 1000-4999 kW	Customer Charge	\$ 4,550,112	\$ 4,419,606	\$ 4,149,424	\$ 4,086,031	\$ 4,296,929	\$ 4,201,021	n/a	\$ 4,142,557	n/a	\$ 4,351,031	n/a	\$ 3,742,449	\$ 4,452,100	\$ 4,693,251	\$ 5,112,203	\$ 5,486,973	\$ 5,796,894	/C
13		Distribution Charge	\$ 50,520,973	\$ 48,003,988	\$ 45,682,570	\$ 44,995,820	\$ 47,763,803	\$ 47,875,997	n/a	\$ 49,109,344	n/a	\$ 50,562,117	n/a	\$ 49,476,043	\$ 58,330,030	\$ 61,470,766	\$ 66,628,213	\$ 71,401,200	\$ 75,225,034	/C
14		Transformer Allowance	(5,595,547)	(5,358,542)	(5,435,318)	(5,384,155)	(5,219,569)	(5,220,656)	n/a	(5,404,286)	n/a	(5,575,354)	n/a	(5,337,927)	(5,302,746)	(5,325,112)	(5,310,981)	(5,314,965)	(5,312,395)	/C
15	Large Use	Customer Charge	\$ 1,573,308	\$ 1,509,091	\$ 1,643,460	\$ 1,643,460	\$ 1,720,709	\$ 1,830,542	n/a	\$ 1,903,764	n/a	\$ 1,922,073	n/a	\$ 1,793,738	\$ 2,187,330	\$ 2,295,385	\$ 2,545,534	\$ 2,726,015	\$ 2,930,957	/C
16		Distribution Charge	\$ 21,387,047	\$ 21,378,998	\$ 21,612,378	\$ 22,889,314	\$ 24,002,088	\$ 26,155,908	n/a	\$ 26,757,753	n/a	\$ 26,213,693	n/a	\$ 26,348,106	\$ 31,089,485	\$ 32,659,873	\$ 35,325,690	\$ 37,788,405	\$ 39,778,312	/C
17		Transformer Allowance	(3,254,452)	(3,207,880)	(2,963,777)	(3,145,318)	(2,976,922)	(3,217,346)	n/a	(3,358,865)	n/a	(3,272,558)	n/a	(3,222,780)	(3,183,523)	(3,186,889)	(3,171,749)	(3,168,202)	(3,163,878)	/C
18	Street Lighting	Service Charge (per device)	\$ 1,759,059	\$ 1,756,561	\$ 2,607,396	\$ 2,617,202	\$ 2,574,590	\$ 2,579,240	n/a	\$ 2,581,438	n/a	\$ 2,604,738	n/a	\$ 2,631,030	\$ 2,635,414	\$ 2,779,788	\$ 3,024,785	\$ 3,230,430	\$ 3,416,659	/C
19		Distribution Charge	\$ 6,360,852	\$ 6,432,436	\$ 9,514,299	\$ 9,538,348	\$ 9,378,515	\$ 9,391,867	n/a	\$ 9,399,435	n/a	\$ 9,503,477	n/a	\$ 9,630,523	\$ 9,645,892	\$ 10,138,149	\$ 11,035,260	\$ 11,836,160	\$ 12,495,777	/C
20	Unmetered Scattered Load	Cust/Conn Charge	\$ 132,004	\$ 136,119	\$ 199,795	\$ 140,231	\$ 196,064	\$ 135,053	n/a	\$ 120,852	n/a	\$ 122,186	n/a	\$ 125,269	\$ 155,273	\$ 162,828	\$ 177,502	\$ 189,986	\$ 200,169	/C
21		Distribution Charge	\$ 2,396,711	\$ 2,354,719	\$ 3,191,971	\$ 3,173,342	\$ 3,413,257	\$ 2,595,490	n/a	\$ 2,497,342	n/a	\$ 2,520,591	n/a	\$ 2,548,149	\$ 3,154,440	\$ 3,319,401	\$ 3,597,436	\$ 3,852,868	\$ 4,060,997	/C
22	Total	Customer Charge	\$ 155,367,270	\$ 154,861,689	\$ 169,859,019	\$ 170,364,047	\$ 172,315,074	\$ 172,715,544	n/a	\$ 174,286,262	n/a	\$ 178,090,321	n/a	\$ 182,086,563	\$ 223,314,000	\$ 237,760,141	\$ 261,485,031	\$ 283,395,755	\$ 302,483,599	/C
23		Distribution Charge	\$ 338,981,346	\$ 327,286,857	\$ 360,580,867	\$ 361,286,339	\$ 361,238,894	\$ 363,803,690	n/a	\$ 363,548,540	n/a	\$ 364,909,555	n/a	\$ 369,473,316	\$ 443,811,034	\$ 467,192,257	\$ 505,005,632	\$ 539,153,974	\$ 567,368,012	/C
24		Transformer Allowance	(12,113,709)	(11,747,881)	(11,718,646)	(11,830,170)	(11,479,841)	(12,024,926)	n/a	(12,381,333)	n/a	(12,411,857)	n/a	(12,132,485)	(12,073,593)	(12,106,720)	(12,061,183)	(12,054,953)	(12,042,156)	/C
25																				
26	Total Distribution Revenue		\$ 482,234,908	\$ 470,400,665	\$ 518,721,240	\$ 519,820,216	\$ 522,074,126	\$ 524,494,308	n/a	\$ 525,453,469	n/a	\$ 530,588,019	n/a	\$ 539,427,394	\$ 655,051,441	\$ 692,845,678	\$ 754,429,480	\$ 810,494,775	\$ 857,809,455	/C
27	Notes																			
28	1. Based on Approved rates for each rate year																			
29	2. CSMUR rate class implementation date - Jun 01, 2013. Prior years were included in Residential class.																			

Table 1: Weather-normalized Revenues by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	
1																				
2			2009 Board Approved	2009 Actuals	2010 Board Approved	2010 Actual	2011 Board Approved	2011 Actual	2012 Board Approved	2012 Actual	2013 Board Approved	2013 Actual	2014 Board Approved	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	
3	Residential	Customer Charge	\$ 125,425,779	\$ 124,940,074	\$ 136,520,338	\$ 136,865,151	\$ 138,422,132	\$ 138,698,105	n/a	\$ 140,362,973	n/a	\$ 135,962,871	n/a	\$ 138,526,315	\$ 169,445,400	\$ 178,330,300	\$ 194,392,979	\$ 208,817,011	\$ 220,757,092	/C
4		Distribution Charge	\$ 79,128,358	\$ 73,954,741	\$ 79,465,765	\$ 81,443,462	\$ 74,931,254	\$ 77,757,097	n/a	\$ 78,516,418	n/a	\$ 75,960,256	n/a	\$ 75,873,988	\$ 92,109,689	\$ 96,591,666	\$ 103,826,062	\$ 110,132,442	\$ 115,299,286	/C
5	Competitive Sector Multi-Unit Residential (CSMUR)	Customer Charge	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	\$ 7,548,650	n/a	\$ 9,201,697	\$ 12,445,354	\$ 15,774,871	\$ 19,408,826	\$ 23,334,753	\$ 27,442,367	/C
6		Distribution Charge	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	\$ 2,203,832	n/a	\$ 4,497,642	\$ 6,075,961	\$ 7,645,347	\$ 9,417,386	\$ 11,315,133	\$ 13,296,204	/C
7	GS <50 kW	Customer Charge	\$ 17,266,106	\$ 17,235,623	\$ 19,438,004	\$ 19,453,474	\$ 19,451,451	\$ 19,714,238	n/a	\$ 19,927,106	n/a	\$ 20,387,603	n/a	\$ 20,786,711	\$ 25,594,485	\$ 26,908,571	\$ 29,308,812	\$ 31,447,065	\$ 33,212,422	/C
8		Distribution Charge	\$ 50,964,660	\$ 43,747,038	\$ 50,530,656	\$ 47,495,433	\$ 47,706,409	\$ 46,497,068	n/a	\$ 48,143,141	n/a	\$ 48,745,938	n/a	\$ 48,947,300	\$ 59,611,837	\$ 62,071,943	\$ 66,068,283	\$ 69,310,888	\$ 71,987,746	/C
9	GS 50-999 kW	Customer Charge	\$ 4,660,902	\$ 4,864,615	\$ 5,300,602	\$ 5,558,497	\$ 5,653,199	\$ 5,557,346	n/a	\$ 5,247,571	n/a	\$ 5,191,170	n/a	\$ 5,279,354	\$ 6,398,645	\$ 6,815,147	\$ 7,514,390	\$ 8,163,522	\$ 8,727,039	/C
10		Distribution Charge	\$ 132,526,828	\$ 135,796,015	\$ 149,998,264	\$ 151,172,876	\$ 151,961,388	\$ 151,509,833	n/a	\$ 151,059,744	n/a	\$ 148,294,977	n/a	\$ 152,151,564	\$ 183,793,699	\$ 193,295,112	\$ 209,107,303	\$ 223,516,879	\$ 235,224,656	/C
11		Tranformer Allowance	(3,304,560)	(3,223,774)	(3,317,373)	(3,299,101)	(3,265,076)	(3,570,178)	n/a	(3,647,641)	n/a	(3,551,895)	n/a	(3,571,778)	(3,587,324)	(3,594,720)	(3,578,454)	(3,571,786)	(3,565,882)	/C
12	GS 1000-4999 kW	Customer Charge	\$ 4,550,112	\$ 4,419,606	\$ 4,149,424	\$ 4,086,031	\$ 4,296,929	\$ 4,201,021	n/a	\$ 4,142,557	n/a	\$ 4,351,031	n/a	\$ 3,742,449	\$ 4,452,100	\$ 4,693,251	\$ 5,112,203	\$ 5,486,973	\$ 5,796,894	/C
13		Distribution Charge	\$ 50,872,050	\$ 48,362,568	\$ 45,706,941	\$ 45,015,926	\$ 47,560,758	\$ 47,686,318	n/a	\$ 49,550,679	n/a	\$ 50,386,320	n/a	\$ 49,476,043	\$ 58,330,030	\$ 61,470,766	\$ 66,628,213	\$ 71,401,200	\$ 75,225,034	/C
14		Tranformer Allowance	(5,634,431)	(5,399,531)	(5,438,218)	(5,386,664)	(5,197,381)	(5,199,455)	n/a	(5,450,082)	n/a	(5,556,139)	n/a	(5,337,927)	(5,302,746)	(5,325,112)	(5,310,981)	(5,314,965)	(5,312,395)	/C
15	Large Use	Customer Charge	\$ 1,573,308	\$ 1,509,091	\$ 1,643,460	\$ 1,643,460	\$ 1,720,709	\$ 1,830,542	n/a	\$ 1,903,764	n/a	\$ 1,922,073	n/a	\$ 1,793,738	\$ 2,187,330	\$ 2,295,385	\$ 2,545,534	\$ 2,726,015	\$ 2,930,957	/C
16		Distribution Charge	\$ 21,528,604	\$ 21,531,890	\$ 21,622,152	\$ 22,897,102	\$ 23,912,192	\$ 26,061,123	n/a	\$ 26,974,645	n/a	\$ 26,125,976	n/a	\$ 26,348,106	\$ 31,089,485	\$ 32,659,873	\$ 35,325,690	\$ 37,788,405	\$ 39,778,312	/C

Table 1: Variances - Revenues by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	
1															
2			2010 Actual (norm) vs 2009 Actual (norm)	2011 Actual (norm) vs 2010 Actual (norm)	2011 Actual vs 2011 Board Approved	2011 Actual (norm) vs 2011 Board Approved (norm)	2012 Actual (norm) vs 2011 Actual (norm)	2013 Actual (norm) vs 2012 Actual (norm)	2014 Bridge Year vs 2013 Actual (norm)	2015 Test Year vs 2014 Bridge Year	2016 Test Year vs 2015 Test Year	2017 Test Year vs 2016 Test Year	2018 Test Year vs 2017 Test Year	2019 Test Year vs 2018 Test Year	
3	Residential	Customer Charge	\$ 11,925,077	\$ 1,832,954	\$ 275,973	\$ 275,973	\$ 1,664,868	-\$ 4,400,102	\$ 2,563,444	\$ 30,919,086	\$ 8,884,900	\$ 16,062,679	\$ 14,424,032	\$ 11,940,081	/C
4		Distribution Charge	\$ 7,488,721	-\$ 3,686,364	\$ 2,825,843	\$ 2,825,843	\$ 759,320	-\$ 2,556,161	-\$ 86,268	\$ 16,235,701	\$ 4,481,977	\$ 7,234,396	\$ 6,306,380	\$ 5,166,845	/C
5	Competitive Sector Multi-Unit Residential (CSMUR)	Customer Charge	n/a	n/a	n/a	n/a	n/a	\$ 7,548,650	\$ 1,653,047	\$ 3,243,657	\$ 3,329,517	\$ 3,633,955	\$ 3,925,927	\$ 4,107,613	/C
6		Distribution Charge	n/a	n/a	n/a	n/a	n/a	\$ 2,203,832	\$ 2,293,809	\$ 1,578,319	\$ 1,569,387	\$ 1,772,039	\$ 1,897,746	\$ 1,981,071	/C
7	GS <50 kW	Customer Charge	\$ 2,217,851	\$ 260,763	\$ 262,787	\$ 262,787	\$ 212,868	\$ 460,497	\$ 399,109	\$ 4,807,774	\$ 1,314,086	\$ 2,400,240	\$ 2,138,254	\$ 1,765,357	/C
8		Distribution Charge	\$ 3,748,395	-\$ 998,365	-\$ 1,209,341	-\$ 1,209,341	\$ 1,646,073	\$ 602,798	\$ 201,362	\$ 10,664,537	\$ 2,460,106	\$ 3,996,340	\$ 3,242,605	\$ 2,676,859	/C
9	GS 50-999 kW	Customer Charge	\$ 693,882	-\$ 1,151	-\$ 95,852	-\$ 95,852	-\$ 309,775	-\$ 56,402	\$ 88,184	\$ 1,119,291	\$ 416,502	\$ 699,243	\$ 649,131	\$ 563,518	/C
10		Distribution Charge	\$ 15,376,861	\$ 336,958	-\$ 513,303	-\$ 451,555	-\$ 450,089	-\$ 2,764,767	\$ 3,856,587	\$ 31,642,136	\$ 9,501,413	\$ 15,812,191	\$ 14,409,575	\$ 11,707,777	/C
11		Tranformer Allowance	-\$ 75,326	-\$ 271,077	-\$ 303,575	-\$ 305,102	-\$ 77,463	\$ 95,745	-\$ 19,882	-\$ 15,546	-\$ 7,397	\$ 16,267	\$ 6,668	\$ 5,903	/C
12	GS 1000-4999 kW	Customer Charge	-\$ 333,574	\$ 114,989	-\$ 95,908	-\$ 95,908	-\$ 58,464	\$ 208,473	-\$ 608,582	\$ 709,651	\$ 241,151	\$ 418,952	\$ 374,770	\$ 309,921	/C
13		Distribution Charge	-\$ 3,346,641	\$ 2,670,391	\$ 112,193	\$ 125,559	\$ 1,864,361	\$ 835,641	-\$ 910,276	\$ 8,853,987	\$ 3,140,735	\$ 5,157,447	\$ 4,772,987	\$ 3,823,834	/C
14		Tranformer Allowance	\$ 12,868	\$ 187,209	-\$ 1,086	-\$ 2,074	-\$ 250,627	-\$ 106,057	\$ 218,212	\$ 35,180	-\$ 22,365	\$ 14,130	-\$ 3,984	\$ 2,571	/C
15	Large Use	Customer Charge	\$ 134,369	\$ 187,081	\$ 109,833	\$ 109,833	\$ 73,222	\$ 18,309	-\$ 128,334	\$ 393,591	\$ 108,055	\$ 250,150	\$ 180,480	\$ 204,942	/C
16		Distribution Charge	\$ 1,365,212	\$ 3,164,020	\$ 2,153,820	\$ 2,148,931	\$ 913,522	-\$ 848,669	\$ 222,130	\$ 4,741,378	\$ 1,570,388	\$ 2,665,817	\$ 2,462,716	\$ 1,989,906	/C
17		Tranformer Allowance	\$ 84,402	-\$ 59,123	-\$ 240,424	-\$ 239,814	-\$ 180,252	\$ 124,255	\$ 38,803	\$ 39,258	-\$ 3,366	\$ 15,140	\$ 3,547	\$ 4,324	/C
18	Street Lighting	Service Charge (per device)	\$ 860,640	-\$ 37,962	\$ 4,650	\$ 4,650	\$ 2,199	\$ 23,300	\$ 26,291	\$ 4,384	\$ 144,374	\$ 244,997	\$ 205,645	\$ 186,230	/C
19		Distribution Charge	\$ 3,105,912	-\$ 146,482	\$ 13,352	\$ 13,352	\$ 7,569	\$ 104,041	\$ 127,047	\$ 15,369	\$ 492,257	\$ 897,111	\$ 800,900	\$ 659,616	/C
20	Unmetered Scattered Load	Cust/Conn Charge	\$ 4,112	-\$ 5,178	-\$ 61,011	-\$ 61,011	-\$ 14,200	\$ 1,334	\$ 3,083	\$ 30,003	\$ 7,556	\$ 14,674	\$ 12,483	\$ 10,183	/C
21		Distribution Charge	\$ 818,623	-\$ 577,852	-\$ 817,768	-\$ 817,768	-\$ 98,148	\$ 23,249	\$ 27,559	\$ 606,291	\$ 164,961	\$ 278,034	\$ 255,432	\$ 208,130	/C
22	Total	Customer Charge	\$ 15,502,358	\$ 2,351,497	\$ 400,471	\$ 400,471	\$ 1,570,718	\$ 3,804,060	\$ 3,996,242	\$ 41,227,437	\$ 14,446,141	\$ 23,724,890	\$ 21,910,723	\$ 19,087,844	/C
23		Distribution Charge	\$ 28,557,084	\$ 762,306	\$ 2,564,796	\$ 2,635,021	\$ 4,642,608	-\$ 2,400,037	\$ 5,731,949	\$ 74,337,718	\$ 23,381,223	\$ 37,813,375	\$ 34,148,341	\$ 28,214,039	/C
24		Transformer Allowance	\$ 21,944	-\$ 142,991	-\$ 545,085	-\$ 546,990	-\$ 508,342	\$ 113,944	\$ 237,133	\$ 58,892	-\$ 33,128	\$ 45,537	\$ 6,230	\$ 12,797	/C
25															
26	Total Distribution Revenue		\$ 44,081,385	\$ 2,970,811	\$ 2,420,182	\$ 2,488,502	\$ 5,704,984	\$ 1,517,967	\$ 9,965,324	\$ 115,624,047	\$ 37,794,237	\$ 61,583,802	\$ 56,065,295	\$ 47,314,680	/C
27	Notes														
28	1. Based on Approved rates for each rate year except for test years														
	2. Test years based on proposed rates for each rate year														
29	3. CSMUR rate class implementation date - Jun 01, 2013. Prior years were included in Residential class.														

Table 1: Summary of Depreciation Expense

OEB	Description	2011 CGAAP	2012 UGAAP	2013 UGAAP	2014 UGAAP			2014 MIFRS				2015 MIFRS		
		Total Depreciation Expense	Total Depreciation Expense	Total Depreciation Expense	Depreciation Expense	Transfers	Total Depreciation Expense	Depreciation Expense	Transfers	Derecognition	Total Depreciation Expense	Depreciation Expense	Derecognition	Total Depreciation Expense
1611	Computer Software (Formally known as Account 1925)	\$ 24,893,304	\$ 20,224,259	\$ 17,210,554	\$ 19,182,023	(\$ 17,128)	\$ 19,164,895	\$ 19,182,937	(\$ 17,170)	\$ -	\$ 19,165,768	\$ 21,011,750	\$ -	\$ 21,011,750
1612	Land Rights	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 89,423	\$ -	\$ -	\$ 89,423	\$ 89,423	\$ -	\$ 89,423
1805	Land	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
1808	Buildings	\$ 1,550,177	\$ 1,495,626	\$ 1,866,209	\$ 2,023,489	(\$ 316,955)	\$ 1,706,533	\$ 2,034,879	(\$ 316,976)	\$ -	\$ 1,717,903	\$ 2,164,056	\$ -	\$ 2,164,056
1815	Transformer Station Equipment >50 kV	\$ 380,940	\$ 402,730	\$ 404,101	\$ 410,092	(\$ 3,623)	\$ 406,469	\$ 410,099	(\$ 3,630)	\$ -	\$ 406,469	\$ 433,082	\$ 38,849	\$ 471,931
1820	Distribution Station Equipment <50 kV	\$ 7,083,676	\$ 6,499,970	\$ 6,699,017	\$ 7,040,253	(\$ 342,531)	\$ 6,697,722	\$ 7,040,476	(\$ 342,783)	\$ 78,054	\$ 6,775,747	\$ 8,071,762	\$ 82,859	\$ 8,154,621
1830	Poles, Towers & Fixtures	\$ 5,824,614	\$ 6,469,781	\$ 6,883,833	\$ 7,596,852	(\$ 603,230)	\$ 6,993,622	\$ 7,597,440	(\$ 603,611)	\$ 9,218,952	\$ 16,212,780	\$ 9,383,299	\$ 12,792,932	\$ 22,176,231
1835	Overhead Conductors & Devices	\$ 4,341,875	\$ 5,152,543	\$ 5,922,635	\$ 6,901,315	(\$ 518,672)	\$ 6,382,643	\$ 6,906,901	(\$ 519,020)	\$ 2,422,530	\$ 8,810,411	\$ 8,010,517	\$ 2,404,482	\$ 10,414,999
1840	Underground Conduit	\$ 31,948,117	\$ 32,737,980	\$ 34,220,426	\$ 36,940,621	(\$ 2,658,269)	\$ 34,282,352	\$ 36,952,150	(\$ 2,660,137)	\$ 324,832	\$ 34,616,844	\$ 40,909,577	\$ -	\$ 40,909,577
1845	Underground Conductors & Devices	\$ 13,844,464	\$ 14,554,813	\$ 16,600,725	\$ 17,590,134	(\$ 1,777,485)	\$ 15,812,649	\$ 17,441,988	(\$ 1,777,944)	\$ 3,266,345	\$ 18,930,388	\$ 18,874,495	\$ 6,327,408	\$ 25,201,903
1850	Line Transformers	\$ 21,426,917	\$ 20,415,257	\$ 21,501,170	\$ 22,171,293	(\$ 1,181,371)	\$ 20,989,923	\$ 22,237,759	(\$ 1,181,907)	\$ 9,507,212	\$ 30,563,065	\$ 22,574,248	\$ 9,755,037	\$ 32,329,284
1855	Services (Overhead & Underground)	\$ 1,433,856	\$ 1,552,305	\$ 1,651,822	\$ 1,874,227	(\$ 154,401)	\$ 1,719,826	\$ 1,874,323	(\$ 154,539)	\$ -	\$ 1,719,784	\$ 2,235,152	\$ 446	\$ 2,235,598
1860	Meters	\$ 9,162,626	\$ 9,461,636	\$ 9,864,020	\$ 12,464,057	(\$ 139,433)	\$ 12,324,624	\$ 12,464,374	(\$ 139,514)	\$ -	\$ 12,324,860	\$ 13,258,376	\$ 546,556	\$ 13,804,932
1905	Land	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
1908	Buildings & Fixtures	\$ 6,395,106	\$ 5,597,338	\$ 5,715,814	\$ 6,377,509	(\$ 143)	\$ 6,377,366	\$ 6,377,517	(\$ 143)	\$ 12,500	\$ 6,389,874	\$ 6,162,152	\$ 596,416	\$ 6,758,568
1910	Leasehold Improvements	\$ 5,993,705	\$ 604,412	\$ 284,866	\$ 314,340	\$ -	\$ 314,340	\$ 314,340	\$ -	\$ -	\$ 314,340	\$ 305,716	\$ -	\$ 305,716
1915	Office Furniture & Equipment	\$ 1,452,357	\$ 1,695,701	\$ 2,321,386	\$ 2,128,106	\$ -	\$ 2,128,106	\$ 2,128,107	\$ -	\$ 357	\$ 2,128,464	\$ 1,988,900	\$ 12,017	\$ 2,000,917
1920	Computer Equipment - Hardware	\$ 4,373,915	\$ 4,401,165	\$ 4,595,199	\$ 7,028,006	(\$ 16,303)	\$ 7,011,702	\$ 7,028,569	(\$ 16,343)	\$ -	\$ 7,012,227	\$ 12,430,692	\$ -	\$ 12,430,692
1930	Transportation Equipment	\$ 7,074,141	\$ 7,499,760	\$ 7,148,702	\$ 6,558,032	(\$ 218)	\$ 6,557,814	\$ 6,558,138	(\$ 218)	\$ -	\$ 6,557,920	\$ 6,376,745	\$ -	\$ 6,376,745
1935	Stores Equipment	\$ 7,709	\$ 7,709	\$ 7,709	\$ 7,066	\$ -	\$ 7,066	\$ 7,066	\$ -	\$ -	\$ 7,066	\$ -	\$ -	\$ -
1940	Tools, Shop & Garage Equipment	\$ 1,924,584	\$ 2,006,371	\$ 2,188,127	\$ 2,216,738	\$ -	\$ 2,216,738	\$ 2,216,753	\$ -	\$ -	\$ 2,216,753	\$ 2,220,076	\$ -	\$ 2,220,076
1945	Measurement & Testing Equipment	\$ 1,086,963	\$ 2,061,676	\$ 2,081,814	\$ 2,032,666	\$ -	\$ 2,032,666	\$ 2,032,667	\$ -	\$ -	\$ 2,032,667	\$ 2,028,389	\$ -	\$ 2,028,389
1955	Communications Equipment	\$ 2,899,180	\$ 2,684,558	\$ 1,901,560	\$ 1,855,881	\$ -	\$ 1,855,881	\$ 1,855,881	\$ -	\$ -	\$ 1,855,881	\$ 1,924,002	\$ -	\$ 1,924,002
1960	Miscellaneous Equipment	\$ 25,285	\$ 36,918	\$ 36,918	\$ 36,918	\$ -	\$ 36,918	\$ 36,918	\$ -	\$ -	\$ 36,918	\$ 37,146	\$ -	\$ 37,146
1970	Load Management Controls Customer Premises	\$ 1,025,729	\$ 1,082,077	\$ 1,082,077	\$ 1,082,077	\$ -	\$ 1,082,077	\$ 1,082,077	\$ -	\$ -	\$ 1,082,077	\$ 1,070,206	\$ -	\$ 1,070,206
1975	Load Management Controls Utility Premises	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
1980	System Supervisor Equipment	\$ 1,763,841	\$ 1,761,636	\$ 1,814,662	\$ 2,048,691	(\$ 72,158)	\$ 1,976,533	\$ 2,048,748	(\$ 72,168)	\$ 904,959	\$ 2,881,540	\$ 2,137,803	\$ 1,375,389	\$ 3,513,193
1995	Contributions & Grants	(\$ 8,200,745)	(\$ 9,011,788)	(\$ 9,836,203)	(\$ 10,351,884)	\$ 18,199	(\$ 10,333,685)	(\$ 10,369,809)	\$ 18,239	\$ -	(\$ 10,351,570)	(\$ 10,852,528)	\$ -	(\$ 10,852,528)
1609	Capital Contributions Paid	\$ 916,010	\$ 734,850	\$ 901,706	\$ 955,031	\$ 36,296	\$ 991,327	\$ 955,180	\$ 36,296	\$ -	\$ 991,476	\$ 1,150,182	\$ -	\$ 1,150,182
2005	Property Under Capital Leases	\$ -	\$ -	\$ -	\$ 1,712,109	\$ -	\$ 1,712,109	\$ 1,712,109	\$ -	\$ -	\$ 1,712,109	\$ 190,234	\$ -	\$ 190,234
		\$ 148,628,347	\$ 140,129,282	\$ 143,068,846	\$ 158,195,645	(\$ 7,747,425)	\$ 150,448,220	\$ 158,217,010	(\$ 7,751,568)	\$ 25,735,741	\$ 176,201,183	\$ 174,185,452	\$ 33,932,393	\$ 208,117,844

Less: Fully Allocated Depreciation

Transportation	(\$ 2,189,844)	(\$ 1,620,301)	(\$ 2,314,931)	(\$ 2,342,979)	\$ -	(\$ 2,342,979)	(\$ 2,342,979)	\$ -		(\$ 2,342,979)	(\$ 1,671,045)		(\$ 1,671,045)
Stores Equipment				\$ -	\$ -	\$ -	\$ -	\$ -		\$ -	\$ -		\$ -
Net Depreciation as per Appendix 2-BA	\$ 146,438,503	\$ 138,508,981	\$ 140,753,915	\$ 155,852,666	(\$ 7,747,425)	\$ 148,105,240	\$ 155,874,031	(\$ 7,751,568)	\$ 25,735,741	\$ 173,858,204	\$ 172,514,406	\$ 33,932,393	\$ 206,446,799

Other Reconciling Items:

Less: 2014 Derecognition in transition year transferred to 1575: IFRS-UGAAP Transitional PPE Amounts													
Add: Stranded Meter Depreciation													
Add: Smart Meter Clearance													
Total Depreciation Expense	\$ 146,438,503	\$ 138,508,981	\$ 169,486,980				\$ 150,577,644			(\$ 25,735,741)	\$ 2,472,404		\$ 206,446,799

CORPORATE TAXES (PILs)

1. INTRODUCTION

The Revenue Requirement filed at Exhibit 6, Tab 1, Schedule 1 of this Application reflects amounts for Payments in Lieu of Taxes (“PILs”) recovery of \$24,045,463 /C (excluding investment tax credits of \$2,000,000 reallocated to OM&A), for the 2015 Test Year. The 2015 PILs tax models are filed at Exhibit 4B, Tab 2, Schedule 2.¹

2. PRUDENT MANAGEMENT OF PILS/TAXES

The amount of PILs paid by Toronto Hydro in any given year is strongly correlated with its net income. Toronto Hydro manages its tax costs diligently in an effort to keep the effective rate of tax as low as possible. A dedicated group of tax personnel administers Toronto Hydro’s taxes and helps ensure that the PILs are managed prudently. Where it can, Toronto Hydro takes advantage of available tax deductions and tax credits, such as research and development tax credits, to minimize its tax burden.

3. METHODOLOGY

The methodology for calculating PILs is consistent with the principles set out in Chapter 2 of the OEB’s Filing Requirements, and reflects appropriate legislative changes that have been enacted, such as changes to corporate tax rates and capital cost allowance rates. Toronto Hydro confirms that non-recoverable expenses and expenses disallowed for regulatory purposes have been excluded from the regulatory tax calculation.

4. DISCLOSURE OF PILS TAX ADMINISTRATION AND TAX RULINGS

Toronto Hydro has not received any specific tax rulings that are inconsistent with Toronto Hydro’s previously filed and approved tax model except for reassessments received in respect of post employment benefit plan costs. Toronto Hydro amended its tax returns for the years 2006 to 2010 in respect of its tax treatment of post employment

¹ The formatting of Toronto Hydro’s PILs model for the 2015 test year differs from the OEB model.

- 1 • Schedule 8 of the most recent tax return filed with the application has a closing
2 December 31st historic year UCC that agrees with the opening bridge year UCC
3 at January 1st. A reconciliation has been provided to remove the non distribution
4 amounts in Exhibit 4B, Tab 2, Schedule 2;
- 5 • The CCA deductions in the application's PILs tax model for historical, bridge and
6 test years agree with the numbers in Schedule 8;
- 7 • Accounting OPEB and pension amounts added back on Schedule 1;
- 8 • Reconciliation of accounting income to net income for tax purposes, agree with
9 the OM&A analysis for compensation and are reasonable when compared with
10 the notes to the audited financial statements, and the actuarial valuations; and
- 11 • The income tax rate used to calculate the tax expense is consistent with the
12 current legislated rate.

13

14 **17. TAX PAYABLE FILINGS**

15 Details of actual taxes paid by Toronto Hydro from 2008 to 2013, as well as the
16 forecasted taxes to be paid for 2014, are outlined in the tables below. Explanations of the
17 variances for the forecasted years are also provided. Tax return copies for the historical
18 year 2013 are in Exhibit 4B, Tab 2, Schedule 3.

19

20 **Table 1: Summary of PILs by Year (\$ Millions)**

	2008 Historic	2009 Historic	2010 Historic	2011 Historic	2012 Historic	2013 Historic	2014 Bridge	2015 Test
Income Taxes	28.21	17.56	17.89	9.44	3.62	7.99	9.52	24.05
Capital Tax	5.50	5.58	2.06	-	-	-	-	-
Total PILs	33.71	23.14	19.95	9.44	3.62	7.99	9.52	24.05

/C

/C

1 **17.1. 2013 to 2014**

2 The increase in PILs of approximately \$1.53 million is mainly due to differences between /C
3 the tax and book treatment of various costs.

4

5 **17.2. 2014 to 2015**

6 The increase in PILs of approximately \$14.53 million is mainly attributable to increased /C
7 return on a larger capital base and differences between the tax and book treatment of
8 various costs.

9

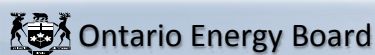
10 **18. PROPERTY TAX**

11 Property taxes are included in the Facilities Management program (Exhibit 4A, Tab 2,
12 Schedule 11).

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited Table of Contents

<u>1. Info</u>		<u>I. Schedule 8 CCA Bridge Year</u>	/C	<u>O. Schedule 8 CCA Test Year</u>	/C
<u>A. Data Input Sheet</u>	/C	<u>J. Schedule 10 CEC Bridge Year</u>	/C	<u>P. Schedule 10 CEC Test Year</u>	/C
<u>B. Tax Rates & Exemptions</u>		<u>K. Sch 13 Tax Reserves Bridge</u>		<u>Q. Sch 13 Tax Reserve Test Year</u>	
<u>C. Sch 8 Hist</u>		<u>L. Sch 7-1 Loss Cfwd Bridge</u>		<u>R. Sch 7-1 Loss Cfwd Test Year</u>	
<u>D. Schedule 10 CEC Hist</u>		<u>M. Adj. Taxable Income Bridge</u>	/C	<u>S. Taxable Income Test Year</u>	/C
<u>E. Sch 13 Tax Reserves Hist</u>		<u>Sch 7-3 Interest Bridge</u>	/C	<u>Sch 7-3 Interest Test Year</u>	/C
<u>F. Sch 7-1 Loss Cfwd Hist</u>		<u>N. PILs, Tax Provision Bridge</u>	/C	<u>T. PILs, Tax Provision Test Year</u>	/C
<u>G. Adj. Taxable Income Historic</u>					
<u>H. PILS, Tax Provision Historic</u>					



Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited Data Input Sheet - Applicant's Rate Base

Rate Base

\$ 3,247,562,846

Return on Ratebase

Deemed ShortTerm Debt %	4.00%	T	\$	129,902,514	$W = S * T$
Deemed Long Term Debt %	56.00%	U	\$	1,818,635,194	$X = S * U$
Deemed Equity %	40.00%	V	\$	1,299,025,138	$Y = S * V$
Short Term Interest Rate	1.38%	Z	\$	1,792,655	$AC = W * Z$
Long Term Interest	4.31%	AA	\$	78,383,177	$AD = X * AA$
Return on Equity (Regulatory Income)	9.30%	AB	\$	120,809,338	$AE = Y * AB$
Return on Rate Base			\$	200,985,169	$AF = AC + AD + AE$

Questions that must be answered

- Does the applicant have any Investment Tax Credits (ITC)?
- Does the applicant have any SRED Expenditures?
- Does the applicant have any Capital Gains or Losses for tax purposes?
- Does the applicant have any Capital Leases?
- Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?
- Since 1999, has the applicant acquired another regulated applicant's assets?
- Did the applicant pay dividends?
If Yes, please describe what was the tax treatment in the manager's summary.
- Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?

Historical	Bridge	Test Year
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
No	No	No
No	No	No
Yes	No	No
No	No	No

Toronto Hydro-Electric System Limited
Schedule 8 CCA - Bridge Year

I. Sch 8 CCA Bridge Year-Corr



Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital

21,820,146

Additions

Cost of Eligible Capital Property Acquired during Test Year	1,705,181		
Other Adjustments	0		
Subtotal	1,705,181	x 3/4 =	1,278,886
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0
			1,278,886
Amount transferred on amalgamation or wind-up of subsidiary	0		0
Subtotal			23,099,032

Deductions

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year			
Other Adjustments	0		
Subtotal	0	x 3/4 =	0

Cumulative Eligible Capital Balance

23,099,032

Current Year Deduction 23,099,032 x 7% = 1,616,932

Cumulative Eligible Capital - Closing Balance 21,482,100



Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
	A	
Income before PILs/Taxes		108,739,493
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	150,406,396
Amortization of intangible assets	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	145,900
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	364,296
Non-deductible meals and entertainment expense	121	121,681
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	
Reserves from financial statements- balance at end of year	126	243,040,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	919,144
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
ARO Accretion expense		23,685
Capital Contributions Received (ITA 12(1)(x))		17,521,727
Deferred Revenue (ITA 12(1)(a))		793,994
Non-deductible portion of auto leases (>\$800/month)		
Investment Tax Credits taxed in the year		2,263,000
Total Additions		415,599,823



Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Deductions:		
Gain on disposal of assets per financial statements	401	453,469
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	220,984,071
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	1,616,932
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	
Reserves from financial statements - balance at beginning of year	414	235,460,000
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
Financing Fees for Tax Under S.20(1)(e) / 20(1)(e.1)		1,961,842
Excess Interest (see Tab "Sch 7-3 Interest Bridge")		0
ARO Payments - Deductible for Tax when Paid		1,555,139
ARO provision credit to income		292,382
ITA 13(7.4) Election - Capital Contributions Received		17,521,727
Deferred Revenue - ITA 20(1)(m) reserve		793,994
Land Lease payment capitalized for accounting		89,423
Lease payment capitalized for accounting		3,483,931
Other Post-Employment Benefits adjustment - change in balance with no Income Statement Impact		422,000
Other Post-Employment Benefits adjustment - current year capitalized portion with no Income Statement Impact		6,295,217
Other Post-Employment Benefits adjustment - sick leave payment credit to income		206,000
Lease Cancellation payment		46,154
Total Deductions		491,182,281
Net Income for Tax Purposes		33,157,035
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 (Please include explanation and calculation in Manager's summary)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		33,157,035

Note: Schedule is unchanged from Update provided in September 2014 except the following:

- Amortization of tangible assets, Capital Contributions Received (ITA 12(1)(x)), Capital cost allowance from Schedule 8, Cumulative eligible capital deduction from Schedule 10 and ITA 13(7.4) Election - Capital Contributions Received



Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited
Excess Interest Expense - Bridge Year

Calculated Deemed Interest Expense

88,126,662

Bridge Year Actual Interest Expense

70,364,323

Bridge Year Capitalized Interest (USoA 6040)

Bridge Year Capitalized Interest (USoA 6042)

0

Bridge Year Actual Interest

70,364,323

Interest Forecast for Tier 1 or 2 Adjustments

Total Interest

70,364,323

Excess Interest Expense for Bridge Year PILs

0

Note: Bridge Year Actual Interest Expense is updated



Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited

PILS Tax Provision - Bridge Year

Wires Only

Regulatory Taxable Income

\$ 33,157,035 A

Ontario Income Taxes

Income tax payable Ontario Income Tax 11.50% B \$ 3,813,059 C = A * B

Small business credit Ontario Small Business Threshold \$ 500,000 D
Rate reduction -7.00% E -\$ 35,000 F = D * E

Ontario Income tax

\$ 3,778,059 J = C + F

Combined Tax Rate and PILs

Effective Ontario Tax Rate 11.39% K = J / A
Federal tax rate (Maximum 15%) 15.00% L
Combined tax rate

26.39% M = K + L

Total Income Taxes

\$ 8,751,614 N = A * M

Investment Tax Credits

\$ 1,206,000 O

Miscellaneous Tax Credits

\$ 1,057,000 P

Total Tax Credits

\$ 2,263,000 Q = O + P

Corporate PILs/Income Tax Provision for Bridge Year

\$ 6,488,614 R = N - Q

Corporate PILs/Income Tax Provision Gross Up ¹

73.61% S = 1 - M \$ 2,326,772 T = R / S - R

Income Tax (grossed-up)

\$ 8,815,386 U = R + T

Tax credits reclass to OM&A

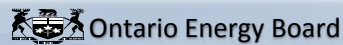
\$ 700,000 V

Income Tax (grossed-up)

\$ 9,515,386 W = U + V

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.



Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance (note 1)	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	\$ 1,051,152,700	59,888,497	-16,318,959	\$ 1,094,722,238	\$ 21,784,769	\$ 1,072,937,469	4%	\$ 42,917,499	\$ 1,051,804,739
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	\$ -			\$ -	\$ -	\$ -	6%	\$ -	\$ -
2	Distribution System - pre 1988	\$ 291,132,705			\$ 291,132,705	\$ -	\$ 291,132,705	6%	\$ 17,467,962	\$ 273,664,743
8	General Office/Stores Equip	\$ 26,779,433	3,415,063		\$ 30,194,496	\$ 1,707,532	\$ 28,486,964	20%	\$ 5,697,393	\$ 24,497,103
10	Computer Hardware/ Vehicles	\$ 13,390,916	3,876,736		\$ 17,267,652	\$ 1,938,368	\$ 15,329,284	30%	\$ 4,598,785	\$ 12,668,867
10.1	Certain Automobiles	\$ -			\$ -	\$ -	\$ -	30%	\$ -	\$ -
12	Computer Software	\$ 7,149,799	23,681,726		\$ 30,831,525	\$ 11,840,863	\$ 18,990,662	100%	\$ 18,990,662	\$ 11,840,863
13 1	Lease # 1	\$ -			\$ -	\$ -	\$ -	SL	\$ -	\$ -
13 2	Lease #2	\$ 31,168			\$ 31,168	\$ -	\$ 31,168	SL	\$ 31,169	\$ -
13 3	Lease # 3	\$ 57,546			\$ 57,546	\$ -	\$ 57,546	SL	\$ 38,365	\$ 19,181
13 4	Lease # 4	\$ 293,732			\$ 293,732	\$ -	\$ 293,732	SL	\$ 117,492	\$ 176,240
13 5	Lease # 5	\$ 348,832			\$ 348,832	\$ -	\$ 348,832	SL	\$ 77,518	\$ 271,314
13 6	Lease # 6	\$ -	43,066		\$ 43,066	\$ 21,533	\$ 21,533	SL	\$ 4,307	\$ 38,759
13 7	Lease # 7	\$ -			\$ -	\$ -	\$ -	SL	\$ -	\$ -
14	Franchise	\$ -			\$ -	\$ -	\$ -		\$ -	\$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	\$ 17,508,188		-1,034,729	\$ 16,473,459	\$ -	\$ 16,473,459	8%	\$ 1,317,877	\$ 15,155,582
42	Fibre Optic Cable	\$ 32,921			\$ 32,921	\$ -	\$ 32,921	12%	\$ 3,951	\$ 28,969
43.1	Certain Energy-Efficient Electrical Generating Equipment	\$ -			\$ -	\$ -	\$ -	30%	\$ -	\$ -
43.2	Certain Clean Energy Generation Equipment	\$ -			\$ -	\$ -	\$ -	50%	\$ -	\$ -
45	Computers & Systems Software acq'd post Mar 22/04	\$ 44,912			\$ 44,912	\$ -	\$ 44,912	45%	\$ 20,210	\$ 24,702
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	\$ -	196,970		\$ 196,970	\$ 98,485	\$ 98,485	30%	\$ 29,546	\$ 167,425
47	Distribution System - post February 2005	\$ 1,563,252,621	372,624,511		\$ 1,935,877,132	\$ 186,312,256	\$ 1,749,564,877	8%	\$ 139,965,190	\$ 1,795,911,942
50	Data Network Infrastructure Equipment - post Mar 2007	\$ 26,836,289	13,139,757		\$ 39,976,046	\$ 6,569,879	\$ 33,406,168	55%	\$ 18,373,392	\$ 21,602,654
52	Computer Hardware and system software	\$ -			\$ -	\$ -	\$ -	100%	\$ -	\$ -
95	CWIP	\$ 405,809,399			\$ 405,809,399	\$ -	\$ 405,809,399	0%	\$ -	\$ 405,809,399
					\$ -	\$ -	\$ -	0%	\$ -	\$ -
					\$ -	\$ -	\$ -	0%	\$ -	\$ -
					\$ -	\$ -	\$ -	0%	\$ -	\$ -
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					\$ -	\$ -	\$ -	0%	\$ -	\$ -
					\$ -	\$ -	\$ -	0%	\$ -	\$ -
					\$ -	\$ -	\$ -	0%	\$ -	\$ -
					\$ -	\$ -	\$ -	0%	\$ -	\$ -
					\$ -	\$ -	\$ -	0%	\$ -	\$ -
					\$ -	\$ -	\$ -	0%	\$ -	\$ -
	TOTAL	\$ 3,403,821,160	\$ 476,866,326	-\$ 17,353,688	\$ 3,863,333,798	\$ 230,273,684	\$ 3,633,060,115		\$ 249,651,318	\$ 3,613,682,481

Note 1 - UCC Opening balance for Class 1
UCC ending balance per 2014 Bridge Year Schedule 8 1,011,495,002
UCC re: Transfer of Streetlighting assets per OEB's decision 39,657,698
Adjusted UCC opening balance for Class 1 1,051,152,700



Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited Schedule 10 CEC - Test Year

Cumulative Eligible Capital - Beginning of Year

21,482,100

Additions

Cost of Eligible Capital Property Acquired during Test Year 46,291,502

Other Adjustments 0

Subtotal 46,291,502 x 3/4 = 34,718,627

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 0 x 1/2 = 0

34,718,627 34,718,627

Amount transferred on amalgamation or wind-up of subsidiary 0 0

Subtotal 56,200,726

Deductions

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year 0

Other Adjustments 0

Subtotal 0 x 3/4 = 0

Cumulative Eligible Capital Balance 56,200,726

Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income") 56,200,726 x 7% = 3,934,051

Cumulative Eligible Capital - Closing Balance 52,266,676



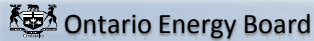
Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited Taxable Income - Test Year

	T2 S1 line #	Test Year	Taxable Income
Net Income Before Taxes			120,809,338

Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets 2-4 ADJUSTED ACCOUNTING DATA P489	104	172,608,641
Amortization of intangible assets 2-4 ADJUSTED ACCOUNTING DATA P490	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	0
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	370,489
Non-deductible meals and entertainment expense	121	123,687
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	
Reserves from financial statements- balance at end of year	126	251,561,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	1,028,805
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
<i>Other Additions: (please explain in detail the nature of the item)</i>		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
ARO Accretion expense		7,461
Capital Contributions Received (ITA 12(1)(x))		15,244,339
Deferred Revenue (ITA 12(1)(a))		387,306
Non-deductible portion of auto leases (>\$800/month)		
Investment Tax Credits taxed in the year		2,263,000
Derecognition of tangible assets		33,932,393
Total Additions		477,527,121



Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited Taxable Income - Test Year

	T2 S1 line #	Test Year	Taxable Income
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403		249,651,318
Terminal loss from Schedule 8	404		
Cumulative eligible capital deduction from Schedule 10 CEC	405		3,934,051
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413		
Reserves from financial statements - balance at beginning of year	414		243,040,000
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
Financing Fees for Tax Under S.20(1)(e) / S.20(1)(e.1)			1,865,108
Excess Interest (see Tab "Sch 7-3 Interest Test Year")			3,037,819
ARO Payments - Deductible for Tax when Paid			52,000
ITA 13(7.4) Election - Capital Contributions Received			15,244,339
Deferred Revenue - ITA 20(1)(m) reserve			387,306
Land Lease payment capitalized for accounting			89,423
Lease payment capitalized for accounting			2,492,112
Other Post-Employment Benefits adjustment - change in balance with no Income Statement Impact			446,000
Other Post-Employment Benefits adjustment - current year capitalized portion with no Income Statement Impact			6,519,410
Lease Cancellation payment			1,719,231
Total Deductions			528,478,118
NET INCOME FOR TAX PURPOSES			69,858,341
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331		
Net-capital losses of preceding taxation years (Please show calculation)	332		
Limited partnership losses of preceding taxation years from Schedule 4	335		
REGULATORY TAXABLE INCOME			69,858,341



Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited
Excess Interest Expense - Test Year

Calculated Deemed Interest Expense

80,175,832

Test Year Actual Interest Expense

83,213,651

Test Year Capitalized Interest (USoA 6040)

Test Year Capitalized Interest (USoA 6042)

0

Test Year Actual Interest

83,213,651

Interest Forecast for Tier 1 or 2 Adjustments

Total Interest

83,213,651

Excess Interest Expense for Test Year PILs

3,037,819



Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited PILS Tax Provision - Test Year

Wires Only

Regulatory Taxable Income

\$ 69,858,341 A

Ontario Income Taxes

Income tax payable

Ontario Income Tax

11.50% B

\$ 8,033,709 C = A * B

Small business credit

Ontario Small Business Threshold
Rate reduction

\$ 500,000 D

-7.00% E

-\$ 35,000 F = D * E

Ontario Income tax

\$ 7,998,709 J = C + F

Combined Tax Rate and PILs

Effective Ontario Tax Rate

11.45%

K = J / A

Federal tax rate

15.00%

L

Combined tax rate

26.45% M = K + L

Total Income Taxes

\$ 18,477,460 N = A * M

Investment Tax Credits

\$ 1,206,000 O

Miscellaneous Tax Credits

\$ 1,057,000 P

Total Tax Credits

\$ 2,263,000 Q = O + P

Corporate PILs/Income Tax Provision for Test Year

\$ 16,214,460 R = N - Q

Corporate PILs/Income Tax Provision Gross Up ¹

73.55%

S = 1 - M \$ 5,831,003 T = R / S - R

Income Tax (grossed-up)

\$ 22,045,463 U = R + T

Tax credits reclass to OM&A

\$ 2,000,000 V

Income Tax (grossed-up)

\$ 24,045,463 W = U + V

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

REVENUE REQUIREMENT AND SUFFICIENCY / DEFICIENCY

Toronto Hydro earns the majority of its revenue through the distribution tariff and earns other revenues through the provision of non-distribution related activities. These other revenues offset the required revenue to be collected from Toronto Hydro's distribution service customers.

The recovery of Deferral and Variance Accounts is not included in the revenue requirement. Deferral and Variance Accounts are recovered through separate rate riders as described in Exhibit 9.

Table 1 below summarizes THESL's 2015 revenue requirement.

Table 1: 2015 Revenue Requirement (\$ millions)

	2015 Test Year
OM&A Expenses	265.1
Amortization/Depreciation	206.5
Property Taxes	6.5
Income Taxes (Grossed up)	22.0
Deemed Interest Expense	80.2
Return on Deemed Equity	120.8
Service Revenue Requirement	701.1
Revenue Offsets	46.1
Base Revenue Requirement	655.0

/C

Full details on the calculation of Revenue Requirement, including the Determination of Net Utility Income, Statement of Ratebase, Actual Utility Return on Rate Base, Indicated Rate of Return, Requested Rate of Return and the Deficiency in Revenue can be found in the Revenue Requirement WorkForm, filed as Exhibit 6, Tab 1, Schedule 2.

4. OVERALL REVENUE DEFICIENCY

For the test year, revenue deficiency/sufficiency is the difference between the 2015 test year Revenue Requirement and the 2015 test year revenues calculated at current rates (before rates are adjusted to recover the 2015 Base Revenue Requirement).

The test year revenue at current rates is determined using the 2015 forecast of billing units at 2014 approved base distribution rates.

Toronto Hydro's revenue deficiency for the 2015 test year is forecast as follows:

Table 2: Revenue Deficiency (\$ millions)

	2015 Test Year
2015 Revenue at Current (2014 approved) Rates	600.9
2015 Service Revenue Requirement	701.1
Gross Revenue Deficiency	(100.2)

/C

/C

Full details of the calculation of Revenue Deficiency are shown in the Revenue Requirement Workform tab 8, filed in Exhibit 6, Tab 1, Schedule 2.

5. CAUSES OF REVENUE DEFICIENCY

The drivers of the revenue deficiency are summarized as follows:

1 **Table 3: Revenue Deficiency Drivers (\$ millions)**

	2015 Test	Driver	
Higher Net Fixed Assets	62.2	Inclusion of ICM and streetlighting capital, plus 2015 capital (Exhibit 2A, Tab 1), offset by removal of stranded meters (Exhibit 2A, Tab 4)	/C
Lower WCA	-3.4	Increased due to higher COP and expenses offset by results of lead-lag study (Exhibit 2A, Tab 3)	
Lower Cost of Capital	-17.3	Lower debt and equity rates (Exhibit 5, Tab 1)	
Higher OMA	33.5	Higher operating expenses (Exhibit 4A, Tabs 1 & 2)	
Higher Depreciation	67.7	Higher net fixed assets (Exhibit 2A, Tab 1), plus increase due to derecognition amounts (Exhibit 4B, Tab 1)	/C
Higher PILS	10.3	Exhibit 4B, Tab 2	/C
Higher Distribution Revenue	-32.7	Result of 2012-14 IRM funding on base rates (Exhibit 2A, Tab 1) and load/customer growth (Exhibit 3, Tab 1)	
Higher Revenue Offsets	-20.1	Higher Revenue Offsets (Exhibit 3, Tab 2)	
Total Revenue Deficiency	100.2		/C

2 The revenue deficiency arising from the increase in net fixed assets is primarily due to
3 the combination of the additions to fixed assets over the 2012-15 period. Expenditures
4 undertaken through the approved ICM programs (see Exhibit 2A, Tab 1, Schedule 1) and
5 Streetlighting assets (see Exhibit 2A, Tab 5) are added to ratebase at the beginning of
6 2015, with Toronto Hydro's significant capital program (see Exhibit 2B) continuing in
7 2015. Partially offsetting the increase in ratebase described above is the removal of the
8 Stranded Meter assets, which had been previously included in rate base (see Exhibit 2A,
9 Tab 4).

10

11 A combination of the updated Lead-Lag study (Exhibit 2A, Tab 3, Schedule 2) which has
12 resulted in a reduction in the Working Capital Allowance, together with a lower overall
13 Cost of Capital (Exhibit 5, Tab 1), results in a reduction in revenue deficiency.

14



Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers



Version 5.00

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	EB-2014-0116
Name and Title	Anthony Lam, Economist - Rates
Phone Number	416 542 2876
Email Address	alam@torontohydro.com

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While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.



Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

[1. Info](#)

[2. Table of Contents](#)

[3. Data Input Sheet](#)

[4. Rate Base](#)

[5. Utility Income](#)

[6. Taxes PILs](#)

[7. Cost of Capital](#)

[8. Rev Def Suff](#)

[9. Rev Regt](#)

[10. Tracking Sheet](#)

Notes:

- (1) Pale green cells represent inputs
- (2) Pale green boxes at the bottom of each page are for additional notes
- (3) Pale yellow cells represent drop-down lists
- (4) **Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.**
- (5) **Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel**



Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Data Input ⁽¹⁾

	Initial Application	(2)		(6)		Per Board Decision
1	<u>Rate Base</u>					
	Gross Fixed Assets (average)	\$5,777,050,247		\$ 5,777,050,247		\$5,777,050,247
	Accumulated Depreciation (average)	(\$2,771,027,667)	(5)	(\$2,771,027,667)		(\$2,771,027,667)
	<u>Allowance for Working Capital:</u>					
	Controllable Expenses	\$269,529,393		\$ 269,529,393		\$269,529,393
	Cost of Power	\$2,751,934,010		\$2,751,934,010		\$2,751,934,010
	Working Capital Rate (%)	7.99%	(9)	7.99%	(9)	7.99% (9)
2	<u>Utility Income</u>					
	<u>Operating Revenues:</u>					
	Distribution Revenue at Current Rates	\$554,785,563				
	Distribution Revenue at Proposed Rates	\$655,005,726				
	<u>Other Revenue:</u>					
	Specific Service Charges	\$9,877,024				
	Late Payment Charges	\$4,000,000				
	Other Distribution Revenue	\$30,677,670				
	Other Income and Deductions	\$1,540,639				
	Total Revenue Offsets	\$46,095,333	(7)			
	<u>Operating Expenses:</u>					
	OM+A Expenses	\$265,067,891	(10)	\$ 265,067,891		\$265,067,891
	Depreciation/Amortization	\$206,541,033		\$ 206,541,033		\$206,541,033
	Property taxes	\$6,461,502		\$ 6,461,502		\$6,461,502
	Other expenses					

3 Taxes/PILs

Taxable Income:

Adjustments required to arrive at taxable income							
Utility Income Taxes and Rates:							
Income taxes (not grossed up)							
Income taxes (grossed up)							
Federal tax (%)							
Provincial tax (%)							
Income Tax Credits							

4 Capitalization/Cost of Capital

Capital Structure:

Long-term debt Capitalization Ratio (%)							
Short-term debt Capitalization Ratio (%)							
Common Equity Capitalization Ratio (%)							
Preferred Shares Capitalization Ratio (%)							

Cost of Capital

Long-term debt Cost Rate (%)							
Short-term debt Cost Rate (%)							
Common Equity Cost Rate (%)							
Preferred Shares Cost Rate (%)							

Notes:

- General** Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.
- (1) All inputs are in dollars (\$) except where inputs are individually identified as percentages (%)
- (2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I
- (3) Net of addbacks and deductions to arrive at taxable income.
- (4) Average of Gross Fixed Assets at beginning and end of the Test Year
- (5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
- (6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.
- (7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement
- (8) 4.0% unless an Applicant has proposed or been approved for another amount.
- (9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.
- (10) Investment tax credits of \$2 million reclass to Taxes/PILs



Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Rate Base and Working Capital

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	\$5,777,050,247	\$ -	\$5,777,050,247	\$ -	\$5,777,050,247
2	Accumulated Depreciation (average)	(3)	(\$2,771,027,667)	\$ -	(\$2,771,027,667)	\$ -	(\$2,771,027,667)
3	Net Fixed Assets (average)	(3)	\$3,006,022,581	\$ -	\$3,006,022,581	\$ -	\$3,006,022,581
4	Allowance for Working Capital	(1)	\$241,540,265	\$ -	\$241,540,265	\$ -	\$241,540,265
5	Total Rate Base		\$3,247,562,846	\$ -	\$3,247,562,846	\$ -	\$3,247,562,846

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		\$269,529,393	\$ -	\$269,529,393	\$ -	\$269,529,393
7	Cost of Power		\$2,751,934,010	\$ -	\$2,751,934,010	\$ -	\$2,751,934,010
8	Working Capital Base		\$3,021,463,403	\$ -	\$3,021,463,403	\$ -	\$3,021,463,403
9	Working Capital Rate %	(2)	7.99%	0.00%	7.99%	0.00%	7.99%
10	Working Capital Allowance		\$241,540,265	\$ -	\$241,540,265	\$ -	\$241,540,265

Notes

- (2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.
(3) Average of opening and closing balances for the year.



Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Utility Income

Line No.	Particulars	Initial Application				Per Board Decision			
	<u>Operating Revenues:</u>								
1	Distribution Revenue (at Proposed Rates)	\$655,005,726		(\$655,005,726)		\$ -		\$ -	
2	Other Revenue	(1) \$46,095,333		(\$46,095,333)		\$ -		\$ -	
3	Total Operating Revenues	\$701,101,059		(\$701,101,059)		\$ -		\$ -	
	<u>Operating Expenses:</u>								
4	OM+A Expenses	\$265,067,891		\$ -		\$265,067,891		\$ -	
5	Depreciation/Amortization	\$206,541,033		\$ -		\$206,541,033		\$ -	
6	Property taxes	\$6,461,502		\$ -		\$6,461,502		\$ -	
7	Capital taxes	\$ -		\$ -		\$ -		\$ -	
8	Other expense	\$ -		\$ -		\$ -		\$ -	
9	Subtotal (lines 4 to 8)	\$478,070,427		\$ -		\$478,070,427		\$ -	
10	Deemed Interest Expense	\$80,175,832		(\$80,175,832)		\$ -		\$ -	
11	Total Expenses (lines 9 to 10)	\$558,246,258		(\$80,175,832)		\$478,070,427		\$ -	
12	Utility income before income taxes	\$142,854,801		(\$620,925,227)		(\$478,070,427)		\$ -	
13	Income taxes (grossed-up)	\$22,045,463		\$ -		\$22,045,463		\$ -	
14	Utility net income	\$120,809,338		(\$620,925,227)		(\$500,115,890)		\$ -	

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	\$9,877,024			\$ -			\$ -
	Late Payment Charges	\$4,000,000			\$ -			\$ -
	Other Distribution Revenue	\$30,677,670			\$ -			\$ -
	Other Income and Deductions	\$1,540,639			\$ -			\$ -
	Total Revenue Offsets	\$46,095,333		\$ -	\$ -		\$ -	\$ -



Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Taxes/PILs

Line No.	Particulars	Application				Per Board Decision	
<u>Determination of Taxable Income</u>							
1	Utility net income before taxes	\$120,809,338		\$ -		\$ -	
2	Adjustments required to arrive at taxable utility income	(\$50,950,997)		\$ -		(\$50,950,997)	
3	Taxable income	<u>\$69,858,341</u>		<u>\$ -</u>		<u>(\$50,950,997)</u>	
<u>Calculation of Utility income Taxes</u>							
4	Income taxes	<u>\$16,214,460</u>		<u>\$16,214,460</u>		<u>\$16,214,460</u>	
6	Total taxes	<u>\$16,214,460</u>		<u>\$16,214,460</u>		<u>\$16,214,460</u>	
7	Gross-up of Income Taxes	<u>\$5,831,003</u>		<u>\$5,831,003</u>		<u>\$5,831,003</u>	
8	Grossed-up Income Taxes	<u>\$22,045,463</u>		<u>\$22,045,463</u>		<u>\$22,045,463</u>	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	<u>\$22,045,463</u>		<u>\$22,045,463</u>		<u>\$22,045,463</u>	
10	Other tax Credits	(\$2,263,000)		(\$2,263,000)		(\$2,263,000)	
<u>Tax Rates</u>							
11	Federal tax (%)	15.00%		15.00%		15.00%	
12	Provincial tax (%)	11.45%		11.45%		11.45%	
13	Total tax rate (%)	26.45%		26.45%		26.45%	

Notes

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	(\$)	(%)	(\$)
Initial Application					
	Debt				
1	Long-term Debt	56.00%	\$1,818,635,194	4.31%	\$78,383,177
2	Short-term Debt	4.00%	\$129,902,514	1.38%	\$1,792,655
3	Total Debt	60.00%	\$1,948,537,707	4.11%	\$80,175,832
	Equity				
4	Common Equity	40.00%	\$1,299,025,138	9.30%	\$120,809,338
5	Preferred Shares	0.00%	\$ -	0.00%	\$ -
6	Total Equity	40.00%	\$1,299,025,138	9.30%	\$120,809,338
7	Total	100.00%	\$3,247,562,846	6.19%	\$200,985,169
Per Board Decision					
	Debt				
1	Long-term Debt	0.00%	\$ -	0.00%	\$ -
2	Short-term Debt	0.00%	\$ -	0.00%	\$ -
3	Total Debt	0.00%	\$ -	0.00%	\$ -
	Equity				
4	Common Equity	0.00%	\$ -	0.00%	\$ -
5	Preferred Shares	0.00%	\$ -	0.00%	\$ -
6	Total Equity	0.00%	\$ -	0.00%	\$ -
7	Total	0.00%	\$3,247,562,846	0.00%	\$ -
	Debt				
8	Long-term Debt	0.00%	\$ -	4.31%	\$ -
9	Short-term Debt	0.00%	\$ -	1.38%	\$ -
10	Total Debt	0.00%	\$ -	0.00%	\$ -
	Equity				
11	Common Equity	0.00%	\$ -	9.30%	\$ -
12	Preferred Shares	0.00%	\$ -	0.00%	\$ -
13	Total Equity	0.00%	\$ -	0.00%	\$ -
14	Total	0.00%	\$3,247,562,846	0.00%	\$ -

Notes

(1)

Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I



Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		\$100,220,163		(\$98,114,817)
2	Distribution Revenue	\$554,785,563	\$554,785,563	\$554,785,563	\$753,120,543
3	Other Operating Revenue	\$46,095,333	\$46,095,333	\$ -	\$ -
	Offsets - net				
4	Total Revenue	\$600,880,896	\$701,101,059	\$554,785,563	\$655,005,726
5	Operating Expenses	\$478,070,427	\$478,070,427	\$478,070,427	\$478,070,427
6	Deemed Interest Expense	\$80,175,832	\$80,175,832	\$ -	\$ -
8	Total Cost and Expenses	\$558,246,258	\$558,246,258	\$478,070,427	\$478,070,427
9	Utility Income Before Income Taxes	\$42,634,637	\$142,854,801	\$76,715,136	\$176,935,299
10	Tax Adjustments to Accounting Income per 2013 PILs model	(\$50,950,997)	(\$50,950,997)	(\$50,950,997)	(\$50,950,997)
11	Taxable Income	(\$8,316,360)	\$91,903,804	\$25,764,139	\$125,984,302
12	Income Tax Rate	26.45%	26.45%	26.45%	26.45%
13	Income Tax on Taxable Income	(\$2,199,669)	\$24,308,463	\$6,814,589	\$33,322,720
14	Income Tax Credits	(\$2,263,000)	(\$2,263,000)	(\$2,263,000)	(\$2,263,000)
15	Utility Net Income	\$47,097,306	\$120,809,338	\$72,163,547	(\$500,115,890)
16	Utility Rate Base	\$3,247,562,846	\$3,247,562,846	\$3,247,562,846	\$3,247,562,846
17	Deemed Equity Portion of Rate Base	\$1,299,025,138	\$1,299,025,138	\$ -	\$ -
18	Income/(Equity Portion of Rate Base)	3.63%	9.30%	0.00%	0.00%
19	Target Return - Equity on Rate Base	9.30%	9.30%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-5.67%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	3.92%	6.19%	2.22%	0.00%
22	Requested Rate of Return on Rate Base	6.19%	6.19%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-2.27%	0.00%	2.22%	0.00%
24	Target Return on Equity	\$120,809,338	\$120,809,338	\$ -	\$ -
25	Revenue Deficiency/(Sufficiency)	\$73,712,032	(\$0)	(\$72,163,547)	\$ -
26	Gross Revenue Deficiency/(Sufficiency)	\$100,220,163 (1)		(\$98,114,817) (1)	\$478,070,427 (1)

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)



Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Revenue Requirement

Line No.	Particulars	Application		Per Board Decision	
1	OM&A Expenses	\$265,067,891		\$265,067,891	
2	Amortization/Depreciation	\$206,541,033		\$206,541,033	
3	Property Taxes	\$6,461,502		\$6,461,502	
5	Income Taxes (Grossed up)	\$22,045,463		\$22,045,463	
6	Other Expenses	\$ -		\$ -	
7	Return				
	Deemed Interest Expense	\$80,175,832		\$ -	
	Return on Deemed Equity	\$120,809,338		\$ -	
8	Service Revenue Requirement (before Revenues)	<u>\$701,101,059</u>		<u>\$500,115,890</u>	
9	Revenue Offsets	\$46,095,333		\$ -	
10	Base Revenue Requirement (excluding Transformer Ownership Allowance credit adjustment)	<u>\$655,005,726</u>		<u>\$500,115,890</u>	
11	Distribution revenue	\$655,005,726		\$ -	
12	Other revenue	\$46,095,333		\$ -	
13	Total revenue	<u>\$701,101,059</u>		<u>\$ -</u>	
14	Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)	<u>(\$0)</u>	(1)	<u>(\$500,115,890)</u>	(1)

Notes

(1) Line 11 - Line 8



Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Tracking Form

The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.) Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

⁽¹⁾ Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

⁽²⁾ Short description of change, issue, etc.

60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.

Summary of Proposed Changes

1

Reference ⁽¹⁾	Item / Description ⁽²⁾	Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
		Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance (\$)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	\$ 200,985,169	6.19%	\$3,247,562,846	\$3,021,463,403	\$ 241,540,265	\$ 206,541,033	\$ 22,045,463	\$ 265,067,891	\$ 701,101,059	\$ 46,095,333	\$ 655,005,726	#####

COST ALLOCATION

Toronto Hydro's total revenue requirement, as detailed in Exhibit 6, is allocated to rate classes as the basis for determining distribution rates for the 2015 rebasing year. The allocation methodology employed for the 2015 Test Year is the OEB's Cost Allocation Model.

The results of the cost allocation, which shows the revenue/cost ratios prior to applying the proposed rates is summarized in Table 1 below.

Table 1: Revenue / Cost Ratios from Cost Allocation Model (%)

Rate Class	2015 Revenue/Cost Ratio	OEB's Guideline Ranges
Residential	94	85-115
Competitive Sector Multi-Unit Residential	110	n/a
General Service <50kW	90	80-120
General Service 50-999kW	119	80-120
Intermediate 1000-4999kW	102	80-120
Large Use	95	85-115
Streetlighting	92	70-120
Unmetered Scattered Load	87	80-120

Exhibit 7, Tab 1, Schedule 2 provides sheets I-6, I-8, O-1 and O-2 from the Cost Allocation model for the Test Year, as required by the OEB's Filing Guidelines. The full live MS Excel model has also been filed electronically.

/C

/C

/C

1 **Table 2: Revenue / Cost Ratios (%)**

Rate Class	2011 OEB Approved	2015		OEB's Guideline Ranges
		Model	Proposed	
Residential	89	94	94	85-115
Competitive Sector Multi-Unit Residential		110	100	
General Service <50kW	97	90	92	80-120
General Service 50-999kW	118	119	119	80-120
Intermediate 1000-4999kW	124	102	102	80-120
Large Use	116	95	96	85-115
Streetlighting	71	92	82	70-120
Unmetered Scattered Load	82	87	89	80-120

/C

2 The proposed Revenue to Cost ratios for all THESL rate classes are within the OEB's
3 "target ranges".

4
5 With respect to the CSMUR class, as directed in the EB-2010-1042 decision, Toronto
6 Hydro has adjusted rates to this class to make the revenue-to-cost ratio equal to unity.
7 This ensures that this class is recovering its fully allocated costs.

8
9 With respect to the Streetlighting class, rates for this class were maintained at the same
10 level as 2014. As is explained in more detail in Exhibit 8, Tab 1, Schedule 1, the cost
11 allocation model with respect to the Streetlighting class is subject to further OEB review.
12 Until such time as that review is complete, and given that rates to this class since 2006
13 have risen substantially due to the implementation of the existing cost allocation model,
14 Toronto Hydro believes it is not appropriate to set rates for 2015 based on the current cost
15 allocation model.

16

2015 Cost Allocation Model

EB-2014-0116

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:

Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

		Total	1 Residential	2 Competitive Sector Multi-Unit Residential	3 GS<50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MV	7 Street Light	9 Unmetered Scattered Load
Rate Base Assets	Distribution Revenue at Existing Rates	\$542,879,037	\$214,465,673	\$17,001,339	\$69,430,402	\$154,639,009	\$47,664,824	\$24,719,345	\$12,284,580	\$2,673,863
	Miscellaneous Revenue (mi)	\$46,095,333	\$19,510,221	\$1,297,588	\$8,137,006	\$6,475,013	\$893,042	\$331,213	\$8,843,082	\$608,167
	Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	\$588,974,369	\$233,975,894	\$18,298,927	\$77,567,407	\$161,114,022	\$48,557,866	\$25,050,559	\$21,127,663	\$3,282,031
	Factor required to recover deficiency (1 + D)									
crev mi		1.2065								
	Distribution Revenue at Status Quo Rates	\$655,005,729	\$258,761,594	\$20,512,810	\$83,770,615	\$186,578,280	\$57,509,557	\$29,824,900	\$14,821,848	\$3,226,126
	Miscellaneous Revenue (mi)	\$46,095,333	\$19,510,221	\$1,297,588	\$8,137,006	\$6,475,013	\$893,042	\$331,213	\$8,843,082	\$608,167
	Total Revenue at Status Quo Rates	\$701,101,062	\$278,271,815	\$21,810,398	\$91,907,621	\$193,053,292	\$58,402,599	\$30,156,113	\$23,664,930	\$3,834,293
di cu ad dep INPUT INT	Expenses									
	Distribution Costs (di)	\$123,655,008	\$47,339,900	\$1,303,876	\$18,138,423	\$35,094,824	\$13,432,161	\$6,053,468	\$1,997,398	\$294,959
	Customer Related Costs (cu)	\$44,534,641	\$25,013,514	\$2,382,606	\$9,538,037	\$5,488,893	\$375,257	\$39,113	\$307,298	\$1,389,922
	General and Administration (ad)	\$96,546,705	\$40,606,899	\$2,411,413	\$15,197,838	\$22,633,196	\$7,775,439	\$3,694,183	\$3,265,267	\$962,470
	Depreciation and Amortization (dep)	\$201,165,099	\$89,157,842	\$3,231,799	\$29,045,708	\$48,987,984	\$16,993,928	\$8,353,460	\$4,801,357	\$593,021
	PILs (INPUT)	\$23,111,953	\$10,194,379	\$541,869	\$3,190,458	\$5,355,542	\$1,924,226	\$1,056,782	\$769,315	\$79,383
	Interest	\$77,063,190	\$33,991,562	\$1,806,778	\$10,638,082	\$17,857,215	\$6,416,030	\$3,523,673	\$2,565,161	\$264,689
	Total Expenses	\$566,076,597	\$246,304,096	\$11,678,342	\$85,748,545	\$135,417,655	\$46,917,041	\$22,720,679	\$13,705,796	\$3,584,444
	Direct Allocation	\$18,905,270	\$0	\$5,420,542	\$0	\$376,917	\$786,507	\$3,716,575	\$8,174,493	\$430,236
NI	Allocated Net Income (NI)	\$116,119,194	\$51,218,653	\$2,722,463	\$16,029,514	\$26,907,340	\$9,667,706	\$5,309,488	\$3,865,197	\$398,835
	Revenue Requirement (includes NI)	\$701,101,062	\$297,522,749	\$19,821,346	\$101,778,059	\$162,701,911	\$57,371,254	\$31,746,741	\$25,745,486	\$4,413,515
	Revenue Requirement Input equals Output									



Ontario Energy Board

2015 Cost Allocation Model

EB-2014-0116

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:

Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

		Total	1 Residential	2 Competitive Sector Multi-Unit Residential	3 GS<50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MV	7 Street Light	9 Unmetered Scattered Load
Rate Base Calculation										
Net Assets										
dp	Distribution Plant - Gross	\$5,105,708,297	\$2,356,398,997	\$66,497,553	\$730,117,270	\$1,232,551,019	\$417,103,844	\$182,710,716	\$105,628,857	\$14,700,042
gp	General Plant - Gross	\$889,556,321	\$386,608,898	\$21,801,383	\$122,034,760	\$206,022,616	\$73,923,883	\$45,925,008	\$30,139,413	\$3,100,359
accum dep	Accumulated Depreciation	(\$2,728,750,263)	(\$1,259,585,950)	(\$41,865,983)	(\$382,561,484)	(\$649,977,813)	(\$218,854,866)	(\$104,077,054)	(\$63,675,875)	(\$8,151,238)
co	Capital Contribution	(\$364,731,111)	(\$159,584,408)	(\$5,800,074)	(\$54,903,585)	(\$94,749,957)	(\$27,535,460)	(\$11,604,576)	(\$9,274,754)	(\$1,278,297)
Total Net Plant		\$2,901,783,244	\$1,323,837,537	\$40,632,880	\$414,686,961	\$693,845,865	\$244,637,400	\$112,954,095	\$62,817,641	\$8,370,865
Directly Allocated Net Fixed Assets		\$104,239,340	\$0	\$30,185,716	\$0	\$2,676,286	\$5,584,568	\$26,389,410	\$37,433,192	\$1,970,168
COP	Cost of Power (COP)	\$2,751,934,010	\$559,997,319	\$24,306,991	\$241,613,878	\$1,123,281,537	\$530,871,999	\$254,158,102	\$13,012,843	\$4,691,341
	OM&A Expenses	\$264,736,354	\$112,960,312	\$6,097,896	\$42,874,298	\$63,216,913	\$21,582,856	\$9,786,765	\$5,569,963	\$2,647,351
	Directly Allocated Expenses	\$4,793,042	\$0	\$658,560	\$0	\$30,542	\$63,732	\$301,162	\$3,552,094	\$186,952
	Subtotal	\$3,021,463,406	\$672,957,631	\$31,063,447	\$284,488,175	\$1,186,528,993	\$552,518,587	\$264,246,029	\$22,134,900	\$7,525,644
Working Capital		\$241,540,317	\$53,797,242	\$2,483,259	\$22,742,411	\$94,852,907	\$44,169,165	\$21,124,224	\$1,769,497	\$601,611
Total Rate Base		\$3,247,562,901	\$1,377,634,780	\$73,301,854	\$437,429,372	\$791,375,059	\$294,391,132	\$160,467,729	\$102,020,330	\$10,942,645
		Rate Base Input equals Output								
Equity Component of Rate Base		\$1,299,025,160	\$551,053,912	\$29,320,742	\$174,971,749	\$316,550,023	\$117,756,453	\$64,187,092	\$40,808,132	\$4,377,058
Net Income on Allocated Assets		\$116,119,194	\$31,967,719	\$4,711,514	\$6,159,076	\$57,258,721	\$10,699,051	\$3,718,860	\$1,784,641	(\$180,388)
Net Income on Direct Allocation Assets		\$4,690,144	\$0	\$1,358,176	\$0	\$120,417	\$251,272	\$1,187,365	\$1,684,269	\$88,646
Net Income		\$120,809,338	\$31,967,719	\$6,069,690	\$6,159,076	\$57,379,138	\$10,950,323	\$4,906,224	\$3,468,909	(\$91,742)
RATIOS ANALYSIS										
REVENUE TO EXPENSES STATUS QUO%		100.00%	93.53%	110.03%	90.30%	118.65%	101.80%	94.99%	91.92%	86.88%
EXISTING REVENUE MINUS ALLOCATED COSTS		(\$112,126,693)	(\$63,546,854)	(\$1,522,419)	(\$24,210,651)	(\$1,587,889)	(\$8,813,388)	(\$6,696,182)	(\$4,617,824)	(\$1,131,485)
Deficiency Input Does Not Equal Output										
STATUS QUO REVENUE MINUS ALLOCATED COSTS		(\$0)	(\$19,250,934)	\$1,989,051	(\$9,870,438)	\$30,351,382	\$1,031,345	(\$1,590,628)	(\$2,080,556)	(\$579,223)
RETURN ON EQUITY COMPONENT OF RATE BASE		9.30%	5.80%	20.70%	3.52%	18.13%	9.30%	7.64%	8.50%	-2.10%

2015 Cost Allocation Model

EB-2014-0116

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	4	5	6	7	9
	Residential	Competitive Sector Multi-Unit Residential	GS<50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MV	Street Light	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	\$4.24	\$3.40	\$13.78	\$43.33	\$82.84	-\$35.49	\$0.23	\$9.53
Customer Unit Cost per month - Directly Related	\$6.14	\$5.42	\$19.89	\$64.65	\$124.46	\$19.76	\$0.39	\$14.56
Customer Unit Cost per month - Minimum System with PLCC Adjustment	\$19.34	\$9.32	\$31.66	\$86.22	\$244.36	\$210.01	\$10.53	\$19.32
Existing Approved Fixed Charge	\$18.89	\$17.59	\$25.14	\$36.79	\$710.41	\$3,114.13	\$1.34	\$5.01

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	4	5	6	7	9
	Total	Residential	Competitive Sector Multi-Unit Residential	GS<50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MV	Street Light	Unmetered Scattered Load
General Plant - Gross Assets	\$889,556,321	\$386,608,898	\$21,801,383	\$122,034,760	\$206,022,616	\$73,923,883	\$45,925,008	\$30,139,413	\$3,100,359
General Plant - Accumulated Depreciation	(\$568,544,462)	(\$247,094,358)	(\$13,933,975)	(\$77,996,396)	(\$131,675,774)	(\$47,247,165)	(\$29,352,171)	(\$19,263,082)	(\$1,981,541)
General Plant - Net Fixed Assets	\$321,011,859	\$139,514,540	\$7,867,408	\$44,038,364	\$74,346,842	\$26,676,718	\$16,572,837	\$10,876,331	\$1,118,819
General Plant - Depreciation	\$63,258,092	\$27,492,516	\$1,550,339	\$8,678,131	\$14,650,672	\$5,256,872	\$3,265,817	\$2,143,273	\$220,473
Total Net Fixed Assets Excluding General Plant	\$2,685,010,725	\$1,184,322,997	\$62,951,188	\$370,648,597	\$622,175,310	\$223,545,250	\$122,770,668	\$89,374,502	\$9,222,215
Total Administration and General Expense	\$96,546,705	\$40,606,899	\$2,411,413	\$15,197,838	\$22,633,196	\$7,775,439	\$3,694,183	\$3,265,267	\$962,470
Total O&M	\$172,982,691	\$72,353,413	\$4,345,042	\$27,676,460	\$40,614,259	\$13,871,150	\$6,393,743	\$5,856,790	\$1,871,833

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 Competitive Sector Multi-Unit Residential	3 GS<50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MV	7 Street Light	9 Unmetered Scattered Load	
1860	<u>Distribution Plant</u> Meters	\$183,224,614	\$113,139,896	\$0	\$41,927,909	\$23,642,330	\$4,096,154	\$418,324	\$0	\$0	CWMC
	<u>Accumulated Amortization</u> Accum. Amortization of Electric Utility Plant - Meters only	(\$62,288,063)	(\$38,462,436)	\$0	(\$14,253,589)	(\$8,037,320)	(\$1,392,507)	(\$142,211)	\$0	\$0	
	Meter Net Fixed Assets	\$120,936,551	\$74,677,461	\$0	\$27,674,321	\$15,605,010	\$2,703,647	\$276,113	\$0	\$0	
	<u>Misc Revenue</u>										
4082	Retail Services Revenues	(\$467,880)	(\$199,640)	(\$10,777)	(\$75,774)	(\$111,726)	(\$38,144)	(\$17,297)	(\$9,844)	(\$4,679)	CWNB
4084	Service Transaction Requests (STR) Revenues	(\$28,360)	(\$12,101)	(\$653)	(\$4,593)	(\$6,772)	(\$2,312)	(\$1,048)	(\$597)	(\$284)	CWNB
4090	Electric Services Incidental to Energy Sales	(\$2,115,000)	(\$902,449)	(\$48,717)	(\$342,526)	(\$505,045)	(\$172,427)	(\$78,187)	(\$44,499)	(\$21,150)	CWNB
4220	Other Electric Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	NFA
4225	Late Payment Charges	(\$4,000,000)	(\$2,229,964)	(\$90,781)	(\$920,612)	(\$646,365)	(\$89,987)	(\$14,363)	\$0	(\$7,928)	LPHA
	Sub-total	(\$6,611,240)	(\$3,344,153)	(\$150,928)	(\$1,343,504)	(\$1,269,908)	(\$302,871)	(\$110,895)	(\$54,940)	(\$34,040)	
	<u>Operation</u>										
5065	Meter Expense	\$845,002	\$521,783	\$0	\$193,365	\$109,035	\$18,891	\$1,929	\$0	\$0	CWMC
5070	Customer Premises - Operation Labour	\$2,532,470	\$1,822,739	\$160,934	\$205,564	\$35,843	\$1,308	\$146	\$271,085	\$34,850	CCA
5075	Customer Premises - Materials and Expenses	\$334,323	\$240,628	\$21,246	\$27,137	\$4,732	\$173	\$19	\$35,787	\$4,601	CCA
	Sub-total	\$3,711,795	\$2,585,150	\$182,180	\$426,066	\$149,610	\$20,372	\$2,094	\$306,872	\$39,451	
	<u>Maintenance</u>										
5175	Maintenance of Meters	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1860
	<u>Billing and Collection</u>										
5310	Meter Reading Expense	\$4,020,342	\$2,511,917	\$0	\$750,328	\$627,622	\$112,181	\$18,294	\$0	\$0	CWMR
5315	Customer Billing	\$10,123,962	\$5,340,964	\$747,456	\$2,212,101	\$1,322,940	\$35,912	\$6,361	\$145	\$458,083	CWNB
5320	Collecting	\$19,389,048	\$10,228,823	\$1,431,501	\$4,236,537	\$2,533,648	\$68,777	\$12,182	\$277	\$877,304	CWNB
5325	Collecting- Cash Over and Short	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	CWNB
5330	Collection Charges	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	CWNB
	Sub-total	\$33,533,352	\$18,081,704	\$2,178,957	\$7,198,966	\$4,484,210	\$216,870	\$36,837	\$422	\$1,335,387	
	Total Operation, Maintenance and Billing	\$37,245,147	\$20,666,854	\$2,361,137	\$7,625,033	\$4,633,819	\$237,242	\$38,931	\$307,294	\$1,374,838	
	Amortization Expense - Meters	\$13,797,005	\$8,519,553	\$0	\$3,157,215	\$1,780,292	\$308,445	\$31,500	\$0	\$0	
	Allocated PILs	\$930,852	\$575,063	\$0	\$212,917	\$119,987	\$20,791	\$2,094	\$0	\$0	
	Allocated Debt Return	\$3,103,779	\$1,917,458	\$0	\$709,937	\$400,076	\$69,325	\$0	\$6,982	\$0	
	Allocated Equity Return	\$4,676,790	\$2,889,236	\$0	\$1,069,737	\$602,837	\$104,460	\$10,521	\$0	\$0	
	Total	\$53,142,333	\$31,224,011	\$2,210,208	\$11,431,334	\$6,267,103	\$437,391	(\$20,866)	\$252,354	\$1,340,797	

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 Competitive Sector Multi-Unit Residential	3 GS<50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MV	7 Street Light	9 Unmetered Scattered Load	
1860	<u>Distribution Plant</u>										
	Meters	\$183,224,614	\$113,139,896	\$0	\$41,927,909	\$23,642,330	\$4,096,154	\$418,324	\$0	\$0	CWMC
	<u>Accumulated Amortization</u>										
	Accum. Amortization of Electric Utility Plant - Meters only	(\$62,288,063)	(\$38,462,436)	\$0	(\$14,253,589)	(\$8,037,320)	(\$1,392,507)	(\$142,211)	\$0	\$0	
	Meter Net Fixed Assets	\$120,936,551	\$74,677,461	\$0	\$27,674,321	\$15,605,010	\$2,703,647	\$276,113	\$0	\$0	
	Allocated General Plant Net Fixed Assets	\$14,309,824	\$8,797,086	\$0	\$3,288,106	\$1,864,721	\$322,639	\$37,273	\$0	\$0	
	Meter Net Fixed Assets Including General Plant	\$135,246,376	\$83,474,547	\$0	\$30,962,427	\$17,469,730	\$3,026,286	\$313,386	\$0	\$0	
	<u>Misc Revenue</u>										
4082	Retail Services Revenues	(\$467,880)	(\$199,640)	(\$10,777)	(\$75,774)	(\$111,726)	(\$38,144)	(\$17,297)	(\$9,844)	(\$4,679)	CWNB
4084	Service Transaction Requests (STR) Revenues	(\$28,360)	(\$12,101)	(\$653)	(\$4,593)	(\$6,772)	(\$2,312)	(\$1,048)	(\$597)	(\$284)	CWNB
4090	Electric Services Incidental to Energy Sales	(\$2,115,000)	(\$902,449)	(\$48,717)	(\$342,526)	(\$505,045)	(\$172,427)	(\$78,187)	(\$44,499)	(\$21,150)	CWNB
4220	Other Electric Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	NFA
4225	Late Payment Charges	(\$4,000,000)	(\$2,229,964)	(\$90,781)	(\$920,612)	(\$646,365)	(\$89,987)	(\$14,363)	\$0	(\$7,928)	LPHA
	Sub-total	(\$6,611,240)	(\$3,344,153)	(\$150,928)	(\$1,343,504)	(\$1,269,908)	(\$302,871)	(\$110,895)	(\$54,940)	(\$34,040)	
	<u>Operation</u>										
5065	Meter Expense	\$845,002	\$521,783	\$0	\$193,365	\$109,035	\$18,891	\$1,929	\$0	\$0	CWMC
5070	Customer Premises - Operation Labour	\$2,532,470	\$1,822,739	\$160,934	\$205,564	\$35,843	\$1,308	\$146	\$271,085	\$34,850	CCA
5075	Customer Premises - Materials and Expenses	\$334,323	\$240,628	\$21,246	\$27,137	\$4,732	\$173	\$19	\$35,787	\$4,601	CCA
	Sub-total	\$3,711,795	\$2,585,150	\$182,180	\$426,066	\$149,610	\$20,372	\$2,094	\$306,872	\$39,451	
	<u>Maintenance</u>										
5175	Maintenance of Meters	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1860
	<u>Billing and Collection</u>										
5310	Meter Reading Expense	\$4,020,342	\$2,511,917	\$0	\$750,328	\$627,622	\$112,181	\$18,294	\$0	\$0	CWMR
5315	Customer Billing	\$10,123,962	\$5,340,964	\$747,456	\$2,212,101	\$1,322,940	\$35,912	\$6,361	\$145	\$458,083	CWNB
5320	Collecting	\$19,389,048	\$10,228,823	\$1,431,501	\$4,236,537	\$2,533,648	\$68,777	\$12,182	\$277	\$877,304	CWNB
5325	Collecting- Cash Over and Short	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	CWNB
5330	Collection Charges	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	CWNB
	Sub-total	\$33,533,352	\$18,081,704	\$2,178,957	\$7,198,966	\$4,484,210	\$216,870	\$36,837	\$422	\$1,335,387	
	Total Operation, Maintenance and Billing	\$37,245,147	\$20,666,854	\$2,361,137	\$7,625,033	\$4,633,819	\$237,242	\$38,931	\$307,294	\$1,374,838	
	Amortization Expense - Meters	\$13,797,005	\$8,519,553	\$0	\$3,157,215	\$1,780,292	\$308,445	\$31,500	\$0	\$0	
	Amortization Expense - General Plant assigned to Meters	\$2,819,872	\$1,733,540	\$0	\$647,949	\$367,459	\$63,579	\$7,345	\$0	\$0	
	Admin and General	\$20,712,359	\$11,598,856	\$1,310,384	\$4,187,097	\$2,582,298	\$132,985	\$22,494	\$171,322	\$706,922	
	Allocated PILs	\$1,040,994	\$642,806	\$0	\$238,214	\$134,324	\$23,272	\$2,377	\$0	\$0	
	Allocated Debt Return	\$3,471,031	\$2,143,337	\$0	\$794,288	\$447,883	\$77,598	\$7,925	\$0	\$0	
	Allocated Equity Return	\$5,230,167	\$3,229,591	\$0	\$1,196,837	\$674,873	\$116,925	\$11,941	\$0	\$0	
	Total	\$77,705,335	\$45,190,384	\$3,520,593	\$16,503,128	\$9,351,041	\$657,175	\$11,618	\$423,676	\$2,047,720	

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1 Residential	2 Competitive Sector Multi-Unit Residential	3 GS<50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MV	7 Street Light	9 Unmetered Scattered Load	
Distribution Plant											
1565	Conservation and Demand Management										CDMPP
	Expenditures and Recoveries	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
1830	Poles, Towers and Fixtures	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	#N/A
	Poles, Towers and Fixtures - Subtransmission Bulk										BCP
1830-3	Delivery	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
1830-4	Poles, Towers and Fixtures - Primary	\$62,477,797	\$49,688,844	\$4,387,154	\$12,726	\$28,614	\$16,942	\$3,567	\$7,389,922	\$950,029	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	\$39,944,821	\$28,775,971	\$2,540,703	\$3,237,916	\$549,292	\$10,844	\$235	\$4,279,676	\$550,184	SNCP
1835	Overhead Conductors and Devices	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	#N/A
	Overhead Conductors and Devices -										BCP
1835-3	Subtransmission Bulk Delivery	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
1835-4	Overhead Conductors and Devices - Primary	\$54,668,758	\$43,478,284	\$3,838,808	\$11,136	\$25,038	\$14,824	\$3,121	\$6,466,262	\$831,285	PNCP
1835-5	Overhead Conductors and Devices - Secondary	\$34,952,157	\$25,179,291	\$2,223,143	\$2,833,212	\$480,636	\$9,489	\$205	\$3,744,764	\$481,417	SNCP
1840	Underground Conduit	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	BCP
1840-4	Underground Conduit - Primary	\$268,695,738	\$213,694,803	\$18,867,656	\$54,732	\$123,061	\$72,860	\$15,339	\$31,781,537	\$4,085,749	PNCP
1840-5	Underground Conduit - Secondary	\$107,681,539	\$77,573,031	\$6,849,120	\$8,728,635	\$1,480,757	\$29,233	\$633	\$11,536,968	\$1,483,162	SNCP
1845	Underground Conductors and Devices	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	#N/A
	Underground Conductors and Devices - Bulk										BCP
1845-3	Delivery	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
1845-4	Underground Conductors and Devices - Primary	\$112,292,772	\$89,306,894	\$7,885,132	\$22,874	\$51,429	\$30,450	\$6,410	\$13,282,075	\$1,707,508	PNCP
											SNCP
1845-5	Underground Conductors and Devices - Secondary	\$45,002,048	\$32,419,162	\$2,862,370	\$3,647,853	\$618,835	\$12,217	\$264	\$4,821,506	\$619,840	
1850	Line Transformers	\$191,491,077	\$147,885,583	\$13,057,193	\$0	\$2,857,422	\$2,857,422	\$11,821	\$21,994,129	\$2,827,506	LTNCP
1855	Services	\$557,472,388	\$492,315,320	\$173,871	\$55,396,065	\$9,397,590	\$185,526	\$4,016	\$0	\$0	CWCS
1860	Meters	\$183,224,614	\$113,139,896	\$0	\$41,927,909	\$23,642,330	\$4,096,154	\$418,324	\$0	\$0	CWMC
0											
Sub-total		\$1,657,903,710	\$1,313,457,080	\$62,685,151	\$115,873,059	\$39,255,005	\$7,335,960	\$463,936	\$105,296,840	\$13,536,680	
Accumulated Amortization											
Accum. Amortization of Electric Utility Plant -Line											
Transformers, Services and Meters		(\$813,262,237)	(\$649,646,036)	(\$31,902,799)	(\$51,604,406)	(\$16,178,793)	(\$3,285,906)	(\$165,709)	(\$53,589,291)	(\$6,889,296)	
Customer Related Net Fixed Assets		\$844,641,473	\$663,811,044	\$30,782,352	\$64,268,652	\$23,076,212	\$4,050,054	\$298,226	\$51,707,549	\$6,647,384	
Allocated General Plant Net Fixed Assets		\$100,060,767	\$78,197,665	\$3,847,065	\$7,636,037	\$2,757,492	\$483,312	\$40,258	\$6,292,493	\$806,446	
Customer Related NFA Including General Plant		\$944,702,240	\$742,008,709	\$34,629,417	\$71,904,689	\$25,833,704	\$4,533,366	\$338,484	\$58,000,041	\$7,453,830	
Misc Revenue											
4082	Retail Services Revenues	(\$467,880)	(\$199,640)	(\$10,777)	(\$75,774)	(\$111,726)	(\$38,144)	(\$17,297)	(\$9,844)	(\$4,679)	CWNB
4084	Service Transaction Requests (STR) Revenues	(\$28,360)	(\$12,101)	(\$653)	(\$4,593)	(\$6,772)	(\$2,312)	(\$1,048)	(\$597)	(\$284)	CWNB
4090	Electric Services Incidental to Energy Sales	(\$2,115,000)	(\$902,449)	(\$48,717)	(\$342,526)	(\$505,045)	(\$172,427)	(\$78,187)	(\$44,499)	(\$21,150)	CWNB
4220	Other Electric Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	NFA
4225	Late Payment Charges	(\$4,000,000)	(\$2,229,964)	(\$90,781)	(\$920,612)	(\$646,365)	(\$89,987)	(\$14,363)	\$0	(\$7,928)	LPHA
4235	Miscellaneous Service Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	CWNB
Sub-total		(\$6,611,240)	(\$3,344,153)	(\$150,928)	(\$1,343,504)	(\$1,269,908)	(\$302,871)	(\$110,895)	(\$54,940)	(\$34,040)	

Operating and Maintenance											
5005	Operation Supervision and Engineering	\$7,245,609	\$5,874,321	\$306,711	\$364,752	\$91,855	\$23,183	\$3,741	\$514,820	\$66,226	1815-1855
5010	Load Dispatching	\$2,536,440	\$2,056,399	\$107,369	\$127,687	\$32,155	\$8,115	\$1,310	\$180,221	\$23,183	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	\$206,215	\$157,979	\$13,948	\$6,545	\$1,164	\$56	\$8	\$23,495	\$3,020	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	\$324,805	\$248,829	\$21,970	\$10,309	\$1,833	\$88	\$12	\$37,007	\$4,758	1830 & 1835
5035	Overhead Distribution Transformers- Operation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	\$177,068	\$137,028	\$12,099	\$4,132	\$755	\$48	\$8	\$20,379	\$2,620	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	\$818,435	\$633,364	\$55,921	\$19,099	\$3,488	\$222	\$35	\$94,196	\$12,110	1840 & 1845
5055	Underground Distribution Transformers - Operation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1850
5065	Meter Expense	\$845,002	\$521,783	\$0	\$193,365	\$109,035	\$18,891	\$1,929	\$0	\$0	CWMC
5070	Customer Premises - Operation Labour	\$2,532,470	\$1,822,739	\$160,934	\$205,564	\$35,843	\$1,308	\$146	\$271,085	\$34,850	CCA
5075	Customer Premises - Materials and Expenses	\$334,323	\$240,628	\$21,246	\$27,137	\$4,732	\$173	\$19	\$35,787	\$4,601	CCA
5085	Miscellaneous Distribution Expense	\$1,695,511	\$1,374,622	\$71,772	\$85,354	\$21,495	\$5,425	\$875	\$120,471	\$15,497	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1830 & 1835
5096	Other Rent	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	O&M
5105	Maintenance Supervision and Engineering	\$3,674,909	\$2,979,404	\$155,561	\$184,999	\$46,588	\$11,758	\$1,897	\$261,112	\$33,589	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1830
5125	Maintenance of Overhead Conductors and Devices	\$3,351,797	\$2,567,774	\$226,715	\$106,378	\$18,912	\$909	\$124	\$381,890	\$49,095	1835
5130	Maintenance of Overhead Services	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	\$1,061,229	\$812,995	\$71,781	\$33,681	\$5,988	\$288	\$39	\$120,912	\$15,544	1830 & 1835
5145	Maintenance of Underground Conduit	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1840
5150	Maintenance of Underground Conductors and Devices	\$1,773,580	\$1,372,524	\$121,184	\$41,389	\$7,558	\$481	\$75	\$204,127	\$26,242	1845
5155	Maintenance of Underground Services	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1855
5160	Maintenance of Line Transformers	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1850
5175	Maintenance of Meters	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	1860
Sub-total		\$26,577,392	\$20,800,390	\$1,347,212	\$1,410,392	\$381,398	\$70,945	\$10,218	\$2,265,503	\$291,334	
Billing and Collection											
5305	Supervision	\$289,494	\$152,725	\$21,373	\$63,255	\$37,829	\$1,027	\$182	\$4	\$13,099	CWNB
5310	Meter Reading Expense	\$4,020,342	\$2,511,917	\$0	\$750,328	\$627,622	\$112,181	\$18,294	\$0	\$0	CWMR
5315	Customer Billing	\$10,123,962	\$5,340,964	\$747,456	\$2,212,101	\$1,322,940	\$35,912	\$6,361	\$145	\$458,083	CWNB
5320	Collecting	\$19,389,048	\$10,228,823	\$1,431,501	\$4,236,537	\$2,533,648	\$68,777	\$12,182	\$277	\$877,304	CWNB
5325	Collecting- Cash Over and Short	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	CWNB
5330	Collection Charges	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	CWNB
5335	Bad Debt Expense	\$7,000,000	\$4,193,935	\$96	\$1,849,750	\$817,244	\$136,989	\$0	\$0	\$1,986	BDHA
5340	Miscellaneous Customer Accounts Expenses	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	CWNB
Sub-total		\$40,822,846	\$22,428,364	\$2,200,426	\$9,111,971	\$5,339,284	\$354,885	\$37,019	\$426	\$1,350,471	
Sub Total Operating, Maintenance and Billing		\$67,400,238	\$43,228,753	\$3,547,638	\$10,522,363	\$5,720,682	\$425,831	\$47,237	\$2,265,929	\$1,641,806	
Amortization Expense - Customer Related		\$47,443,032	\$35,000,973	\$1,579,684	\$4,629,617	\$2,522,655	\$594,663	\$128,996	\$2,645,235	\$341,209	
Amortization Expense - General Plant assigned to Meters		\$19,717,818	\$15,409,509	\$758,097	\$1,504,745	\$543,387	\$95,241	\$7,933	\$1,239,989	\$158,917	
Admin and General		\$37,569,689	\$24,261,269	\$1,968,870	\$5,778,093	\$3,187,977	\$238,698	\$27,293	\$1,263,296	\$844,194	
Allocated PILs		\$7,270,479	\$5,713,932	\$264,967	\$553,210	\$198,635	\$34,862	\$2,567	\$445,087	\$57,219	
Allocated Debt Return		\$24,242,274	\$19,052,213	\$883,492	\$1,844,591	\$662,316	\$116,242	\$8,559	\$1,484,072	\$190,788	
Allocated Equity Return		\$36,528,378	\$28,707,969	\$1,331,251	\$2,779,439	\$997,982	\$175,153	\$12,897	\$2,236,207	\$287,481	
PLCC Adjustment for Line Transformer		\$4,776,708	\$4,165,030	\$370,242	\$0	\$80,605	\$80,593	\$338	\$0	\$79,899	
PLCC Adjustment for Primary Costs		\$11,792,861	\$10,632,368	\$944,344	\$2,722	\$6,082	\$3,583	\$766	\$0	\$202,996	
PLCC Adjustment for Secondary Costs		\$14,294,465	\$10,981,069	\$2,814,440	\$2,646	\$5,842	\$3,435	\$0	\$0	\$487,034	
Total		\$202,696,635	\$142,251,998	\$6,054,044	\$26,263,187	\$12,471,196	\$1,290,207	\$123,484	\$11,524,875	\$2,717,644	

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	Competitive Sector Multi-Unit Residential	GS<50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MV	Street Light	Unmetered Scattered Load
<u>Distribution Plant</u>									
CWMC	\$ 183,224,614	\$ 113,139,896	\$ -	\$ 41,927,909	\$ 23,642,330	\$ 4,096,154	\$ 418,324	\$ -	\$ -
<u>Accumulated Amortization</u>									
Accum. Amortization of Electric Utility Plant - Meters only	\$ (62,288,063)	\$ (38,462,436)	\$ -	\$ (14,253,589)	\$ (8,037,320)	\$ (1,392,507)	\$ (142,211)	\$ -	\$ -
Meter Net Fixed Assets	\$ 120,936,551	\$ 74,677,461	\$ -	\$ 27,674,321	\$ 15,605,010	\$ 2,703,647	\$ 276,113	\$ -	\$ -
<u>Misc Revenue</u>									
CWNB	\$ (2,611,240)	\$ (1,114,190)	\$ (60,147)	\$ (422,893)	\$ (623,543)	\$ (212,884)	\$ (96,532)	\$ (54,940)	\$ (26,112)
NFA	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
LPHA	\$ (4,000,000)	\$ (2,229,964)	\$ (90,781)	\$ (920,612)	\$ (646,365)	\$ (89,987)	\$ (14,363)	\$ -	\$ (7,928)
Sub-total	\$ (6,611,240)	\$ (3,344,153)	\$ (150,928)	\$ (1,343,504)	\$ (1,269,908)	\$ (302,871)	\$ (110,895)	\$ (54,940)	\$ (34,040)
<u>Operation</u>									
CWMC	\$ 845,002	\$ 521,783	\$ -	\$ 193,365	\$ 109,035	\$ 18,891	\$ 1,929	\$ -	\$ -
CCA	\$ 2,866,793	\$ 2,063,368	\$ 182,180	\$ 232,702	\$ 40,575	\$ 1,481	\$ 165	\$ 306,872	\$ 39,451
Sub-total	\$ 3,711,795	\$ 2,585,150	\$ 182,180	\$ 426,066	\$ 149,610	\$ 20,372	\$ 2,094	\$ 306,872	\$ 39,451
<u>Maintenance</u>									
1860	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<u>Billing and Collection</u>									
CWMR	\$ 4,020,342	\$ 2,511,917	\$ -	\$ 750,328	\$ 627,622	\$ 112,181	\$ 18,294	\$ -	\$ -
CWNB	\$ 29,513,010	\$ 15,569,787	\$ 2,178,957	\$ 6,448,638	\$ 3,856,588	\$ 104,688	\$ 18,543	\$ 422	\$ 1,335,387
Sub-total	\$ 33,533,352	\$ 18,081,704	\$ 2,178,957	\$ 7,198,966	\$ 4,484,210	\$ 216,870	\$ 36,837	\$ 422	\$ 1,335,387
Total Operation, Maintenance and Billing	\$ 37,245,147	\$ 20,666,854	\$ 2,361,137	\$ 7,625,033	\$ 4,633,819	\$ 237,242	\$ 38,931	\$ 307,294	\$ 1,374,838
Amortization Expense - Meters	\$ 13,797,005	\$ 8,519,553	\$ -	\$ 3,157,215	\$ 1,780,292	\$ 308,445	\$ 31,500	\$ -	\$ -
Allocated PILs	\$ 930,852	\$ 575,063	\$ -	\$ 212,917	\$ 119,987	\$ 20,791	\$ 2,094	\$ -	\$ -
Allocated Debt Return	\$ 3,103,779	\$ 1,917,458	\$ -	\$ 709,937	\$ 400,076	\$ 69,325	\$ 6,982	\$ -	\$ -
Allocated Equity Return	\$ 4,676,790	\$ 2,889,236	\$ -	\$ 1,069,737	\$ 602,837	\$ 104,460	\$ 10,521	\$ -	\$ -
Total	\$ 53,142,333	\$ 31,224,011	\$ 2,210,208	\$ 11,431,334	\$ 6,267,103	\$ 437,391	\$ (20,866)	\$ 252,354	\$ 1,340,797

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	Competitive Sector Multi-Unit Residential	GS<50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MV	Street Light	Unmetered Scattered Load
<u>Distribution Plant</u>									
CWMC	\$ 183,224,614	\$ 113,139,896	\$ -	\$ 41,927,909	\$ 23,642,330	\$ 4,096,154	\$ 418,324	\$ -	\$ -
<u>Accumulated Amortization</u>									
Accum. Amortization of Electric Utility Plant - Meters only	\$ (62,288,063)	\$ (38,462,436)	\$ -	\$ (14,253,589)	\$ (8,037,320)	\$ (1,392,507)	\$ (142,211)	\$ -	\$ -
Meter Net Fixed Assets	\$ 120,936,551	\$ 74,677,461	\$ -	\$ 27,674,321	\$ 15,605,010	\$ 2,703,647	\$ 276,113	\$ -	\$ -
Allocated General Plant Net Fixed Assets	\$ 14,309,824	\$ 8,797,086	\$ -	\$ 3,288,106	\$ 1,864,721	\$ 322,639	\$ 37,273	\$ -	\$ -
Meter Net Fixed Assets Including General Plant	\$ 135,246,376	\$ 83,474,547	\$ -	\$ 30,962,427	\$ 17,469,730	\$ 3,026,286	\$ 313,386	\$ -	\$ -
<u>Misc Revenue</u>									
CWNB	\$ (2,611,240)	\$ (1,114,190)	\$ (60,147)	\$ (422,893)	\$ (623,543)	\$ (212,884)	\$ (96,532)	\$ (54,940)	\$ (26,112)
NFA	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
LPHA	\$ (4,000,000)	\$ (2,229,964)	\$ (90,781)	\$ (920,612)	\$ (646,365)	\$ (89,987)	\$ (14,363)	\$ -	\$ (7,928)
Sub-total	\$ (6,611,240)	\$ (3,344,153)	\$ (150,928)	\$ (1,343,504)	\$ (1,269,908)	\$ (302,871)	\$ (110,895)	\$ (54,940)	\$ (34,040)
<u>Operation</u>									
CWMC	\$ 845,002	\$ 521,783	\$ -	\$ 193,365	\$ 109,035	\$ 18,891	\$ 1,929	\$ -	\$ -
CCA	\$ 2,866,793	\$ 2,063,368	\$ 182,180	\$ 232,702	\$ 40,575	\$ 1,481	\$ 165	\$ 306,872	\$ 39,451
Sub-total	\$ 3,711,795	\$ 2,585,150	\$ 182,180	\$ 426,066	\$ 149,610	\$ 20,372	\$ 2,094	\$ 306,872	\$ 39,451
<u>Maintenance</u>									
1860	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<u>Billing and Collection</u>									
CWMR	\$ 4,020,342	\$ 2,511,917	\$ -	\$ 750,328	\$ 627,622	\$ 112,181	\$ 18,294	\$ -	\$ -
CWNB	\$ 29,513,010	\$ 15,569,787	\$ 2,178,957	\$ 6,448,638	\$ 3,856,588	\$ 104,688	\$ 18,543	\$ 422	\$ 1,335,387
Sub-total	\$ 33,533,352	\$ 18,081,704	\$ 2,178,957	\$ 7,198,966	\$ 4,484,210	\$ 216,870	\$ 36,837	\$ 422	\$ 1,335,387
Total Operation, Maintenance and Billing	\$ 37,245,147	\$ 20,666,854	\$ 2,361,137	\$ 7,625,033	\$ 4,633,819	\$ 237,242	\$ 38,931	\$ 307,294	\$ 1,374,838
Amortization Expense - Meters	\$ 13,797,005	\$ 8,519,553	\$ -	\$ 3,157,215	\$ 1,780,292	\$ 308,445	\$ 31,500	\$ -	\$ -
Amortization Expense - General Plant assigned to Meters	\$ 2,819,872	\$ 1,733,540	\$ -	\$ 647,949	\$ 367,459	\$ 63,579	\$ 7,345	\$ -	\$ -
Admin and General	\$ 20,712,359	\$ 11,598,856	\$ 1,310,384	\$ 4,187,097	\$ 2,582,298	\$ 132,985	\$ 22,494	\$ 171,322	\$ 706,922
Allocated PILs	\$ 1,040,994	\$ 642,806	\$ -	\$ 238,214	\$ 134,324	\$ 23,272	\$ 2,377	\$ -	\$ -
Allocated Debt Return	\$ 3,471,031	\$ 2,143,337	\$ -	\$ 794,288	\$ 447,883	\$ 77,598	\$ 7,925	\$ -	\$ -
Allocated Equity Return	\$ 5,230,167	\$ 3,229,591	\$ -	\$ 1,196,837	\$ 674,873	\$ 116,925	\$ 11,941	\$ -	\$ -
Total	\$ 77,705,335	\$ 45,190,384	\$ 3,520,593	\$ 16,503,128	\$ 9,351,041	\$ 657,175	\$ 11,618	\$ 423,676	\$ 2,047,720

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	Competitive Sector Multi-Unit Residential	GS<50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MV	Street Light	Unmetered Scattered Load
Distribution Plant										
	CDMPP	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	Poles, Towers and Fixtures	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	BCP	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	PNCP	\$ 498,135,066	\$ 396,168,826	\$ 34,978,750	\$ 101,468	\$ 228,142	\$ 135,076	\$ 28,437	\$ 58,919,796	\$ 7,574,571
	SNCP	\$ 227,580,565	\$ 163,947,455	\$ 14,475,337	\$ 18,447,616	\$ 3,129,521	\$ 61,783	\$ 1,337	\$ 24,382,915	\$ 3,134,602
	Overhead Conductors and Devices	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	LTNCP	\$ 191,491,077	\$ 147,885,583	\$ 13,057,193	\$ -	\$ 2,857,422	\$ 2,857,422	\$ 11,821	\$ 21,994,129	\$ 2,827,506
	CWCS	\$ 557,472,388	\$ 492,315,320	\$ 173,871	\$ 55,396,065	\$ 9,397,590	\$ 185,526	\$ 4,016	\$ -	\$ -
	CWMC	\$ 183,224,614	\$ 113,139,896	\$ -	\$ 41,927,909	\$ 23,642,330	\$ 4,096,154	\$ 418,324	\$ -	\$ -
	Sub-total	\$ 1,657,903,710	\$ 1,313,457,080	\$ 62,685,151	\$ 115,873,059	\$ 39,255,005	\$ 7,335,960	\$ 463,936	\$ 105,296,840	\$ 13,536,680
Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	\$ (813,262,237)	\$ (649,646,036)	\$ (31,902,799)	\$ (51,604,406)	\$ (16,178,793)	\$ (3,285,906)	\$ (165,709)	\$ (53,589,291)	\$ (6,889,296)
	Customer Related Net Fixed Assets	\$ 844,641,473	\$ 663,811,044	\$ 30,782,352	\$ 64,268,652	\$ 23,076,212	\$ 4,050,054	\$ 298,226	\$ 51,707,549	\$ 6,647,384
	Allocated General Plant Net Fixed Assets	\$ 100,060,767	\$ 78,197,665	\$ 3,847,065	\$ 7,636,037	\$ 2,757,492	\$ 483,312	\$ 40,258	\$ 6,292,493	\$ 806,446
	Customer Related NFA Including General Plant	\$ 944,702,240	\$ 742,008,709	\$ 34,629,417	\$ 71,904,689	\$ 25,833,704	\$ 4,533,366	\$ 338,484	\$ 58,000,041	\$ 7,453,830
Misc Revenue										
	CWNB	\$ (2,611,240)	\$ (1,114,190)	\$ (60,147)	\$ (422,893)	\$ (623,543)	\$ (212,884)	\$ (96,532)	\$ (54,940)	\$ (26,112)
	NFA	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
	LPFA	\$ (4,000,000)	\$ (2,229,964)	\$ (90,781)	\$ (920,612)	\$ (646,365)	\$ (89,987)	\$ (14,363)	\$ -	\$ (7,928)
	Sub-total	\$ (6,611,240)	\$ (3,344,153)	\$ (150,928)	\$ (1,343,504)	\$ (1,269,908)	\$ (302,871)	\$ (110,895)	\$ (54,940)	\$ (34,040)
Operating and Maintenance										
	1815-1855	\$ 15,152,469	\$ 12,284,746	\$ 641,413	\$ 762,793	\$ 192,093	\$ 48,481	\$ 7,823	\$ 1,076,624	\$ 138,495
	1830 & 1835	\$ 1,592,248	\$ 1,219,803	\$ 107,700	\$ 50,534	\$ 8,984	\$ 432	\$ 59	\$ 181,414	\$ 23,322
	1850	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	1840 & 1845	\$ 995,503	\$ 770,392	\$ 68,020	\$ 23,232	\$ 4,242	\$ 270	\$ 42	\$ 114,576	\$ 14,730
	CWMC	\$ 845,002	\$ 521,783	\$ -	\$ 193,365	\$ 109,035	\$ 18,891	\$ 1,929	\$ -	\$ -
	CCA	\$ 2,866,793	\$ 2,063,368	\$ 182,180	\$ 232,702	\$ 40,575	\$ 1,481	\$ 165	\$ 306,872	\$ 39,451
	O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	1830	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	1835	\$ 3,351,797	\$ 2,567,774	\$ 226,715	\$ 106,378	\$ 18,912	\$ 909	\$ 124	\$ 381,890	\$ 49,095
	1855	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	1840	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	1845	\$ 1,773,580	\$ 1,372,524	\$ 121,184	\$ 41,389	\$ 7,558	\$ 481	\$ 75	\$ 204,127	\$ 26,242
	1860	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	Sub-total	\$ 26,577,392	\$ 20,800,390	\$ 1,347,212	\$ 1,410,392	\$ 381,398	\$ 70,945	\$ 10,218	\$ 2,265,503	\$ 291,334

Billing and Collection

CWNB	\$	29,802,504	\$	15,722,511	\$	2,200,330	\$	6,511,893	\$	3,894,418	\$	105,715	\$	18,725	\$	426	\$	1,348,486
CWMMR	\$	4,020,342	\$	2,511,917	\$	-	\$	750,328	\$	627,622	\$	112,181	\$	18,294	\$	-	\$	-
BDHA	\$	7,000,000	\$	4,193,935	\$	96	\$	1,849,750	\$	817,244	\$	136,989	\$	-	\$	-	\$	1,986
Sub-total	\$	40,822,846	\$	22,428,364	\$	2,200,426	\$	9,111,971	\$	5,339,284	\$	354,885	\$	37,019	\$	426	\$	1,350,471
Sub Total Operating, Maintenance and Billing	\$	67,400,238	\$	43,228,753	\$	3,547,638	\$	10,522,363	\$	5,720,682	\$	425,831	\$	47,237	\$	2,265,929	\$	1,641,806
Amortization Expense - Customer Related	\$	47,443,032	\$	35,000,973	\$	1,579,684	\$	4,629,617	\$	2,522,655	\$	594,663	\$	128,996	\$	2,645,235	\$	341,209
Amortization Expense - General Plant assigned to Meters	\$	19,717,818	\$	15,409,509	\$	758,097	\$	1,504,745	\$	543,387	\$	95,241	\$	7,933	\$	1,239,989	\$	158,917
Admin and General	\$	37,569,689	\$	24,261,269	\$	1,968,870	\$	5,778,093	\$	3,187,977	\$	238,698	\$	27,293	\$	1,263,296	\$	844,194
Allocated PILs	\$	7,270,479	\$	5,713,932	\$	264,967	\$	553,210	\$	198,635	\$	34,862	\$	2,567	\$	445,087	\$	57,219
Allocated Debt Return	\$	24,242,274	\$	19,052,213	\$	883,492	\$	1,844,591	\$	662,316	\$	116,242	\$	8,559	\$	1,484,072	\$	190,788
Allocated Equity Return	\$	36,528,378	\$	28,707,969	\$	1,331,251	\$	2,779,439	\$	997,982	\$	175,153	\$	12,897	\$	2,236,207	\$	287,481
PLCC Adjustment for Line Transformer	\$	4,776,708	\$	4,165,030	\$	370,242	\$	-	\$	80,605	\$	80,593	\$	338	\$	-	\$	79,899
PLCC Adjustment for Primary Costs	\$	11,792,861	\$	10,632,368	\$	944,344	\$	2,722	\$	6,082	\$	3,583	\$	766	\$	-	\$	202,996
PLCC Adjustment for Secondary Costs	\$	14,294,465	\$	10,981,069	\$	2,814,440	\$	2,646	\$	5,842	\$	3,435	\$	-	\$	-	\$	487,034
Total	\$	202,696,635	\$	142,251,998	\$	6,054,044	\$	26,263,187	\$	12,471,196	\$	1,290,207	\$	123,484	\$	11,524,875	\$	2,717,644

OEB Appendix 2-P Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%	
Residential	\$ 256,839,427	46.86%	\$ 297,522,749	42.44%	/C
GS < 50 kW	\$ 74,280,097	13.55%	\$ 101,778,059	14.52%	/C
GS 50-999 kW	\$ 136,457,707	24.90%	\$ 162,701,911	23.21%	/C
GS 1000-4999 kW	\$ 38,493,073	7.02%	\$ 57,371,254	8.18%	/C
Large User	\$ 20,035,803	3.66%	\$ 31,746,741	4.53%	/C
Street Lighting	\$ 17,331,487	3.16%	\$ 25,745,486	3.67%	/C
Unmetered Scattered Load (USL)	\$ 4,627,832	0.84%	\$ 4,413,515	0.63%	/C
Competitive Sector Multi-Unit Residential (New Rate Class in 2013)		0.00%	\$ 19,821,346	2.83%	/C
		0.00%		0.00%	
Embedded distributor class		0.00%		0.00%	
Total	\$ 548,065,426	100.00%	\$ 701,101,061	100.00%	/C

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E	
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue	
Residential	\$ 214,465,673	\$ 258,761,594	\$ 261,546,284	\$ 19,510,221	/C
GS < 50 kW	\$ 69,430,402	\$ 83,770,615	\$ 85,198,396	\$ 8,137,006	/C
GS 50-999 kW	\$ 158,177,191	\$ 186,578,280	\$ 186,578,280	\$ 6,475,013	/C
GS 1000-4999 kW	\$ 52,894,930	\$ 57,509,557	\$ 57,509,557	\$ 893,042	/C
Large User	\$ 27,857,584	\$ 29,824,900	\$ 30,054,988	\$ 331,213	/C
Street Lighting	\$ 12,284,580	\$ 14,821,848	\$ 12,284,555	\$ 8,843,082	/C
Unmetered Scattered Load (USL)	\$ 2,673,863	\$ 3,226,126	\$ 3,309,911	\$ 608,167	/C
Competitive Sector Multi-Unit Residential (New Rate Class in 2013)	\$ 17,001,339	\$ 20,512,810	\$ 18,523,758	\$ 1,297,588	/C
Embedded distributor class					
Total	\$ 554,785,562	\$ 655,005,730	\$ 655,005,729	\$ 46,095,332	/C

Notes:

- Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transformer Ownership Allowance. Exclude revenue from rate adders and rate riders.
- Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement
- Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.
- Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2011	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	89%	94	94	85 - 115
GS < 50 kW	97%	90	92	80 - 120
GS 50-999 kW	118%	119	119	80 - 120
GS 1000-4999 kW	124%	102	102	80 - 120
Large User	116%	95	96	85 - 115
Street Lighting	71%	92	82	70 - 120
Unmetered Scattered Load (USL)	82%	87	89	80 - 120
Competitive Sector Multi-Unit Residential (New Rate Class in 2013)		110	100	85-115
Embedded distributor class				

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before"

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range	
	0	1	2		
	%	%	%		
Residential	94			85 - 115	/C
GS < 50 kW	92			80 - 120	/C
GS 50-999 kW	119			80 - 120	
GS 1000-4999 kW	102			80 - 120	
Large User	96			85 - 115	
Street Lighting	82			70 - 120	/C
Sentinel Lighting				80 - 120	
Unmetered Scattered Load (USL)	89			80 - 120	/C
Competitive Sector Multi-Unit Residential (New Rate Class in 2013)	100			85-115	
				0	
Embedded distributor class					

Note

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2014 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2014. In 2015 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2014 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Tariff Schedules for the Bridge and Test Years are shown in Exhibit 8, Tab 3, Schedules 1 through 3. Exhibit 8, Tab 7, Schedule 1 shows the bill impacts for customers in each rate class for various levels of billing units.

The proposed rate changes primarily reflect THESL's increase in revenue requirement and the results of applying the OEB's Cost Allocation model.

A summary of the bill impacts (including all rate riders) arising from the utility's proposals is shown in Table 1 below.

Table 1: Bill Impacts – change in monthly bill (total bill before tax & OCEB)

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

/C

1 **2.2. Streetlighting Rates**

2 The OEB initiated a consultation in 2012 related to cost allocation policy for unmetered
3 loads. The result of this consultation was the EB-2012-0383 Report of the Board issued
4 on December 19, 2013.

5
6 Specifically with respect to the Streetlighting class, the OEB noted the following:

7 *“The Board remains concerned with the allocation of costs to daisy-chain*
8 *configured systems. The disparity in the cost allocation result between a street*
9 *lighting customer configuration with multiple devices per connection and a street*
10 *lighting customer with a device to connection ratio close to 1:1 appears to be*
11 *disproportionate when compared to actual costs to serve the street lighting rate*
12 *class. The Board believes that further investigation is necessary before making a*
13 *determination. The Board will issue a letter shortly to begin a consultation*
14 *process for this single issue.” (page 18)*

15
16 In Toronto Hydro’s 2008 rates application (EB-2007-0680), the utility raised its concern
17 that the device to connection ratio may be inappropriately over-allocating costs to the
18 Streetlighting class. Nevertheless, Toronto Hydro’s streetlighting distribution rates have
19 been set since that time guided by the model. Over the 2008-2010 period, the
20 Streetlighting class experienced a significant increase in rates as the model-derived
21 revenue-to-cost ratio was brought from its level of approximately 27% to 70% in 2010.

22
23 In the current 2015 cost allocation exercise, the revenue-to-cost ratio for the streetlighting
24 class based on current rates (adjusted for the 2015 revenue requirement) is 0.92. This /C
25 value is a result of the inputs in the model as described in Exhibit 7, Tab 1, Schedule 1.

26 In light of the OEB’s findings in the EB-2012-0383 consultation which echo Toronto
27 Hydro’s previously stated concerns, the utility proposes to hold distribution rates for the

1 Streetlighting class at 2014 levels. Holding the rates constant would result in a revenue-
2 to-cost ratio of 0.82 for this class, which is within the OEB's guidelines. /C

3
4 The OEB has indicated that it will be initiating a consultation on the single issue of the
5 device to connection ratio in the cost allocation model. Toronto Hydro will incorporate
6 any directives resulting from that process, if they occur before the time of rate
7 finalization for 2015.

8 9 **2.3. Fixed versus Variable Charge**

10 Toronto Hydro has maintained the fixed/variable split at 2014 approved ratios for the
11 purposes of designing the fixed and variable components of rates for all years in this
12 application.

13
14 Toronto Hydro notes that the OEB is currently undergoing a process to review rate design
15 for the Residential and small General Service classes (EB-2012-0410). Toronto Hydro
16 has not incorporated any of the rate designs as outlined in the Draft Report of the Board
17 at this time. However, should the OEB issue direction to LDCs related to this
18 consultation, Toronto Hydro is prepared to incorporate changes in rate design and update
19 its evidence accordingly.

20 21 **2.4. Monthly Fixed Charge**

22 The OEB's Cost Allocation model produces estimates of the floor and ceiling monthly
23 fixed rates for each rate class based on data from the model. The following table
24 summarizes that information for the 2015 model, and shows the current and proposed
25 fixed rates for each customer class.

1 **Table 2: Monthly Fixed Charge**

	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Streetlighting	USL
CA Model Floor	4.24	3.40	13.78	43.31	82.72	-35.83	0.23	9.53
CA Model Ceiling	19.34	9.32	31.66	86.22	244.36	210.01	10.53	19.32
Current (2014)	18.63	17.35	24.80	36.29	700.68	3,071.47	1.32	4.94
Proposed (2015)	22.72	18.90	30.43	43.63	831.65	3,668.99	1.32	6.12

2 The proposed fixed rate for the Residential, CSMUR, GS 1000-4999 kW, and Large Use
3 classes is above the model calculated ceiling. For the Residential and CSMUR classes,
4 this is a result of changes in inputs to the Cost Allocation model as well as maintaining
5 the fixed variable split at current levels. For the GS 1000-4999 kW and Large Use
6 classes, the fixed charge has been above the ceiling rate since information from the Cost
7 Allocation model has been provided in 2006. Toronto Hydro notes that the proportion of
8 total revenue recovered through the fixed rate for the GS 1000-4999 kW and Large Use
9 classes is less than 10%.

10

11 **2.5. Transformer Allowance**

12 THESL is not proposing to change its current transformer allowance credit in this
13 application. The rate provided to customers that own their own transformation facilities
14 will remain at \$0.62/kVA per 30 days.

15

16 **2.6. Billing Determinants**

17 Toronto Hydro is not proposing any changes to the currently approved billing
18 determinants for any customer class. Customers will continue to be billed on a 30-day
19 fixed portion and on a kVA or kWh variable portion. For the Unmetered Scattered Load

TOTALS

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015⁴

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a separately metered living accommodation, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to a dwelling unit that consists of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; a separately metered dwelling within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per 30 days)	\$	~~18.63~~ 22.72
~~Rate Rider for Smart Meter Incremental Revenue Requirement – effective until April 30, 2015~~	~~\$~~	~~0.67 (per 30 days)~~
Rate Rider for ~~Recovery of 2008 – 2010~~ Smart Meter ~~Costs Disposition~~ – effective until April 30, 2017	\$	0.08 (per 30 days)
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	\$	0.78 (per 30 days)
~~Rate Rider for Smart Metering Entity Variance – effective until April 30, 2016~~	~~\$~~	~~0.05 (per 30 days)~~
~~Rate Rider for Stranded Meters Disposition – effective until April 30, 2020~~	~~\$~~	~~0.22 (per 30 days)~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$~~	~~0.07 (per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	~~\$~~	~~0.73 (per 30 days)~~
Distribution Volumetric Rate	\$/kWh	~~0.015380~~ 0.01876
~~Rate Rider for Low Voltage Variance – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00005~~
~~Rate Rider for PILs and Tax Variance – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00022~~
~~Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00010~~
~~Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00059~~
~~Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00016~~
~~Rate Rider for Residual RARA – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00007~~
~~Rate Rider for LRAMVA – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00003~~
~~Rate Rider for POEB – Tax Savings – effective until April 30, 2018~~	~~\$/kWh~~	~~-0.00069~~
~~Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018~~	~~\$/kWh~~	~~-0.00213~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$/kWh~~	~~0.00005~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	~~\$/kWh~~	~~0.00061~~
~~Rate Rider for Application of Tax Change – effective until April 30, 2015~~	~~\$/kWh~~	~~(0.00004)~~
Retail Transmission Rate – Network Service Rate	\$/kWh	~~0.008060~~ 0.00819
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	~~0.005600~~ 0.00563

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~**4**

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
~~Rural Rate Protection Charge~~ <u>Rural or Remote Electricity Rate Protection Charge (RRRP)</u>			
	\$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015~~4~~

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a multi-unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per 30 days)	\$	~~17.35~~ 18.90
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018 ~~day~~ days)	\$	0.78 ____ (per 30
~~Rate Rider for Smart Metering Entity Variance – effective until April 30, 2016~~	~~\$~~	~~0.03 (per 30 days)~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$~~	~~0.06 (per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~ ~~(per 30 days)~~	~~\$~~	~~0.68~~
Distribution Volumetric Rate	\$/kWh	~~0.026170~~ 0.02851
~~Rate Rider for Low Voltage Variance – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00002~~
~~Rate Rider for PILs and Tax Variance – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00021~~
~~Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00010~~
~~Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00052~~
~~Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00016~~
~~Rate Rider for Residual RARA – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00006~~
~~Rate Rider for LRAMVA – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00001~~
~~Rate Rider for POEB – Tax Savings – effective until April 30, 2018~~	~~\$/kWh~~	~~-0.00067~~
~~Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018~~	~~\$/kWh~~	~~-0.00208~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$/kWh~~	~~0.00009~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	~~\$/kWh~~	~~0.00103~~
~~Rate Rider for Application of Tax Change – effective until April 30, 2015~~	~~\$/kWh~~	~~(0.00007)~~
Retail Transmission Rate – Network Service Rate	\$/kWh	~~0.008060~~ 0.00819
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	~~0.005600~~ 0.00563

MONTHLY RATES AND CHARGES – Regulatory Component

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~**4**

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

Wholesale Market Service Rate	\$/kWh	0.0044	
~~Rural or Remote Electricity Rate Protection Charge (RRRP)~~ ~~Rural Rate Protection Charge~~	~~\$/kWh~~	~~0.0013~~	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015⁵⁴

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per 30 days)	\$	24.8030.43	
~~Rate Rider for Recovery of 2008 – 2010 Smart Meter Costs – effective until April 30, 2017~~			
~~Rate Rider for Smart Meter Incremental Revenue Requirement – effective until April 30, 2015~~	\$	3.68	(per 30 days)
~~Rate Rider for Smart Meter Disposition – effective until April 30, 2017~~	\$	5.60	(per 30 days)
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018 ~~days)~~	\$	0.78	(per 30 days)
~~Rate Rider for Smart Metering Entity Variance – effective until April 30, 2016~~	\$	0.05	(per 30 days)
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	\$	0.09	(per 30 days)
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~ ~~(per 30 days)~~	\$	0.97	
~~Rate Rider for Stranded Meters Disposition – effective until April 30, 2020~~	\$	1.19	(per 30 days)
Distribution Volumetric Rate	\$/kWh	0.022930.02814	
Rate Rider for Low Voltage Variance – effective until April 30, 2016	\$/kWh	0.00005	
Rate Rider for PILs and Tax Variance – effective until April 30, 2016	\$/kWh	-0.00015	
Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016	\$/kWh	-0.00007	
Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016	\$/kWh	0.00051	
Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016	\$/kWh	0.00011	
Rate Rider for Residual RARA – effective until April 30, 2016	\$/kWh	-0.00007	
Rate Rider for LRAMVA – effective until April 30, 2016	\$/kWh	0.00046	
Rate Rider for POEB – Tax Savings – effective until April 30, 2018	\$/kWh	-0.00047	
Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018	\$/kWh	-0.00147	
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	\$/kWh	0.00008	
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	\$/kWh	0.00090	
~~Rate Rider for Application of Tax Change – effective until April 30, 2015~~	\$/kWh	(0.00003)	
Retail Transmission Rate – Network Service Rate	\$/kWh	0.007890.00792	
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.005050.00508	

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
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Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~**4**

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

~~Rural or Remote Electricity Rate Protection Charge (RRRP)~~ ~~Rural Rate Protection Charge~~

~~\$/kWh 0.0013~~

Standard Supply Service – Administration Charge (if applicable)

\$

0.25

(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015⁵⁴

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per 30 days)	\$	<u>36,2943.63</u>	
~~Rate Rider for Recovery of 2008 – 2010 Smart Meter Costs – effective until April 30, 2017~~			
~~Rate Rider for Smart Meter Incremental Revenue Requirement – effective until April 30, 2015~~	\$	~~11.16~~	~~(per 30 days)~~
~~Rate Rider for Smart Meter Disposition – effective until April 30, 2017~~	\$	~~18.79~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	\$	~~0.13~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	\$	~~1.42~~	
~~(per 30 days)~~			
~~Rate Rider for Stranded Meters Disposition – effective until April 30, 2020~~	\$	~~3.62~~	~~(per 30 days)~~
Distribution Volumetric Rate (per 30 days)	\$/kVA	<u>5.71166.8676</u>	
~~Rate Rider for Low Voltage Variance – effective until April 30, 2016~~	\$/kVA	~~0.0188~~	~~(per 30 days)~~
~~Rate Rider for PILs and Tax Variance – effective until April 30, 2016~~	\$/kVA	~~-0.0244~~	~~(per 30 days)~~
~~Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016~~	\$/kVA	~~-0.0116~~	~~(per 30 days)~~
~~Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016~~	\$/kVA	~~0.0440~~	~~(per 30 days)~~
~~Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016~~	\$/kVA	~~0.0183~~	~~(per 30 days)~~
~~Rate Rider for Residual RARA – effective until April 30, 2016~~	\$/kVA	~~-0.0287~~	~~(per 30 days)~~
~~Rate Rider for LRAMVA – effective until April 30, 2016~~	\$/kVA	~~0.1077~~	~~(per 30 days)~~
~~Rate Rider for POEB – Tax Savings – effective until April 30, 2018~~	\$/kVA	~~-0.0766~~	~~(per 30 days)~~
~~Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018~~	\$/kVA	~~-0.2382~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	\$/kVA	~~0.0202~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	\$/kVA	~~0.2225~~	
~~(per 30 days)~~			
~~Rate Rider for Application of Tax Change – effective until April 30, 2015~~	\$/kVA	~~(0.0056)~~	~~(per 30 days)~~
Retail Transmission Rate – Network Service Rate (per 30 days)	\$/kW	<u>2.79172.8350</u>	
Retail Transmission Rate – Line and Transformation Connection Service Rate (per 30 days)	\$/kW	<u>1.92531.9361</u>	

MONTHLY RATES AND CHARGES – Regulatory Component

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~**4**

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

Wholesale Market Service Rate	\$/kWh	0.0044	
~~Rural or Remote Electricity Rate Protection Charge (RRRP)~~ ~~Rural Rate Protection Charge~~			
~~\$/kWh 0.0013~~			
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015⁵⁴

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per 30 days)	\$	700.68831.65
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$~~	~~2.49 (per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	~~\$~~	~~27.34~~
~~(per 30 days)~~		
Distribution Volumetric Rate (per 30 days)	\$/kVA	4.54195.3909
~~Rate Rider for Low Voltage Variance – effective until April 30, 2016~~	~~\$/kVA~~	~~0.0230 (per 30 days)~~
~~Rate Rider for PILs and Tax Variance – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0197 (per 30 days)~~
~~Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0093 (per 30 days)~~
~~Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016~~	~~\$/kVA~~	~~0.0217 (per 30 days)~~
~~Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016~~	~~\$/kVA~~	~~0.0147 (per 30 days)~~
~~Rate Rider for Residual RARA – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0327 (per 30 days)~~
~~Rate Rider for LRAMVA – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0035 (per 30 days)~~
~~Rate Rider for POEB – Tax Savings – effective until April 30, 2018~~	~~\$/kVA~~	~~-0.0616 (per 30 days)~~
~~Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018~~	~~\$/kVA~~	~~-0.1916 (per 30 days)~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$/kVA~~	~~0.0161 (per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	~~\$/kVA~~	~~0.1771~~
~~(per 30 days)~~		
~~Rate Rider for Application of Tax Change – effective until April 30, 2015~~	~~\$/kVA~~	~~(0.0047) (per 30 days)~~
Retail Transmission Rate – Network Service Rate (per 30 days)	\$/kW	2.69722.7391
Retail Transmission Rate – Line and Transformation Connection Service Rate (per 30 days)	\$/kW	1.92341.9342

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
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Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~**4**

This schedule supersedes and replaces all previously
 approved schedules of Rates, Charges and Loss Factors

~~Rural or Remote Electricity Rate Protection Charge (RRRP)~~ ~~Rural Rate Protection Charge~~

~~\$/kWh 0.0013~~

Standard Supply Service – Administration Charge (if applicable)

\$

0.25

(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015⁵⁴

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

LARGE USE > 5000 KW SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	3,071,473,668.99	
(per 30 days)			
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$~~	~~10.90~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	~~\$~~	~~119.83~~	
~~(per 30 days)~~			
Distribution Volumetric Rate	\$/kVA	4.83885,7801	
(per 30 days)			
~~Rate Rider for Low Voltage Variance – effective until April 30, 2016~~	~~\$/kVA~~	~~0.0219~~	~~(per 30 days)~~
~~Rate Rider for PILs and Tax Variance – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0202~~	~~(per 30 days)~~
~~Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0096~~	~~(per 30 days)~~
~~Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016~~	~~\$/kVA~~	~~0.0170~~	~~(per 30 days)~~
~~Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016~~	~~\$/kVA~~	~~0.0151~~	~~(per 30 days)~~
~~Rate Rider for Residual RARA – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0343~~	~~(per 30 days)~~
~~Rate Rider for LRAMVA – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0187~~	~~(per 30 days)~~
~~Rate Rider for POEB – Tax Savings – effective until April 30, 2018~~	~~\$/kVA~~	~~-0.0634~~	~~(per 30 days)~~
~~Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018~~	~~\$/kVA~~	~~-0.1974~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$/kVA~~	~~0.0172~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	~~\$/kVA~~	~~0.1887~~	
~~(per 30 days)~~			
~~Rate Rider for Application of Tax Change – effective until April 30, 2015~~	~~\$/kVA~~	~~(0.0049)~~	~~(per 30 days)~~
Retail Transmission Rate – Network Service Rate	\$/kW	3,07473,1224	
(per 30 days)			
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	2,13692,1489	
(per 30 days)			

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
~~Rural or Remote Electricity Rate Protection Charge (RRRP)~~	~~\$/kWh~~	~~0.0013~~
~~Rural Rate Protection Charge~~		

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~**4**

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)
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Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~**4**

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

STANDBY POWER SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g., nameplate rating of generation facility).

Service Charge	\$	202.01	(per 30 days)
Distribution Volumetric Rate			
For General Service 50 – 999 kW	\$/kVA	~~5.7116~~ 6.8676	(per 30 days)
For General Service 1,000 – 4,999 kW	\$/kVA	~~4.5419~~ 5.3909	(per 30 days)
For Large Use	\$/kVA	~~4.8388~~ 5.7801	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015⁵⁴

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	4.946.12	(per 30 days)
Connection Charge (per connection)	\$	0.590.62	(per 30 days)
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$~~	~~0.02~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Foregone Revenue (per connection) – effective until April 30, 2015~~	~~\$~~	~~0.00~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	~~\$~~	~~0.02~~	~~(per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs (per connection) – effective until April 30, 2015~~	~~\$~~	~~0.19~~	~~(per 30 days)~~
Distribution Volumetric Rate	\$/kWh	0.061950.07669	
~~Rate Rider for Low Voltage Variance – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00005~~	
~~Rate Rider for PILs and Tax Variance – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00029~~	
~~Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00014~~	
~~Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00113~~	
~~Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016~~	~~\$/kWh~~	~~0.00021~~	
~~Rate Rider for Residual RARA – effective until April 30, 2016~~	~~\$/kWh~~	~~-0.00009~~	
~~Rate Rider for POEB – Tax Savings – effective until April 30, 2018~~	~~\$/kWh~~	~~-0.00090~~	
~~Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018~~	~~\$/kWh~~	~~-0.00280~~	
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$/kWh~~	~~0.00022~~	
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~	~~\$/kWh~~	~~0.00245~~	
~~Rate Rider for Application of Tax Change – effective until April 30, 2015~~	~~\$/kWh~~	~~(0.00006)~~	
Retail Transmission Rate – Network Service Rate	\$/kWh	0.004990.00498	
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.003540.00356	

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
~~Rural or Remote Electricity Rate Protection Charge (RRRP) Rural Rate Protection Charge~~	~~\$/kWh~~	~~0.0013~~	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015~~4~~

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (Per Device) _____ (per 30 days)	\$	~~1,321.32~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$~~	~~0.00 (per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~ ~~(per 30 days)~~	~~\$~~	~~0.05~~
Distribution Volumetric Rate ~~(per 30 days)~~	~~\$/kVA~~	~~29.3201~~ ~~29.3201~~
~~Rate Rider for Low Voltage Variance – effective until April 30, 2016~~	~~\$/kVA~~	~~0.0174 (per 30 days)~~
~~Rate Rider for PILs and Tax Variance – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.1604 (per 30 days)~~
~~Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0759 (per 30 days)~~
~~Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016~~	~~\$/kVA~~	~~0.2850 (per 30 days)~~
~~Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016~~	~~\$/kVA~~	~~0.1200 (per 30 days)~~
~~Rate Rider for Residual RARA – effective until April 30, 2016~~	~~\$/kVA~~	~~-0.0293 (per 30 days)~~
~~Rate Rider for POEB – Tax Savings – effective until April 30, 2018~~	~~\$/kVA~~	~~-0.5028 (per 30 days)~~
~~Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018~~	~~\$/kVA~~	~~-1.5641 (per 30 days)~~
~~Rate Rider for Recovery of Foregone Revenue – effective until April 30, 2015~~	~~\$/kVA~~	~~0.1041 (per 30 days)~~
~~Rate Rider for Recovery of Incremental Capital Module Costs – effective until April 30, 2015~~ ~~(per 30 days)~~	~~\$/kVA~~	~~1.1439~~
~~Rate Rider for Application of Tax Change – effective until April 30, 2015~~	~~\$/kVA~~	~~(0.0354) (per 30 days)~~
Retail Transmission Rate – Network Service Rate (per 30 days)	\$/kW	~~2.4829~~ ~~2.5215~~
Retail Transmission Rate – Line and Transformation Connection Service Rate (per 30 days)	\$/kW	~~2.2957~~ ~~2.3086~~

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
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Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~**4**

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

~~Rural or Remote Electricity Rate Protection Charge (RRRP)~~ ~~Rural Rate Protection Charge~~

~~\$/kWh 0.0013~~

Standard Supply Service – Administration Charge (if applicable)

\$

0.25

(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~⁴

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	5.33	(per 30 days)
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Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015~~4~~

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

ALLOWANCES

Transformer Allowance for Ownership	\$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)	

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Customer Administration

Duplicate Invoices for Previous Billing	\$	~~1525.00~~
~~Request for Other Billing or System Information~~	\$	~~25.00~~
Easement Letter	\$	~~1525.00~~
Income Tax Letter	\$	~~1525.00~~
~~Account History~~	\$	~~25.00~~
~~Returned Cheque (plus bank charges)~~	\$	~~25.00~~
Account ~~Set Up~~ Charge/ ~~Change of~~ ~~Occupancy~~ ~~Charge~~ (plus credit agency costs if applicable)	\$	~~3035.00~~
~~Returned Cheque (plus bank charges)~~	\$	~~1525.00~~
~~Special Meter Reads~~	\$	~~3055.00~~
Meter ~~Dispute~~ ~~Charge~~ plus Measurement Canada ~~Fees~~ (if meter found correct)	\$	~~3055.00~~
~~Service Ceall – Customer Owned Equipment or Customer Missed Appointment~~	\$	~~55.00~~
~~Collection of Account Charge – No Disconnection~~	\$	~~55.00~~
~~Non-Payment of Account~~		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
~~Collection of Account Charge – No Disconnection~~	\$	~~3055.00~~
~~Disconnect/Reconnect Charges for non-payment of account~~		
~~At Meter During Regular Hours~~	\$	~~65120.00~~
~~At Meter After Hours~~	\$	~~185400.00~~
~~Disconnect/Reconnect at Meter – During Regular Hours~~	\$	~~120.00~~
~~Disconnect/Reconnect at Meter – After Regular Hours~~	\$	~~400.00~~
Install/Remove Load Control Device – During Regular hours	\$	~~65120.00~~
Install/Remove Load Control Device – After Regular hours	\$	~~185400.00~~
Disconnect/Reconnect at Pole – During Regular Hours	\$	~~185400.00~~
Disconnect/Reconnect at Pole – After Regular Hours	\$	~~415820.00~~
~~Temporary Service Install & Remove —Overhead – With Transformer~~	\$	~~2040.00~~
Specific Charge for Access to ~~the~~ Power Poles (~~Wireline Attachments~~) – per pole/year	\$	~~22.35~~ 92.53
~~Specific Charge for Access to the Power Poles – per pole/year~~ (Third Party Attachments to Poles)	\$	~~18.55~~
~~Specific Charge for Access to the Power Poles – per pole/year~~ (Hydro Attachments on Third Party Poles)	\$	~~(22.75)~~

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 201~~5~~**4**

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approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

Establishing Service Agreements		
Standard charge (one-time charge), per agreement per retailer	\$	100.00
Monthly Fixed Charge, per retailer	\$	20.00
Monthly Variable Charge, per customer, per retailer	\$	0.50
Distributor-Consolidated Billing		
Standard billing charge, per month, per customer, per retailer	\$	0.30
Retailer-Consolidated Billing		
Avoided cost credit, per month, per customer, per retailer	\$	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, regardless of whether or not the STR can be processed	\$	0.25
Processing fee, per request, applied to the requesting party if the request is processed	\$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	\$	2.00

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015⁵⁴

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Billing Determinant:

The billing determinant is the customer's metered energy consumption adjusted by the Total Loss Factor as approved by the Board and set out in this Schedule of Rates.

(A) Primary Metering Adjustment	0.9900
(B) Supply Facilities Loss Factor	1.0045

Distribution Loss Factors	
(C) Customer less than 5,000 kW	1.0330
(D) Customer greater than 5,000 kW	1.0141

Total Loss Factors

Secondary Metered Customers	
(E) Customer less than 5,000 kW (B)*(C)	1.0376
(F) Customer greater than 5,000 kW (B)*(D)	1.0187

Primary metered customers	
(G) Customer less than 5,000 kW (A)*(E)	1.0272
(H) Customer greater than 5,000 kW (A)*(F)	1.0085

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

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RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a separately metered living accommodation, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to a dwelling unit that consists of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; a separately metered dwelling within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	22.72	(per 30 days)
Rate Rider for Recovery of 2008 – 2010 Smart Meter Costs – effective until April 30, 2017	\$	0.08	(per 30 days)
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	\$	0.78	(per 30 days)
Rate Rider for Smart Metering Entity Variance – effective until April 30, 2016	\$	0.05	(per 30 days)
Rate Rider for Stranded Meters Disposition – effective until April 30, 2020	\$	0.22	(per 30days)
Distribution Volumetric Rate	\$/kWh	0.01876	
Rate Rider for Low Voltage Variance – effective until April 30, 2016	\$/kWh	0.00005	
Rate Rider for PILs and Tax Variance – effective until April 30, 2016	\$/kWh	-0.00022	
Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016	\$/kWh	-0.00010	
Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016	\$/kWh	0.00059	
Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016	\$/kWh	0.00016	
Rate Rider for Residual RARA– effective until April 30, 2016	\$/kWh	-0.00007	
Rate Rider for LRAMVA – effective until April 30, 2016	\$/kWh	-0.00003	
Rate Rider for POEB – Tax Savings – effective until April 30, 2018	\$/kWh	-0.00069	
Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018	\$/kWh	-0.00213	
Retail Transmission Rate – Network Service Rate	\$/kWh	0.00819	
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.00563	

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a multi-unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	18.90	(per 30 days)
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	\$	0.78	(per 30 days)
Rate Rider for Smart Metering Entity Variance – effective until April 30, 2016	\$	0.03	(per 30 days)
Distribution Volumetric Rate	\$/kWh	0.02851	
Rate Rider for Low Voltage Variance – effective until April 30, 2016	\$/kWh	0.00002	
Rate Rider for PILs and Tax Variance – effective until April 30, 2016	\$/kWh	-0.00021	
Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016	\$/kWh	-0.00010	
Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016	\$/kWh	0.00052	
Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016	\$/kWh	0.00016	
Rate Rider for Residual RARA – effective until April 30, 2016	\$/kWh	-0.00006	
Rate Rider for LRAMVA – effective until April 30, 2016	\$/kWh	0.00001	
Rate Rider for POEB – Tax Savings – effective until April 30, 2018	\$/kWh	-0.00067	
Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018	\$/kWh	-0.00208	
Retail Transmission Rate – Network Service Rate	\$/kWh	0.00819	
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.00563	

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	30.43	(per 30 days)
Rate Rider for Recovery of 2008 – 2010 Smart Meter Costs – effective until April 30, 2017	\$	5.60	(per 30 days)
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	\$	0.78	(per 30 days)
Rate Rider for Smart Metering Entity Variance – effective until April 30, 2016	\$	0.05	(per 30 days)
Rate Rider for Stranded Meters Disposition – effective until April 30, 2020	\$	1.19	(per 30 days)
Distribution Volumetric Rate	\$/kWh	0.02814	
Rate Rider for Low Voltage Variance – effective until April 30, 2016	\$/kWh	0.00005	
Rate Rider for PILs and Tax Variance – effective until April 30, 2016	\$/kWh	-0.00015	
Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016	\$/kWh	-0.00007	
Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016	\$/kWh	0.00051	
Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016	\$/kWh	0.00011	
Rate Rider for Residual RARA – effective until April 30, 2016	\$/kWh	-0.00007	
Rate Rider for LRAMVA – effective until April 30, 2016	\$/kWh	0.00046	
Rate Rider for POEB – Tax Savings – effective until April 30, 2018	\$/kWh	-0.00047	
Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018	\$/kWh	-0.00147	
Retail Transmission Rate – Network Service Rate	\$/kWh	0.00792	
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.00508	

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	43.63	(per 30 days)
Rate Rider for Recovery of 2008 – 2010 Smart Meter Costs – effective until April 30, 2017	\$	18.79	(per 30 days)
Rate Rider for Stranded Meters Disposition – effective until April 30, 2020	\$	3.62	(per 30 days)
Distribution Volumetric Rate	\$/kVA	6.8676	(per 30 days)
Rate Rider for Low Voltage Variance – effective until April 30, 2016	\$/kVA	0.0188	(per 30 days)
Rate Rider for PILs and Tax Variance – effective until April 30, 2016	\$/kVA	-0.0244	(per 30 days)
Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016	\$/kVA	-0.0116	(per 30 days)
Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016	\$/kVA	0.0440	(per 30 days)
Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016	\$/kVA	0.0183	(per 30 days)
Rate Rider for Residual RARA – effective until April 30, 2016	\$/kVA	-0.0287	(per 30 days)
Rate Rider for LRAMVA – effective until April 30, 2016	\$/kVA	0.1077	(per 30 days)
Rate Rider for POEB – Tax Savings – effective until April 30, 2018	\$/kVA	-0.0766	(per 30 days)
Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018	\$/kVA	-0.2382	(per 30 days)
Retail Transmission Rate – Network Service Rate	\$/kW	2.8350	(per 30 days)
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.9361	(per 30 days)

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	831.65	(per 30 days)
Distribution Volumetric Rate	\$/kVA	5.3909	(per 30 days)
Rate Rider for Low Voltage Variance – effective until April 30, 2016	\$/kVA	0.0230	(per 30 days)
Rate Rider for PILs and Tax Variance – effective until April 30, 2016	\$/kVA	-0.0197	(per 30 days)
Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016	\$/kVA	-0.0093	(per 30 days)
Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016	\$/kVA	0.0217	(per 30 days)
Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016	\$/kVA	0.0147	(per 30 days)
Rate Rider for Residual RARA– effective until April 30, 2016	\$/kVA	-0.0327	(per 30 days)
Rate Rider for LRAMVA – effective until April 30, 2016	\$/kVA	-0.0035	(per 30 days)
Rate Rider for POEB – Tax Savings – effective until April 30, 2018	\$/kVA	-0.0616	(per 30 days)
Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018	\$/kVA	-0.1916	(per 30 days)
Retail Transmission Rate – Network Service Rate	\$/kW	2.7391	(per 30 days)
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.9342	(per 30 days)

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

LARGE USE > 5000 KW SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	3,668.99	(per 30 days)
Distribution Volumetric Rate	\$/kVA	5.7801	(per 30 days)
Rate Rider for Low Voltage Variance – effective until April 30, 2016	\$/kVA	0.0219	(per 30 days)
Rate Rider for PILs and Tax Variance – effective until April 30, 2016	\$/kVA	-0.0202	(per 30 days)
Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016	\$/kVA	-0.0096	(per 30 days)
Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016	\$/kVA	0.0170	(per 30 days)
Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016	\$/kVA	0.0151	(per 30 days)
Rate Rider for Residual RARA – effective until April 30, 2016	\$/kVA	-0.0343	(per 30 days)
Rate Rider for LRAMVA – effective until April 30, 2016	\$/kVA	-0.0187	(per 30 days)
Rate Rider for POEB – Tax Savings – effective until April 30, 2018	\$/kVA	-0.0634	(per 30 days)
Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018	\$/kVA	-0.1974	(per 30 days)
Retail Transmission Rate – Network Service Rate	\$/kW	3.1224	(per 30 days)
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	2.1489	(per 30 days)

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

STANDBY POWER SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g., nameplate rating of generation facility).

Service Charge	\$	202.01	(per 30 days)
Distribution Volumetric Rate			
For General Service 50 – 999 kW	\$/kVA	6.8676	(per 30 days)
For General Service 1,000 – 4,999 kW	\$/kVA	5.3909	(per 30 days)
For Large Use	\$/kVA	5.7801	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	6.12	(per 30 days)
Connection Charge (per connection)	\$	0.62	(per 30 days)
Distribution Volumetric Rate	\$/kWh	0.07669	
Rate Rider for Low Voltage Variance – effective until April 30, 2016	\$/kWh	0.00005	
Rate Rider for PILs and Tax Variance – effective until April 30, 2016	\$/kWh	-0.00029	
Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016	\$/kWh	-0.00014	
Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016	\$/kWh	0.00113	
Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016	\$/kWh	0.00021	
Rate Rider for Residual RARA– effective until April 30, 2016	\$/kWh	-0.00009	
Rate Rider for POEB – Tax Savings – effective until April 30, 2018	\$/kWh	-0.00090	
Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018	\$/kWh	-0.00280	
Retail Transmission Rate – Network Service Rate	\$/kWh	0.00498	
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.00356	

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (Per Device)	\$	1.32	(per 30 days)
Distribution Volumetric Rate	\$/kVA	29.3201	(per 30 days)
Rate Rider for Low Voltage Variance – effective until April 30, 2016	\$/kVA	0.0174	(per 30 days)
Rate Rider for PILs and Tax Variance – effective until April 30, 2016	\$/kVA	-0.1604	(per 30 days)
Rate Rider for PILs and Tax Variance HST – effective until April 30, 2016	\$/kVA	-0.0759	(per 30 days)
Rate Rider for Gain on Sale Named Properties – effective until April 30, 2016	\$/kVA	0.2850	(per 30 days)
Rate Rider for Hydro One Capital Contributions Variance – effective until April 30, 2016	\$/kVA	0.1200	(per 30 days)
Rate Rider for Residual RARA – effective until April 30, 2016	\$/kVA	-0.0293	(per 30 days)
Rate Rider for POEB – Tax Savings – effective until April 30, 2018	\$/kVA	-0.5028	(per 30 days)
Rate Rider for Operations Center Consolidation Plan Sharing – effective until April 30, 2018	\$/kVA	-1.5641	(per 30 days)
Retail Transmission Rate – Network Service Rate	\$/kW	2.5215	(per 30 days)
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	2.3086	(per 30 days)

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044	
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	\$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	5.33	(per 30 days)
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Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

ALLOWANCES

Transformer Allowance for Ownership	\$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)	

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Duplicate Invoices for Previous Billing	\$	25.00
Request for Other Billing or System Information	\$	25.00
Easement Letter	\$	25.00
Income Tax Letter	\$	25.00
Account History	\$	25.00
Returned Cheque (plus bank charges)	\$	25.00
Account Set Up Charge/Change of Occupancy Charge (plus credit agency costs if applicable)	\$	35.00
Special Meter Reads	\$	55.00
Meter Dispute Charge plus Measurement Canada Fees (if meter found correct)	\$	55.00
Service Call – Customer Owned Equipment or Customer Missed Appointment	\$	55.00
Collection of Account Charge – No Disconnection	\$	55.00
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Disconnect/Reconnect at Meter – During Regular Hours	\$	120.00
Disconnect/Reconnect at Meter – After Regular Hours	\$	400.00
Install/Remove Load Control Device – During Regular hours	\$	120.00
Install/Remove Load Control Device – After Regular hours	\$	400.00
Disconnect/Reconnect at Pole – During Regular Hours	\$	400.00
Disconnect/Reconnect at Pole – After Regular Hours	\$	820.00
Temporary Service Install & Remove —Overhead – With Transformer	\$	2040.00
Specific Charge for Access to Power Poles (Wireline Attachments) – per pole/year	\$	92.53

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

Establishing Service Agreements		
Standard charge (one-time charge), per agreement per retailer	\$	100.00
Monthly Fixed Charge, per retailer	\$	20.00
Monthly Variable Charge, per customer, per retailer	\$	0.50
Distributor-Consolidated Billing		
Standard billing charge, per month, per customer, per retailer	\$	0.30
Retailer-Consolidated Billing		
Avoided cost credit, per month, per customer, per retailer	\$	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, regardless of whether or not the STR can be processed	\$	0.25
Processing fee, per request, applied to the requesting party if the request is processed	\$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	\$	2.00

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Proposed Implementation Date May 1, 2015

**This schedule supersedes and replaces all previously
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LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Billing Determinant:

The billing determinant is the customer's metered energy consumption adjusted by the Total Loss Factor as approved by the Board and set out in this Schedule of Rates.

(A) Primary Metering Adjustment	0.9900
(B) Supply Facilities Loss Factor	1.0045

Distribution Loss Factors	
(C) Customer less than 5,000 kW	1.0330
(D) Customer greater than 5,000 kW	1.0141

Total Loss Factors

Secondary Metered Customers	
(E) Customer less than 5,000 kW (B)*(C)	1.0376
(F) Customer greater than 5,000 kW (B)*(D)	1.0187

Primary metered customers	
(G) Customer less than 5,000 kW (A)*(E)	1.0272
(H) Customer greater than 5,000 kW (A)*(F)	1.0085

OEB Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections/ Devices	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates (Adjusted for Day of Service)	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference (from Rounding)
		Start of Test Year (see note 3)	End of Test Year (see note 3)	Average	kWh	kW	Monthly Service Charge Adjusted for Days of Service	Volumetric						
								kWh	kW (Adjusted for Days of Service)	1.0139				
Residential	Customers	612,985	612,985	612,985	4,909,898,145	-	\$ 22.72	\$ 0.01876		\$ 261,555,089	\$ 261,546,284		\$ 261,546,284	-\$ 8,805
GS < 50 kW	Customers	69,131	69,131	69,131	2,118,402,162	-	\$ 30.43	\$ 0.02814		\$ 85,206,322	\$ 85,198,396		\$ 85,198,396	-\$ 7,926
GS 50-999 kW	Customers	12,054	12,054	12,054	9,848,614,894	26,395,826	\$ 43.63		\$ 6.8676	\$ 190,192,341	\$ 186,578,280	\$ 3,614,998	\$ 190,193,278	\$ 937
GS 1000-4999 kW	Customers	440	440	440	4,654,535,571	10,671,871	\$ 831.65		\$ 5.3909	\$ 62,782,131	\$ 57,509,557	\$ 5,272,905	\$ 62,782,462	\$ 331
Large User	Customers	49	49	49	2,228,386,374	5,305,030	\$ 3,668.99		\$ 5.7801	\$ 33,276,817	\$ 30,054,988	\$ 3,221,994	\$ 33,276,982	\$ 165
Street Lighting	Devices	164,098	164,098	164,098	114,092,929	324,479	\$ 1.32		\$ 29.3201	\$ 12,281,306	\$ 12,284,555		\$ 12,284,555	\$ 3,249
Unmetered Scattered Load (USL)	Customers	898	898	898	41,132,354	-	\$ 6.12	\$ 0.07669		\$ 3,220,389	\$ 3,221,123		\$ 3,221,123	\$ 734
Unmetered Scattered Load (USL)	Connections	11,720	11,720	11,720			\$ 0.62			\$ 87,197	\$ 88,788		\$ 88,788	\$ 1,591
Competitive Sector Multi-Unit Residential	Customers	54,122	54,122	54,122	213,116,822		\$ 18.90	\$ 0.02851		\$ 18,521,314	\$ 18,523,758		\$ 18,523,758	\$ 2,444
				-						\$ -			\$ -	\$ -
				-						\$ -			\$ -	\$ -
				-						\$ -			\$ -	\$ -
				-						\$ -			\$ -	\$ -
										\$ -			\$ -	\$ -
Total										\$ 667,122,907	\$ 655,005,729	\$ 12,109,897	\$ 667,115,626	-\$ 7,281

Note

- 1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement.
- 2 Rates should be entered with the number of decimal places that will show on the Tariff of Rates and Charges.
- 3 Toronto Hydro uses Mid-year customers/connections/devices

Appendix 2-W
Bill Impacts

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 800 kWh ☒ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Service Charge	per 30 days	\$ 18.63	1	\$ 18.63	\$ 22.72	1	\$ 22.72	\$ 4.09	21.95%	\$ 23.84	1	\$ 23.84	\$ 1.12	4.93%	\$ 25.91	1	\$ 25.91	\$ 2.07	8.68%	\$ 27.75	1	\$ 27.75	\$ 1.84	7.10%	\$ 29.25	1	\$ 29.25	\$ 1.50	5.41%
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$ 0.08	1	\$ 0.08	\$ 0.08	1	\$ 0.08	\$ -	0.00%	\$ 0.08	1	\$ 0.08	\$ -	0.00%		1	\$ -	\$ -0.08			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ 0.67	1	\$ 0.67		1	\$ -	-\$ 0.67			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.07	1	\$ 0.07		1	\$ -	-\$ 0.07			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.73	1	\$ 0.73		1	\$ -	-\$ 0.73			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Stranded Meters Disposition - 5 yrs.	per 30 days				\$ 0.22	1	\$ 0.22	\$ 0.22		\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%
Rate Rider for Smart Metering Entity Variance	per 30 days				\$ 0.05	1	\$ 0.05	\$ 0.05			1	\$ 0.05	\$ 0.05																
Distribution Volumetric Rate	per kWh	\$ 0.01538	800	\$ 12.30	\$ 0.01876	800	\$ 15.01	\$ 2.70	21.98%	\$ 0.01969	800	\$ 15.75	\$ 0.74	4.96%	\$ 0.02140	800	\$ 17.12	\$ 1.37	8.68%	\$ 0.02291	800	\$ 18.33	\$ 1.21	7.06%	\$ 0.02415	800	\$ 19.32	\$ 0.99	5.41%
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00005	800	\$ 0.04		800	\$ -	-\$ 0.04			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00061	800	\$ 0.49		800	\$ -	-\$ 0.49			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00004	800	-\$ 0.03		800	\$ -	\$ 0.03			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Rate Rider for PILs and Tax Variance	per kWh		800	\$ -	-\$ 0.00022	800	-\$ 0.18	-\$ 0.18			800	\$ -	\$ 0.18			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Rate Rider for PILs and Tax Variance HST	per kWh		800	\$ -	-\$ 0.00010	800	-\$ 0.08	-\$ 0.08			800	\$ -	\$ 0.08			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Rate Rider for Gain on Sale Named Properties	per kWh		800	\$ -	\$ 0.00059	800	\$ 0.47	\$ 0.47			800	\$ -	-\$ 0.47			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Rate Rider for Hydro One Capital Contributions Variance	per kWh		800	\$ -	\$ 0.00016	800	\$ 0.13	\$ 0.13			800	\$ -	-\$ 0.13			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Rate Rider for Residual RARA	per kWh		800	\$ -	-\$ 0.00007	800	-\$ 0.06	-\$ 0.06			800	\$ -	\$ 0.06			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Rate Rider for LRAMVA	per kWh		800	\$ -	-\$ 0.00003	800	-\$ 0.02	-\$ 0.02			800	\$ -	\$ 0.02			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Rate Rider for IFRS - 2014 Derecognition	per kWh		800	\$ -		800	\$ -	\$ -		\$ 0.00067	800	\$ 0.54	\$ 0.54		\$ 0.00067	800	\$ 0.54	\$ -	0.00%	\$ 0.00067	800	\$ 0.54	\$ -	0.00%	\$ 0.00067	800	\$ 0.54	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kWh		800	\$ -	-\$ 0.00069	800	-\$ 0.55	-\$ 0.55		-\$ 0.00069	800	-\$ 0.55	\$ -	0.00%	-\$ 0.00069	800	-\$ 0.55	\$ -	0.00%		800	\$ -	\$ 0.55		800	\$ -	\$ -		
Rate Rider for 2012-14 Lost Revenue	per kWh		800	\$ -		800	\$ -	\$ -		\$ 0.00074	800	\$ 0.59	\$ 0.59		\$ 0.00074	800	\$ 0.59	\$ -	0.00%	\$ 0.00074	800	\$ 0.59	\$ -	0.00%	\$ 0.00074	800	\$ 0.59	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		800	\$ -	-\$ 0.00213	800	-\$ 1.70	-\$ 1.70		-\$ 0.00213	800	-\$ 1.70	\$ -	0.00%	-\$ 0.00213	800	-\$ 1.70	\$ -	0.00%		800	\$ -	\$ 1.70		800	\$ -	\$ -		
Sub-Total A (excluding pass through)				\$ 32.98			\$ 36.09	\$ 3.11	9.42%			\$ 38.76	\$ 2.68	7.42%			\$ 42.12	\$ 3.36	8.66%			\$ 47.43	\$ 5.30	12.59%			\$ 49.92	\$ 2.49	5.25%
Rate Rider for Low Voltage Variance	per kWh		800	\$ -	\$ 0.00005	800	\$ 0.04	\$ 0.04			800	\$ -	-\$ 0.04			800	\$ -	\$ -			800	\$ -	\$ -		800	\$ -	\$ -		
Line Losses on Cost of Power	per kWh	\$ 0.0925	30	\$ 2.78	\$ 0.0925	30	\$ 2.78	\$ -	0.00%	\$ 0.0925	30	\$ 2.78	\$ -	0.00%	\$ 0.0925	30	\$ 2.78	\$ -	0.00%	\$ 0.0925	30	\$ 2.78	\$ -	0.00%	\$ 0.0925	30	\$ 2.78	\$ -	0.00%
Rate Rider for Smart Metering Entity Charge - Ends Oct. 31, 2018.	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ -	-\$ 0.78	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 36.54			\$ 39.69	\$ 3.15	8.61%			\$ 42.33	\$ 2.64	6.65%			\$ 45.68	\$ 3.36	7.93%			\$ 50.99	\$ 5.30	11.61%			\$ 52.70	\$ 1.71	3.36%
RTSR - Network	per kWh	\$ 0.00806	830	\$ 6.69	\$ 0.00819	830	\$ 6.80	\$ 0.11	1.61%	\$ 0.00819	830	\$ 6.80	\$ -	0.00%	\$ 0.00819	830	\$ 6.80	\$ -	0.00%	\$ 0.00819	830	\$ 6.80	\$ -	0.00%	\$ 0.00819	830	\$ 6.80	\$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	\$ 0.00560	830	\$ 4.65	\$ 0.00563	830	\$ 4.67	\$ 0.02	0.54%	\$ 0.00563	830	\$ 4.67	\$ -	0.00%	\$ 0.00563	830	\$ 4.67	\$ -	0.00%	\$ 0.00563	830	\$ 4.67	\$ -	0.00%	\$ 0.00563	830	\$ 4.67	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				\$ 47.88			\$ 51.16	\$ 3.28	6.85%			\$ 53.80	\$ 2.64	5.16%			\$ 57.15	\$ 3.36	6.24%			\$ 62.46	\$ 5.30	9.28%			\$ 64.17	\$ 1.71	2.74%
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	830	\$ 3.65	\$ 0.0044	830	\$ 3.65	\$ -	0.00%	\$ 0.0044	830	\$ 3.65	\$ -	0.00%	\$ 0.0044	830	\$ 3.65	\$ -	0.00%	\$ 0.0044	830	\$ 3.65	\$ -	0.00%	\$ 0.0044	830	\$ 3.65	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	830	\$ 1.08	\$ 0.0013	830	\$ 1.08	\$ -	0.00%	\$ 0.0013	830	\$ 1.08	\$ -	0.00%	\$ 0.0013	830	\$ 1.08	\$ -	0.00%	\$ 0.0013	830	\$ 1.08	\$ -	0.00%	\$ 0.0013	830	\$ 1.08	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	800	\$ 5.60	\$ 0.0070	800	\$ 5.60	\$ -	0.00%	\$ 0.0070	800	\$ 5.60	\$ -	0.00%	\$ 0.0070	800	\$ 5.60	\$ -	0.00%	\$ 0.0070	800	\$ 5.60	\$ -	0.00%	\$ 0.0070	800	\$ 5.60	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	512	\$ 38.40	\$ 0.0750	512	\$ 38.40	\$ -	0.00%	\$ 0.0750	512	\$ 38.40	\$ -	0.00%	\$ 0.0750	512	\$ 38.40	\$ -	0.00%	\$ 0.0750	512	\$ 38.40	\$ -	0.00%	\$ 0.0750	512	\$ 38.40	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	144	\$ 16.13	\$ 0.1120	144	\$ 16.13	\$ -	0.00%	\$ 0.1120	144	\$ 16.13	\$ -	0.00%	\$ 0.1120	144	\$ 16.13	\$ -	0.00%	\$ 0.1120	144	\$ 16.13	\$ -	0.00%	\$ 0.1120	144	\$ 16.13	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	144	\$ 19.44	\$ 0.1350	144	\$ 19.44	\$ -	0.00%	\$ 0.1350	144	\$ 19.44	\$ -	0.00%	\$ 0.1350	144	\$ 19.44	\$ -	0.00%	\$ 0.1350	144	\$ 19.44	\$ -	0.00%	\$ 0.1350	144	\$ 19.44	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	600	\$ 51.60	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	200	\$ 20.20	\$ 0.1010	200	\$ 20.20	\$ -	0.00%	\$ 0.1010	200	\$ 20.20	\$ -	0.00%	\$ 0.1010	200	\$ 20.20	\$ -	0.00%	\$ 0.1010	200	\$ 20.20	\$ -	0.00%	\$ 0.1010	200	\$ 20.20	\$ -	0.00%
Total Bill on TOU (before Taxes)				\$ 132.43			\$ 135.71	\$ 3.28	2.48%			\$ 138.35	\$ 2.64	1.94%			\$ 141.70	\$ 3.36	2.43%			\$ 147.01	\$ 5.30	3.74%			\$ 148.72	\$	

Appendix 2-W
Bill Impacts

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 400 kWh ☒ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact		
Charge Unit		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	
Service Charge	per 30 days	\$ 18.63	1	\$ 18.63	\$ 22.72	1	\$ 22.72	\$ 4.09	21.95%	\$ 23.84	1	\$ 23.84	\$ 1.12	4.93%	\$ 25.91	1	\$ 25.91	\$ 2.07	8.68%	\$ 27.75	1	\$ 27.75	\$ 1.84	7.10%	\$ 29.25	1	\$ 29.25	\$ 1.50	5.41%	
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$ 0.08	1	\$ 0.08	\$ 0.08	1	\$ 0.08	\$ -	0.00%	\$ 0.08	1	\$ 0.08	\$ -	0.00%		1	\$ -	\$ -0.08				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ 0.67	1	\$ 0.67		1	\$ -	-\$ 0.67			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.07	1	\$ 0.07		1	\$ -	-\$ 0.07			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.73	1	\$ 0.73		1	\$ -	-\$ 0.73			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Stranded Meters Disposition	per 30 days				\$ 0.22	1	\$ 0.22	\$ 0.22		\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	
Rate Rider for Smart Metering Entity Variance	per 30 days				\$ 0.05	1	\$ 0.05	\$ 0.05			1	\$ 0.05	\$ 0.05			1	\$ 0.05	\$ -				1	\$ 0.05	\$ -		1	\$ 0.05	\$ -		
Distribution Volumetric Rate	per kWh	\$ 0.01538	400	\$ 6.15	\$ 0.01876	400	\$ 7.50	\$ 1.35	21.98%	\$ 0.01969	400	\$ 7.88	\$ 0.37	4.96%	\$ 0.02140	400	\$ 8.56	\$ 0.68	8.68%	\$ 0.02291	400	\$ 9.16	\$ 0.60	7.06%	\$ 0.02415	400	\$ 9.66	\$ 0.50	5.41%	
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00005	400	\$ 0.02		400	\$ -	-\$ 0.02			400	\$ -	\$ -			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00061	400	\$ 0.24		400	\$ -	-\$ 0.24			400	\$ -	\$ -			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00004	400	-\$ 0.02		400	\$ -	\$ 0.02			400	\$ -	\$ -			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Rate Rider for PILs and Tax Variance	per kWh		400	\$ -	-\$ 0.00022	400	-\$ 0.09	-\$ 0.09			400	\$ -	\$ 0.09			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Rate Rider for PILs and Tax Variance HST	per kWh		400	\$ -	-\$ 0.00010	400	-\$ 0.04	-\$ 0.04			400	\$ -	\$ 0.04			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Rate Rider for Gain on Sale Named Properties	per kWh		400	\$ -	\$ 0.00059	400	\$ 0.24	\$ 0.24			400	\$ -	-\$ 0.24			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Rate Rider for Hydro One Capital Contributions Variance	per kWh		400	\$ -	\$ 0.00016	400	\$ 0.06	\$ 0.06			400	\$ -	-\$ 0.06			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Rate Rider for Residual RARA	per kWh		400	\$ -	-\$ 0.00007	400	-\$ 0.03	-\$ 0.03			400	\$ -	\$ 0.03			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Rate Rider for LRAMVA	per kWh		400	\$ -	-\$ 0.00003	400	-\$ 0.01	-\$ 0.01			400	\$ -	\$ 0.01			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Rate Rider for IFRS - 2014 Derecognition	per kWh		400	\$ -		400	\$ -	\$ -		\$ 0.00067	400	\$ 0.27	\$ 0.27		\$ 0.00067	400	\$ 0.27	\$ -	0.00%	\$ 0.00067	400	\$ 0.27	\$ -	0.00%	\$ 0.00067	400	\$ 0.27	\$ -	0.00%	
Rate Rider for POEB - Tax Savings	per kWh		400	\$ -	-\$ 0.00069	400	-\$ 0.28	-\$ 0.28		-\$ 0.00069	400	-\$ 0.28	\$ -	0.00%	-\$ 0.00069	400	-\$ 0.28	\$ -	0.00%		400	\$ -	\$ 0.28		400	\$ -	\$ -			
Rate Rider for 2012-14 Lost Revenue	per kWh		400	\$ -		400	\$ -	\$ -		\$ 0.00074	400	\$ 0.30	\$ 0.30		\$ 0.00074	400	\$ 0.30	\$ -	0.00%	\$ 0.00074	400	\$ 0.30	\$ -	0.00%	\$ 0.00074	400	\$ 0.30	\$ -	0.00%	
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		400	\$ -	-\$ 0.00213	400	-\$ 0.85	-\$ 0.85		-\$ 0.00213	400	-\$ 0.85	\$ -	0.00%	-\$ 0.00213	400	-\$ 0.85	\$ -	0.00%		400	\$ -	\$ 0.85		400	\$ -	\$ -			
Sub-Total A (excluding pass through)				\$ 26.58			\$ 29.58	\$ 3.00	11.28%			\$ 31.45	\$ 1.87	6.34%			\$ 34.13	\$ 2.67	8.50%			\$ 37.70	\$ 3.57	10.47%			\$ 39.69	\$ 2.00	5.29%	
Rate Rider for Low Voltage Variance	per kWh		400	\$ -	\$ 0.00005	400	\$ 0.02	\$ 0.02			400	\$ -	-\$ 0.02			400	\$ -	\$ -				400	\$ -	\$ -		400	\$ -	\$ -		
Line Losses on Cost of Power	per kWh	\$ 0.0925	15	\$ 1.39	\$ 0.0925	15	\$ 1.39	\$ -	0.00%	\$ 0.0925	15	\$ 1.39	\$ -	0.00%	\$ 0.0925	15	\$ 1.39	\$ -	0.00%	\$ 0.0925	15	\$ 1.39	\$ -	0.00%	\$ 0.0925	15	\$ 1.39	\$ -	0.00%	
Rate Rider for Smart Metering Entity Charge	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%		1	\$ -	-\$ 0.78		
Sub-Total B - Distribution (includes Sub-Total A)				\$ 28.75			\$ 31.77	\$ 3.02	10.50%			\$ 33.62	\$ 1.85	5.84%			\$ 36.30	\$ 2.67	7.95%			\$ 39.87	\$ 3.57	9.84%			\$ 41.08	\$ 1.22	3.05%	
RTSR - Network	per kWh	\$ 0.00806	415	\$ 3.35	\$ 0.00819	415	\$ 3.40	\$ 0.05	1.61%	\$ 0.00819	415	\$ 3.40	\$ -	0.00%	\$ 0.00819	415	\$ 3.40	\$ -	0.00%	\$ 0.00819	415	\$ 3.40	\$ -	0.00%	\$ 0.00819	415	\$ 3.40	\$ -	0.00%	
RTSR - Line and Transformation Connection	per kWh	\$ 0.00560	415	\$ 2.32	\$ 0.00563	415	\$ 2.34	\$ 0.01	0.54%	\$ 0.00563	415	\$ 2.34	\$ -	0.00%	\$ 0.00563	415	\$ 2.34	\$ -	0.00%	\$ 0.00563	415	\$ 2.34	\$ -	0.00%	\$ 0.00563	415	\$ 2.34	\$ -	0.00%	
Sub-Total C - Delivery (including Sub-Total B)				\$ 34.42			\$ 37.50	\$ 3.08	8.96%			\$ 39.36	\$ 1.85	4.94%			\$ 42.03	\$ 2.67	6.79%			\$ 45.60	\$ 3.57	8.50%			\$ 46.82	\$ 1.22	2.67%	
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	415	\$ 1.83	\$ 0.0044	415	\$ 1.83	\$ -	0.00%	\$ 0.0044	415	\$ 1.83	\$ -	0.00%	\$ 0.0044	415	\$ 1.83	\$ -	0.00%	\$ 0.0044	415	\$ 1.83	\$ -	0.00%	\$ 0.0044	415	\$ 1.83	\$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	415	\$ 0.54	\$ 0.0013	415	\$ 0.54	\$ -	0.00%	\$ 0.0013	415	\$ 0.54	\$ -	0.00%	\$ 0.0013	415	\$ 0.54	\$ -	0.00%	\$ 0.0013	415	\$ 0.54	\$ -	0.00%	\$ 0.0013	415	\$ 0.54	\$ -	0.00%	
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	400	\$ 2.80	\$ 0.0070	400	\$ 2.80	\$ -	0.00%	\$ 0.0070	400	\$ 2.80	\$ -	0.00%	\$ 0.0070	400	\$ 2.80	\$ -	0.00%	\$ 0.0070	400	\$ 2.80	\$ -	0.00%	\$ 0.0070	400	\$ 2.80	\$ -	0.00%	
TOU - Off Peak	per kWh	\$ 0.0750	256	\$ 19.20	\$ 0.0750	256	\$ 19.20	\$ -	0.00%	\$ 0.0750	256	\$ 19.20	\$ -	0.00%	\$ 0.0750	256	\$ 19.20	\$ -	0.00%	\$ 0.0750	256	\$ 19.20	\$ -	0.00%	\$ 0.0750	256	\$ 19.20	\$ -	0.00%	
TOU - Mid Peak	per kWh	\$ 0.1120	72	\$ 8.06	\$ 0.1120	72	\$ 8.06	\$ -	0.00%	\$ 0.1120	72	\$ 8.06	\$ -	0.00%	\$ 0.1120	72	\$ 8.06	\$ -	0.00%	\$ 0.1120	72	\$ 8.06	\$ -	0.00%	\$ 0.1120	72	\$ 8.06	\$ -	0.00%	
TOU - On Peak	per kWh	\$ 0.1350	72	\$ 9.72	\$ 0.1350	72	\$ 9.72	\$ -	0.00%	\$ 0.1350	72	\$ 9.72	\$ -	0.00%	\$ 0.1350	72	\$ 9.72	\$ -	0.00%	\$ 0.1350	72	\$ 9.72	\$ -	0.00%	\$ 0.1350	72	\$ 9.72	\$ -	0.00%	
Energy - RPP - Tier 1	per kWh	\$ 0.0860	400	\$ 34.40	\$ 0.0860	400	\$ 34.40	\$ -	0.00%	\$ 0.0860	400	\$ 34.40	\$ -	0.00%	\$ 0.0860	400	\$ 34.40	\$ -	0.00%	\$ 0.0860	400	\$ 34.40	\$ -	0.00%	\$ 0.0860	400	\$ 34.40	\$ -	0.00%	
Energy - RPP - Tier 2	per kWh	\$ 0.1010	0	\$ -	\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		
Total Bill on TOU (before Taxes)				\$ 76.82			\$ 79.90	\$ 3.08	4.02%			\$ 81.76	\$ 1.85	2.32%			\$ 84.43	\$ 2.67	3.27%			\$ 88.00	\$ 3.57	4.23%			\$ 89.22	\$ 1.22	1.38%	
HST																														

Appendix 2-W
Bill Impacts

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 1,500 kWh ☒ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact		
Charge Unit		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	
Service Charge	per 30 days	\$ 18.63	1	\$ 18.63	\$ 22.72	1	\$ 22.72	\$ 4.09	21.95%	\$ 23.84	1	\$ 23.84	\$ 1.12	4.93%	\$ 25.91	1	\$ 25.91	\$ 2.07	8.68%	\$ 27.75	1	\$ 27.75	\$ 1.84	7.10%	\$ 29.25	1	\$ 29.25	\$ 1.50	5.41%	
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$ 0.08	1	\$ 0.08	\$ 0.08	1	\$ 0.08	\$ -	0.00%	\$ 0.08	1	\$ 0.08	\$ -	0.00%		1	\$ -	\$ -0.08				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ 0.67	1	\$ 0.67		1	\$ -	-\$ 0.67			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.07	1	\$ 0.07		1	\$ -	-\$ 0.07			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.73	1	\$ 0.73		1	\$ -	-\$ 0.73			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Stranded Meters Disposition	per 30 days				\$ 0.22	1	\$ 0.22	\$ 0.22		\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	
Rate Rider for Smart Metering Entity Variance	per 30 days				\$ 0.05	1	\$ 0.05	\$ 0.05																						
Distribution Volumetric Rate	per kWh	\$ 0.01538	1,500	\$ 23.07	\$ 0.01876	1,500	\$ 28.14	\$ 5.07	21.98%	\$ 0.01969	1,500	\$ 29.54	\$ 1.40	4.96%	\$ 0.02140	1,500	\$ 32.10	\$ 2.57	8.68%	\$ 0.02291	1,500	\$ 34.37	\$ 2.27	7.06%	\$ 0.02415	1,500	\$ 36.23	\$ 1.86	5.41%	
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00005	1,500	\$ 0.08		1,500	\$ -	-\$ 0.08			1,500	\$ -	\$ -			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00061	1,500	\$ 0.92		1,500	\$ -	-\$ 0.92			1,500	\$ -	\$ -			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00004	1,500	-\$ 0.06		1,500	\$ -	\$ 0.06			1,500	\$ -	\$ -			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Rate Rider for PILs and Tax Variance	per kWh		1,500	\$ -	-\$ 0.00022	1,500	-\$ 0.33	-\$ 0.33			1,500	\$ -	\$ 0.33			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Rate Rider for PILs and Tax Variance HST	per kWh		1,500	\$ -	-\$ 0.00010	1,500	-\$ 0.15	-\$ 0.15			1,500	\$ -	\$ 0.15			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Rate Rider for Gain on Sale Named Properties	per kWh		1,500	\$ -	\$ 0.00059	1,500	\$ 0.89	\$ 0.89			1,500	\$ -	-\$ 0.89			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Rate Rider for Hydro One Capital Contributions Variance	per kWh		1,500	\$ -	\$ 0.00016	1,500	\$ 0.24	\$ 0.24			1,500	\$ -	-\$ 0.24			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Rate Rider for Residual RARA	per kWh		1,500	\$ -	-\$ 0.00007	1,500	-\$ 0.11	-\$ 0.11			1,500	\$ -	\$ 0.11			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Rate Rider for LRAMVA	per kWh		1,500	\$ -	-\$ 0.00003	1,500	-\$ 0.05	-\$ 0.05			1,500	\$ -	\$ 0.05			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Rate Rider for IFRS - 2014 Derecognition	per kWh		1,500	\$ -		1,500	\$ -	\$ -		\$ 0.00067	1,500	\$ 1.01	\$ 1.01		\$ 0.00067	1,500	\$ 1.01	\$ -	0.00%	\$ 0.00067	1,500	\$ 1.01	\$ -	0.00%	\$ 0.00067	1,500	\$ 1.01	\$ -	0.00%	
Rate Rider for POEB - Tax Savings	per kWh		1,500	\$ -	-\$ 0.00069	1,500	-\$ 1.04	-\$ 1.04		-\$ 0.00069	1,500	-\$ 1.04	\$ -	0.00%	-\$ 0.00069	1,500	-\$ 1.04	\$ -	0.00%		1,500	\$ -	\$ 1.04		1,500	\$ -	\$ -			
Rate Rider for 2012-14 Lost Revenue	per kWh		1,500	\$ -		1,500	\$ -	\$ -		\$ 0.00074	1,500	\$ 1.11	\$ 1.11		\$ 0.00074	1,500	\$ 1.11	\$ -	0.00%	\$ 0.00074	1,500	\$ 1.11	\$ -	0.00%	\$ 0.00074	1,500	\$ 1.11	\$ -	0.00%	
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		1,500	\$ -	-\$ 0.00213	1,500	-\$ 3.20	-\$ 3.20		-\$ 0.00213	1,500	-\$ 3.20	\$ -	0.00%	-\$ 0.00213	1,500	-\$ 3.20	\$ -	0.00%		1,500	\$ -	\$ 3.20		1,500	\$ -	\$ -			
Sub-Total A (excluding pass through)				\$ 44.18			\$ 47.48	\$ 3.30	7.46%			\$ 51.56	\$ 4.09	8.60%			\$ 56.12	\$ 4.56	8.83%			\$ 64.45	\$ 8.33	14.85%			\$ 67.81	\$ 3.36	5.21%	
Rate Rider for Low Voltage Variance	per kWh		1,500	\$ -	\$ 0.00005	1,500	\$ 0.08	\$ 0.08			1,500	\$ -	-\$ 0.08			1,500	\$ -	\$ -				1,500	\$ -	\$ -		1,500	\$ -	\$ -		
Line Losses on Cost of Power	per kWh	\$ 0.0925	56	\$ 5.21	\$ 0.0925	56	\$ 5.21	\$ -	0.00%	\$ 0.0925	56	\$ 5.21	\$ -	0.00%	\$ 0.0925	56	\$ 5.21	\$ -	0.00%	\$ 0.0925	56	\$ 5.21	\$ -	0.00%	\$ 0.0925	56	\$ 5.21	\$ -	0.00%	
Rate Rider for Smart Metering Entity Charge	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 50.17			\$ 53.54	\$ 3.37	6.72%			\$ 57.55	\$ 4.01	7.49%			\$ 62.11	\$ 4.56	7.91%			\$ 70.44	\$ 8.33	13.42%			\$ 73.02	\$ 2.58	3.66%	
RTSR - Network	per kWh	\$ 0.00806	1,556	\$ 12.54	\$ 0.00819	1,556	\$ 12.75	\$ 0.20	1.61%	\$ 0.00819	1,556	\$ 12.75	\$ -	0.00%	\$ 0.00819	1,556	\$ 12.75	\$ -	0.00%	\$ 0.00819	1,556	\$ 12.75	\$ -	0.00%	\$ 0.00819	1,556	\$ 12.75	\$ -	0.00%	
RTSR - Line and Transformation Connection	per kWh	\$ 0.00560	1,556	\$ 8.72	\$ 0.00563	1,556	\$ 8.76	\$ 0.05	0.54%	\$ 0.00563	1,556	\$ 8.76	\$ -	0.00%	\$ 0.00563	1,556	\$ 8.76	\$ -	0.00%	\$ 0.00563	1,556	\$ 8.76	\$ -	0.00%	\$ 0.00563	1,556	\$ 8.76	\$ -	0.00%	
Sub-Total C - Delivery (including Sub-Total B)				\$ 71.44			\$ 75.05	\$ 3.62	5.07%			\$ 79.06	\$ 4.01	5.34%			\$ 83.62	\$ 4.56	5.76%			\$ 91.95	\$ 8.33	9.97%			\$ 94.53	\$ 2.58	2.81%	
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	1,556	\$ 6.85	\$ 0.0044	1,556	\$ 6.85	\$ -	0.00%	\$ 0.0044	1,556	\$ 6.85	\$ -	0.00%	\$ 0.0044	1,556	\$ 6.85	\$ -	0.00%	\$ 0.0044	1,556	\$ 6.85	\$ -	0.00%	\$ 0.0044	1,556	\$ 6.85	\$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	1,556	\$ 2.02	\$ 0.0013	1,556	\$ 2.02	\$ -	0.00%	\$ 0.0013	1,556	\$ 2.02	\$ -	0.00%	\$ 0.0013	1,556	\$ 2.02	\$ -	0.00%	\$ 0.0013	1,556	\$ 2.02	\$ -	0.00%	\$ 0.0013	1,556	\$ 2.02	\$ -	0.00%	
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	1,500	\$ 10.50	\$ 0.0070	1,500	\$ 10.50	\$ -	0.00%	\$ 0.0070	1,500	\$ 10.50	\$ -	0.00%	\$ 0.0070	1,500	\$ 10.50	\$ -	0.00%	\$ 0.0070	1,500	\$ 10.50	\$ -	0.00%	\$ 0.0070	1,500	\$ 10.50	\$ -	0.00%	
TOU - Off Peak	per kWh	\$ 0.0750	960	\$ 72.00	\$ 0.0750	960	\$ 72.00	\$ -	0.00%	\$ 0.0750	960	\$ 72.00	\$ -	0.00%	\$ 0.0750	960	\$ 72.00	\$ -	0.00%	\$ 0.0750	960	\$ 72.00	\$ -	0.00%	\$ 0.0750	960	\$ 72.00	\$ -	0.00%	
TOU - Mid Peak	per kWh	\$ 0.1120	270	\$ 30.24	\$ 0.1120	270	\$ 30.24	\$ -	0.00%	\$ 0.1120	270	\$ 30.24	\$ -	0.00%	\$ 0.1120	270	\$ 30.24	\$ -	0.00%	\$ 0.1120	270	\$ 30.24	\$ -	0.00%	\$ 0.1120	270	\$ 30.24	\$ -	0.00%	
TOU - On Peak	per kWh	\$ 0.1350	270	\$ 36.45	\$ 0.1350	270	\$ 36.45	\$ -	0.00%	\$ 0.1350	270	\$ 36.45	\$ -	0.00%	\$ 0.1350	270	\$ 36.45	\$ -	0.00%	\$ 0.1350	270	\$ 36.45	\$ -	0.00%	\$ 0.1350	270	\$ 36.45	\$ -	0.00%	
Energy - RPP - Tier 1	per kWh	\$ 0.0860	600	\$ 51.60	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	
Energy - RPP - Tier 2	per kWh	\$ 0.1010	900	\$ 90.90	\$ 0.1010	900	\$ 90.90	\$ -	0.00%	\$ 0.1010	900	\$ 90.90	\$ -	0.00%	\$ 0.1010	900	\$ 90.90	\$ -	0.00%	\$ 0.101										

Appendix 2-W
Bill Impacts

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 2,000 kWh ☐ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact	
Charge Unit		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Service Charge	per 30 days	\$ 18.63	1	\$ 18.63	\$ 22.72	1	\$ 22.72	\$ 4.09	21.95%	\$ 23.84	1	\$ 23.84	\$ 1.12	4.93%	\$ 25.91	1	\$ 25.91	\$ 2.07	8.68%	\$ 27.75	1	\$ 27.75	\$ 1.84	7.10%	\$ 29.25	1	\$ 29.25	\$ 1.50	5.13%
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$ 0.08	1	\$ 0.08	\$ 0.08	1	\$ 0.08	\$ -	0.00%	\$ 0.08	1	\$ 0.08	\$ -	0.00%		1	\$ -	\$ -0.08				1	\$ -	\$ -		1	\$ -	\$ -	
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ 0.67	1	\$ 0.67		1	\$ -	-\$ 0.67			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -	
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.07	1	\$ 0.07		1	\$ -	-\$ 0.07			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.73	1	\$ 0.73		1	\$ -	-\$ 0.73			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -	
Rate Rider for Stranded Meters Disposition	per 30 days				\$ 0.22	1	\$ 0.22	\$ 0.22		\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%	\$ 0.22	1	\$ 0.22	\$ -	0.00%
Rate Rider for Smart Metering Entity Variance	per 30 days				\$ 0.05	1	\$ 0.05	\$ 0.05																					
Distribution Volumetric Rate	per kWh	\$ 0.01538	2,000	\$ 30.76	\$ 0.01876	2,000	\$ 37.52	\$ 6.76	21.98%	\$ 0.01969	2,000	\$ 39.38	\$ 1.86	4.96%	\$ 0.02140	2,000	\$ 42.80	\$ 3.42	8.68%	\$ 0.02291	2,000	\$ 45.82	\$ 3.02	7.06%	\$ 0.02415	2,000	\$ 48.30	\$ 2.48	5.13%
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00005	2,000	\$ 0.10		2,000	\$ -	-\$ 0.10			2,000	\$ -	\$ -			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00061	2,000	\$ 1.22		2,000	\$ -	-\$ 1.22			2,000	\$ -	\$ -			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00004	2,000	-\$ 0.08		2,000	\$ -	\$ 0.08			2,000	\$ -	\$ -			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Rate Rider for PILs and Tax Variance	per kWh		2,000	\$ -	-\$ 0.00022	2,000	-\$ 0.44	-\$ 0.44			2,000	\$ -	\$ 0.44			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Rate Rider for PILs and Tax Variance HST	per kWh		2,000	\$ -	-\$ 0.00010	2,000	-\$ 0.20	-\$ 0.20			2,000	\$ -	\$ 0.20			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Rate Rider for Gain on Sale Named Properties	per kWh		2,000	\$ -	\$ 0.00059	2,000	\$ 1.18	\$ 1.18			2,000	\$ -	-\$ 1.18			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Rate Rider for Hydro One Capital Contributions Variance	per kWh		2,000	\$ -	\$ 0.00016	2,000	\$ 0.32	\$ 0.32			2,000	\$ -	-\$ 0.32			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Rate Rider for Residual RARA	per kWh		2,000	\$ -	-\$ 0.00007	2,000	-\$ 0.14	-\$ 0.14			2,000	\$ -	\$ 0.14			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Rate Rider for LRAMVA	per kWh		2,000	\$ -	-\$ 0.00003	2,000	-\$ 0.06	-\$ 0.06			2,000	\$ -	\$ 0.06			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Rate Rider for IFRS - 2014 Derecognition	per kWh		2,000	\$ -		2,000	\$ -	\$ -		\$ 0.00067	2,000	\$ 1.34	\$ 1.34		\$ 0.00067	2,000	\$ 1.34	\$ -	0.00%	\$ 0.00067	2,000	\$ 1.34	\$ -	0.00%	\$ 0.00067	2,000	\$ 1.34	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kWh		2,000	\$ -	-\$ 0.00069	2,000	-\$ 1.38	-\$ 1.38		-\$ 0.00069	2,000	-\$ 1.38	\$ -	0.00%	-\$ 0.00069	2,000	-\$ 1.38	\$ -	0.00%		2,000	\$ -	\$ 1.38		2,000	\$ -	\$ -		
Rate Rider for 2012-14 Lost Revenue	per kWh		2,000	\$ -		2,000	\$ -	\$ -		\$ 0.00074	2,000	\$ 1.48	\$ 1.48		\$ 0.00074	2,000	\$ 1.48	\$ -	0.00%	\$ 0.00074	2,000	\$ 1.48	\$ -	0.00%	\$ 0.00074	2,000	\$ 1.48	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		2,000	\$ -	-\$ 0.00213	2,000	-\$ 4.26	-\$ 4.26		-\$ 0.00213	2,000	-\$ 4.26	\$ -	0.00%	-\$ 0.00213	2,000	-\$ 4.26	\$ -	0.00%		2,000	\$ -	\$ 4.26		2,000	\$ -	\$ -		
Sub-Total A (excluding pass through)				\$ 52.18			\$ 55.61	\$ 3.43	6.57%			\$ 60.70	\$ 5.09	9.15%			\$ 66.11	\$ 5.41	8.91%			\$ 76.61	\$ 10.50	15.88%			\$ 80.59	\$ 3.98	4.94%
Rate Rider for Low Voltage Variance	per kWh		2,000	\$ -	\$ 0.00005	2,000	\$ 0.10	\$ 0.10			2,000	\$ -	-\$ 0.10			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -	
Line Losses on Cost of Power	per kWh	\$ 0.0925	75	\$ 6.95	\$ 0.0925	75	\$ 6.95	\$ -	0.00%	\$ 0.0925	75	\$ 6.95	\$ -	0.00%	\$ 0.0925	75	\$ 6.95	\$ -	0.00%	\$ 0.0925	75	\$ 6.95	\$ -	0.00%	\$ 0.0925	75	\$ 6.95	\$ -	0.00%
Rate Rider for Smart Metering Entity Charge - Ends Oct. 31, 2018.	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ -	-\$ 0.78	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 59.91			\$ 63.44	\$ 3.53	5.89%			\$ 68.43	\$ 4.99	7.87%			\$ 73.84	\$ 5.41	7.91%			\$ 84.34	\$ 10.50	14.22%			\$ 87.54	\$ 3.20	3.66%
RTSR - Network	per kWh	\$ 0.00806	2,075	\$ 16.73	\$ 0.00819	2,075	\$ 17.00	\$ 0.27	1.61%	\$ 0.00819	2,075	\$ 17.00	\$ -	0.00%	\$ 0.00819	2,075	\$ 17.00	\$ -	0.00%	\$ 0.00819	2,075	\$ 17.00	\$ -	0.00%	\$ 0.00819	2,075	\$ 17.00	\$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	\$ 0.00560	2,075	\$ 11.62	\$ 0.00563	2,075	\$ 11.68	\$ 0.06	0.54%	\$ 0.00563	2,075	\$ 11.68	\$ -	0.00%	\$ 0.00563	2,075	\$ 11.68	\$ -	0.00%	\$ 0.00563	2,075	\$ 11.68	\$ -	0.00%	\$ 0.00563	2,075	\$ 11.68	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				\$ 88.26			\$ 92.12	\$ 3.86	4.38%			\$ 97.11	\$ 4.99	5.42%			\$ 102.52	\$ 5.41	5.57%			\$ 113.02	\$ 10.50	10.24%			\$ 116.22	\$ 3.20	2.75%
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	2,075	\$ 9.13	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	2,075	\$ 2.70	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	2,000	\$ 14.00	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	1,280	\$ 96.00	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	360	\$ 40.32	\$ 0.1120	360	\$ 40.32	\$ -	0.00%	\$ 0.1120	360	\$ 40.32	\$ -	0.00%	\$ 0.1120	360	\$ 40.32	\$ -	0.00%	\$ 0.1120	360	\$ 40.32	\$ -	0.00%	\$ 0.1120	360	\$ 40.32	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	360	\$ 48.60	\$ 0.1350	360	\$ 48.60	\$ -	0.00%	\$ 0.1350	360	\$ 48.60	\$ -	0.00%	\$ 0.1350	360	\$ 48.60	\$ -	0.00%	\$ 0.1350	360	\$ 48.60	\$ -	0.00%	\$ 0.1350	360	\$ 48.60	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	600	\$ 51.60	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	1,400	\$ 141.40	\$ 0.1010	1,400	\$ 141.40	\$ -	0.00%	\$ 0.1010	1,400	\$ 141.40	\$ -	0.00%	\$ 0.1010	1,400	\$ 141.40	\$ -	0.00%	\$ 0.1010	1,400	\$ 141.							

Appendix 2-W
Bill Impacts

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 334 kWh ☒ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Service Charge	per 30 days	\$ 17.35	1	\$ 17.35	\$ 18.90	1	\$ 18.90	\$ 1.55	8.93%	\$ 19.83	1	\$ 19.83	\$ 0.93	4.92%	\$ 21.56	1	\$ 21.56	\$ 1.73	8.72%	\$ 23.08	1	\$ 23.08	\$ 1.52	7.05%	\$ 24.33	1	\$ 24.33	\$ 1.25	5.42%
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.06	1	\$ 0.06		1	\$ -	-\$ 0.06			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.68	1	\$ 0.68		1	\$ -	-\$ 0.68			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -	
Rate Rider for Smart Metering Entity Variance	per 30 days				\$ 0.03	1	\$ 0.03	\$ 0.03																					
Distribution Volumetric Rate	per kWh	\$ 0.02617	334	\$ 8.74	\$ 0.02851	334	\$ 9.52	\$ 0.78	8.94%	\$ 0.02992	334	\$ 9.99	\$ 0.47	4.95%	\$ 0.03252	334	\$ 10.86	\$ 0.87	8.69%	\$ 0.03482	334	\$ 11.63	\$ 0.77	7.07%	\$ 0.03670	334	\$ 12.26	\$ 0.63	5.40%
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00009	334	\$ 0.03		334	\$ -	-\$ 0.03			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00103	334	\$ 0.34		334	\$ -	-\$ 0.34			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -	
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00007	334	-\$ 0.02		334	\$ -	\$ 0.02			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -	
Rate Rider for PILs and Tax Variance	per kWh		334	\$ -	-\$ 0.00021	334	-\$ 0.07	-\$ 0.07			334	\$ -	\$ 0.07			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -	
Rate Rider for PILs and Tax Variance HST	per kWh		334	\$ -	-\$ 0.00010	334	-\$ 0.03	-\$ 0.03			334	\$ -	\$ 0.03			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -	
Rate Rider for Gain on Sale Named Properties	per kWh		334	\$ -	\$ 0.00052	334	\$ 0.17	\$ 0.17			334	\$ -	-\$ 0.17			334	\$ -	-\$ 0.17			334	\$ -	\$ -			334	\$ -	\$ -	
Rate Rider for Hydro One Capital Contributions Variance	per kWh		334	\$ -	\$ 0.00016	334	\$ 0.05	\$ 0.05			334	\$ -	-\$ 0.05			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -	
Rate Rider for Residual RARA	per kWh		334	\$ -	-\$ 0.00006	334	-\$ 0.02	-\$ 0.02			334	\$ -	\$ 0.02			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -	
Rate Rider for LRAMVA	per kWh		334	\$ -	\$ 0.00001	334	\$ 0.00	\$ 0.00			334	\$ -	-\$ 0.00			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -	
Rate Rider for IFRS - 2014 Derecognition	per kWh		334	\$ -		334	\$ -	\$ -			\$ 0.00066	334	\$ 0.22	\$ 0.22	\$ 0.00066	334	\$ 0.22	\$ -	0.00%	\$ 0.00066	334	\$ 0.22	\$ -	0.00%	\$ 0.00066	334	\$ 0.22	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kWh		334	\$ -	-\$ 0.00067	334	-\$ 0.22	-\$ 0.22			-\$ 0.00067	334	-\$ 0.22	\$ -	0.00%	-\$ 0.00067	334	-\$ 0.22	\$ -	0.00%		334	\$ -	\$ 0.22		334	\$ -	\$ -	
Rate Rider for 2012-14 Lost Revenue	per kWh		334	\$ -		334	\$ -	\$ -			\$ 0.00072	334	\$ 0.24	\$ 0.24	\$ 0.00072	334	\$ 0.24	\$ -	0.00%	\$ 0.00072	334	\$ 0.24	\$ -	0.00%	\$ 0.00072	334	\$ 0.24	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		334	\$ -	-\$ 0.00208	334	-\$ 0.69	-\$ 0.69			-\$ 0.00208	334	-\$ 0.69	\$ 0.00%	-\$ 0.00208	334	-\$ 0.69	\$ -	0.00%	-\$ 0.00208	334	-\$ 0.69	\$ -	0.00%		334	\$ -	\$ -	
Sub-Total A (excluding pass through)				\$ 27.18			\$ 27.64	\$ 0.46	1.69%			\$ 29.37	\$ 1.72	6.24%			\$ 31.96	\$ 2.60	8.85%			\$ 35.17	\$ 3.21	10.03%			\$ 37.05	\$ 1.88	5.34%
Rate Rider for Low Voltage Variance	per kWh		334	\$ -	\$ 0.00002	334	\$ 0.01	\$ 0.01			334	\$ -	-\$ 0.01			334	\$ -	\$ -			334	\$ -	\$ -			334	\$ -	\$ -	
Line Losses on Cost of Power	per kWh	\$ 0.0925	13	\$ 1.16	\$ 0.0925	13	\$ 1.16	\$ -	0.00%	\$ 0.0925	13	\$ 1.16	\$ -	0.00%	\$ 0.0925	13	\$ 1.16	\$ -	0.00%	\$ 0.0925	13	\$ 1.16	\$ -	0.00%	\$ 0.0925	13	\$ 1.16	\$ -	0.00%
Rate Rider for Smart Metering Entity Charge	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -		\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%		1	\$ -	-\$ 0.78	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 29.12			\$ 29.59	\$ 0.47	1.60%			\$ 31.31	\$ 1.72	5.81%			\$ 33.91	\$ 2.60	8.30%			\$ 37.11	\$ 3.21	9.46%			\$ 38.21	\$ 1.10	2.96%
RTSR - Network	per kWh	\$ 0.00806	347	\$ 2.79	\$ 0.00819	347	\$ 2.84	\$ 0.05	1.61%	\$ 0.00819	347	\$ 2.84	\$ -	0.00%	\$ 0.00819	347	\$ 2.84	\$ -	0.00%	\$ 0.00819	347	\$ 2.84	\$ -	0.00%	\$ 0.00819	347	\$ 2.84	\$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	\$ 0.00560	347	\$ 1.94	\$ 0.00563	347	\$ 1.95	\$ 0.01	0.54%	\$ 0.00563	347	\$ 1.95	\$ -	0.00%	\$ 0.00563	347	\$ 1.95	\$ -	0.00%	\$ 0.00563	347	\$ 1.95	\$ -	0.00%	\$ 0.00563	347	\$ 1.95	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				\$ 33.86			\$ 34.38	\$ 0.52	1.54%			\$ 36.10	\$ 1.72	5.00%			\$ 38.69	\$ 2.60	7.20%			\$ 41.90	\$ 3.21	8.29%			\$ 43.00	\$ 1.10	2.62%
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	347	\$ 1.52	\$ 0.0044	347	\$ 1.52	\$ -	0.00%	\$ 0.0044	347	\$ 1.52	\$ -	0.00%	\$ 0.0044	347	\$ 1.52	\$ -	0.00%	\$ 0.0044	347	\$ 1.52	\$ -	0.00%	\$ 0.0044	347	\$ 1.52	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	347	\$ 0.45	\$ 0.0013	347	\$ 0.45	\$ -	0.00%	\$ 0.0013	347	\$ 0.45	\$ -	0.00%	\$ 0.0013	347	\$ 0.45	\$ -	0.00%	\$ 0.0013	347	\$ 0.45	\$ -	0.00%	\$ 0.0013	347	\$ 0.45	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	334	\$ 2.34	\$ 0.0070	334	\$ 2.34	\$ -	0.00%	\$ 0.0070	334	\$ 2.34	\$ -	0.00%	\$ 0.0070	334	\$ 2.34	\$ -	0.00%	\$ 0.0070	334	\$ 2.34	\$ -	0.00%	\$ 0.0070	334	\$ 2.34	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	214	\$ 16.03	\$ 0.0750	214	\$ 16.03	\$ -	0.00%	\$ 0.0750	214	\$ 16.03	\$ -	0.00%	\$ 0.0750	214	\$ 16.03	\$ -	0.00%	\$ 0.0750	214	\$ 16.03	\$ -	0.00%	\$ 0.0750	214	\$ 16.03	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	60	\$ 6.73	\$ 0.1120	60	\$ 6.73	\$ -	0.00%	\$ 0.1120	60	\$ 6.73	\$ -	0.00%	\$ 0.1120	60	\$ 6.73	\$ -	0.00%	\$ 0.1120	60	\$ 6.73	\$ -	0.00%	\$ 0.1120	60	\$ 6.73	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	60	\$ 8.12	\$ 0.1350	60	\$ 8.12	\$ -	0.00%	\$ 0.1350	60	\$ 8.12	\$ -	0.00%	\$ 0.1350	60	\$ 8.12	\$ -	0.00%	\$ 0.1350	60	\$ 8.12	\$ -	0.00%	\$ 0.1350	60	\$ 8.12	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	334	\$ 28.72	\$ 0.0860	334	\$ 28.72	\$ -	0.00%	\$ 0.0860	334	\$ 28.72	\$ -	0.00%	\$ 0.0860	334	\$ 28.72	\$ -	0.00%	\$ 0.0860	334	\$ 28.72	\$ -	0.00%	\$ 0.0860	334	\$ 28.72	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	0	\$ -	\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -	
Total Bill on TOU (before Taxes)				\$ 69.30			\$ 69.82	\$ 0.52	0.75%			\$ 71.54	\$ 1.72	2.46%			\$ 74.14	\$ 2.60	3.63%			\$ 77.35	\$ 3.21	4.33%			\$ 78.44	\$ 1.10	1.42%
HST		13%		\$ 9.01	13%		\$ 9.08	\$ 0.07	0.75%	13%		\$ 9.30	\$ 0.22	2.46%	13%		\$ 9.64	\$ 0.34	3.63%	13%		\$ 10.06	\$ 0.42	4.33%	13%		\$ 10.20	\$ 0.14	1.42%
Total Bill (including HST)				\$ 78.31			\$ 78.90	\$ 0.59	0.75%			\$ 80.84	\$ 1.94	2.46%			\$ 83.78	\$ 2.94	3.63%			\$ 87.40	\$ 3.62	4.33%			\$ 88.64	\$ 1.24	1.42%
Ontario Clean Energy Benefit ¹				-\$ 7.83			-\$ 7.89	-\$ 0.06	0.77%			\$ -	\$ 7.89				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -	
Total Bill on TOU (including OCEB)				\$ 70.48			\$ 71.01	\$ 0.53	0.75%			\$ 80.84	\$ 9.83	13.85%			\$ 83.78	\$ 2.94	3.63%			\$ 87.40	\$ 3.62	4.33%			\$ 88.64	\$ 1.24	1.42%
Total Bill on RPP (before Taxes)				\$ 67.14			\$ 67.67	\$ 0.52	0.78%			\$ 69.38	\$ 1.72	2.54%			\$ 71.98	\$ 2.60	3.74%			\$ 75.19	\$ 3.21	4.45%			\$ 76.29	\$ 1.10	1.46%
HST		13%		\$ 8.73	13%		\$ 8.80	\$ 0.07	0.78%	13%		\$ 9.02	\$ 0.22	2.54%	13%		\$ 9.36	\$ 0.34	3.74%	13%		\$ 9.77	\$ 0.42	4.45%	13%		\$ 9.92	\$ 0.14	1.46%
Total Bill (including HST)				\$ 75.87			\$ 76.46	\$ 0.59	0.78%			\$ 78.40	\$ 1.94	2.54%			\$ 81.34	\$ 2.94	3.74%			\$ 84.96	\$ 3.62	4.45%			\$ 86.20	\$ 1.24	1.46%
Ontario Clean Energy Benefit ¹				-\$ 7.59			-\$ 7.65	-\$ 0.06	0.79%			\$ -	\$ 7.65				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -	
Total Bill on RPP (including OCEB)				\$ 68.28			\$ 68.81	\$ 0.53	0.77%			\$ 78.40	\$ 9.59	13.94%			\$ 81.34	\$ 2.94	3.74%			\$ 84.96	\$ 3.62	4.45%			\$ 86.20	\$ 1.24	1.46%

Loss Factor (%) 3.76% 3.76% 3.76% 3.76% 3.76%

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL

TOU / non-TOU: TOU

Consumption 200 kWh ☒ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Service Charge	per 30 days	\$ 17.35	1	\$ 17.35	\$ 18.90	1	\$ 18.90	\$ 1.55	8.93%	\$ 19.83	1	\$ 19.83	\$ 0.93	4.92%	\$ 21.56	1	\$ 21.56	\$ 1.73	8.72%	\$ 23.08	1	\$ 23.08	\$ 1.52	7.05%	\$ 24.33	1	\$ 24.33	\$ 1.25	5.42%
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.06	1	\$ 0.06		1	\$ -	-\$ 0.06			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.68	1	\$ 0.68		1	\$ -	-\$ 0.68			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -	
Distribution Volumetric Rate	per kWh	\$ 0.02617	200	\$ 5.23	\$ 0.02851	200	\$ 5.70	\$ 0.47	8.94%	\$ 0.02992	200	\$ 5.98	\$ 0.28	4.95%	\$ 0.03252	200	\$ 6.50	\$ 0.52	8.69%	\$ 0.03482	200	\$ 6.96	\$ 0.46	7.07%	\$ 0.03670	200	\$ 7.34	\$ 0.38	5.40%
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00009	200	\$ 0.02		200	\$ -	-\$ 0.02			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00103	200	\$ 0.21		200	\$ -	-\$ 0.21			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00007	200	-\$ 0.01		200	\$ -	\$ 0.01			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Rate Rider for PILs and Tax Variance	per kWh		200	\$ -	-\$ 0.00021	200	-\$ 0.04	-\$ 0.04			200	\$ -	\$ 0.04			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Rate Rider for PILs and Tax Variance HST	per kWh		200	\$ -	-\$ 0.00010	200	-\$ 0.02	-\$ 0.02			200	\$ -	\$ 0.02			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Rate Rider for Gain on Sale Named Properties	per kWh		200	\$ -	\$ 0.00052	200	\$ 0.10	\$ 0.10			200	\$ -	-\$ 0.10			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Rate Rider for Hydro One Capital Contributions Variance	per kWh		200	\$ -	\$ 0.00016	200	\$ 0.03	\$ 0.03			200	\$ -	-\$ 0.03			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Rate Rider for Residual RARA	per kWh		200	\$ -	-\$ 0.00006	200	-\$ 0.01	-\$ 0.01			200	\$ -	\$ 0.01			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Rate Rider for LRAMVA	per kWh		200	\$ -	\$ 0.00001	200	\$ 0.00	\$ 0.00			200	\$ -	-\$ 0.00			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Rate Rider for IFRS - 2014 Derecognition	per kWh		200	\$ -		200	\$ -	\$ -		\$ 0.00066	200	\$ 0.13	\$ 0.13		\$ 0.00066	200	\$ 0.13	\$ -	0.00%	\$ 0.00066	200	\$ 0.13	\$ -	0.00%	\$ 0.00066	200	\$ 0.13	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kWh		200	\$ -	-\$ 0.00067	200	-\$ 0.13	-\$ 0.13		-\$ 0.00067	200	-\$ 0.13	\$ -	0.00%	-\$ 0.00067	200	-\$ 0.13	\$ -	0.00%		200	\$ -	\$ 0.13			200	\$ -	\$ -	
Rate Rider for 2012-14 Lost Revenue	per kWh		200	\$ -		200	\$ -	\$ -		\$ 0.00072	200	\$ 0.14	\$ 0.14		\$ 0.00072	200	\$ 0.14	\$ -	0.00%	\$ 0.00072	200	\$ 0.14	\$ -	0.00%	\$ 0.00072	200	\$ 0.14	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		200	\$ -	-\$ 0.00208	200	-\$ 0.42	-\$ 0.42		-\$ 0.00208	200	-\$ 0.42	\$ -	0.00%	-\$ 0.00208	200	-\$ 0.42	\$ -	0.00%		200	\$ -	\$ 0.42			200	\$ -	\$ -	
Sub-Total A (excluding pass through)				\$ 23.53			\$ 24.12	\$ 0.58	2.47%			\$ 25.54	\$ 1.42	5.90%			\$ 27.79	\$ 2.25	8.81%			\$ 30.32	\$ 2.53	9.10%			\$ 31.95	\$ 1.63	5.36%
Rate Rider for Low Voltage Variance	per kWh		200	\$ -	\$ 0.00002	200	\$ 0.00	\$ 0.00			200	\$ -	-\$ 0.00			200	\$ -	\$ -			200	\$ -	\$ -			200	\$ -	\$ -	
Line Losses on Cost of Power	per kWh	\$ 0.0925	8	\$ 0.70	\$ 0.0925	8	\$ 0.70	\$ -	0.00%	\$ 0.0925	8	\$ 0.70	\$ -	0.00%	\$ 0.0925	8	\$ 0.70	\$ -	0.00%	\$ 0.0925	8	\$ 0.70	\$ -	0.00%	\$ 0.0925	8	\$ 0.70	\$ -	0.00%
Rate Rider for Smart Metering Entity Charge	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%		1	\$ -	-\$ 0.78	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 25.01			\$ 25.60	\$ 0.59	2.34%			\$ 27.02	\$ 1.42	5.55%			\$ 29.27	\$ 2.25	8.33%			\$ 31.80	\$ 2.53	8.65%			\$ 32.64	\$ 0.85	2.66%
RTSR - Network	per kWh	\$ 0.00806	208	\$ 1.67	\$ 0.00819	208	\$ 1.70	\$ 0.03	1.61%	\$ 0.00819	208	\$ 1.70	\$ -	0.00%	\$ 0.00819	208	\$ 1.70	\$ -	0.00%	\$ 0.00819	208	\$ 1.70	\$ -	0.00%	\$ 0.00819	208	\$ 1.70	\$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	\$ 0.00560	208	\$ 1.16	\$ 0.00563	208	\$ 1.17	\$ 0.01	0.54%	\$ 0.00563	208	\$ 1.17	\$ -	0.00%	\$ 0.00563	208	\$ 1.17	\$ -	0.00%	\$ 0.00563	208	\$ 1.17	\$ -	0.00%	\$ 0.00563	208	\$ 1.17	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				\$ 27.84			\$ 28.46	\$ 0.62	2.22%			\$ 29.88	\$ 1.42	4.99%			\$ 32.13	\$ 2.25	7.53%			\$ 34.66	\$ 2.53	7.87%			\$ 35.51	\$ 0.85	2.44%
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	208	\$ 0.91	\$ 0.0044	208	\$ 0.91	\$ -	0.00%	\$ 0.0044	208	\$ 0.91	\$ -	0.00%	\$ 0.0044	208	\$ 0.91	\$ -	0.00%	\$ 0.0044	208	\$ 0.91	\$ -	0.00%	\$ 0.0044	208	\$ 0.91	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	208	\$ 0.27	\$ 0.0013	208	\$ 0.27	\$ -	0.00%	\$ 0.0013	208	\$ 0.27	\$ -	0.00%	\$ 0.0013	208	\$ 0.27	\$ -	0.00%	\$ 0.0013	208	\$ 0.27	\$ -	0.00%	\$ 0.0013	208	\$ 0.27	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	200	\$ 1.40	\$ 0.0070	200	\$ 1.40	\$ -	0.00%	\$ 0.0070	200	\$ 1.40	\$ -	0.00%	\$ 0.0070	200	\$ 1.40	\$ -	0.00%	\$ 0.0070	200	\$ 1.40	\$ -	0.00%	\$ 0.0070	200	\$ 1.40	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	128	\$ 9.60	\$ 0.0750	128	\$ 9.60	\$ -	0.00%	\$ 0.0750	128	\$ 9.60	\$ -	0.00%	\$ 0.0750	128	\$ 9.60	\$ -	0.00%	\$ 0.0750	128	\$ 9.60	\$ -	0.00%	\$ 0.0750	128	\$ 9.60	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	36	\$ 4.03	\$ 0.1120	36	\$ 4.03	\$ -	0.00%	\$ 0.1120	36	\$ 4.03	\$ -	0.00%	\$ 0.1120	36	\$ 4.03	\$ -	0.00%	\$ 0.1120	36	\$ 4.03	\$ -	0.00%	\$ 0.1120	36	\$ 4.03	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	36	\$ 4.86	\$ 0.1350	36	\$ 4.86	\$ -	0.00%	\$ 0.1350	36	\$ 4.86	\$ -	0.00%	\$ 0.1350	36	\$ 4.86	\$ -	0.00%	\$ 0.1350	36	\$ 4.86	\$ -	0.00%	\$ 0.1350	36	\$ 4.86	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	200	\$ 17.20	\$ 0.0860	200	\$ 17.20	\$ -	0.00%	\$ 0.0860	200	\$ 17.20	\$ -	0.00%	\$ 0.0860	200	\$ 17.20	\$ -	0.00%	\$ 0.0860	200	\$ 17.20	\$ -	0.00%	\$ 0.0860	200	\$ 17.20	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	0	\$ -	\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -	
Total Bill on TOU (before Taxes)				\$ 49.17			\$ 49.79	\$ 0.62	1.26%			\$ 51.21	\$ 1.42	2.85%			\$ 53.46	\$ 2.25	4.39%			\$ 55.99	\$ 2.53	4.73%			\$ 56.83	\$ 0.85	1.51%
HST		13%		\$ 6.39	13%		\$ 6.47	\$ 0.08	1.26%	13%		\$ 6.66	\$ 0.18	2.85%	13%		\$ 6.95	\$ 0.29	4.39%	13%		\$ 7.28	\$ 0.33	4.73%	13%		\$ 7.39	\$ 0.11	1.51%
Total Bill (including HST)				\$ 55.56			\$ 56.26	\$ 0.70	1.26%			\$ 57.87	\$ 1.60	2.85%			\$ 60.41	\$ 2.54	4.39%			\$ 63.27	\$ 2.86	4.73%			\$ 64.22	\$ 0.96	1.51%
Ontario Clean Energy Benefit ¹				-\$ 5.56			-\$ 5.63	-\$ 0.07	1.26%			\$ -	\$ 5.63			\$ -	\$ -				\$ -	\$ -				\$ -	\$ -		
Total Bill on TOU (including OCEB)				\$ 50.00			\$ 50.63	\$ 0.63	1.26%			\$ 57.87	\$ 7.23	14.29%			\$ 60.41	\$ 2.54	4.39%			\$ 63.27	\$ 2.86	4.73%			\$ 64.22	\$ 0.96	1.51%
Total Bill on RPP (before Taxes)				\$ 47.88			\$ 48.50	\$ 0.62	1.29%			\$ 49.92	\$ 1.42	2.93%			\$ 52.17	\$ 2.25	4.51%			\$ 54.70	\$ 2.53	4.85%			\$ 55.54	\$ 0.85	1.55%
HST		13%		\$ 6.22	13%		\$ 6.30	\$ 0.08	1.29%	13%		\$ 6.49	\$ 0.18	2.93%	13%		\$ 6.78	\$ 0.29	4.51%	13%		\$ 7.11	\$ 0.33	4.85%	13%		\$ 7.22	\$ 0.11	1.55%
Total Bill (including HST)				\$ 54.10			\$ 54.80	\$ 0.70	1.29%			\$ 56.41	\$ 1.60	2.93%			\$ 58.95	\$ 2.54	4.51%			\$ 61.81	\$ 2.86	4.85%			\$ 62.76	\$ 0.96	1.55%
Ontario Clean Energy Benefit ¹				-\$ 5.41			-\$ 5.48	-\$ 0.07	1.29%			\$ -	\$ 5.48			\$ -	\$ -				\$ -	\$ -				\$ -	\$ -		
Total Bill on RPP (including OCEB)				\$ 48.69			\$ 49.32	\$ 0.63	1.29%			\$ 56.41	\$ 7.08	14.36%			\$ 58.95	\$ 2.54	4.51%			\$ 61.81	\$ 2.86	4.85%			\$ 62.76	\$ 0.96	1.55%

Loss Factor (%) 3.76%

3.76%

3.76%

3.76%

3.76%

3.76%

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000

GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000

GS>50kW (kW) - 60, 100, 500, 1000

Large User - range appropriate for utility

Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL

TOU / non-TOU: TOU

Consumption 600 kWh ☐ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Service Charge	per 30 days	\$ 17.35	1	\$ 17.35	\$ 18.90	1	\$ 18.90	\$ 1.55	8.93%	\$ 19.83	1	\$ 19.83	\$ 0.93	4.92%	\$ 21.56	1	\$ 21.56	\$ 1.73	8.72%	\$ 23.08	1	\$ 23.08	\$ 1.52	7.05%	\$ 24.33	1	\$ 24.33	\$ 1.25	5.42%
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.06	1	\$ 0.06		1	\$ -	-\$ 0.06			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.68	1	\$ 0.68		1	\$ -	-\$ 0.68			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -	
Distribution Volumetric Rate	per kWh	\$ 0.02617	600	\$ 15.70	\$ 0.02851	600	\$ 17.11	\$ 1.40	8.94%	\$ 0.02992	600	\$ 17.95	\$ 0.85	4.95%	\$ 0.03252	600	\$ 19.51	\$ 1.56	8.69%	\$ 0.03482	600	\$ 20.89	\$ 1.38	7.07%	\$ 0.03670	600	\$ 22.02	\$ 1.13	5.40%
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00009	600	\$ 0.05		600	\$ -	-\$ 0.05			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00103	600	\$ 0.62		600	\$ -	-\$ 0.62			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00007	600	-\$ 0.04		600	\$ -	\$ 0.04			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Rate Rider for PILs and Tax Variance	per kWh		600	\$ -	-\$ 0.00021	600	-\$ 0.13	-\$ 0.13			600	\$ -	\$ 0.13			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Rate Rider for PILs and Tax Variance HST	per kWh		600	\$ -	-\$ 0.00010	600	-\$ 0.06	-\$ 0.06			600	\$ -	\$ 0.06			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Rate Rider for Gain on Sale Named Properties	per kWh		600	\$ -	\$ 0.00052	600	\$ 0.31	\$ 0.31			600	\$ -	-\$ 0.31			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Rate Rider for Hydro One Capital Contributions Variance	per kWh		600	\$ -	\$ 0.00016	600	\$ 0.10	\$ 0.10			600	\$ -	-\$ 0.10			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Rate Rider for Residual RARA	per kWh		600	\$ -	-\$ 0.00006	600	-\$ 0.04	-\$ 0.04			600	\$ -	\$ 0.04			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Rate Rider for LRAMVA	per kWh		600	\$ -	\$ 0.00001	600	\$ 0.01	\$ 0.01			600	\$ -	-\$ 0.01			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Rate Rider for IFRS - 2014 Derecognition	per kWh		600	\$ -		600	\$ -	\$ -		\$ 0.00066	600	\$ 0.40	\$ 0.40		\$ 0.00066	600	\$ 0.40	\$ -	0.00%	\$ 0.00066	600	\$ 0.40	\$ -	0.00%	\$ 0.00066	600	\$ 0.40	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kWh		600	\$ -	-\$ 0.00067	600	-\$ 0.40	-\$ 0.40		-\$ 0.00067	600	-\$ 0.40	\$ -	0.00%	-\$ 0.00067	600	-\$ 0.40	\$ -	0.00%		600	\$ -	\$ 0.40			600	\$ -	\$ -	
Rate Rider for 2012-14 Lost Revenue	per kWh		600	\$ -		600	\$ -	\$ -		\$ 0.00072	600	\$ 0.43	\$ 0.43		\$ 0.00072	600	\$ 0.43	\$ -	0.00%	\$ 0.00072	600	\$ 0.43	\$ -	0.00%	\$ 0.00072	600	\$ 0.43	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		600	\$ -	-\$ 0.00208	600	-\$ 1.25	-\$ 1.25		-\$ 0.00208	600	-\$ 1.25	\$ -	0.00%	-\$ 0.00208	600	-\$ 1.25	\$ -	0.00%		600	\$ -	\$ 1.25			600	\$ -	\$ -	
Sub-Total A (excluding pass through)				\$ 34.42			\$ 34.55	\$ 0.13	0.37%			\$ 36.96	\$ 2.41	6.98%			\$ 40.25	\$ 3.29	8.90%			\$ 44.80	\$ 4.55	11.30%			\$ 47.18	\$ 2.38	5.31%
Rate Rider for Low Voltage Variance	per kWh		600	\$ -	\$ 0.00002	600	\$ 0.01	\$ 0.01			600	\$ -	-\$ 0.01			600	\$ -	\$ -			600	\$ -	\$ -			600	\$ -	\$ -	
Line Losses on Cost of Power	per kWh	\$ 0.0925	23	\$ 2.09	\$ 0.0925	23	\$ 2.09	\$ -	0.00%	\$ 0.0925	23	\$ 2.09	\$ -	0.00%	\$ 0.0925	23	\$ 2.09	\$ -	0.00%	\$ 0.0925	23	\$ 2.09	\$ -	0.00%	\$ 0.0925	23	\$ 2.09	\$ -	0.00%
Rate Rider for Smart Metering Entity Charge	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%		1	\$ -	-\$ 0.78	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 37.29			\$ 37.43	\$ 0.14	0.37%			\$ 39.83	\$ 2.40	6.41%			\$ 43.12	\$ 3.29	8.26%			\$ 47.67	\$ 4.55	10.55%			\$ 49.26	\$ 1.60	3.35%
RTSR - Network	per kWh	\$ 0.00806	623	\$ 5.02	\$ 0.00819	623	\$ 5.10	\$ 0.08	1.61%	\$ 0.00819	623	\$ 5.10	\$ -	0.00%	\$ 0.00819	623	\$ 5.10	\$ -	0.00%	\$ 0.00819	623	\$ 5.10	\$ -	0.00%	\$ 0.00819	623	\$ 5.10	\$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	\$ 0.00560	623	\$ 3.49	\$ 0.00563	623	\$ 3.51	\$ 0.02	0.54%	\$ 0.00563	623	\$ 3.51	\$ -	0.00%	\$ 0.00563	623	\$ 3.51	\$ -	0.00%	\$ 0.00563	623	\$ 3.51	\$ -	0.00%	\$ 0.00563	623	\$ 3.51	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				\$ 45.79			\$ 46.03	\$ 0.24	0.52%			\$ 48.43	\$ 2.40	5.21%			\$ 51.72	\$ 3.29	6.79%			\$ 56.27	\$ 4.55	8.80%			\$ 57.87	\$ 1.60	2.84%
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	623	\$ 2.74	\$ 0.0044	623	\$ 2.74	\$ -	0.00%	\$ 0.0044	623	\$ 2.74	\$ -	0.00%	\$ 0.0044	623	\$ 2.74	\$ -	0.00%	\$ 0.0044	623	\$ 2.74	\$ -	0.00%	\$ 0.0044	623	\$ 2.74	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	623	\$ 0.81	\$ 0.0013	623	\$ 0.81	\$ -	0.00%	\$ 0.0013	623	\$ 0.81	\$ -	0.00%	\$ 0.0013	623	\$ 0.81	\$ -	0.00%	\$ 0.0013	623	\$ 0.81	\$ -	0.00%	\$ 0.0013	623	\$ 0.81	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	600	\$ 4.20	\$ 0.0070	600	\$ 4.20	\$ -	0.00%	\$ 0.0070	600	\$ 4.20	\$ -	0.00%	\$ 0.0070	600	\$ 4.20	\$ -	0.00%	\$ 0.0070	600	\$ 4.20	\$ -	0.00%	\$ 0.0070	600	\$ 4.20	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	384	\$ 28.80	\$ 0.0750	384	\$ 28.80	\$ -	0.00%	\$ 0.0750	384	\$ 28.80	\$ -	0.00%	\$ 0.0750	384	\$ 28.80	\$ -	0.00%	\$ 0.0750	384	\$ 28.80	\$ -	0.00%	\$ 0.0750	384	\$ 28.80	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	108	\$ 12.10	\$ 0.1120	108	\$ 12.10	\$ -	0.00%	\$ 0.1120	108	\$ 12.10	\$ -	0.00%	\$ 0.1120	108	\$ 12.10	\$ -	0.00%	\$ 0.1120	108	\$ 12.10	\$ -	0.00%	\$ 0.1120	108	\$ 12.10	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	108	\$ 14.58	\$ 0.1350	108	\$ 14.58	\$ -	0.00%	\$ 0.1350	108	\$ 14.58	\$ -	0.00%	\$ 0.1350	108	\$ 14.58	\$ -	0.00%	\$ 0.1350	108	\$ 14.58	\$ -	0.00%	\$ 0.1350	108	\$ 14.58	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	600	\$ 51.60	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	0	\$ -	\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -		\$ 0.1010	0	\$ -	\$ -	
Total Bill on TOU (before Taxes)				\$ 109.27			\$ 109.50	\$ 0.24	0.22%			\$ 111.90	\$ 2.40	2.19%			\$ 115.19	\$ 3.29	2.94%			\$ 119.74	\$ 4.55	3.95%			\$ 121.34	\$ 1.60	1.33%
HST		13%		\$ 14.20	13%		\$ 14.24	\$ 0.03	0.22%	13%		\$ 14.55	\$ 0.31	2.19%	13%		\$ 14.98	\$ 0.43	2.94%	13%		\$ 15.57	\$ 0.59	3.95%	13%		\$ 15.77	\$ 0.21	1.33%
Total Bill (including HST)				\$ 123.47			\$ 123.74	\$ 0.27	0.22%			\$ 126.45	\$ 2.71	2.19%			\$ 130.17	\$ 3.72	2.94%			\$ 135.31	\$ 5.14	3.95%			\$ 137.12	\$ 1.81	1.33%
Ontario Clean Energy Benefit ¹				-\$ 12.35			-\$ 12.37	-\$ 0.02	0.16%			\$ -	\$ 12.37			\$ -	\$ -				\$ -	\$ -				\$ -	\$ -		
Total Bill on TOU (including OCEB)				\$ 111.12			\$ 111.37	\$ 0.25	0.22%			\$ 126.45	\$ 15.08	13.54%			\$ 130.17	\$ 3.72	2.94%			\$ 135.31	\$ 5.14	3.95%			\$ 137.12	\$ 1.81	1.33%
Total Bill on RPP (before Taxes)				\$ 105.39			\$ 105.63	\$ 0.24	0.23%			\$ 108.03	\$ 2.40	2.27%			\$ 111.32	\$ 3.29	3.05%			\$ 115.87	\$ 4.55	4.09%			\$ 117.47	\$ 1.60	1.38%
HST		13%		\$ 13.70	13%		\$ 13.73	\$ 0.03	0.23%	13%		\$ 14.04	\$ 0.31	2.27%	13%		\$ 14.47	\$ 0.43	3.05%	13%		\$ 15.06	\$ 0.59	4.09%	13%		\$ 15.27	\$ 0.21	1.38%
Total Bill (including HST)				\$ 119.09			\$ 119.36	\$ 0.27	0.23%			\$ 122.07	\$ 2.71	2.27%			\$ 125.79	\$ 3.72	3.05%			\$ 130.93	\$ 5.14	4.09%			\$ 132.74	\$ 1.81	1.38%
Ontario Clean Energy Benefit ¹				-\$ 11.91			-\$ 11.94	-\$ 0.03	0.25%			\$ -	\$ 11.94			\$ -	\$ -				\$ -	\$ -				\$ -	\$ -		
Total Bill on RPP (including OCEB)				\$ 107.18			\$ 107.42	\$ 0.24	0.22%			\$ 122.07	\$ 14.65	13.64%			\$ 125.79	\$ 3.72	3.05%			\$ 130.93	\$ 5.14	4.09%			\$ 132.74	\$ 1.81	1.38%

Loss Factor (%) 3.76%

3.76%

3.76%

3.76%

3.76%

3.76%

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL

TOU / non-TOU: TOU

Consumption 800 kWh ☐ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Service Charge	per 30 days	\$ 17.35	1	\$ 17.35	\$ 18.90	1	\$ 18.90	\$ 1.55	8.93%	\$ 19.83	1	\$ 19.83	\$ 0.93	4.92%	\$ 21.56	1	\$ 21.56	\$ 1.73	8.72%	\$ 23.08	1	\$ 23.08	\$ 1.52	7.05%	\$ 24.33	1	\$ 24.33	\$ 1.25	5.42%
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.06	1	\$ 0.06		1	\$ -	-\$ 0.06			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.68	1	\$ 0.68		1	\$ -	-\$ 0.68			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -	
Distribution Volumetric Rate	per kWh	\$ 0.02617	800	\$ 20.94	\$ 0.02851	800	\$ 22.81	\$ 1.87	8.94%	\$ 0.02992	800	\$ 23.94	\$ 1.13	4.95%	\$ 0.03252	800	\$ 26.02	\$ 2.08	8.69%	\$ 0.03482	800	\$ 27.86	\$ 1.84	7.07%	\$ 0.03670	800	\$ 29.36	\$ 1.50	5.40%
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00009	800	\$ 0.07		800	\$ -	-\$ 0.07			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00103	800	\$ 0.82		800	\$ -	-\$ 0.82			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00007	800	\$ 0.06		800	\$ -	\$ 0.06			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Rate Rider for PILs and Tax Variance	per kWh		800	\$ -	-\$ 0.00021	800	-\$ 0.17	-\$ 0.17			800	\$ -	\$ 0.17			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Rate Rider for PILs and Tax Variance HST	per kWh		800	\$ -	-\$ 0.00010	800	-\$ 0.08	-\$ 0.08			800	\$ -	\$ 0.08			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Rate Rider for Gain on Sale Named Properties	per kWh		800	\$ -	\$ 0.00052	800	\$ 0.42	\$ 0.42			800	\$ -	-\$ 0.42			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Rate Rider for Hydro One Capital Contributions Variance	per kWh		800	\$ -	\$ 0.00016	800	\$ 0.13	\$ 0.13			800	\$ -	-\$ 0.13			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Rate Rider for Residual RARA	per kWh		800	\$ -	-\$ 0.00006	800	-\$ 0.05	-\$ 0.05			800	\$ -	\$ 0.05			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Rate Rider for LRAMVA	per kWh		800	\$ -	\$ 0.00001	800	\$ 0.01	\$ 0.01			800	\$ -	-\$ 0.01			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Rate Rider for IFRS - 2014 Derecognition	per kWh		800	\$ -		800	\$ -	\$ -		\$ 0.00066	800	\$ 0.53	\$ 0.53		\$ 0.00066	800	\$ 0.53	\$ -	0.00%	\$ 0.00066	800	\$ 0.53	\$ -	0.00%	\$ 0.00066	800	\$ 0.53	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kWh		800	\$ -	-\$ 0.00067	800	-\$ 0.54	-\$ 0.54		-\$ 0.00067	800	-\$ 0.54	\$ -	0.00%	-\$ 0.00067	800	-\$ 0.54	\$ -	0.00%		800	\$ -	\$ 0.54			800	\$ -	\$ -	
Rate Rider for 2012-14 Lost Revenue	per kWh		800	\$ -		800	\$ -	\$ -		\$ 0.00072	800	\$ 0.58	\$ 0.58		\$ 0.00072	800	\$ 0.58	\$ -	0.00%	\$ 0.00072	800	\$ 0.58	\$ -	0.00%	\$ 0.00072	800	\$ 0.58	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		800	\$ -	-\$ 0.00208	800	-\$ 1.66	-\$ 1.66		-\$ 0.00208	800	-\$ 1.66	\$ -	0.00%	-\$ 0.00208	800	-\$ 1.66	\$ -	0.00%		800	\$ -	\$ 1.66			800	\$ -	\$ -	
Sub-Total A (excluding pass through)				\$ 39.87			\$ 39.76	-\$ 0.10	-0.26%			\$ 42.67	\$ 2.91	7.31%			\$ 46.48	\$ 3.81	8.93%			\$ 52.04	\$ 5.56	11.96%			\$ 54.79	\$ 2.75	5.29%
Rate Rider for Low Voltage Variance	per kWh		800	\$ -	\$ 0.00002	800	\$ 0.02	\$ 0.02			800	\$ -	-\$ 0.02			800	\$ -	\$ -			800	\$ -	\$ -			800	\$ -	\$ -	
Line Losses on Cost of Power	per kWh	\$ 0.0925	30	\$ 2.78	\$ 0.0925	30	\$ 2.78	\$ -	0.00%	\$ 0.0925	30	\$ 2.78	\$ -	0.00%	\$ 0.0925	30	\$ 2.78	\$ -	0.00%	\$ 0.0925	30	\$ 2.78	\$ -	0.00%	\$ 0.0925	30	\$ 2.78	\$ -	0.00%
Rate Rider for Smart Metering Entity Charge	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%		1	\$ -	-\$ 0.78	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 43.43			\$ 43.34	-\$ 0.09	-0.20%			\$ 46.23	\$ 2.89	6.67%			\$ 50.04	\$ 3.81	8.24%			\$ 55.60	\$ 5.56	11.11%			\$ 57.58	\$ 1.97	3.55%
RTSR - Network	per kWh	\$ 0.00806	830	\$ 6.69	\$ 0.00819	830	\$ 6.80	\$ 0.11	1.61%	\$ 0.00819	830	\$ 6.80	\$ -	0.00%	\$ 0.00819	830	\$ 6.80	\$ -	0.00%	\$ 0.00819	830	\$ 6.80	\$ -	0.00%	\$ 0.00819	830	\$ 6.80	\$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	\$ 0.00560	830	\$ 4.65	\$ 0.00563	830	\$ 4.67	\$ 0.02	0.54%	\$ 0.00563	830	\$ 4.67	\$ -	0.00%	\$ 0.00563	830	\$ 4.67	\$ -	0.00%	\$ 0.00563	830	\$ 4.67	\$ -	0.00%	\$ 0.00563	830	\$ 4.67	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				\$ 54.77			\$ 54.81	\$ 0.05	0.09%			\$ 57.70	\$ 2.89	5.27%			\$ 61.51	\$ 3.81	6.60%			\$ 67.07	\$ 5.56	9.04%			\$ 69.05	\$ 1.97	2.94%
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	830	\$ 3.65	\$ 0.0044	830	\$ 3.65	\$ -	0.00%	\$ 0.0044	830	\$ 3.65	\$ -	0.00%	\$ 0.0044	830	\$ 3.65	\$ -	0.00%	\$ 0.0044	830	\$ 3.65	\$ -	0.00%	\$ 0.0044	830	\$ 3.65	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	830	\$ 1.08	\$ 0.0013	830	\$ 1.08	\$ -	0.00%	\$ 0.0013	830	\$ 1.08	\$ -	0.00%	\$ 0.0013	830	\$ 1.08	\$ -	0.00%	\$ 0.0013	830	\$ 1.08	\$ -	0.00%	\$ 0.0013	830	\$ 1.08	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	800	\$ 5.60	\$ 0.0070	800	\$ 5.60	\$ -	0.00%	\$ 0.0070	800	\$ 5.60	\$ -	0.00%	\$ 0.0070	800	\$ 5.60	\$ -	0.00%	\$ 0.0070	800	\$ 5.60	\$ -	0.00%	\$ 0.0070	800	\$ 5.60	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	512	\$ 38.40	\$ 0.0750	512	\$ 38.40	\$ -	0.00%	\$ 0.0750	512	\$ 38.40	\$ -	0.00%	\$ 0.0750	512	\$ 38.40	\$ -	0.00%	\$ 0.0750	512	\$ 38.40	\$ -	0.00%	\$ 0.0750	512	\$ 38.40	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	144	\$ 16.13	\$ 0.1120	144	\$ 16.13	\$ -	0.00%	\$ 0.1120	144	\$ 16.13	\$ -	0.00%	\$ 0.1120	144	\$ 16.13	\$ -	0.00%	\$ 0.1120	144	\$ 16.13	\$ -	0.00%	\$ 0.1120	144	\$ 16.13	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	144	\$ 19.44	\$ 0.1350	144	\$ 19.44	\$ -	0.00%	\$ 0.1350	144	\$ 19.44	\$ -	0.00%	\$ 0.1350	144	\$ 19.44	\$ -	0.00%	\$ 0.1350	144	\$ 19.44	\$ -	0.00%	\$ 0.1350	144	\$ 19.44	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	600	\$ 51.60	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	200	\$ 20.20	\$ 0.1010	200	\$ 20.20	\$ -	0.00%	\$ 0.1010	200	\$ 20.20	\$ -	0.00%	\$ 0.1010	200	\$ 20.20	\$ -	0.00%	\$ 0.1010	200	\$ 20.20	\$ -	0.00%	\$ 0.1010	200	\$ 20.20	\$ -	0.00%
Total Bill on TOU (before Taxes)				\$ 139.32			\$ 139.36	\$ 0.05	0.03%			\$ 142.25	\$ 2.89	2.07%			\$ 146.06	\$ 3.81	2.68%			\$ 151.62	\$ 5.56	3.81%			\$ 153.60	\$ 1.97	1.30%
HST		13%		\$ 18.11	13%		\$ 18.12	\$ 0.01	0.03%	13%		\$ 18.49	\$ 0.38	2.07%	13%		\$ 18.99	\$ 0.50	2.68%	13%		\$ 19.71	\$ 0.72	3.81%	13%		\$ 19.97	\$ 0.26	1.30%
Total Bill (including HST)				\$ 157.43			\$ 157.48	\$ 0.05	0.03%			\$ 160.75	\$ 3.27	2.07%			\$ 165.05	\$ 4.31	2.68%			\$ 171.33	\$ 6.28	3.81%			\$ 173.56	\$ 2.23	1.30%
Ontario Clean Energy Benefit ¹				-\$ 15.74			-\$ 15.75	-\$ 0.01	0.06%			\$ -	\$ 15.75			\$ -	\$ -	\$ -			\$ -	\$ -	\$ -			\$ -	\$ -		
Total Bill on TOU (including OCEB)				\$ 141.69			\$ 141.73	\$ 0.04	0.03%			\$ 160.75	\$ 19.02	13.42%			\$ 165.05	\$ 4.31	2.68%			\$ 171.33	\$ 6.28	3.81%			\$ 173.56	\$ 2.23	1.30%
Total Bill on RPP (before Taxes)				\$ 137.15			\$ 137.19	\$ 0.05	0.03%			\$ 140.08	\$ 2.89	2.11%			\$ 143.89	\$ 3.81	2.72%			\$ 149.45	\$ 5.56	3.86%			\$ 151.43	\$ 1.97	1.32%
HST		13%		\$ 17.83	13%		\$ 17.84	\$ 0.01	0.03%	13%		\$ 18.21	\$ 0.38	2.11%	13%		\$ 18.71	\$ 0.50	2.72%	13%		\$ 19.43	\$ 0.72	3.86%	13%		\$ 19.69	\$ 0.26	1.32%
Total Bill (including HST)				\$ 154.98			\$ 155.03	\$ 0.05	0.03%			\$ 158.30	\$ 3.27																

Loss Factor (%) 3.76% 3.76% 3.76% 3.76% 3.76%

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption 2,000 kWh ☒ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact		
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	
Service Charge	per 30 days	\$ 24.80	1	\$ 24.80	\$ 30.43	1	\$ 30.43	\$ 5.63	22.70%	\$ 31.93	1	\$ 31.93	\$ 1.50	4.93%	\$ 34.71	1	\$ 34.71	\$ 2.78	8.71%	\$ 37.17	1	\$ 37.17	\$ 2.46	7.09%	\$ 39.18	1	\$ 39.18	\$ 2.01	5.41%	
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$ 5.60	1	\$ 5.60	\$ 5.60	1	\$ 5.60	\$ -	0.00%	\$ 5.60	1	\$ 5.60	\$ -	0.00%		1	\$ -	\$ -5.60				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ 3.68	1	\$ 3.68		1	\$ -	-\$ 3.68			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.09	1	\$ 0.09		1	\$ -	-\$ 0.09			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.97	1	\$ 0.97		1	\$ -	-\$ 0.97			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Stranded Meters Disposition	per 30 days				\$ 1.19	1	\$ 1.19	\$ 1.19		\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	
Rate Rider for Smart Metering Entity Variance	per 30 days				\$ 0.05	1	\$ 0.05	\$ 0.05																						
Distribution Volumetric Rate	per kWh	\$ 0.02293	2,000	\$ 45.86	\$ 0.02814	2,000	\$ 56.28	\$ 10.42	22.72%	\$ 0.02953	2,000	\$ 59.06	\$ 2.78	4.94%	\$ 0.03209	2,000	\$ 64.18	\$ 5.12	8.67%	\$ 0.03437	2,000	\$ 68.74	\$ 4.56	7.11%	\$ 0.03623	2,000	\$ 72.46	\$ 3.72	5.41%	
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00008	2,000	\$ 0.16		2,000	\$ -	-\$ 0.16			2,000	\$ -	\$ -			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00090	2,000	\$ 1.80		2,000	\$ -	-\$ 1.80			2,000	\$ -	\$ -			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00003	2,000	-\$ 0.06		2,000	\$ -	\$ 0.06			2,000	\$ -	\$ -			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Rate Rider for PILs and Tax Variance	per kWh		2,000	\$ -	-\$ 0.00015	2,000	-\$ 0.30	-\$ 0.30			2,000	\$ -	\$ 0.30			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Rate Rider for PILs and Tax Variance HST	per kWh		2,000	\$ -	-\$ 0.00007	2,000	-\$ 0.14	-\$ 0.14			2,000	\$ -	\$ 0.14			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Rate Rider for Gain on Sale Named Properties	per kWh		2,000	\$ -	\$ 0.00051	2,000	\$ 1.02	\$ 1.02			2,000	\$ -	-\$ 1.02			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Rate Rider for Hydro One Capital Contributions Variance	per kWh		2,000	\$ -	\$ 0.00011	2,000	\$ 0.22	\$ 0.22			2,000	\$ -	-\$ 0.22			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Rate Rider for Residual RARA	per kWh		2,000	\$ -	-\$ 0.00007	2,000	-\$ 0.14	-\$ 0.14			2,000	\$ -	\$ 0.14			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Rate Rider for LRAMVA	per kWh		2,000	\$ -	\$ 0.00046	2,000	\$ 0.92	\$ 0.92			2,000	\$ -	-\$ 0.92			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Rate Rider for IFRS - 2014 Derecognition	per kWh		2,000	\$ -		2,000	\$ -	\$ -		\$ 0.00046	2,000	\$ 0.92	\$ 0.92		\$ 0.00046	2,000	\$ 0.92	\$ -	0.00%	\$ 0.00046	2,000	\$ 0.92	\$ -	0.00%	\$ 0.00046	2,000	\$ 0.92	\$ -	0.00%	
Rate Rider for POEB - Tax Savings	per kWh		2,000	\$ -	-\$ 0.00047	2,000	-\$ 0.94	-\$ 0.94		-\$ 0.00047	2,000	-\$ 0.94	\$ -	0.00%	-\$ 0.00047	2,000	-\$ 0.94	\$ -	0.00%		2,000	\$ -	\$ 0.94		2,000	\$ -	\$ -			
Rate Rider for 2012-14 Lost Revenue	per kWh		2,000	\$ -		2,000	\$ -	\$ -		\$ 0.00050	2,000	\$ 1.00	\$ 1.00		\$ 0.00050	2,000	\$ 1.00	\$ -	0.00%	\$ 0.00050	2,000	\$ 1.00	\$ -	0.00%	\$ 0.00050	2,000	\$ 1.00	\$ -	0.00%	
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		2,000	\$ -	-\$ 0.00147	2,000	-\$ 2.94	-\$ 2.94		-\$ 0.00147	2,000	-\$ 2.94	\$ -	0.00%	-\$ 0.00147	2,000	-\$ 2.94	\$ -	0.00%		2,000	\$ -	\$ 2.94		2,000	\$ -	\$ -			
Sub-Total A (excluding pass through)				\$ 82.90			\$ 91.25	\$ 8.35	10.07%			\$ 95.82	\$ 4.57	5.01%			\$ 98.12	\$ 2.30	2.40%			\$ 109.02	\$ 10.90	11.11%			\$ 114.75	\$ 5.73	5.26%	
Rate Rider for Low Voltage Variance	per kWh		2,000	\$ -	\$ 0.00005	2,000	\$ 0.10	\$ 0.10			2,000	\$ -	-\$ 0.10			2,000	\$ -	\$ -				2,000	\$ -	\$ -		2,000	\$ -	\$ -		
Line Losses on Cost of Power	per kWh	\$ 0.0925	75	\$ 6.95	\$ 0.0925	75	\$ 6.95	\$ -	0.00%	\$ 0.0925	75	\$ 6.95	\$ -	0.00%	\$ 0.0925	75	\$ 6.95	\$ -	0.00%	\$ 0.0925	75	\$ 6.95	\$ -	0.00%	\$ 0.0925	75	\$ 6.95	\$ -	0.00%	
Rate Rider for Smart Metering Entity Charge	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%		1	\$ -	-\$ 0.78		
Sub-Total B - Distribution (includes Sub-Total A)				\$ 90.63			\$ 99.08	\$ 8.45	9.32%			\$ 103.55	\$ 4.47	4.51%			\$ 105.85	\$ 2.30	2.22%			\$ 116.75	\$ 10.90	10.30%			\$ 121.70	\$ 4.95	4.24%	
RTSR - Network	per kWh	\$ 0.00780	2,075	\$ 16.19	\$ 0.00792	2,075	\$ 16.44	\$ 0.25	1.54%	\$ 0.00792	2,075	\$ 16.44	\$ -	0.00%	\$ 0.00792	2,075	\$ 16.44	\$ -	0.00%	\$ 0.00792	2,075	\$ 16.44	\$ -	0.00%	\$ 0.00792	2,075	\$ 16.44	\$ -	0.00%	
RTSR - Line and Transformation Connection	per kWh	\$ 0.00505	2,075	\$ 10.48	\$ 0.00508	2,075	\$ 10.54	\$ 0.06	0.59%	\$ 0.00508	2,075	\$ 10.54	\$ -	0.00%	\$ 0.00508	2,075	\$ 10.54	\$ -	0.00%	\$ 0.00508	2,075	\$ 10.54	\$ -	0.00%	\$ 0.00508	2,075	\$ 10.54	\$ -	0.00%	
Sub-Total C - Delivery (including Sub-Total B)				\$ 117.30			\$ 126.06	\$ 8.76	7.47%			\$ 130.53	\$ 4.47	3.55%			\$ 132.83	\$ 2.30	1.76%			\$ 143.73	\$ 10.90	8.21%			\$ 148.68	\$ 4.95	3.44%	
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	2,075	\$ 9.13	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%	\$ 0.0044	2,075	\$ 9.13	\$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	2,075	\$ 2.70	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%	\$ 0.0013	2,075	\$ 2.70	\$ -	0.00%	
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	2,000	\$ 14.00	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%	\$ 0.0070	2,000	\$ 14.00	\$ -	0.00%	
TOU - Off Peak	per kWh	\$ 0.0750	1,280	\$ 96.00	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%	\$ 0.0750	1,280	\$ 96.00	\$ -	0.00%	
TOU - Mid Peak	per kWh	\$ 0.1120	360	\$ 40.32	\$ 0.1120	360	\$ 40.32	\$ -	0.00%	\$ 0.1120	360	\$ 40.32	\$ -	0.00%	\$ 0.1120	360	\$ 40.32	\$ -	0.00%	\$ 0.1120	360	\$ 40.32	\$ -	0.00%	\$ 0.1120	360	\$ 40.32	\$ -	0.00%	
TOU - On Peak	per kWh	\$ 0.1350	360	\$ 48.60	\$ 0.1350	360	\$ 48.60	\$ -	0.00%	\$ 0.1350	360	\$ 48.60	\$ -	0.00%	\$ 0.1350	360	\$ 48.60	\$ -	0.00%	\$ 0.1350	360	\$ 48.60	\$ -	0.00%	\$ 0.1350	360	\$ 48.60	\$ -	0.00%	
Energy - RPP - Tier 1	per kWh	\$ 0.0860	600	\$ 51.60	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	
Energy - RPP - Tier 2	per kWh	\$ 0.1010	1,400	\$ 141.40	\$ 0.1010	1,400	\$ 141.40	\$ -	0.00%</																					

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption ☒ 1,000 kWh ☐ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Service Charge	per 30 days	\$ 24.80	1	\$ 24.80	\$ 30.43	1	\$ 30.43	\$ 5.63	22.70%	\$ 31.93	1	\$ 31.93	\$ 1.50	4.93%	\$ 34.71	1	\$ 34.71	\$ 2.78	8.71%	\$ 37.17	1	\$ 37.17	\$ 2.46	7.09%	\$ 39.18	1	\$ 39.18	\$ 2.01	5.41%
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$ 5.60	1	\$ 5.60	\$ 5.60	1	\$ 5.60	\$ -	0.00%	\$ 5.60	1	\$ 5.60	\$ -	0.00%		1	\$ -	-\$ 5.60			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ 3.68	1	\$ 3.68		1	\$ -	-\$ 3.68			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.09	1	\$ 0.09		1	\$ -	-\$ 0.09			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.97	1	\$ 0.97		1	\$ -	-\$ 0.97			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Stranded Meters Disposition	per 30 days				\$ 1.19	1	\$ 1.19	\$ 1.19		\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%
Distribution Volumetric Rate	per kWh	\$ 0.02293	1,000	\$ 22.93	\$ 0.02814	1,000	\$ 28.14	\$ 5.21	22.72%	\$ 0.02953	1,000	\$ 29.53	\$ 1.39	4.94%	\$ 0.03209	1,000	\$ 32.09	\$ 2.56	8.67%	\$ 0.03437	1,000	\$ 34.37	\$ 2.28	7.11%	\$ 0.03623	1,000	\$ 36.23	\$ 1.86	5.41%
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00008	1,000	\$ 0.08		1,000	\$ -	-\$ 0.08			1,000	\$ -	\$ -			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00090	1,000	\$ 0.90		1,000	\$ -	-\$ 0.90			1,000	\$ -	\$ -			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00003	1,000	-\$ 0.03		1,000	\$ -	\$ 0.03			1,000	\$ -	\$ -			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Rate Rider for PILs and Tax Variance	per kWh		1,000	\$ -	-\$ 0.00015	1,000	-\$ 0.15	-\$ 0.15			1,000	\$ -	\$ 0.15			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Rate Rider for PILs and Tax Variance HST	per kWh		1,000	\$ -	-\$ 0.00007	1,000	-\$ 0.07	-\$ 0.07			1,000	\$ -	\$ 0.07			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Rate Rider for Gain on Sale Named Properties	per kWh		1,000	\$ -	\$ 0.00051	1,000	\$ 0.51	\$ 0.51			1,000	\$ -	-\$ 0.51			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Rate Rider for Hydro One Capital Contributions Variance	per kWh		1,000	\$ -	\$ 0.00011	1,000	\$ 0.11	\$ 0.11			1,000	\$ -	-\$ 0.11			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Rate Rider for Residual RARA	per kWh		1,000	\$ -	-\$ 0.00007	1,000	-\$ 0.07	-\$ 0.07			1,000	\$ -	\$ 0.07			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Rate Rider for LRAMVA	per kWh		1,000	\$ -	\$ 0.00046	1,000	\$ 0.46	\$ 0.46			1,000	\$ -	-\$ 0.46			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Rate Rider for IFRS - 2014 Derecognition	per kWh		1,000	\$ -		1,000	\$ -	\$ -		\$ 0.00046	1,000	\$ 0.46	\$ 0.46		\$ 0.00046	1,000	\$ 0.46	\$ -	0.00%	\$ 0.00046	1,000	\$ 0.46	\$ -	0.00%	\$ 0.00046	1,000	\$ 0.46	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kWh		1,000	\$ -	-\$ 0.00047	1,000	-\$ 0.47	-\$ 0.47		-\$ 0.00047	1,000	-\$ 0.47	\$ -	0.00%	-\$ 0.00047	1,000	-\$ 0.47	\$ -	0.00%	\$ 0.00047	1,000	\$ -	\$ 0.47		1,000	\$ -	\$ -		
Rate Rider for 2012-14 Lost Revenue	per kWh		1,000	\$ -		1,000	\$ -	\$ -		\$ 0.00050	1,000	\$ 0.50	\$ 0.50		\$ 0.00050	1,000	\$ 0.50	\$ -	0.00%	\$ 0.00050	1,000	\$ 0.50	\$ -	0.00%	\$ 0.00050	1,000	\$ 0.50	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		1,000	\$ -	-\$ 0.00147	1,000	-\$ 1.47	-\$ 1.47		-\$ 0.00147	1,000	-\$ 1.47	\$ -	0.00%	-\$ 0.00147	1,000	-\$ 1.47	\$ -	0.00%	-\$ 0.00147	1,000	\$ -	\$ 1.47		1,000	\$ -	\$ -		
Sub-Total A (excluding pass through)				\$ 59.02			\$ 64.21	\$ 5.19	8.79%			\$ 67.27	\$ 3.06	4.77%			\$ 67.01	-\$ 0.26	-0.39%			\$ 73.69	\$ 6.68	9.97%			\$ 77.56	\$ 3.87	5.25%
Rate Rider for Low Voltage Variance	per kWh		1,000	\$ -	\$ 0.00005	1,000	\$ 0.05	\$ 0.05			1,000	\$ -	-\$ 0.05			1,000	\$ -	\$ -			1,000	\$ -	\$ -		1,000	\$ -	\$ -		
Line Losses on Cost of Power	per kWh	\$ 0.0925	38	\$ 3.48	\$ 0.0925	38	\$ 3.48	\$ -	0.00%	\$ 0.0925	38	\$ 3.48	\$ -	0.00%	\$ 0.0925	38	\$ 3.48	\$ -	0.00%	\$ 0.0925	38	\$ 3.48	\$ -	0.00%	\$ 0.0925	38	\$ 3.48	\$ -	0.00%
Rate Rider for Smart Metering Entity Charge	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%		1	\$ -	-\$ 0.78	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 63.28			\$ 68.52	\$ 5.24	8.28%			\$ 71.53	\$ 3.01	4.39%			\$ 71.27	-\$ 0.26	-0.36%			\$ 77.95	\$ 6.68	9.37%			\$ 81.04	\$ 3.09	3.96%
RTSR - Network	per kWh	\$ 0.00780	1,038	\$ 8.09	\$ 0.00792	1,038	\$ 8.22	\$ 0.12	1.54%	\$ 0.00792	1,038	\$ 8.22	\$ -	0.00%	\$ 0.00792	1,038	\$ 8.22	\$ -	0.00%	\$ 0.00792	1,038	\$ 8.22	\$ -	0.00%	\$ 0.00792	1,038	\$ 8.22	\$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	\$ 0.00505	1,038	\$ 5.24	\$ 0.00508	1,038	\$ 5.27	\$ 0.03	0.59%	\$ 0.00508	1,038	\$ 5.27	\$ -	0.00%	\$ 0.00508	1,038	\$ 5.27	\$ -	0.00%	\$ 0.00508	1,038	\$ 5.27	\$ -	0.00%	\$ 0.00508	1,038	\$ 5.27	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				\$ 76.61			\$ 82.01	\$ 5.40	7.04%			\$ 85.02	\$ 3.01	3.67%			\$ 84.76	-\$ 0.26	-0.31%			\$ 91.44	\$ 6.68	7.88%			\$ 94.53	\$ 3.09	3.38%
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	1,038	\$ 4.57	\$ 0.0044	1,038	\$ 4.57	\$ -	0.00%	\$ 0.0044	1,038	\$ 4.57	\$ -	0.00%	\$ 0.0044	1,038	\$ 4.57	\$ -	0.00%	\$ 0.0044	1,038	\$ 4.57	\$ -	0.00%	\$ 0.0044	1,038	\$ 4.57	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	1,038	\$ 1.35	\$ 0.0013	1,038	\$ 1.35	\$ -	0.00%	\$ 0.0013	1,038	\$ 1.35	\$ -	0.00%	\$ 0.0013	1,038	\$ 1.35	\$ -	0.00%	\$ 0.0013	1,038	\$ 1.35	\$ -	0.00%	\$ 0.0013	1,038	\$ 1.35	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	1,000	\$ 7.00	\$ 0.0070	1,000	\$ 7.00	\$ -	0.00%	\$ 0.0070	1,000	\$ 7.00	\$ -	0.00%	\$ 0.0070	1,000	\$ 7.00	\$ -	0.00%	\$ 0.0070	1,000	\$ 7.00	\$ -	0.00%	\$ 0.0070	1,000	\$ 7.00	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	640	\$ 48.00	\$ 0.0750	640	\$ 48.00	\$ -	0.00%	\$ 0.0750	640	\$ 48.00	\$ -	0.00%	\$ 0.0750	640	\$ 48.00	\$ -	0.00%	\$ 0.0750	640	\$ 48.00	\$ -	0.00%	\$ 0.0750	640	\$ 48.00	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	180	\$ 20.16	\$ 0.1120	180	\$ 20.16	\$ -	0.00%	\$ 0.1120	180	\$ 20.16	\$ -	0.00%	\$ 0.1120	180	\$ 20.16	\$ -	0.00%	\$ 0.1120	180	\$ 20.16	\$ -	0.00%	\$ 0.1120	180	\$ 20.16	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	180	\$ 24.30	\$ 0.1350	180	\$ 24.30	\$ -	0.00%	\$ 0.1350	180	\$ 24.30	\$ -	0.00%	\$ 0.1350	180	\$ 24.30	\$ -	0.00%	\$ 0.1350	180	\$ 24.30	\$ -	0.00%	\$ 0.1350	180	\$ 24.30	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	600	\$ 51.60	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	400	\$ 40.40	\$ 0.1010	400	\$ 40.40	\$ -	0.00%	\$ 0.1010	400	\$ 40.40	\$ -	0.00%	\$ 0.1010	400	\$ 40.40	\$ -	0.00%	\$ 0.1010	400	\$ 40.40	\$ -	0.00%	\$ 0.1010	400	\$ 40.40	\$ -	0.00%
Total Bill on TOU (before Taxes)				\$ 182.23			\$ 187.63	\$ 5.40	2.96%			\$ 190.64	\$ 3.01	1.60%			\$ 190.38	-\$ 0.26	-0.14%										

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption 5,000 kWh ☒ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact						
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change					
Service Charge	per 30 days	\$ 24.80	1	\$ 24.80	\$ 30.43	1	\$ 30.43	\$ 5.63	22.70%	\$ 31.93	1	\$ 31.93	\$ 1.50	4.93%	\$ 34.71	1	\$ 34.71	\$ 2.78	8.71%	\$ 37.17	1	\$ 37.17	\$ 2.46	7.09%	\$ 39.18	1	\$ 39.18	\$ 2.01	5.41%					
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$ 5.60	1	\$ 5.60	\$ 5.60	1	\$ 5.60	\$ -	0.00%	\$ 5.60	1	\$ 5.60	\$ -	0.00%		1	\$ -	-\$ 5.60			1	\$ -	\$ -			1	\$ -	\$ -						
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ 3.68	1	\$ 3.68		1	\$ -	-\$ 3.68			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -						
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.09	1	\$ 0.09		1	\$ -	-\$ 0.09			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -						
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.97	1	\$ 0.97		1	\$ -	-\$ 0.97			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -						
Rate Rider for Stranded Meters Disposition	per 30 days				\$ 1.19	1	\$ 1.19	\$ 1.19		\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%
Distribution Volumetric Rate	per kWh	\$ 0.02293	5,000	\$ 114.65	\$ 0.02814	5,000	\$ 140.70	\$ 26.05	22.72%	\$ 0.02953	5,000	\$ 147.65	\$ 6.95	4.94%	\$ 0.03209	5,000	\$ 160.45	\$ 12.80	8.67%	\$ 0.03437	5,000	\$ 171.85	\$ 11.40	7.11%	\$ 0.03623	5,000	\$ 181.15	\$ 9.30	5.41%					
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00008	5,000	\$ 0.40		5,000	\$ -	-\$ 0.40			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00090	5,000	\$ 4.50		5,000	\$ -	-\$ 4.50			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00003	5,000	-\$ 0.15		5,000	\$ -	\$ 0.15			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Rate Rider for PILs and Tax Variance	per kWh		5,000	\$ -	-\$ 0.00015	5,000	-\$ 0.75	-\$ 0.75			5,000	\$ -	\$ 0.75			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Rate Rider for PILs and Tax Variance HST	per kWh		5,000	\$ -	-\$ 0.00007	5,000	-\$ 0.35	-\$ 0.35			5,000	\$ -	\$ 0.35			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Rate Rider for Gain on Sale Named Properties	per kWh		5,000	\$ -	\$ 0.00051	5,000	\$ 2.55	\$ 2.55			5,000	\$ -	-\$ 2.55			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Rate Rider for Hydro One Capital Contributions Variance	per kWh		5,000	\$ -	\$ 0.00011	5,000	\$ 0.55	\$ 0.55			5,000	\$ -	-\$ 0.55			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Rate Rider for Residual RARA	per kWh		5,000	\$ -	-\$ 0.00007	5,000	-\$ 0.35	-\$ 0.35			5,000	\$ -	\$ 0.35			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Rate Rider for LRAMVA	per kWh		5,000	\$ -	\$ 0.00046	5,000	\$ 2.30	\$ 2.30			5,000	\$ -	-\$ 2.30			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Rate Rider for IFRS - 2014 Derecognition	per kWh		5,000	\$ -		5,000	\$ -	\$ -		\$ 0.00046	5,000	\$ 2.30	\$ 2.30		\$ 0.00046	5,000	\$ 2.30	\$ -	0.00%	\$ 0.00046	5,000	\$ 2.30	\$ -	0.00%	\$ 0.00046	5,000	\$ 2.30	\$ -	0.00%					
Rate Rider for POEB - Tax Savings	per kWh		5,000	\$ -	-\$ 0.00047	5,000	-\$ 2.35	-\$ 2.35		-\$ 0.00047	5,000	-\$ 2.35	\$ -	0.00%	-\$ 0.00047	5,000	-\$ 2.35	\$ -	0.00%	\$ 0.00047	5,000	\$ -	\$ 2.35		\$ 0.00047	5,000	\$ -	\$ -						
Rate Rider for 2012-14 Lost Revenue	per kWh		5,000	\$ -		5,000	\$ -	\$ -		\$ 0.00050	5,000	\$ 2.50	\$ 2.50		\$ 0.00050	5,000	\$ 2.50	\$ -	0.00%	\$ 0.00050	5,000	\$ 2.50	\$ -	0.00%	\$ 0.00050	5,000	\$ 2.50	\$ -	0.00%					
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		5,000	\$ -	-\$ 0.00147	5,000	-\$ 7.35	-\$ 7.35		-\$ 0.00147	5,000	-\$ 7.35	\$ -	0.00%	-\$ 0.00147	5,000	-\$ 7.35	\$ -	0.00%	-\$ 0.00147	5,000	\$ -	\$ 7.35		-\$ 0.00147	5,000	\$ -	\$ -						
Sub-Total A (excluding pass through)				\$ 154.54			\$ 172.17	\$ 17.63	11.41%			\$ 181.47	\$ 9.30	5.40%			\$ 191.45	\$ 9.98	5.50%			\$ 215.01	\$ 23.56	12.31%			\$ 226.32	\$ 11.31	5.26%					
Rate Rider for Low Voltage Variance	per kWh		5,000	\$ -	\$ 0.00005	5,000	\$ 0.25	\$ 0.25			5,000	\$ -	-\$ 0.25			5,000	\$ -	\$ -			5,000	\$ -	\$ -			5,000	\$ -	\$ -						
Line Losses on Cost of Power	per kWh	\$ 0.0925	188	\$ 17.38	\$ 0.0925	188	\$ 17.38	\$ -	0.00%	\$ 0.0925	188	\$ 17.38	\$ -	0.00%	\$ 0.0925	188	\$ 17.38	\$ -	0.00%	\$ 0.0925	188	\$ 17.38	\$ -	0.00%	\$ 0.0925	188	\$ 17.38	\$ -	0.00%					
Rate Rider for Smart Metering Entity Charge	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%		1	\$ -	-\$ 0.78						
Sub-Total B - Distribution (includes Sub-Total A)				\$ 172.70			\$ 190.58	\$ 17.88	10.35%			\$ 199.63	\$ 9.05	4.75%			\$ 209.61	\$ 9.98	5.00%			\$ 233.17	\$ 23.56	11.24%			\$ 243.70	\$ 10.53	4.52%					
RTSR - Network	per kWh	\$ 0.00780	5,188	\$ 40.47	\$ 0.00792	5,188	\$ 41.09	\$ 0.62	1.54%	\$ 0.00792	5,188	\$ 41.09	\$ -	0.00%	\$ 0.00792	5,188	\$ 41.09	\$ -	0.00%	\$ 0.00792	5,188	\$ 41.09	\$ -	0.00%	\$ 0.00792	5,188	\$ 41.09	\$ -	0.00%					
RTSR - Line and Transformation Connection	per kWh	\$ 0.00505	5,188	\$ 26.20	\$ 0.00508	5,188	\$ 26.36	\$ 0.16	0.59%	\$ 0.00508	5,188	\$ 26.36	\$ -	0.00%	\$ 0.00508	5,188	\$ 26.36	\$ -	0.00%	\$ 0.00508	5,188	\$ 26.36	\$ -	0.00%	\$ 0.00508	5,188	\$ 26.36	\$ -	0.00%					
Sub-Total C - Delivery (including Sub-Total B)				\$ 239.37			\$ 258.03	\$ 18.66	7.79%			\$ 267.08	\$ 9.05	3.51%			\$ 277.06	\$ 9.98	3.74%			\$ 300.62	\$ 23.56	8.50%			\$ 311.15	\$ 10.53	3.50%					
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	5,188	\$ 22.83	\$ 0.0044	5,188	\$ 22.83	\$ -	0.00%	\$ 0.0044	5,188	\$ 22.83	\$ -	0.00%	\$ 0.0044	5,188	\$ 22.83	\$ -	0.00%	\$ 0.0044	5,188	\$ 22.83	\$ -	0.00%	\$ 0.0044	5,188	\$ 22.83	\$ -	0.00%					
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	5,188	\$ 6.74	\$ 0.0013	5,188	\$ 6.74	\$ -	0.00%	\$ 0.0013	5,188	\$ 6.74	\$ -	0.00%	\$ 0.0013	5,188	\$ 6.74	\$ -	0.00%	\$ 0.0013	5,188	\$ 6.74	\$ -	0.00%	\$ 0.0013	5,188	\$ 6.74	\$ -	0.00%					
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%					
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	5,000	\$ 35.00	\$ 0.0070	5,000	\$ 35.00	\$ -	0.00%	\$ 0.0070	5,000	\$ 35.00	\$ -	0.00%	\$ 0.0070	5,000	\$ 35.00	\$ -	0.00%	\$ 0.0070	5,000	\$ 35.00	\$ -	0.00%	\$ 0.0070	5,000	\$ 35.00	\$ -	0.00%					
TOU - Off Peak	per kWh	\$ 0.0750	3,200	\$ 240.00	\$ 0.0750	3,200	\$ 240.00	\$ -	0.00%	\$ 0.0750	3,200	\$ 240.00	\$ -	0.00%	\$ 0.0750	3,200	\$ 240.00	\$ -	0.00%	\$ 0.0750	3,200	\$ 240.00	\$ -	0.00%	\$ 0.0750	3,200	\$ 240.00	\$ -	0.00%					
TOU - Mid Peak	per kWh	\$ 0.1120	900	\$ 100.80	\$ 0.1120	900	\$ 100.80	\$ -	0.00%	\$ 0.1120	900	\$ 100.80	\$ -	0.00%	\$ 0.1120	900	\$ 100.80	\$ -	0.00%	\$ 0.1120	900	\$ 100.80	\$ -	0.00%	\$ 0.1120	900	\$ 100.80	\$ -	0.00%					
TOU - On Peak	per kWh	\$ 0.1350	900	\$ 121.50	\$ 0.1350	900	\$ 121.50	\$ -	0.00%	\$ 0.1350	900	\$ 121.50	\$ -	0.00%	\$ 0.1350	900	\$ 121.50	\$ -	0.00%	\$ 0.1350	900	\$ 121.50	\$ -	0.00%	\$ 0.1350	900	\$ 121.50	\$ -	0.00%					
Energy - RPP - Tier 1	per kWh	\$ 0.0860	600	\$ 51.60	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%					
Energy - RPP - Tier 2	per kWh	\$ 0.1010	4,400	\$ 444.40	\$ 0.1010	4,400	\$ 444.40	\$ -	0.00%	\$ 0.1010	4,400	\$ 444.40	\$ -	0.00%	\$ 0.1010	4,400	\$ 444.40	\$ -&																

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption ☒ 10,000 kWh ☐ May 1 - October 31 ☐ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Service Charge	per 30 days	\$ 24.80	1	\$ 24.80	\$ 30.43	1	\$ 30.43	\$ 5.63	22.70%	\$ 31.93	1	\$ 31.93	\$ 1.50	4.93%	\$ 34.71	1	\$ 34.71	\$ 2.78	8.71%	\$ 37.17	1	\$ 37.17	\$ 2.46	7.09%	\$ 39.18	1	\$ 39.18	\$ 2.01	5.41%
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$ 5.60	1	\$ 5.60	\$ 5.60	1	\$ 5.60	\$ -	0.00%	\$ 5.60	1	\$ 5.60	\$ -	0.00%		1	\$ -	-\$ 5.60			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ 3.68	1	\$ 3.68		1	\$ -	-\$ 3.68			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.09	1	\$ 0.09		1	\$ -	-\$ 0.09			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.97	1	\$ 0.97		1	\$ -	-\$ 0.97			1	\$ -	\$ -			1	\$ -	\$ -			1	\$ -	\$ -		1	\$ -	\$ -		
Rate Rider for Stranded Meters Disposition	per 30 days				\$ 1.19	1	\$ 1.19	\$ 1.19		\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%	\$ 1.19	1	\$ 1.19	\$ -	0.00%
Distribution Volumetric Rate	per kWh	\$ 0.02293	10,000	\$ 229.30	\$ 0.02814	10,000	\$ 281.40	\$ 52.10	22.72%	\$ 0.02953	10,000	\$ 295.30	\$ 13.90	4.94%	\$ 0.03209	10,000	\$ 320.90	\$ 25.60	8.67%	\$ 0.03437	10,000	\$ 343.70	\$ 22.80	7.11%	\$ 0.03623	10,000	\$ 362.30	\$ 18.60	5.41%
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00008	10,000	\$ 0.80		10,000	\$ -	-\$ 0.80			10,000	\$ -	\$ -			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00090	10,000	\$ 9.00		10,000	\$ -	-\$ 9.00			10,000	\$ -	\$ -			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00003	10,000	\$ 0.30		10,000	\$ -	\$ 0.30			10,000	\$ -	\$ -			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Rate Rider for PILs and Tax Variance	per kWh		10,000	\$ -	-\$ 0.00015	10,000	-\$ 1.50	-\$ 1.50			10,000	\$ -	\$ 1.50			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Rate Rider for PILs and Tax Variance HST	per kWh		10,000	\$ -	-\$ 0.00007	10,000	-\$ 0.70	-\$ 0.70			10,000	\$ -	\$ 0.70			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Rate Rider for Gain on Sale Named Properties	per kWh		10,000	\$ -	\$ 0.00051	10,000	\$ 5.10	\$ 5.10			10,000	\$ -	-\$ 5.10			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Rate Rider for Hydro One Capital Contributions Variance	per kWh		10,000	\$ -	\$ 0.00011	10,000	\$ 1.10	\$ 1.10			10,000	\$ -	-\$ 1.10			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Rate Rider for Residual RARA	per kWh		10,000	\$ -	-\$ 0.00007	10,000	-\$ 0.70	-\$ 0.70			10,000	\$ -	\$ 0.70			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Rate Rider for LRAMVA	per kWh		10,000	\$ -	\$ 0.00046	10,000	\$ 4.60	\$ 4.60			10,000	\$ -	-\$ 4.60			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Rate Rider for IFRS - 2014 Derecognition	per kWh		10,000	\$ -		10,000	\$ -	\$ -		\$ 0.00046	10,000	\$ 4.60	\$ 4.60		\$ 0.00046	10,000	\$ 4.60	\$ -	0.00%	\$ 0.00046	10,000	\$ 4.60	\$ -	0.00%	\$ 0.00046	10,000	\$ 4.60	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kWh		10,000	\$ -	-\$ 0.00047	10,000	-\$ 4.70	-\$ 4.70		-\$ 0.00047	10,000	-\$ 4.70	\$ -	0.00%	-\$ 0.00047	10,000	-\$ 4.70	\$ -	0.00%	\$ 0.00047	10,000	\$ -	\$ 4.70		10,000	\$ -	\$ -		
Rate Rider for 2012-14 Lost Revenue	per kWh		10,000	\$ -		10,000	\$ -	\$ -		\$ 0.00050	10,000	\$ 5.00	\$ 5.00		\$ 0.00050	10,000	\$ 5.00	\$ -	0.00%	\$ 0.00050	10,000	\$ 5.00	\$ -	0.00%	\$ 0.00050	10,000	\$ 5.00	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh		10,000	\$ -	-\$ 0.00147	10,000	-\$ 14.70	-\$ 14.70		-\$ 0.00147	10,000	-\$ 14.70	\$ -	0.00%	-\$ 0.00147	10,000	-\$ 14.70	\$ -	0.00%	-\$ 0.00147	10,000	\$ -	\$ 14.70		10,000	\$ -	\$ -		
Sub-Total A (excluding pass through)				\$ 273.94		\$ 307.12	\$ 33.18	12.11%			\$ 324.22	\$ 17.10	5.57%			\$ 347.00	\$ 22.78	7.03%			\$ 391.66	\$ 44.66	12.87%			\$ 412.27	\$ 20.61	5.26%	
Rate Rider for Low Voltage Variance	per kWh		10,000	\$ -	\$ 0.00005	10,000	\$ 0.50	\$ 0.50			10,000	\$ -	-\$ 0.50			10,000	\$ -	\$ -			10,000	\$ -	\$ -		10,000	\$ -	\$ -		
Line Losses on Cost of Power	per kWh	\$ 0.0925	376	\$ 34.76	\$ 0.0925	376	\$ 34.76	\$ -	0.00%	\$ 0.0925	376	\$ 34.76	\$ -	0.00%	\$ 0.0925	376	\$ 34.76	\$ -	0.00%	\$ 0.0925	376	\$ 34.76	\$ -	0.00%	\$ 0.0925	376	\$ 34.76	\$ -	0.00%
Rate Rider for Smart Metering Entity Charge - Ends Oct. 31, 2018.	per 30 days	\$ 0.78	1	\$ 0.78	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%	\$ 0.78	1	\$ 0.78	\$ -	0.00%		1	\$ -	-\$ 0.78	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 309.48		\$ 343.16	\$ 33.68	10.88%			\$ 359.76	\$ 16.60	4.84%			\$ 382.54	\$ 22.78	6.33%			\$ 427.20	\$ 44.66	11.67%			\$ 447.03	\$ 19.83	4.64%	
RTSR - Network	per kWh	\$ 0.00780	10,376	\$ 80.93	\$ 0.00792	10,376	\$ 82.18	\$ 1.25	1.54%	\$ 0.00792	10,376	\$ 82.18	\$ -	0.00%	\$ 0.00792	10,376	\$ 82.18	\$ -	0.00%	\$ 0.00792	10,376	\$ 82.18	\$ -	0.00%	\$ 0.00792	10,376	\$ 82.18	\$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	\$ 0.00505	10,376	\$ 52.40	\$ 0.00508	10,376	\$ 52.71	\$ 0.31	0.59%	\$ 0.00508	10,376	\$ 52.71	\$ -	0.00%	\$ 0.00508	10,376	\$ 52.71	\$ -	0.00%	\$ 0.00508	10,376	\$ 52.71	\$ -	0.00%	\$ 0.00508	10,376	\$ 52.71	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				\$ 442.82		\$ 478.05	\$ 35.24	7.96%			\$ 494.65	\$ 16.60	3.47%			\$ 517.43	\$ 22.78	4.61%			\$ 562.09	\$ 44.66	8.63%			\$ 581.92	\$ 19.83	3.53%	
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	10,376	\$ 45.65	\$ 0.0044	10,376	\$ 45.65	\$ -	0.00%	\$ 0.0044	10,376	\$ 45.65	\$ -	0.00%	\$ 0.0044	10,376	\$ 45.65	\$ -	0.00%	\$ 0.0044	10,376	\$ 45.65	\$ -	0.00%	\$ 0.0044	10,376	\$ 45.65	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	10,376	\$ 13.49	\$ 0.0013	10,376	\$ 13.49	\$ -	0.00%	\$ 0.0013	10,376	\$ 13.49	\$ -	0.00%	\$ 0.0013	10,376	\$ 13.49	\$ -	0.00%	\$ 0.0013	10,376	\$ 13.49	\$ -	0.00%	\$ 0.0013	10,376	\$ 13.49	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	10,000	\$ 70.00	\$ 0.0070	10,000	\$ 70.00	\$ -	0.00%	\$ 0.0070	10,000	\$ 70.00	\$ -	0.00%	\$ 0.0070	10,000	\$ 70.00	\$ -	0.00%	\$ 0.0070	10,000	\$ 70.00	\$ -	0.00%	\$ 0.0070	10,000	\$ 70.00	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	6,400	\$ 480.00	\$ 0.0750	6,400	\$ 480.00	\$ -	0.00%	\$ 0.0750	6,400	\$ 480.00	\$ -	0.00%	\$ 0.0750	6,400	\$ 480.00	\$ -	0.00%	\$ 0.0750	6,400	\$ 480.00	\$ -	0.00%	\$ 0.0750	6,400	\$ 480.00	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	1,800	\$ 201.60	\$ 0.1120	1,800	\$ 201.60	\$ -	0.00%	\$ 0.1120	1,800	\$ 201.60	\$ -	0.00%	\$ 0.1120	1,800	\$ 201.60	\$ -	0.00%	\$ 0.1120	1,800	\$ 201.60	\$ -	0.00%	\$ 0.1120	1,800	\$ 201.60	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	1,800	\$ 243.00	\$ 0.1350	1,800	\$ 243.00	\$ -	0.00%	\$ 0.1350	1,800	\$ 243.00	\$ -	0.00%	\$ 0.1350	1,800	\$ 243.00	\$ -	0.00%	\$ 0.1350	1,800	\$ 243.00	\$ -	0.00%	\$ 0.1350	1,800	\$ 243.00	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	600	\$ 51.60	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%	\$ 0.0860	600	\$ 51.60	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	9,400	\$ 949.40	\$ 0.1010	9,400	\$ 949.40	\$ -	0.00%	\$ 0.1010	9,400	\$ 949.40	\$ -	0.00%	\$ 0.1010	9,400	\$ 949.40	\$ -	0.00%	\$ 0.1010	9,400	\$ 949.40	\$ -	0.00%	\$ 0.101				

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000

GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000

GS>50kW (kW) - 60, 100, 500, 1000

Large User - range appropriate for utility

Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

GS 50-999 kW

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 50 TO 999 kW SERVICE

TOU / non-TOU: non-TOU

Consumption		100	kW		111	kVA		May 1 - October 31		November 1 - April 30 (Select this radio button for applications filed after Oct 31)		40,000	kWh																
		Current Board-Approved						2015 Proposed		Impact		2016 Proposed		Impact		2017 Proposed		Impact		2018 Proposed		Impact		2019 Proposed		Impact			
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Monthly Service Charge	per 30 days	\$ 36.29	1	\$ 36.29	\$ 43.63	1	\$ 43.63	\$ 7.34	20.23%	\$ 45.79	1	\$ 45.79	\$ 2.16	4.95%	\$ 49.76	1	\$ 49.76	\$ 3.97	8.67%	\$ 53.29	1	\$ 53.29	\$ 3.53	7.09%	\$ 56.17	1	\$ 56.17	\$ 2.88	5.40%
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$ 18.79	1	\$ 18.79	\$ 18.79	1	\$ 18.79	\$ -	0.00%	\$ 18.79	1	\$ 18.79	\$ -	0.00%		1	\$ -	\$ 18.79	\$ -		1	\$ -	\$ -	\$ -		1	\$ -	\$ -	\$ -
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ 11.16	1	\$ 11.16		1	\$ -	-\$ 11.16			1	\$ -	\$ -			1	\$ -	\$ -	\$ -		1	\$ -	\$ -	\$ -		1	\$ -	\$ -	\$ -
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.13	1	\$ 0.13		1	\$ -	-\$ 0.13			1	\$ -	\$ -			1	\$ -	\$ -	\$ -		1	\$ -	\$ -	\$ -		1	\$ -	\$ -	\$ -
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 1.42	1	\$ 1.42		1	\$ -	-\$ 1.42			1	\$ -	\$ -			1	\$ -	\$ -	\$ -		1	\$ -	\$ -	\$ -		1	\$ -	\$ -	\$ -
Rate Rider for Stranded Meters Disposition	per 30 days				\$ 3.62	1	\$ 3.62	\$ 3.62		\$ 3.62	1	\$ 3.62	\$ -	0.00%	\$ 3.62	1	\$ 3.62	\$ -	0.00%	\$ 3.62	1	\$ 3.62	\$ -	0.00%	\$ 3.62	1	\$ 3.62	\$ -	0.00%
Distribution Volumetric Rate	per kVA	\$ 5.7116	111	\$ 633.99	\$ 6.8676	111	\$ 762.30	\$ 128.32	20.24%	\$ 7.2069	111	\$ 799.97	\$ 37.66	4.94%	\$ 7.8324	111	\$ 869.40	\$ 69.43	8.68%	\$ 8.3877	111	\$ 931.03	\$ 61.64	7.09%	\$ 8.8415	111	\$ 981.41	\$ 50.37	5.41%
Rate Rider for Recovery of Foregone Revenue	per kVA	\$ 0.0202	111	\$ 2.24		111	\$ -	-\$ 2.24			111	\$ -	\$ -			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Rate Rider for Recovery of Incremental Capital Module Costs	per kVA	\$ 0.2225	111	\$ 24.70		111	\$ -	-\$ 24.70			111	\$ -	\$ -			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Rate Rider for Application of Tax Change	per kVA	-\$ 0.0056	111	\$ 0.62		111	\$ -	\$ 0.62			111	\$ -	\$ -			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Rate Rider for PILs and Tax Variance	per kVA		111	\$ -	-\$ 0.0244	111	\$ 2.71	-\$ 2.71			111	\$ -	\$ 2.71			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Rate Rider for PILs and Tax Variance HST	per kVA		111	\$ -	-\$ 0.0116	111	\$ 1.29	-\$ 1.29			111	\$ -	\$ 1.29			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Rate Rider for Gain on Sale Named Properties	per kVA		111	\$ -	\$ 0.0440	111	\$ 4.88	\$ 4.88			111	\$ -	-\$ 4.88			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Rate Rider for Hydro One Capital Contributions Variance	per kVA		111	\$ -	\$ 0.0183	111	\$ 2.03	\$ 2.03			111	\$ -	-\$ 2.03			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Rate Rider for Residual RARA	per kVA		111	\$ -	-\$ 0.0287	111	\$ 3.19	-\$ 3.19			111	\$ -	\$ 3.19			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Rate Rider for LRAMVA	per kVA		111	\$ -	\$ 0.1077	111	\$ 11.95	\$ 11.95			111	\$ -	-\$ 11.95			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Rate Rider for IFRS - 2014 Derecognition	per kVA		111	\$ -		111	\$ -	\$ -		\$ 0.0752	111	\$ 8.35	\$ 8.35		\$ 0.0752	111	\$ 8.35	\$ -	0.00%	\$ 0.0752	111	\$ 8.35	\$ -	0.00%	\$ 0.0752	111	\$ 8.35	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kVA		111	\$ -	-\$ 0.0766	111	\$ 8.50	-\$ 8.50		\$ 0.0766	111	\$ 8.50	\$ -	0.00%	-\$ 0.0766	111	\$ 8.50	\$ -	0.00%	\$ 0.0821	111	\$ -	\$ 8.50		111	\$ -	\$ -	\$ -	
Rate Rider for 2012-14 Lost Revenue	per kVA		111	\$ -		111	\$ -	\$ -		\$ 0.0821	111	\$ 9.11	\$ 9.11		-\$ 0.0821	111	\$ 9.11	\$ -	0.00%	\$ 0.0821	111	\$ 9.11	\$ -	0.00%	\$ 0.0821	111	\$ 9.11	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kVA		111	\$ -	-\$ 0.2382	111	\$ 26.44	-\$ 26.44		-\$ 0.2382	111	\$ 26.44	\$ -	0.00%	-\$ 0.2382	111	\$ 26.44	\$ -	0.00%		111	\$ -	\$ 26.44		111	\$ -	\$ -	\$ -	
Sub-Total A (excluding pass through)				\$ 728.10			\$ 805.09	\$ 76.99	10.57%			\$ 850.68	\$ 45.59	5.66%			\$ 905.29	\$ 54.61	6.42%			\$ 1,005.41	\$ 100.11	11.06%			\$ 1,058.66	\$ 53.25	5.30%
Rate Rider for Low Voltage Variance	per kVA		111	\$ -	\$ 0.0188	111	\$ 2.09	\$ 2.09			111	\$ -	-\$ 2.09			111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -		111	\$ -	\$ -	\$ -
Line Losses on Cost of Power	per kWh	\$ 0.1010	1,504	\$ 151.90	\$ 0.1010	1,504	\$ 151.90	\$ -	0.00%	\$ 0.1010	1,504	\$ 151.90	\$ -	0.00%	\$ 0.1010	1,504	\$ 151.90	\$ -	0.00%	\$ 0.1010	1,504	\$ 151.90	\$ -	0.00%	\$ 0.1010	1,504	\$ 151.90	\$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				\$ 880.00			\$ 959.08	\$ 79.08	8.99%			\$ 1,002.59	\$ 43.51	4.54%			\$ 1,057.20	\$ 54.61	5.45%			\$ 1,157.31	\$ 100.11	9.47%			\$ 1,210.56	\$ 53.25	4.60%
RTSR - Network	per kW	\$ 2.7917	100	\$ 279.17	\$ 2.8350	100	\$ 283.50	\$ 4.33	1.55%	\$ 2.8350	100	\$ 283.50	\$ -	0.00%	\$ 2.8350	100	\$ 283.50	\$ -	0.00%	\$ 2.8350	100	\$ 283.50	\$ -	0.00%	\$ 2.8350	100	\$ 283.50	\$ -	0.00%
RTSR - Line and Transformation Connection	per kW	\$ 1.9253	100	\$ 192.53	\$ 1.9361	100	\$ 193.61	\$ 1.08	0.56%	\$ 1.9361	100	\$ 193.61	\$ -	0.00%	\$ 1.9361	100	\$ 193.61	\$ -	0.00%	\$ 1.9361	100	\$ 193.61	\$ -	0.00%	\$ 1.9361	100	\$ 193.61	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)				\$ 1,351.70			\$ 1,436.19	\$ 84.49	6.25%			\$ 1,479.70	\$ 43.51	3.03%			\$ 1,534.31	\$ 54.61	3.69%			\$ 1,634.42	\$ 100.11	6.52%			\$ 1,687.67	\$ 53.25	3.26%
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	41,504	\$ 182.62	\$ 0.0044	41,504	\$ 182.62	\$ -	0.00%	\$ 0.0044	41,504	\$ 182.62	\$ -	0.00%	\$ 0.0044	41,504	\$ 182.62	\$ -	0.00%	\$ 0.0044	41,504	\$ 182.62	\$ -	0.00%	\$ 0.0044	41,504	\$ 182.62	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	41,504	\$ 53.96	\$ 0.0013	41,504	\$ 53.96	\$ -	0.00%	\$ 0.0013	41,504	\$ 53.96	\$ -	0.00%	\$ 0.0013	41,504	\$ 53.96	\$ -	0.00%	\$ 0.0013	41,504	\$ 53.96	\$ -	0.00%	\$ 0.0013	41,504	\$ 53.96	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	40,000	\$ 280.00	\$ 0.0070	40,000	\$ 280.00	\$ -	0.00%	\$ 0.0070	40,000	\$ 280.00	\$ -	0.00%	\$ 0.0070	40,000	\$ 280.00	\$ -	0.00%	\$ 0.0070	40,000	\$ 280.00	\$ -	0.00%	\$ 0.0070	40,000	\$ 280.00	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	25,600	\$ 1,920.00	\$ 0.0750	25,600	\$ 1,920.00	\$ -	0.00%	\$ 0.0750	25,600	\$ 1,920.00	\$ -	0.00%	\$ 0.0750	25,600	\$ 1,920.00	\$ -	0.00%	\$ 0.0750	25,600	\$ 1,920.00	\$ -	0.00%	\$ 0.0750	25,600	\$ 1,920.00	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	7,200	\$ 806.40	\$ 0.1120	7,200	\$ 806.40	\$ -	0.00%	\$ 0.1120	7,200	\$ 806.40	\$ -	0.00%	\$ 0.1120	7,200	\$ 806.40	\$ -	0.00%	\$ 0.1120	7,200	\$ 806.40	\$ -	0.00%	\$ 0.1120	7,200	\$ 806.40	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	7,200	\$ 972.00	\$ 0.1350	7,200	\$ 972.00	\$ -	0.00%	\$ 0.1350	7,200	\$ 972.00	\$ -	0.00%	\$ 0.1350	7,200	\$ 972.00	\$ -	0.00%	\$ 0.1350	7,200	\$ 972.00	\$ -	0.00%	\$ 0.1350	7,200	\$ 972.00	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	750	\$ 64.50	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750	\$ 64.50	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	39,250	\$ 3,964.25	\$ 0.1010	39,250	\$ 3,964.25	\$ -	0.00%	\$ 0.1010	39,250	\$ 3,964.25	\$ -	0.00%	\$ 0.1010	39,250	\$ 3,964.25	\$ -	0.00%	\$ 0.1010	39,250	\$ 3,964.25	\$ -	0.00%	\$ 0.1010	39,250	\$ 3,964.25	\$ -	0.00%
Total Bill on TOU (before Taxes)				\$ 5,566.92			\$ 5,651.41	\$ 84.49	1.52%			\$ 5,694.92	\$ 43.51	0.77%			\$ 5,749.53	\$ 54.61	0.96%			\$ 5,849.64	\$ 100.11	1.74%			\$ 5,902.89	\$ 53.25	0.91%
HST	13%			\$ 723.70	\$ 734.68	\$ 734.68	\$ 10.98	\$ 10.98	1.52%	13%		\$ 740.34	\$ 5.66	0.77%	13%		\$ 747.44	\$ 7.10	0.96%	13%		\$ 760.45	\$ 13.01	1.74%	13%		\$ 767.38	\$ 6.92	0.91%
Total Bill (including HST)				\$ 6,290.62	\$ 6,386.10	\$ 6,386.10	\$ 95.47	\$ 95.47	1.52%			\$ 6,435.26	\$ 49.16	0.77%			\$ 6,496.97	\$ 61.71	0.96%			\$ 6,610.10	\$ 113.13	1.74%			\$ 6,670.27	\$ 60.17	0.91%
Ontario Clean Energy Benefit ¹				\$ -	\$ -	\$ -	\$ -	\$ -				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -	
Total Bill on TOU (including OCEB)				\$ 6,290.62	\$ 6,386.10	\$ 6,386.10	\$ 95.47	\$ 95.47	1.52%			\$ 6,435.26	\$ 49.16	0.77%			\$ 6,496.97	\$ 61.71	0.96%			\$ 6,610.10	\$ 113.13	1.74%			\$ 6,670.27	\$ 60.17	0.91%
Total Bill on RPP (before Taxes)				\$ 5,897.27			\$ 5,981.76	\$ 84.49	1.43%			\$ 6,025.27	\$ 43.51	0.73%			\$ 6,079.88	\$ 54.61	0.91%			\$ 6,179.99	\$ 100.11	1.65%			\$ 6,233.24	\$ 53.25	0.86%
HST	13%			\$ 766.65	\$ 777.63	\$ 777.63	\$ 10.98	\$ 10.98	1.43%	13%		\$ 783.29	\$ 5.66	0.73%	13%		\$ 790.38	\$ 7.10	0.91%	13%		\$ 803.40	\$ 13.01	1.65%	13%		\$ 810.32	\$ 6.92	0.86%
Total Bill (including HST)				\$ 6,663.92	\$ 6,759.39	\$ 6,759.39	\$ 95.47	\$ 95.47	1.43%			\$ 6,808.56	\$ 49.16	0.73%			\$ 6,870.27	\$ 61.71	0.91%			\$ 6,983.39	\$ 113.13	1.65%			\$ 7,043.57	\$ 60.17	0.86%
Ontario Clean Energy Benefit ¹				\$ -	\$ -	\$ -	\$ -	\$ -				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -	
Total Bill on RPP (including OCEB)				\$ 6,663.92	\$ 6,759.39	\$ 6,759.39	\$ 95.47	\$ 95.47	1.43%			\$ 6,808.56	\$ 49.16	0.73%			\$ 6,870.27	\$ 61.71	0.91%			\$ 6,983.39	\$ 113.13	1.65%			\$ 7,043.57	\$ 60.17	0.86%

Loss Factor (%) 3.76%

3.76%

3.76%

3.76%

3.76%

3.76%

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000

GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000

GS>50kW (kW) - 60, 100, 500, 1000

Large User - range appropriate for utility

Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000

GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000

GS>50kW (kW) - 60, 100, 500, 1000

Large User - range appropriate for utility

Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

GS 50-999 kW

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 50 TO 999 kW SERVICE

TOU / non-TOU: non-TOU

Consumption		800		kW		889		kVA		May 1 - October 31		November 1 - April 30 (Select this radio button for applications filed after Oct 31)		350,000		kWh																															
		Current Board-Approved						2015 Proposed				Impact		2016 Proposed				Impact		2017 Proposed				Impact		2018 Proposed				Impact		2019 Proposed				Impact											
		Rate (\$)		Volume		Charge (\$)		Rate (\$)		Volume		Charge (\$)		\$ Change		% Change		Rate (\$)		Volume		Charge (\$)		\$ Change		% Change		Rate (\$)		Volume		Charge (\$)		\$ Change		% Change		Rate (\$)		Volume		Charge (\$)		\$ Change		% Change	
		Charge Unit																																													
Monthly Service Charge	per 30 days	\$	36.29	1	\$	36.29	\$	43.63	1	\$	43.63	\$	7.34	20.23%	\$	45.79	1	\$	45.79	\$	2.16	4.95%	\$	49.76	1	\$	49.76	\$	3.97	8.67%	\$	53.29	1	\$	53.29	\$	3.53	7.09%	\$	56.17	1	\$	56.17	\$	2.88	5.40%	
Rate Rider for Recovery of 2008-2010 Smart Meter Costs	per 30 days	\$	18.79	1	\$	18.79	\$	18.79	1	\$	18.79	\$	-	0.00%	\$	18.79	1	\$	18.79	\$	-	0.00%	\$	-	1	\$	-	\$	-	18.79	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	-	-			
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$	11.16	1	\$	11.16	1	\$	-	1	\$	-	-\$	11.16	1	\$	-	1	\$	-	\$	-	1	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	-	-
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$	0.13	1	\$	0.13	1	\$	-	1	\$	-	-\$	0.13	1	\$	-	1	\$	-	\$	-	1	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	-	-
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$	1.42	1	\$	1.42	1	\$	-	1	\$	-	-\$	1.42	1	\$	-	1	\$	-	\$	-	1	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	1	\$	-	\$	-	-	-
Rate Rider for Stranded Meters Disposition	per 30 days				\$	3.62	1	\$	3.62	1	\$	3.62	\$	-	0.00%	\$	3.62	1	\$	3.62	\$	-	0.00%	\$	3.62	1	\$	3.62	\$	-	0.00%	\$	3.62	1	\$	3.62	\$	-	0.00%	\$	3.62	1	\$	3.62	\$	-	0.00%
Distribution Volumetric Rate	per kVA	\$	5.7116	889	\$	5,077.61	\$	6.8676	889	\$	6,105.30	\$	1,027.68	20.24%	\$	7.2069	889	\$	6,406.93	\$	301.64	4.94%	\$	7.8324	889	\$	6,963.00	\$	556.07	8.68%	\$	8.3877	889	\$	7,456.67	\$	493.66	7.09%	\$	8.8415	889	\$	7,860.09	\$	403.43	5.41%	
Rate Rider for Recovery of Foregone Revenue	per kVA	\$	0.0202	889	\$	17.96	889	\$	-	889	\$	-	-\$	17.96	889	\$	-	889	\$	-	\$	-	889	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-
Rate Rider for Recovery of Incremental Capital Module Costs	per kVA	\$	0.2225	889	\$	197.80	889	\$	-	889	\$	-	-\$	197.80	889	\$	-	889	\$	-	\$	-	889	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-
Rate Rider for Application of Tax Change	per kVA	-\$	0.0056	889	\$	4.98	889	\$	-	889	\$	-	\$	4.98	889	\$	-	889	\$	-	\$	-	889	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-
Rate Rider for PILs and Tax Variance	per kVA		889	\$	-		-\$	0.0244	889	-\$	21.69	-\$	21.69		889	\$	-	889	\$	-	\$	21.69	889	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-
Rate Rider for PILs and Tax Variance HST	per kVA		889	\$	-		-\$	0.0116	889	-\$	10.31	-\$	10.31		889	\$	-	889	\$	-	\$	10.31	889	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-
Rate Rider for Gain on Sale Named Properties	per kVA		889	\$	-		\$	0.0440	889	\$	39.12	\$	39.12		889	\$	-	889	\$	-	-\$	39.12	889	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-
Rate Rider for Hydro One Capital Contributions Variance	per kVA		889	\$	-		\$	0.0183	889	\$	16.27	\$	16.27		889	\$	-	889	\$	-	-\$	16.27	889	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-
Rate Rider for Residual RARA	per kVA		889	\$	-		-\$	0.0287	889	-\$	25.51	-\$	25.51		889	\$	-	889	\$	-	\$	25.51	889	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-
Rate Rider for LRAMVA	per kVA		889	\$	-		\$	0.1077	889	\$	95.75	\$	95.75		889	\$	-	889	\$	-	-\$	95.75	889	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-
Rate Rider for IFRS - 2014 Derecognition	per kVA		889	\$	-				889	\$	-				\$	0.0752	889	\$	66.85	\$	66.85		\$	0.0752	889	\$	66.85	\$	-	0.00%	\$	0.0752	889	\$	66.85	\$	-	0.00%	\$	0.0752	889	\$	66.85	\$	-	0.00%	
Rate Rider for POEB - Tax Savings	per kVA		889	\$	-		-\$	0.0766	889	-\$	68.10	-\$	68.10		889	\$	-	889	-\$	68.10	\$	-	0.00%	-\$	0.0766	889	-\$	68.10	\$	-	0.00%	\$	-	0.00%	\$	-	0.00%	\$	-	0.00%	\$	-	0.00%	\$	-	0.00%	
Rate Rider for 2012-14 Lost Revenue	per kVA		889	\$	-				889	\$	-				\$	0.0821	889	\$	72.99	\$	72.99		\$	0.0821	889	\$	72.99	\$	-	0.00%	\$	0.0821	889	\$	72.99	\$	-	0.00%	\$	0.0821	889	\$	72.99	\$	-	0.00%	
Rate Rider for Operations Center Consolidation Plan Sharing	per kVA		889	\$	-		-\$	0.2382	889	-\$	211.76	-\$	211.76		889	-\$	211.76	889	-\$	211.76	\$	-	0.00%	-\$	0.2382	889	-\$	211.76	\$	-	0.00%	\$	-	0.00%	\$	-	0.00%	\$	-	0.00%	\$	-	0.00%	\$	-	0.00%	
Sub-Total A (excluding pass through)					\$	5,356.18				\$	5,985.09	\$	628.91	11.74%				\$	6,335.12	\$	350.03	5.85%				\$	6,876.37	\$	541.25	8.54%				\$	7,653.42	\$	777.05	11.30%				\$	8,059.72	\$	406.31	5.31%	
Rate Rider for Low Voltage Variance	per kVA		889	\$	-		\$	0.0188	889	\$	16.71	\$	16.71		889	\$	-	889	\$	-	-\$	16.71			889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	889	\$	-	\$	-	-	-	
Line Losses on Cost of Power	per kWh	\$	0.1010	13,160	\$	1,329.16	\$	0.1010	13,160	\$	1,329.16	\$	-	0.00%	\$	0.1010	13,160	\$	1,329.16	\$	-	0.00%	\$	0.1010	13,160	\$	1,329.16	\$	-	0.00%	\$	0.1010	13,160	\$	1,329.16	\$	-	0.00%	\$	0.1010	13,160	\$	1,329.16	\$	-	0.00%	
Sub-Total B - Distribution (includes Sub-Total A)					\$	6,685.34				\$	7,330.96	\$	645.62	9.66%				\$	7,664.28	\$	333.31	4.55%				\$	8,205.53	\$	541.25	7.06%				\$	8,982.58	\$	777.05	9.47%				\$	9,388.88	\$	406.31	4.52%	
RTSR - Network	per kW	\$	2.7917	800	\$	2,233.36	\$	2.8350	800	\$	2,268.00	\$	34.64	1.55%	\$	2.8350	800	\$	2,268.00	\$	-	0.00%	\$	2.8350	800	\$	2,268.00	\$	-	0.00%	\$	2.8350	800	\$	2,268.00	\$	-	0.00%	\$	2.8350	800	\$	2,268.00	\$	-	0.00%	
RTSR - Line and Transformation Connection	per kW	\$	1.9253	800	\$	1,540.24	\$	1.9361	800	\$	1,548.88	\$	8.64	0.56%	\$	1.9361	800	\$	1,548.88	\$	-	0.00%	\$	1.9361	800	\$	1,548.88	\$	-	0.00%	\$	1.9361	800	\$	1,548.88	\$	-	0.00%	\$	1.9361	800	\$	1,548.88	\$	-	0.00%	
Sub-Total C - Delivery (including Sub-Total B)					\$	10,458.94				\$	11,147.84	\$	688.90	6.59%				\$	11,481.16	\$	333.31	2.99%				\$	12,022.41	\$	541.25	4.71%				\$	12,799.46	\$	777.05	6.46%				\$	13,205.76	\$	406.31	3.17%	
Wholesale Market Service Charge (WMSC)	per kWh	\$	0.0044	363,160	\$	1,597.90	\$	0.0044	363,160	\$	1,597.90	\$	-	0.00%	\$	0.0044	363,160	\$	1,597.90	\$	-	0.00%	\$	0.0044	363,160	\$	1,597.90	\$	-	0.00%	\$	0.0044	363,160	\$	1,597.90	\$	-	0.00%	\$	0.0044	363,160	\$	1,597.90	\$	-	0.00%	
Rural and Remote Rate Protection (RRRP)	per kWh	\$	0.0013	363,160	\$	472.11	\$	0.0013	363,160	\$	472.11	\$	-	0.00%	\$	0.0013	363,160	\$	472.11																												

TOU / non-TOU: non-TOU

Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

GS 1,000-4,999 kW

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 1,000 TO 4,999 kW SERVICE

TOU / non-TOU: non-TOU

Consumption	Charge Unit	1,000 kW		1,111 kVA		500,000 kWh		May 1 - October 31		November 1 - April 30 (Select this radio button for applications filed after Oct 31)	
		Current Board-Approved		2015 Proposed		Impact		2016 Proposed		Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume
Service Charge	per 30 days	\$ 700.68	1	\$ 700.68	\$ 831.65	1	\$ 831.65	\$ 130.97	18.69%	\$ 872.73	1
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 2.49	1	\$ 2.49	\$ -	1	\$ -	\$ -	2.49	\$ -	1
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 27.34	1	\$ 27.34	\$ -	1	\$ -	\$ -	27.34	\$ -	1
Distribution Volumetric Rate	per kVA	\$ 4,5419	1,111	\$ 5,046.05	\$ 5,3909	1,111	\$ 5,989.29	\$ 943.24	18.69%	\$ 5,6572	1,111
Rate Rider for Recovery of Foregone Revenue	per kVA	\$ 0.0161	1,111	\$ 17.89	\$ -	1,111	\$ -	\$ -	17.89	\$ -	1,111
Rate Rider for Recovery of Incremental Capital Module Costs	per kVA	\$ 0.1771	1,111	\$ 196.76	\$ -	1,111	\$ -	\$ -	196.76	\$ -	1,111
Rate Rider for Application of Tax Change	per kVA	\$ 0.0047	1,111	\$ 5.22	\$ -	1,111	\$ -	\$ -	5.22	\$ -	1,111
Rate Rider for PILs and Tax Variance	per kVA	\$ -	1,111	\$ -	\$ 0.0197	1,111	\$ 21.89	\$ -	21.89	\$ -	1,111
Rate Rider for PILs and Tax Variance HST	per kVA	\$ -	1,111	\$ -	\$ 0.0093	1,111	\$ 10.33	\$ -	10.33	\$ -	1,111
Rate Rider for Gain on Sale Named Properties	per kVA	\$ -	1,111	\$ -	\$ 0.0217	1,111	\$ 24.11	\$ -	24.11	\$ -	1,111
Rate Rider for Hydro One Capital Contributions Variance	per kVA	\$ -	1,111	\$ -	\$ 0.0147	1,111	\$ 16.33	\$ -	16.33	\$ -	1,111
Rate Rider for Residual RARA	per kVA	\$ -	1,111	\$ -	\$ 0.0327	1,111	\$ 36.33	\$ -	36.33	\$ -	1,111
Rate Rider for LRAMVA	per kVA	\$ -	1,111	\$ -	\$ 0.0035	1,111	\$ 3.89	\$ -	3.89	\$ -	1,111
Rate Rider for IFRS - 2014 Derecognition	per kVA	\$ -	1,111	\$ -	\$ -	1,111	\$ -	\$ 0.0605	67.22	\$ -	1,111
Rate Rider for POEB - Tax Savings	per kVA	\$ -	1,111	\$ -	\$ 0.0616	1,111	\$ 68.44	\$ -	68.44	\$ -	1,111
Rate Rider for 2012-14 Lost Revenue	per kVA	\$ -	1,111	\$ -	\$ -	1,111	\$ -	\$ 0.0660	73.33	\$ -	1,111
Rate Rider for Operations Center Consolidation Plan Sharing	per kVA	\$ -	1,111	\$ -	\$ 0.1916	1,111	\$ 212.87	\$ -	212.87	\$ -	1,111
Sub-Total A (excluding pass through)				\$ 5,985.98			\$ 6,507.64	\$ 521.65	8.71%		
Rate Rider for Low Voltage Variance	per kVA		1,111	\$ -	\$ 0.0230	1,111	\$ 25.55	\$ -	25.55	\$ -	1,111
Line Losses on Cost of Power	per kWh	\$ 0.1010	18,800	\$ 1,898.80	\$ 0.1010	18,800	\$ 1,898.80	\$ -	0.00%	\$ 0.1010	18,800
Sub-Total B - Distribution (includes Sub-Total A)				\$ 7,884.78			\$ 8,431.99	\$ 547.21	6.94%		
RTSR - Network	per kW	\$ 2,6972	1,000	\$ 2,697.20	\$ 2,7391	1,000	\$ 2,739.10	\$ 41.90	1.55%	\$ 2,7391	1,000
RTSR - Line and Transformation Connection	per kW	\$ 1,9234	1,000	\$ 1,923.40	\$ 1,9342	1,000	\$ 1,934.20	\$ 10.80	0.56%	\$ 1,9342	1,000
Sub-Total C - Delivery (including Sub-Total B)				\$ 12,505.38			\$ 13,105.29	\$ 599.91	4.80%		
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	518,800	\$ 2,282.72	\$ 0.0044	518,800	\$ 2,282.72	\$ -	0.00%	\$ 0.0044	518,800
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	518,800	\$ 674.44	\$ 0.0013	518,800	\$ 674.44	\$ -	0.00%	\$ 0.0013	518,800
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	500,000	\$ 3,500.00	\$ 0.0070	500,000	\$ 3,500.00	\$ -	0.00%	\$ 0.0070	500,000
TOU - Off Peak	per kWh	\$ 0.0750	320,000	\$ 24,000.00	\$ 0.0750	320,000	\$ 24,000.00	\$ -	0.00%	\$ 0.0750	320,000
TOU - Mid Peak	per kWh	\$ 0.1120	90,000	\$ 10,080.00	\$ 0.1120	90,000	\$ 10,080.00	\$ -	0.00%	\$ 0.1120	90,000
TOU - On Peak	per kWh	\$ 0.1350	90,000	\$ 12,150.00	\$ 0.1350	90,000	\$ 12,150.00	\$ -	0.00%	\$ 0.1350	90,000
Energy - RPP - Tier 1	per kWh	\$ 0.0860	750	\$ 64.50	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750
Energy - RPP - Tier 2	per kWh	\$ 0.1010	499,250	\$ 50,424.25	\$ 0.1010	499,250	\$ 50,424.25	\$ -	0.00%	\$ 0.1010	499,250
Total Bill on TOU (before Taxes)				\$ 65,192.79			\$ 65,792.70	\$ 599.91	0.92%		
HST		13%		\$ 8,475.06	13%		\$ 8,553.05	\$ 77.99	0.92%	13%	
Total Bill (including HST)				\$ 73,667.86			\$ 74,345.75	\$ 677.89	0.92%		
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -			
Total Bill on TOU (including OCEB)				\$ 73,667.86			\$ 74,345.75	\$ 677.89	0.92%		
Total Bill on RPP (before Taxes)				\$ 69,451.54			\$ 70,051.45	\$ 599.91	0.86%		
HST		13%		\$ 9,028.70	13%		\$ 9,106.69	\$ 77.99	0.86%	13%	
Total Bill (including HST)				\$ 78,480.25			\$ 79,158.14	\$ 677.89	0.86%		
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -			
Total Bill on RPP (including OCEB)				\$ 78,480.25			\$ 79,158.14	\$ 677.89	0.86%		
Loss Factor (%)			3.76%			3.76%					3.76%

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 1,000 TO 4,999 kW SERVICE

TOU / non-TOU: non-TOU

Consumption	Charge Unit	2,000 kW		2,222 kVA		1,000,000 kWh		May 1 - October 31		November 1 - April 30 (Select this radio button for applications filed after Oct 31)	
		Current Board-Approved		2015 Proposed		Impact		2016 Proposed		Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume
Service Charge	per 30 days	\$ 700.68	1	\$ 700.68	\$ 831.65	1	\$ 831.65	\$ 130.97	18.69%	\$ 872.73	1
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 2.49	1	\$ 2.49	\$ -	1	\$ -	-\$ 2.49	-	\$ -	1
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 27.34	1	\$ 27.34	\$ -	1	\$ -	-\$ 27.34	-	\$ -	1
Distribution Volumetric Rate	per kVA	\$ 4,5419	2,222	\$ 10,092.10	\$ 5.3909	2,222	\$ 11,978.58	\$ 1,886.48	18.69%	\$ 5.6572	2,222
Rate Rider for Recovery of Foregone Revenue	per kVA	\$ 0.0161	2,222	\$ 35.77	\$ -	2,222	\$ -	-\$ 35.77	-	\$ -	2,222
Rate Rider for Recovery of Incremental Capital Module Costs	per kVA	\$ 0.1771	2,222	\$ 393.52	\$ -	2,222	\$ -	-\$ 393.52	-	\$ -	2,222
Rate Rider for Application of Tax Change	per kVA	-\$ 0.0047	2,222	-\$ 10.44	\$ -	2,222	\$ -	\$ 10.44	-	\$ -	2,222
Rate Rider for PILs and Tax Variance	per kVA		2,222	\$ -	-\$ 0.0197	2,222	-\$ 43.77	-\$ 43.77	-	\$ 43.77	2,222
Rate Rider for PILs and Tax Variance HST	per kVA		2,222	\$ -	-\$ 0.0093	2,222	-\$ 20.66	-\$ 20.66	-	\$ 20.66	2,222
Rate Rider for Gain on Sale Named Properties	per kVA		2,222	\$ -	\$ 0.0217	2,222	\$ 48.22	\$ 48.22	-	-\$ 48.22	2,222
Rate Rider for Hydro One Capital Contributions Variance	per kVA		2,222	\$ -	\$ 0.0147	2,222	\$ 32.66	\$ 32.66	-	-\$ 32.66	2,222
Rate Rider for Residual RARA	per kVA		2,222	\$ -	-\$ 0.0327	2,222	-\$ 72.66	-\$ 72.66	-	\$ 72.66	2,222
Rate Rider for LRAMVA	per kVA		2,222	\$ -	\$ 0.0035	2,222	\$ 7.78	\$ 7.78	-	\$ 7.78	2,222
Rate Rider for IFRS - 2014 Derecognition	per kVA		2,222	\$ -	\$ -	2,222	\$ -	\$ -	-	\$ 0.0605	2,222
Rate Rider for POEB - Tax Savings	per kVA		2,222	\$ -	-\$ 0.0616	2,222	-\$ 136.88	-\$ 136.88	0.00%	-\$ 0.0616	2,222
Rate Rider for 2012-14 Lost Revenue	per kVA		2,222	\$ -	\$ -	2,222	\$ -	\$ -	0.00%	\$ 0.0660	2,222
Rate Rider for Operations Center Consolidation Plan Sharing	per kVA		2,222	\$ -	-\$ 0.1916	2,222	-\$ 425.74	-\$ 425.74	0.00%	-\$ 0.1916	2,222
Sub-Total A (excluding pass through)				\$ 11,241.46			\$ 12,183.63	\$ 942.17	8.38%		
Rate Rider for Low Voltage Variance	per kVA		2,222	\$ -	\$ 0.0230	2,222	\$ 51.11	\$ 51.11	-	\$ -	2,222
Line Losses on Cost of Power	per kWh	\$ 0.1010	37,600	\$ 3,797.60	\$ 0.1010	37,600	\$ 3,797.60	\$ -	0.00%	\$ 0.1010	37,600
Sub-Total B - Distribution (includes Sub-Total A)				\$ 15,039.06			\$ 16,032.33	\$ 993.27	6.60%		
RTSR - Network	per kW	\$ 2.6972	2,000	\$ 5,394.40	\$ 2.7391	2,000	\$ 5,478.20	\$ 83.80	1.55%	\$ 2.7391	2,000
RTSR - Line and Transformation Connection	per kW	\$ 1.9234	2,000	\$ 3,846.80	\$ 1.9342	2,000	\$ 3,868.40	\$ 21.60	0.56%	\$ 1.9342	2,000
Sub-Total C - Delivery (including Sub-Total B)				\$ 24,280.26			\$ 25,378.93	\$ 1,098.67	4.52%		
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	1,037,600	\$ 4,565.44	\$ 0.0044	1,037,600	\$ 4,565.44	\$ -	0.00%	\$ 0.0044	1,037,600
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	1,037,600	\$ 1,348.88	\$ 0.0013	1,037,600	\$ 1,348.88	\$ -	0.00%	\$ 0.0013	1,037,600
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	1,000,000	\$ 7,000.00	\$ 0.0070	1,000,000	\$ 7,000.00	\$ -	0.00%	\$ 0.0070	1,000,000
TOU - Off Peak	per kWh	\$ 0.0750	640,000	\$ 48,000.00	\$ 0.0750	640,000	\$ 48,000.00	\$ -	0.00%	\$ 0.0750	640,000
TOU - Mid Peak	per kWh	\$ 0.1120	180,000	\$ 20,160.00	\$ 0.1120	180,000	\$ 20,160.00	\$ -	0.00%	\$ 0.1120	180,000
TOU - On Peak	per kWh	\$ 0.1350	180,000	\$ 24,300.00	\$ 0.1350	180,000	\$ 24,300.00	\$ -	0.00%	\$ 0.1350	180,000
Energy - RPP - Tier 1	per kWh	\$ 0.0860	750	\$ 64.50	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750
Energy - RPP - Tier 2	per kWh	\$ 0.1010	999,250	\$ 100,924.25	\$ 0.1010	999,250	\$ 100,924.25	\$ -	0.00%	\$ 0.1010	999,250
Total Bill on TOU (before Taxes)				\$ 129,654.83			\$ 130,753.50	\$ 1,098.67	0.85%		
HST	13%			\$ 16,855.13	13%		\$ 16,997.96	\$ 142.83	0.85%	13%	
Total Bill (including HST)				\$ 146,509.96			\$ 147,751.46	\$ 1,241.50	0.85%		
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -	-		
Total Bill on TOU (including OCEB)				\$ 146,509.96			\$ 147,751.46	\$ 1,241.50	0.85%		
Total Bill on RPP (before Taxes)				\$ 138,183.58			\$ 139,282.25	\$ 1,098.67	0.80%		
HST	13%			\$ 17,963.87	13%		\$ 18,106.69	\$ 142.83	0.80%	13%	
Total Bill (including HST)				\$ 156,147.44			\$ 157,388.94	\$ 1,241.50	0.80%		
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -	-		
Total Bill on RPP (including OCEB)				\$ 156,147.44			\$ 157,388.94	\$ 1,241.50	0.80%		
Loss Factor (%)		3.76%			3.76%					3.76%	

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 1,000 TO 4,999 kW SERVICE

TOU / non-TOU: non-TOU

Consumption	Charge Unit	4,000 kW		4,444 kVA		2,000,000 kWh		May 1 - October 31		November 1 - April 30 (Select this radio button for applications filed after Oct 31)	
		Current Board-Approved		2015 Proposed		Impact		2016 Proposed		Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume
Service Charge	per 30 days	\$ 700.68	1	\$ 700.68	\$ 831.65	1	\$ 831.65	\$ 130.97	18.69%	\$ 872.73	1
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 2.49	1	\$ 2.49	\$ -	1	\$ -	-\$ 2.49		\$ -	1
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 27.34	1	\$ 27.34	\$ -	1	\$ -	-\$ 27.34		\$ -	1
Distribution Volumetric Rate	per kVA	\$ 4,5419	4,444	\$ 20,184.20	\$ 5.3909	4,444	\$ 23,957.16	\$ 3,772.96	18.69%	\$ 5.6572	4,444
Rate Rider for Recovery of Foregone Revenue	per kVA	\$ 0.0161	4,444	\$ 71.55	\$ -	4,444	\$ -	-\$ 71.55		\$ -	4,444
Rate Rider for Recovery of Incremental Capital Module Costs	per kVA	\$ 0.1771	4,444	\$ 787.03	\$ -	4,444	\$ -	-\$ 787.03		\$ -	4,444
Rate Rider for Application of Tax Change	per kVA	-\$ 0.0047	4,444	-\$ 20.89	\$ -	4,444	\$ -	\$ 20.89		\$ -	4,444
Rate Rider for PILs and Tax Variance	per kVA		4,444	\$ -	-\$ 0.0197	4,444	-\$ 87.55	-\$ 87.55		\$ 87.55	4,444
Rate Rider for PILs and Tax Variance HST	per kVA		4,444	\$ -	-\$ 0.0093	4,444	-\$ 41.33	-\$ 41.33		\$ 41.33	4,444
Rate Rider for Gain on Sale Named Properties	per kVA		4,444	\$ -	\$ 0.0217	4,444	\$ 96.43	\$ 96.43		-\$ 96.43	4,444
Rate Rider for Hydro One Capital Contributions Variance	per kVA		4,444	\$ -	\$ 0.0147	4,444	\$ 65.33	\$ 65.33		-\$ 65.33	4,444
Rate Rider for Residual RARA	per kVA		4,444	\$ -	-\$ 0.0327	4,444	-\$ 145.32	-\$ 145.32		\$ 145.32	4,444
Rate Rider for LRAMVA	per kVA		4,444	\$ -	\$ 0.0035	4,444	\$ 15.55	\$ 15.55		\$ 15.55	4,444
Rate Rider for IFRS - 2014 Derecognition	per kVA		4,444	\$ -		4,444	\$ -	\$ -		\$ 0.0605	4,444
Rate Rider for POEB - Tax Savings	per kVA		4,444	\$ -	-\$ 0.0616	4,444	-\$ 273.75	-\$ 273.75		-\$ 0.0616	4,444
Rate Rider for 2012-14 Lost Revenue	per kVA		4,444	\$ -		4,444	\$ -	\$ -		\$ 0.0660	4,444
Rate Rider for Operations Center Consolidation Plan Sharing	per kVA		4,444	\$ -	-\$ 0.1916	4,444	-\$ 851.47	-\$ 851.47		-\$ 0.1916	4,444
Sub-Total A (excluding pass through)				\$ 21,752.41			\$ 23,535.60	\$ 1,783.19	8.20%		
Rate Rider for Low Voltage Variance	per kVA		4,444	\$ -	\$ 0.0230	4,444	\$ 102.21	\$ 102.21		\$ -	4,444
Line Losses on Cost of Power	per kWh	\$ 0.1010	75,200	\$ 7,595.20	\$ 0.1010	75,200	\$ 7,595.20	\$ -	0.00%	\$ 0.1010	75,200
Sub-Total B - Distribution (includes Sub-Total A)				\$ 29,347.61			\$ 31,233.01	\$ 1,885.41	6.42%		
RTSR - Network	per kW	\$ 2.6972	4,000	\$ 10,788.80	\$ 2.7391	4,000	\$ 10,956.40	\$ 167.60	1.55%	\$ 2.7391	4,000
RTSR - Line and Transformation Connection	per kW	\$ 1.9234	4,000	\$ 7,693.60	\$ 1.9342	4,000	\$ 7,736.80	\$ 43.20	0.56%	\$ 1.9342	4,000
Sub-Total C - Delivery (including Sub-Total B)				\$ 47,830.01			\$ 49,926.21	\$ 2,096.21	4.38%		
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	2,075,200	\$ 9,130.88	\$ 0.0044	2,075,200	\$ 9,130.88	\$ -	0.00%	\$ 0.0044	2,075,200
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	2,075,200	\$ 2,697.76	\$ 0.0013	2,075,200	\$ 2,697.76	\$ -	0.00%	\$ 0.0013	2,075,200
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	2,000,000	\$ 14,000.00	\$ 0.0070	2,000,000	\$ 14,000.00	\$ -	0.00%	\$ 0.0070	2,000,000
TOU - Off Peak	per kWh	\$ 0.0750	1,280,000	\$ 96,000.00	\$ 0.0750	1,280,000	\$ 96,000.00	\$ -	0.00%	\$ 0.0750	1,280,000
TOU - Mid Peak	per kWh	\$ 0.1120	360,000	\$ 40,320.00	\$ 0.1120	360,000	\$ 40,320.00	\$ -	0.00%	\$ 0.1120	360,000
TOU - On Peak	per kWh	\$ 0.1350	360,000	\$ 48,600.00	\$ 0.1350	360,000	\$ 48,600.00	\$ -	0.00%	\$ 0.1350	360,000
Energy - RPP - Tier 1	per kWh	\$ 0.0860	750	\$ 64.50	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750
Energy - RPP - Tier 2	per kWh	\$ 0.1010	1,999,250	\$ 201,924.25	\$ 0.1010	1,999,250	\$ 201,924.25	\$ -	0.00%	\$ 0.1010	1,999,250
Total Bill on TOU (before Taxes)				\$ 258,578.90			\$ 260,675.10	\$ 2,096.21	0.81%		
HST	13%			\$ 33,615.26	13%		\$ 33,887.76	\$ 272.51	0.81%	13%	
Total Bill (including HST)				\$ 292,194.15			\$ 294,562.87	\$ 2,368.71	0.81%		
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -			
Total Bill on TOU (including OCEB)				\$ 292,194.15			\$ 294,562.87	\$ 2,368.71	0.81%		
Total Bill on RPP (before Taxes)				\$ 275,647.65			\$ 277,743.85	\$ 2,096.21	0.76%		
HST	13%			\$ 35,834.19	13%		\$ 36,106.70	\$ 272.51	0.76%	13%	
Total Bill (including HST)				\$ 311,481.84			\$ 313,850.55	\$ 2,368.71	0.76%		
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -			
Total Bill on RPP (including OCEB)				\$ 311,481.84			\$ 313,850.55	\$ 2,368.71	0.76%		
Loss Factor (%)			3.76%			3.76%				3.76%	

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000

GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000

GS>50kW (kW) - 60, 100, 500, 1000

Large User - range appropriate for utility

Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted

LARGE USE SERVICE

Appendix 2-W
Bill Impacts

Customer Class: LARGE USE SERVICE

TOU / non-TOU: non-TOU

Consumption		5,000 kW		5,556 kVA		2,000,000 kWh		May 1 - October 31		November 1 - April 30 (Select this radio button for applications filed after Oct 31)																				
		Current Board-Approved		2015 Proposed		Impact		2016 Proposed		Impact		2017 Proposed		Impact		2018 Proposed		Impact		2019 Proposed		Impact								
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change						
		Charge Unit																												
Service Charge	per 30 days	\$ 3,071.47	1	\$ 3,071.47	\$ 3,668.99	1	\$ 3,668.99	\$ 597.52	19.45%	\$ 3,850.24	1	\$ 3,850.24	\$ 181.25	4.94%	\$ 4,184.44	1	\$ 4,184.44	\$ 334.20	8.68%	\$ 4,481.12	1	\$ 4,481.12	\$ 296.68	7.09%	\$ 4,723.54	1	\$ 4,723.54	\$ 242.42	5.41%	
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 10.90	1	\$ 10.90		1	\$ -	-\$ 10.90			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -			1	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 119.83	1	\$ 119.83		1	\$ -	-\$ 119.83			1	\$ -	\$ -			1	\$ -	\$ -				1	\$ -	\$ -			1	\$ -	\$ -	
Distribution Volumetric Rate	per kVA	\$ 4.8388	5,556	\$ 26,884.37	\$ 5.7801	5,556	\$ 32,114.24	\$ 5,229.86	19.45%	\$ 6.0656	5,556	\$ 33,700.47	\$ 1,586.24	4.94%	\$ 6.5921	5,556	\$ 36,625.71	\$ 2,925.23	8.68%	\$ 7.0595	5,556	\$ 39,222.58	\$ 2,596.87	7.09%	\$ 7.4414	5,556	\$ 41,344.42	\$ 2,121.84	5.41%	
Rate Rider for Recovery of Foregone Revenue	per kVA	\$ 0.0172	5,556	\$ 95.56		5,556	\$ -	-\$ 95.56			5,556	\$ -	\$ -			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Rate Rider for Recovery of Incremental Capital Module Costs	per kVA	\$ 0.1887	5,556	\$ 1,048.42		5,556	\$ -	-\$ 1,048.42			5,556	\$ -	\$ -			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Rate Rider for Application of Tax Change	per kVA	-\$ 0.0049	5,556	\$ 27.22		5,556	\$ -	\$ 27.22			5,556	\$ -	\$ -			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Rate Rider for PILs and Tax Variance	per kVA		5,556	\$ -	-\$ 0.0202	5,556	\$ 112.23	-\$ 112.23			5,556	\$ -	\$ 112.23			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Rate Rider for PILs and Tax Variance HST	per kVA		5,556	\$ -	-\$ 0.0096	5,556	\$ 53.34	-\$ 53.34			5,556	\$ -	\$ 53.34			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Rate Rider for Gain on Sale Named Properties	per kVA		5,556	\$ -	\$ 0.0170	5,556	\$ 94.45	\$ 94.45			5,556	\$ -	-\$ 94.45			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Rate Rider for Hydro One Capital Contributions Variance	per kVA		5,556	\$ -	\$ 0.0151	5,556	\$ 83.90	\$ 83.90			5,556	\$ -	-\$ 83.90			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Rate Rider for Residual RARA	per kVA		5,556	\$ -	-\$ 0.0343	5,556	\$ 190.57	-\$ 190.57			5,556	\$ -	\$ 190.57			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Rate Rider for LRAMVA	per kVA		5,556	\$ -	-\$ 0.0187	5,556	\$ 103.90	-\$ 103.90			5,556	\$ -	\$ 103.90			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Rate Rider for IFRS - 2014 Derecognition	per kVA		5,556	\$ -		5,556	\$ -	\$ -			\$ 0.0623	5,556	\$ 346.14	\$ 346.14		\$ 0.0623	5,556	\$ 346.14	\$ -	0.00%	\$ 0.0623	5,556	\$ 346.14	\$ -	0.00%	\$ 0.0623	5,556	\$ 346.14	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kVA		5,556	\$ -	-\$ 0.0634	5,556	\$ 352.25	-\$ 352.25			-\$ 0.0634	5,556	-\$ 352.25	\$ -	0.00%	-\$ 0.0634	5,556	-\$ 352.25	\$ -	0.00%		5,556	\$ -	\$ 352.25	\$ -		5,556	\$ -	\$ -	
Rate Rider for 2012-14 Lost Revenue	per kVA		5,556	\$ -		5,556	\$ -	\$ -			\$ 0.0680	5,556	\$ 377.81	\$ 377.81		\$ 0.0680	5,556	\$ 377.81	\$ -	0.00%	\$ 0.0680	5,556	\$ 377.81	\$ -	0.00%	\$ 0.0680	5,556	\$ 377.81	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kVA		5,556	\$ -	-\$ 0.1974	5,556	\$ 1,096.75	-\$ 1,096.75			-\$ 0.1974	5,556	\$ 1,096.75	\$ -	0.00%	-\$ 0.1974	5,556	\$ 1,096.75	\$ -	0.00%		5,556	\$ -	\$ 1,096.75	\$ -		5,556	\$ -	\$ -	
Sub-Total A (excluding pass through)				\$ 31,203.33			\$ 34,052.53	\$ 2,849.20	9.13%			\$ 36,825.66	\$ 2,773.12	8.14%			\$ 40,085.09	\$ 3,259.43	8.85%			\$ 44,427.65	\$ 4,342.56	10.83%			\$ 46,791.91	\$ 2,364.26	5.32%	
Rate Rider for Low Voltage Variance	per kVA		5,556	\$ -	\$ 0.0219	5,556	\$ 121.68	\$ 121.68			5,556	\$ -	-\$ 121.68			5,556	\$ -	\$ -				5,556	\$ -	\$ -			5,556	\$ -	\$ -	
Line Losses on Cost of Power	per kWh	\$ 0.1010	37,400	\$ 3,777.40	\$ 0.1010	37,400	\$ 3,777.40	\$ -	0.00%	\$ 0.1010	37,400	\$ 3,777.40	\$ -	0.00%	\$ 0.1010	37,400	\$ 3,777.40	\$ -	0.00%	\$ 0.1010	37,400	\$ 3,777.40	\$ -	0.00%	\$ 0.1010	37,400	\$ 3,777.40	\$ -	0.00%	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 34,980.73			\$ 37,951.61	\$ 2,970.88	8.49%			\$ 40,603.06	\$ 2,651.45	6.99%			\$ 43,862.49	\$ 3,259.43	8.03%			\$ 48,205.05	\$ 4,342.56	9.90%			\$ 50,569.31	\$ 2,364.26	4.90%	
RTSR - Network	per kW	\$ 3.0747	5,000	\$ 15,373.50	\$ 3.1224	5,000	\$ 15,612.00	\$ 238.50	1.55%	\$ 3.1224	5,000	\$ 15,612.00	\$ -	0.00%	\$ 3.1224	5,000	\$ 15,612.00	\$ -	0.00%	\$ 3.1224	5,000	\$ 15,612.00	\$ -	0.00%	\$ 3.1224	5,000	\$ 15,612.00	\$ -	0.00%	
RTSR - Line and Transformation Connection	per kW	\$ 2.1369	5,000	\$ 10,684.50	\$ 2.1489	5,000	\$ 10,744.50	\$ 60.00	0.56%	\$ 2.1489	5,000	\$ 10,744.50	\$ -	0.00%	\$ 2.1489	5,000	\$ 10,744.50	\$ -	0.00%	\$ 2.1489	5,000	\$ 10,744.50	\$ -	0.00%	\$ 2.1489	5,000	\$ 10,744.50	\$ -	0.00%	
Sub-Total C - Delivery (including Sub-Total B)				\$ 61,038.73			\$ 64,308.11	\$ 3,269.38	5.36%			\$ 66,959.56	\$ 2,651.45	4.12%			\$ 70,218.99	\$ 3,259.43	4.87%			\$ 74,561.55	\$ 4,342.56	6.18%			\$ 76,925.81	\$ 2,364.26	3.17%	
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	2,037,400	\$ 8,964.56	\$ 0.0044	2,037,400	\$ 8,964.56	\$ -	0.00%	\$ 0.0044	2,037,400	\$ 8,964.56	\$ -	0.00%	\$ 0.0044	2,037,400	\$ 8,964.56	\$ -	0.00%	\$ 0.0044	2,037,400	\$ 8,964.56	\$ -	0.00%	\$ 0.0044	2,037,400	\$ 8,964.56	\$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	2,037,400	\$ 2,648.62	\$ 0.0013	2,037,400	\$ 2,648.62	\$ -	0.00%	\$ 0.0013	2,037,400	\$ 2,648.62	\$ -	0.00%	\$ 0.0013	2,037,400	\$ 2,648.62	\$ -	0.00%	\$ 0.0013	2,037,400	\$ 2,648.62	\$ -	0.00%	\$ 0.0013	2,037,400	\$ 2,648.62	\$ -	0.00%	
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	2,000,000	\$ 14,000.00	\$ 0.0070	2,000,000	\$ 14,000.00	\$ -	0.00%	\$ 0.0070	2,000,000	\$ 14,000.00	\$ -	0.00%	\$ 0.0070	2,000,000	\$ 14,000.00	\$ -	0.00%	\$ 0.0070	2,000,000	\$ 14,000.00	\$ -	0.00%	\$ 0.0070	2,000,000	\$ 14,000.00	\$ -	0.00%	
TOU - Off Peak	per kWh	\$ 0.0750	1,280,000	\$ 96,000.00	\$ 0.0750	1,280,000	\$ 96,000.00	\$ -	0.00%	\$ 0.0750	1,280,000	\$ 96,000.00	\$ -	0.00%	\$ 0.0750	1,280,000	\$ 96,000.00	\$ -	0.00%	\$ 0.0750	1,280,000	\$ 96,000.00	\$ -	0.00%	\$ 0.0750	1,280,000	\$ 96,000.00	\$ -	0.00%	
TOU - Mid Peak	per kWh	\$ 0.1120	360,000	\$ 40,320.00	\$ 0.1120	360,000	\$ 40,320.00	\$ -	0.00%	\$ 0.1120	360,000	\$ 40,320.00	\$ -	0.00%	\$ 0.1120	360,000	\$ 40,320.00	\$ -	0.00%	\$ 0.1120	360,000	\$ 40,320.00	\$ -	0.00%	\$ 0.1120	360,000	\$ 40,320.00	\$ -	0.00%	
TOU - On Peak	per kWh	\$ 0.1350	360,000	\$ 48,600.00	\$ 0.1350	360,000	\$ 48,600.00	\$ -	0.00%	\$ 0.1350	360,000	\$ 48,600.00	\$ -	0.00%	\$ 0.1350	360,000	\$ 48,600.00	\$ -	0.00%	\$ 0.1350	360,000	\$ 48,600.00	\$ -	0.00%	\$ 0.1350	360,000	\$ 48,600.00	\$ -	0.00%	
Energy - RPP - Tier 1	per kWh	\$ 0.0860	750	\$ 64.50	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	\$ 0.0860	750	\$ 64.50	\$ -	0.00%	
Energy - RPP - Tier 2	per kWh	\$ 0.1010	1,999,250	\$ 201,924.25	\$ 0.1010	1,999,250	\$ 201,924.25	\$ -	0.00%	\$ 0.1010	1,999,250	\$ 201,924.25	\$ -	0.00%	\$ 0.1010	1,999,250	\$ 201,924.25	\$ -	0.00%	\$ 0.1010	1,999,250	\$ 201,924.25	\$ -	0.00%	\$ 0.1010	1,999,250	\$ 201,924.25	\$ -	0.00%	
Total Bill on TOU (before Taxes)				\$ 271,572.16			\$ 274,841.54	\$ 3,269.38	1.20%			\$ 277,492.99	\$ 2,651.45	0.96%			\$ 280,752.42	\$ 3,259.43	1.17%			\$ 285,094.98	\$ 4,342.56	1.55%			\$ 287,459.24	\$ 2,364.26	0.83%	
HST	13%			\$ 35,304.38	13%		\$ 35,729.40	\$ 425.02	1.20%	13%		\$ 36,074.09	\$ 344.69	0.96%	13%		\$ 36,497.81	\$ 423.73	1.17%	13%		\$ 37,062.35	\$ 564.53	1.55%	13%		\$ 37,369.70	\$ 307.35	0.83%	
Total Bill (including HST)				\$ 306,876.54			\$ 310,570.94	\$ 3,694.40	1.20%			\$ 313,567.07	\$ 2,996.14	0.96%			\$ 317,250.23	\$ 3,683.16	1.17%			\$ 322,157.33	\$ 4,907.09	1.55%			\$ 324,828.94	\$ 2,671.61	0.83%	
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -		
Total Bill on TOU (including OCEB)				\$ 306,876.54			\$ 310,570.94	\$ 3,694.40	1.20%			\$ 313,567.07	\$ 2,996.14	0.96%			\$ 317,250.23	\$ 3,683.16	1.17%			\$ 322,157.33	\$ 4,907.09	1.55%			\$ 324,828.94	\$ 2,671.61	0.83%	
Total Bill on RPP (before Taxes)				\$ 288,640.91			\$ 291,910.29	\$ 3,269.38	1.13%			\$ 294,561.74	\$ 2,651.45	0.91%			\$ 297,821.17	\$ 3,259.43	1.11%			\$ 302,163.73	\$ 4,342.56	1.46%			\$ 304,527.99	\$ 2,364.26	0.78%	
HST	13%			\$ 37,523.32	13%		\$ 37,948.34	\$ 425.02	1.13%	13%		\$ 38,293.03	\$ 344.69	0.91%	13%		\$ 38,716.75	\$ 423.73	1.11%	13%		\$ 39,281.28	\$ 564.53	1.46%	13%		\$ 39,588.64	\$ 307.35	0.78%	
Total Bill (including HST)				\$ 326,164.23			\$ 329,858.63	\$ 3,694.40	1.13%			\$ 336,537.92	\$ 2,996.14	0.91%			\$ 336,537.92	\$ 3,683.16	1.11%			\$ 341,445.01	\$ 4,907.09	1.46%			\$ 344,116.62	\$ 2,671.61	0.78%	
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -				\$ -	\$ -		
Total Bill on RPP (including OCEB)				\$ 326,164.23			\$ 329,858.63	\$ 3,694.40	1.13%			\$ 332,854.76	\$ 2,996.14	0.91%			\$ 336,537.92	\$ 3,683.16	1.11%			\$ 341,445.01	\$ 4,907.09	1.46%			\$ 344,116.62	\$ 2,671.61	0.78%	
Loss Factor (%)			1.87%			1.87%					1.87%					1.87%					1.87%						1.87%			

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the reference consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 200K

GS<50kW (kWh) - 1000, 2000, 5000, 10000, 1500K

GS>50kW (kW) - 60, 100, 500, 100K

Large User - range appropriate for utility

Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000

SS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000

GS>50kW (kW) - 60, 100, 500, 1000

Large User - range appropriate for utility

Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted

LARGE USE SERVICE

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000

SS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000

GS>50kW (kW) - 60, 100, 500, 1000

Large User - range appropriate for utility

Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted

Appendix 2-W
Bill Impacts

Customer Class:		STREET LIGHTING SERVICE																												
TOU / non-TOU:		non-TOU																												
Consumption	1 Devices																													
	0.165 kW																													
	0.165 kVA		May 1 - October 31																											
	60 kWh		November 1 - April 30 (Select this radio button for applications filed after Oct 31)																											
		Current Board-Approved		2015 Proposed		Impact		2016 Proposed		Impact		2017 Proposed		Impact		2018 Proposed		Impact		2019 Proposed		Impact								
Charge Unit		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change						
Service Charge (per device)	per device per 30 days	\$ 1.32	1	\$ 1.32	\$ 1.32	1	\$ 1.32	\$ -	0.00%	\$ 1.39	1	\$ 1.39	\$ 0.07	5.30%	\$ 1.51	1	\$ 1.51	\$ 0.12	8.63%	\$ 1.61	1	\$ 1.61	\$ 0.10	6.62%	\$ 1.70	1	\$ 1.70	\$ 0.09	5.59%	
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ -	1	\$ -	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.05	1	\$ 0.05	\$ 0.05	1	\$ -	\$ -0.05	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	
Distribution Volumetric Rate	per kVA	\$ 29.3201	0.165	\$ 4.84	\$ 29.3201	0.165	\$ 4.84	\$ -	0.00%	\$ 30.7685	0.165	\$ 5.08	\$ 0.24	4.94%	\$ 33.4392	0.165	\$ 5.52	\$ 0.44	8.68%	\$ 35.8101	0.165	\$ 5.91	\$ 0.39	7.09%	\$ 37.7474	0.165	\$ 6.23	\$ 0.32	5.41%	
Rate Rider for Recovery of Foregone Revenue	per kVA	\$ 0.1041	0.165	\$ 0.02	\$ 0.165	\$ -	\$ -	\$ 0.02	-	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-	
Rate Rider for Recovery of Incremental Capital Module Costs	per kVA	\$ 1.1439	0.165	\$ 0.19	\$ 0.165	\$ -	\$ -	\$ 0.19	-	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-	
Rate Rider for Application of Tax Change	per kVA	-\$ 0.0354	0.165	-\$ 0.01	\$ 0.165	\$ -	\$ -	\$ 0.01	-	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-	
Rate Rider for PILs and Tax Variance	per kVA	\$ 0.165	0.165	\$ -	-\$ 0.1604	0.165	-\$ 0.03	\$ 0.03	-	\$ 0.165	\$ -	\$ -	\$ 0.03	-	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-
Rate Rider for PILs and Tax Variance HST	per kVA	\$ 0.165	\$ -	\$ -	-\$ 0.0759	0.165	-\$ 0.01	\$ 0.01	-	\$ 0.165	\$ -	\$ -	\$ 0.01	-	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-
Rate Rider for Gain on Sale Named Properties	per kVA	\$ 0.165	\$ -	\$ -	\$ 0.2850	0.165	\$ 0.05	\$ 0.05	-	\$ 0.165	\$ -	\$ -	\$ 0.05	-	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-
Rate Rider for Hydro One Capital Contributions Variance	per kVA	\$ 0.165	\$ -	\$ -	\$ 0.1200	0.165	\$ 0.02	\$ 0.02	-	\$ 0.165	\$ -	\$ -	\$ 0.02	-	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-
Rate Rider for Residual RARA	per kVA	\$ 0.165	\$ -	\$ -	-\$ 0.0293	0.165	-\$ 0.00	\$ 0.00	-	\$ 0.165	\$ -	\$ -	\$ 0.00	-	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.165	\$ -	\$ -	\$ -	-
Rate Rider for IFRS - 2014 Derecognition	per kVA	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.4937	0.165	\$ 0.08	\$ 0.08	-	\$ 0.4937	0.165	\$ 0.08	\$ -	0.00%	\$ 0.4937	0.165	\$ 0.08	\$ -	0.00%	\$ 0.4937	0.165	\$ 0.08	\$ -	0.00%	
Rate Rider for POEB - Tax Savings	per kVA	\$ 0.165	\$ -	\$ -	-\$ 0.5028	0.165	-\$ 0.08	\$ 0.08	-	-\$ 0.5028	0.165	-\$ 0.08	\$ -	0.00%	-\$ 0.5028	0.165	-\$ 0.08	\$ -	0.00%	\$ 0.5390	0.165	\$ 0.09	\$ -	0.08	\$ 0.5390	0.165	\$ -	\$ -	-	
Rate Rider for 2012-14 Lost Revenue	per kVA	\$ 0.165	\$ -	\$ -	\$ 0.165	\$ -	\$ -	\$ -	-	\$ 0.5390	0.165	\$ 0.09	\$ 0.09	-	\$ 0.5390	0.165	\$ 0.09	\$ -	0.00%	\$ 0.5390	0.165	\$ 0.09	\$ -	0.00%	\$ 0.5390	0.165	\$ 0.09	\$ -	0.00%	
Rate Rider for Operations Center Consolidation Plan Sharing	per kVA	\$ -	0.165	\$ -	-\$ 1.5641	0.165	-\$ 0.26	\$ 0.26	-	-\$ 1.5641	0.165	-\$ 0.26	\$ -	0.00%	-\$ 1.5641	0.165	-\$ 0.26	\$ -	0.00%	\$ -	0.165	\$ -	\$ -	0.26	\$ -	0.165	\$ -	\$ -	-	
Sub-Total A (excluding pass through)				\$ 6.41			\$ 5.84	-\$ 0.57	-8.87%			\$ 6.30	\$ 0.46	7.82%			\$ 6.86	\$ 0.56	8.90%			\$ 7.69	\$ 0.83	12.14%			\$ 8.10	\$ 0.41	5.33%	
Rate Rider for Low Voltage Variance	per kVA	\$ -	0.165	\$ -	\$ 0.0174	0.165	\$ 0.00	\$ 0.00	-	\$ 0.0860	0.165	\$ -	\$ -	0.00	\$ 0.0860	0.165	\$ -	\$ -	-	\$ 0.0860	0.165	\$ -	\$ -	-	\$ 0.0860	0.165	\$ -	\$ -	-	
Line Losses on Cost of Power	per kWh	\$ 0.0860	2	\$ 0.19	\$ 0.0860	2	\$ 0.19	\$ -	0.00%	\$ 0.0860	2	\$ 0.19	\$ -	0.00%	\$ 0.0860	2	\$ 0.19	\$ -	0.00%	\$ 0.0860	2	\$ 0.19	\$ -	0.00%	\$ 0.0860	2	\$ 0.19	\$ -	0.00%	
Sub-Total B - Distribution (includes Sub-Total A)				\$ 6.60			\$ 6.04	-\$ 0.57	-8.56%			\$ 6.49	\$ 0.45	7.51%			\$ 7.05	\$ 0.56	8.64%			\$ 7.88	\$ 0.83	11.80%			\$ 8.29	\$ 0.41	5.20%	
RTSR - Network	per kW	\$ 2.4829	0.165	\$ 0.41	\$ 2.5215	0	\$ 0.42	\$ 0.01	1.55%	\$ 2.5215	0	\$ 0.42	\$ -	0.00%	\$ 2.5215	0	\$ 0.42	\$ -	0.00%	\$ 2.5215	0	\$ 0.42	\$ -	0.00%	\$ 2.5215	0	\$ 0.42	\$ -	0.00%	
RTSR - Line and Transformation Connection	per kW	\$ 2.2957	0.165	\$ 0.38	\$ 2.3086	0	\$ 0.38	\$ 0.00	0.56%	\$ 2.3086	0	\$ 0.38	\$ -	0.00%	\$ 2.3086	0	\$ 0.38	\$ -	0.00%	\$ 2.3086	0	\$ 0.38	\$ -	0.00%	\$ 2.3086	0	\$ 0.38	\$ -	0.00%	
Sub-Total C - Delivery (including Sub-Total B)				\$ 7.39			\$ 6.83	-\$ 0.56	-7.53%			\$ 7.29	\$ 0.45	6.64%			\$ 7.85	\$ 0.56	7.69%			\$ 8.68	\$ 0.83	10.60%			\$ 9.09	\$ 0.41	4.72%	
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	62	\$ 0.27	\$ 0.0044	62	\$ 0.27	\$ -	0.00%	\$ 0.0044	62	\$ 0.27	\$ -	0.00%	\$ 0.0044	62	\$ 0.27	\$ -	0.00%	\$ 0.0044	62	\$ 0.27	\$ -	0.00%	\$ 0.0044	62	\$ 0.27	\$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	62	\$ 0.08	\$ 0.0013	62	\$ 0.08	\$ -	0.00%	\$ 0.0013	62	\$ 0.08	\$ -	0.00%	\$ 0.0013	62	\$ 0.08	\$ -	0.00%	\$ 0.0013	62	\$ 0.08	\$ -	0.00%	\$ 0.0013	62	\$ 0.08	\$ -	0.00%	
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	60	\$ 0.42	\$ 0.0070	60	\$ 0.42	\$ -	0.00%	\$ 0.0070	60	\$ 0.42	\$ -	0.00%	\$ 0.0070	60	\$ 0.42	\$ -	0.00%	\$ 0.0070	60	\$ 0.42	\$ -	0.00%	\$ 0.0070	60	\$ 0.42	\$ -	0.00%	
TOU - Off Peak	per kWh	\$ 0.0750	38	\$ 2.88	\$ 0.0750	38	\$ 2.88	\$ -	0.00%	\$ 0.0750	38	\$ 2.88	\$ -	0.00%	\$ 0.0750	38	\$ 2.88	\$ -	0.00%	\$ 0.0750	38	\$ 2.88	\$ -	0.00%	\$ 0.0750	38	\$ 2.88	\$ -	0.00%	
TOU - Mid Peak	per kWh	\$ 0.1120	11	\$ 1.21	\$ 0.1120	11	\$ 1.21	\$ -	0.00%	\$ 0.1120	11	\$ 1.21	\$ -	0.00%	\$ 0.1120	11	\$ 1.21	\$ -	0.00%	\$ 0.1120	11	\$ 1.21	\$ -	0.00%	\$ 0.1120	11	\$ 1.21	\$ -	0.00%	
TOU - On Peak	per kWh	\$ 0.1350	11	\$ 1.46	\$ 0.1350	11	\$ 1.46	\$ -	0.00%	\$ 0.1350	11	\$ 1.46	\$ -	0.00%	\$ 0.1350	11	\$ 1.46	\$ -	0.00%	\$ 0.1350	11	\$ 1.46	\$ -	0.00%	\$ 0.1350	11	\$ 1.46	\$ -	0.00%	
Energy - RPP - Tier 1	per kWh	\$ 0.0860	60	\$ 5.16	\$ 0.0860	60	\$ 5.16	\$ -	0.00%	\$ 0.0860	60	\$ 5.16	\$ -	0.00%	\$ 0.0860	60	\$ 5.16	\$ -	0.00%	\$ 0.0860	60	\$ 5.16	\$ -	0.00%	\$ 0.0860	60	\$ 5.16	\$ -	0.00%	
Energy - RPP - Tier 2	per kWh	\$ 0.1010	-	\$ -	\$ 0.1010	-	\$ -	\$ -	-	\$ 0.1010	-	\$ -	\$ -	-	\$ 0.1010	-	\$ -	\$ -	-	\$ 0.1010	-	\$ -	\$ -	-	\$ 0.1010	-	\$ -	\$ -	-	
Total Bill on TOU (before Taxes)				\$ 13.96			\$ 13.41	-\$ 0.56	-3.99%			\$ 13.86	\$ 0.45	3.88%			\$ 14.42	\$ 0.56	4.05%			\$ 15.25	\$ 0.83	5.77%			\$ 15.66	\$ 0.41	2.69%	
HST		13%		\$ 1.82	13%		\$ 1.74	\$ 0.07	-3.99%	13%		\$ 1.80	\$ 0.06	3.88%	13%		\$ 1.87	\$ 0.07	4.05%	13%		\$ 1.98	\$ 0.11	5.77%	13%		\$ 2.04	\$ 0.05	2.69%	
Total Bill (including HST)				\$ 15.78			\$ 15.15	-\$ 0.63	-3.99%			\$ 15.66	\$ 0.51	3.88%			\$ 16.29	\$ 0.63	4.05%			\$ 17.24	\$ 0.94	5.77%			\$ 17.70	\$ 0.46	2.69%	
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-	
Total Bill on TOU (including OCEB)				\$ 15.78			\$ 15.15	-\$ 0.63	-3.99%			\$ 15.66	\$ 0.51	3.88%			\$ 16.29	\$ 0.63	4.05%			\$ 17.24	\$ 0.94	5.77%			\$ 17.70	\$ 0.46	2.69%	
Total Bill on RPP (before Taxes)				\$ 13.58			\$ 13.02	-\$ 0.56	-4.10%			\$ 13.47	\$ 0.45	3.48%			\$ 14.03	\$ 0.56	4.16%			\$ 14.86	\$ 0.83	5.93%			\$ 15.27	\$ 0.41	2.76%	
HST		13%		\$ 1.76	13%		\$ 1.69	\$ 0.07	-4.10%	13%		\$ 1.75	\$ 0.06	3.48%	13%		\$ 1.82	\$ 0.07	4.16%	13%		\$ 1.93	\$ 0.11	5.93%	13%		\$ 1.99	\$ 0.05	2.76%	
Total Bill (including HST)				\$ 15.34			\$ 14.71	-\$ 0.63	-4.10%			\$ 15.22	\$ 0.51	3.48%			\$ 15.86	\$ 0.63	4.16%			\$ 16.80	\$ 0.94	5.93%			\$ 17.26	\$ 0.46	2.76%	
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-	
Total Bill on RPP (including OCEB)				\$ 15.34			\$ 14.71	-\$ 0.63	-4.10%			\$ 15.22	\$ 0.51	3.48%			\$ 15.86	\$ 0.63	4.16%			\$ 16.80	\$ 0.94	5.93%			\$ 17.26	\$ 0.46	2.76%	
Loss Factor (%)				3.76%			3.76%					3.76%					3.76%					3.76%					3.76%			

Appendix 2-W
Bill Impacts

Customer Class: UNMETERED SCATTERED LOAD SERVICE

TOU / non-TOU: non-TOU

Consumption

1

Connection

365

kWh

May 1 - October 31

November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit		Current Board-Approved			2015 Proposed			Impact		2016 Proposed			Impact		2017 Proposed			Impact		2018 Proposed			Impact		2019 Proposed			Impact	
		Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Service Charge	per 30 days	\$ 4.94	1	\$ 4.94	\$ 6.12	1	\$ 6.12	\$ 1.18	23.89%	\$ 6.42	1	\$ 6.42	\$ 0.30	4.90%	\$ 6.98	1	\$ 6.98	\$ 0.56	8.72%	\$ 7.47	1	\$ 7.47	\$ 0.49	7.02%	\$ 7.88	1	\$ 7.88	\$ 0.41	5.49%
Connection Charge (per connection)	per connection per 30 days	\$ 0.50	1	\$ 0.50	\$ 0.62	1	\$ 0.62	\$ 0.12	24.00%	\$ 0.65	1	\$ 0.65	\$ 0.03	4.84%	\$ 0.71	1	\$ 0.71	\$ 0.06	9.23%	\$ 0.76	1	\$ 0.76	\$ 0.05	7.04%	\$ 0.80	1	\$ 0.80	\$ 0.04	5.26%
Rate Rider for Recovery of Incremental Smart Meter Revenue Requirement	per 30 days	\$ -	1	\$ -	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-
Rate Rider for Recovery of Foregone Revenue	per 30 days	\$ 0.02	1	\$ 0.02	\$ -	1	\$ -	\$ 0.02	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-
Rate Rider for Recovery of Foregone Revenue (per connection)	per connection per 30 days	\$ -	1	\$ -	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-
Rate Rider for Recovery of Incremental Capital Module Costs	per 30 days	\$ 0.02	1	\$ 0.02	\$ -	1	\$ -	\$ 0.02	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-
Rate Rider for Recovery of Incremental Capital Module Costs (per connection)	per connection per 30 days	\$ 0.19	1	\$ 0.19	\$ -	1	\$ -	\$ 0.19	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-	\$ -	1	\$ -	\$ -	-
Distribution Volumetric Rate	per kWh	\$ 0.06195	365	\$ 22.61	\$ 0.07669	365	\$ 27.99	\$ 5.38	23.79%	\$ 0.08048	365	\$ 29.38	\$ 1.38	4.94%	\$ 0.08746	365	\$ 31.92	\$ 2.55	8.67%	\$ 0.09367	365	\$ 34.19	\$ 2.27	7.10%	\$ 0.09873	365	\$ 36.04	\$ 1.85	5.40%
Rate Rider for Recovery of Foregone Revenue	per kWh	\$ 0.00022	365	\$ 0.08	\$ -	365	\$ -	\$ -	0.08	\$ -	365	\$ -	\$ -	-	\$ -	365	\$ -	\$ -	-	\$ -	365	\$ -	\$ -	-	\$ -	365	\$ -	\$ -	-
Rate Rider for Recovery of Incremental Capital Module Costs	per kWh	\$ 0.00245	365	\$ 0.89	\$ -	365	\$ -	\$ 0.89	-	\$ -	365	\$ -	\$ -	-	\$ -	365	\$ -	\$ -	-	\$ -	365	\$ -	\$ -	-	\$ -	365	\$ -	\$ -	-
Rate Rider for Application of Tax Change	per kWh	-\$ 0.00006	365	\$ 0.02	\$ -	365	\$ -	\$ 0.02	-	\$ -	365	\$ -	\$ -	-	\$ -	365	\$ -	\$ -	-	\$ -	365	\$ -	\$ -	-	\$ -	365	\$ -	\$ -	-
Rate Rider for PILs and Tax Variance	per kWh	\$ -	365	\$ -	-\$ 0.00029	365	\$ 0.11	\$ 0.11	-	\$ -	365	\$ -	\$ 0.11	-	\$ -	365	\$ -	\$ 0.11	-	\$ -	365	\$ -	\$ 0.11	-	\$ -	365	\$ -	\$ 0.11	-
Rate Rider for PILs and Tax Variance HST	per kWh	\$ -	365	\$ -	\$ 0.00014	365	\$ 0.05	\$ 0.05	-	\$ -	365	\$ -	\$ 0.05	-	\$ -	365	\$ -	\$ 0.05	-	\$ -	365	\$ -	\$ 0.05	-	\$ -	365	\$ -	\$ 0.05	-
Rate Rider for Gain on Sale Named Properties	per kWh	\$ -	365	\$ -	\$ 0.00113	365	\$ 0.41	\$ 0.41	-	\$ -	365	\$ -	\$ 0.41	-	\$ -	365	\$ -	\$ 0.41	-	\$ -	365	\$ -	\$ 0.41	-	\$ -	365	\$ -	\$ 0.41	-
Rate Rider for Hydro One Capital Contributions Variance	per kWh	\$ -	365	\$ -	\$ 0.00021	365	\$ 0.08	\$ 0.08	-	\$ -	365	\$ -	\$ 0.08	-	\$ -	365	\$ -	\$ 0.08	-	\$ -	365	\$ -	\$ 0.08	-	\$ -	365	\$ -	\$ 0.08	-
Rate Rider for Residual RARA	per kWh	\$ -	365	\$ -	-\$ 0.00009	365	\$ 0.03	\$ 0.03	-	\$ -	365	\$ -	\$ 0.03	-	\$ -	365	\$ -	\$ 0.03	-	\$ -	365	\$ -	\$ 0.03	-	\$ -	365	\$ -	\$ 0.03	-
Rate Rider for IFRS - 2014 Derecognition	per kWh	\$ -	365	\$ -	\$ -	365	\$ -	\$ -	-	\$ 0.00088	365	\$ 0.32	\$ 0.32	-	\$ 0.0009	365	\$ 0.32	\$ -	0.00%	\$ 0.0009	365	\$ 0.32	\$ -	0.00%	\$ 0.0009	365	\$ 0.32	\$ -	0.00%
Rate Rider for POEB - Tax Savings	per kWh	\$ -	365	\$ -	-\$ 0.00090	365	\$ 0.33	\$ 0.33	-	-\$ 0.00090	365	\$ 0.33	\$ -	0.00%	-\$ 0.0009	365	\$ 0.33	\$ -	0.00%	\$ 0.0010	365	\$ 0.35	\$ 0.33	-	\$ 0.0010	365	\$ 0.35	\$ -	-
Rate Rider for 2012-14 Lost Revenue	per kWh	\$ -	365	\$ -	\$ -	365	\$ -	\$ -	-	\$ 0.00096	365	\$ 0.35	\$ 0.35	-	\$ 0.0010	365	\$ 0.35	\$ -	0.00%	\$ 0.0010	365	\$ 0.35	\$ -	0.00%	\$ 0.0010	365	\$ 0.35	\$ -	0.00%
Rate Rider for Operations Center Consolidation Plan Sharing	per kWh	\$ -	365	\$ -	-\$ 0.00280	365	\$ 1.02	\$ 1.02	-	-\$ 0.00280	365	\$ 1.02	\$ -	0.00%	-\$ 0.0028	365	\$ 1.02	\$ -	0.00%	\$ 0.0010	365	\$ 0.35	\$ -	0.00%	\$ 0.0010	365	\$ 0.35	\$ -	0.00%
Sub-Total A (excluding pass through)			\$ -	\$ 29.23		\$ -	\$ 33.68	\$ 4.45	15.21%		0	\$ 35.77	\$ 2.09	6.19%		0	\$ 38.93	\$ 3.17	8.86%		0	\$ 43.09	\$ 4.16	10.68%		0	\$ 45.39	\$ 2.30	5.33%
Rate Rider for Low Voltage Variance	per kWh		365	\$ -	\$ 0.00005	365	\$ 0.02	\$ 0.02	-		365	\$ -	-\$ 0.02	-		365	\$ -	\$ -	-		365	\$ -	\$ -	-		365	\$ -	\$ -	-
Line Losses on Cost of Power	per kWh	\$ 0.0860	14	\$ 1.18	\$ 0.0860	14	\$ 1.18	\$ -	0.00%	\$ 0.0860	14	\$ 1.18	\$ -	0.00%	\$ 0.0860	14	\$ 1.18	\$ -	0.00%	\$ 0.0860	14	\$ 1.18	\$ -	0.00%	\$ 0.0860	14	\$ 1.18	\$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			\$ -	\$ 30.41		\$ -	\$ 34.88	\$ 4.46	14.68%			\$ 36.95	\$ 2.07	5.93%			\$ 40.11	\$ 3.17	8.57%			\$ 44.27	\$ 4.16	10.36%			\$ 46.57	\$ 2.30	5.19%
RTSR - Network	per kWh	\$ 0.00490	379	\$ 1.86	\$ 0.00498	379	\$ 1.89	\$ 0.03	1.63%	\$ 0.0050	379	\$ 1.89	\$ -	0.00%	\$ 0.0050	379	\$ 1.89	\$ -	0.00%	\$ 0.0050	379	\$ 1.89	\$ -	0.00%	\$ 0.0050	379	\$ 1.89	\$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	\$ 0.00354	379	\$ 1.34	\$ 0.00356	379	\$ 1.35	\$ 0.01	0.56%	\$ 0.0036	379	\$ 1.35	\$ -	0.00%	\$ 0.0036	379	\$ 1.35	\$ -	0.00%	\$ 0.0036	379	\$ 1.35	\$ -	0.00%	\$ 0.0036	379	\$ 1.35	\$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			\$ -	\$ 33.61		\$ -	\$ 38.11	\$ 4.50	13.40%			\$ 40.18	\$ 2.07	5.42%			\$ 43.35	\$ 3.17	7.88%			\$ 47.51	\$ 4.16	9.59%			\$ 49.80	\$ 2.30	4.83%
Wholesale Market Service Charge (WMSC)	per kWh	\$ 0.0044	379	\$ 1.67	\$ 0.0044	379	\$ 1.67	\$ -	0.00%	\$ 0.0044	379	\$ 1.67	\$ -	0.00%	\$ 0.0044	379	\$ 1.67	\$ -	0.00%	\$ 0.0044	379	\$ 1.67	\$ -	0.00%	\$ 0.0044	379	\$ 1.67	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	\$ 0.0013	379	\$ 0.49	\$ 0.0013	379	\$ 0.49	\$ -	0.00%	\$ 0.0013	379	\$ 0.49	\$ -	0.00%	\$ 0.0013	379	\$ 0.49	\$ -	0.00%	\$ 0.0013	379	\$ 0.49	\$ -	0.00%	\$ 0.0013	379	\$ 0.49	\$ -	0.00%
Standard Supply Service Charge	per 30 days	\$ 0.25	1	\$ 0.25	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%	\$ 0.25	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	\$ 0.0070	365	\$ 2.56	\$ 0.0070	365	\$ 2.56	\$ -	0.00%	\$ 0.0070	365	\$ 2.56	\$ -	0.00%	\$ 0.0070	365	\$ 2.56	\$ -	0.00%	\$ 0.0070	365	\$ 2.56	\$ -	0.00%	\$ 0.0070	365	\$ 2.56	\$ -	0.00%
TOU - Off Peak	per kWh	\$ 0.0750	234	\$ 17.52	\$ 0.0750	234	\$ 17.52	\$ -	0.00%	\$ 0.0750	234	\$ 17.52	\$ -	0.00%	\$ 0.0750	234	\$ 17.52	\$ -	0.00%	\$ 0.0750	234	\$ 17.52	\$ -	0.00%	\$ 0.0750	234	\$ 17.52	\$ -	0.00%
TOU - Mid Peak	per kWh	\$ 0.1120	66	\$ 7.36	\$ 0.1120	66	\$ 7.36	\$ -	0.00%	\$ 0.1120	66	\$ 7.36	\$ -	0.00%	\$ 0.1120	66	\$ 7.36	\$ -	0.00%	\$ 0.1120	66	\$ 7.36	\$ -	0.00%	\$ 0.1120	66	\$ 7.36	\$ -	0.00%
TOU - On Peak	per kWh	\$ 0.1350	66	\$ 8.87	\$ 0.1350	66	\$ 8.87	\$ -	0.00%	\$ 0.1350	66	\$ 8.87	\$ -	0.00%	\$ 0.1350	66	\$ 8.87	\$ -	0.00%	\$ 0.1350	66	\$ 8.87	\$ -	0.00%	\$ 0.1350	66	\$ 8.87	\$ -	0.00%
Energy - RPP - Tier 1	per kWh	\$ 0.0860	365	\$ 31.39	\$ 0.0860	365	\$ 31.39	\$ -	0.00%	\$ 0.0860	365	\$ 31.39	\$ -	0.00%	\$ 0.0860	365	\$ 31.39	\$ -	0.00%	\$ 0.0860	365	\$ 31.39	\$ -	0.00%	\$ 0.0860	365	\$ 31.39	\$ -	0.00%
Energy - RPP - Tier 2	per kWh	\$ 0.1010	-	\$ -	\$ 0.1010	-	\$ -	\$ -	-	\$ 0.1010	-	\$ -	\$ -	-	\$ 0.1010	-	\$ -	\$ -	-	\$ 0.1010	-	\$ -	\$ -	-	\$ 0.1010	-	\$ -	\$ -	-
Total Bill on TOU (before Taxes)				\$ 72.32			\$ 76.83	\$ 4.50	6.23%			\$ 78.89	\$ 2.07	2.69%			\$ 82.06	\$ 3.17	4.02%			\$ 86.22	\$ 4.16	5.07%			\$ 88.51	\$ 2.30	2.66%
HST		13%		\$ 9.40	13%		\$ 9.99	\$ 0.59	6.23%	13%		\$ 10.26	\$ 0.27	2.69%	13%		\$ 10.67	\$ 0.41	4.02%	13%		\$ 11.21	\$ 0.54	5.07%	13%		\$ 11.51	\$ 0.30	2.66%
Total Bill (including HST)				\$ 81.72			\$ 86.81	\$ 5.09	6.23%			\$ 89.15	\$ 2.34	2.69%			\$ 92.73	\$ 3.58	4.02%			\$ 97.43	\$ 4.70	5.07%			\$ 100.02	\$ 2.60	2.66%
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-
Total Bill on TOU (including OCEB)				\$ 81.72			\$ 86.81	\$ 5.09	6.23%			\$ 89.15	\$ 2.34	2.69%			\$ 92.73	\$ 3.58	4.02%			\$ 97.43	\$ 4.70	5.07%			\$ 100.02	\$ 2.60	2.66%
Total Bill on RPP (before Taxes)				\$ 69.96			\$ 74.47	\$ 4.50	6.44%			\$ 76.53	\$ 2.07	2.78%			\$ 79.70	\$ 3.17	4.14%			\$ 83.86	\$ 4.16	5.22%			\$ 86.16	\$ 2.30	2.74%
HST		13%		\$ 9.10	13%		\$ 9.68	\$ 0.59	6.44%	13%		\$ 9.95	\$ 0.27	2.78%	13%		\$ 10.36	\$ 0.41	4.14%	13%		\$ 10.90	\$ 0.54	5.22%	13%		\$ 11.20	\$ 0.30	2.74%
Total Bill (including HST)				\$ 79.06			\$ 84.15	\$ 5.09	6.44%			\$ 86.48	\$ 2.34	2.78%			\$ 90.06	\$ 3.58	4.14%			\$ 94.76	\$ 4.70	5.22%			\$ 97.36	\$ 2.60	2.74%
Ontario Clean Energy Benefit ¹				\$ -			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-			\$ -	\$ -	-
Total Bill on RPP (including OCEB)				\$ 79.06			\$ 84.15	\$ 5.09	6.44%			\$ 86.48	\$ 2.34	2.78%			\$ 90.06	\$ 3.58	4.14%			\$ 94.76	\$ 4.70	5.22%			\$ 97.36	\$ 2.60	2.74%

Loss Factor (%) 3.76% 3.76% 3.76% 3.76% 3.76%

¹ Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 24:

Reference(s): Exhibit 2B

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

a) Please explain how Toronto Hydro will kept accountable for the approved rate increase in any given year if approval is granted to move capital projects from one year to another? What type of detailed reporting does Toronto Hydro plan to provide regarding its capital program?

RESPONSE:

As explained in Toronto Hydro’s responses to interrogatories to 2A-CCC-23 and 2B-OEBStaff-39, the substitution, deferral or advancement of particular projects occurs in the ordinary course of Toronto Hydro prudently executing its capital work program. Toronto Hydro has detailed throughout this application (see, for example, Exhibit 1B, Tab 2, Schedule 4, pages 13-14), in prior rate applications (e.g., EB-2012-0064) and in its 2013 OEB Scorecard, how a variety of external factors regularly require changes to the timing of Toronto Hydro’s capital plans and forecasts for specific work. These factors

/C

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

1 include work permit timing, weather and re-prioritization of jobs due to system needs. In
2 many of these situations, good utility practice and prudent work planning is best served
3 by: (a) specific projects within a capital program being substituted, on a like-for-like
4 basis, with other projects; or (b) specific projects being added to a given program,
5 accelerated or deferred. These numerous external factors mean that Toronto Hydro
6 cannot with certainty plan in advance execution timing or costs, and attempting to do so
7 would actually be an imprudent use of time and ratepayer funds. Operationally, it is in
8 Toronto Hydro's interests to maintain a smooth flow of work rather than having abrupt
9 changes in work levels. Toronto Hydro has prepared a detailed overview of the practical
10 execution challenges that the utility often faces during development and execution of its
11 capital program. This overview can be found in Exhibit 1B, Tab 2, Schedule 4,
12 Appendix A ("Execution Challenges").

13

14 As detailed in Exhibit 1B, Tab 2, Schedule 6, Toronto Hydro's proposes annual reporting
15 on its capital program that consists of: (a) meeting the OEB's Scorecard Approach for
16 Performance Measurement; and (b) reporting on the proposed Performance Measures
17 Framework as described in the above-noted reference and its DSP (Exhibit 2B, Section
18 C). Toronto Hydro proposes that these metrics and measures will assist the OEB and
19 intervenors in monitoring the utility's performance outcomes.

20

21 For example, per its 2013 OEB Scorecard, Toronto Hydro deems its year-end capital
22 program results to be successful if the year-end results are within +/- 20% of the
23 approved CAPEX amount.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

1 **INTERROGATORY 25:**

2 **Reference(s):** **Exhibit 2B, Sections E5.1, E5, E5.3**

3

4

5 In each of these project's Tables of Historical and Projected Spending – 2014 dollars are
6 listed as Historical. Since dollars spent in 2014 are known – please provide in-service
7 dollars for each project in Sections E5.1to E8.8 that are part of the ICM.

8

9

10 **RESPONSE:**

11 The 2014 dollars listed in the referenced tables are forecasts. Please see Toronto Hydro's
12 response to interrogatory 1B-SEC-9 for a summary of actual and forecasted in-service
13 additions by ICM segment for the years 2012 to 2014.

/C

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

1 **INTERROGATORY 18:**

2 **Reference(s):** Exhibit 2B, Section E8.3, pg. 23

3

4

5 a) Please update the ERP spending for 2014 to show the actual spending to date.

6 b) Has THESL completed its selection of a vendor(s) for this project? If not when is this
7 expected to occur?

8

9 **RESPONSE:**

10 a) Actual 2014 ERP Program spending as of September 30, 2014 is \$0.5 million.

11

12 b) Toronto Hydro has not completed its selection of an ERP System Vendor for the ERP
13 Program. The selection process will be completed only if and when this Application
14 process is completed.

RESPONSES TO SUSTAINABLE INFRASTRUCTURE ALLIANCE OF ONTARIO INTERROGATORIES

1 **INTERROGATORY 39:**

2 **Reference(s):** Exhibit 4A, Tab 2, Schedule 6, page 17

3

4

5 THESL states that it “manages vault access and customer isolation activities by assigning
6 them, to the degree possible, to field workers affected by injuries.” Please explain why?
7 Do customer isolation activities involve a less strenuous level of work that can be
8 performed by “field workers affected by injuries”?

9

10

11 **RESPONSE:**

12 As discussed in pages 14 and 15 of the above-reference Exhibit 4A, Tab 2, Schedule 6, /C
13 Toronto Hydro manages vault access and customer isolation activities by assigning them
14 to field workers affected by injuries. The activities assigned to each accommodated
15 worker are determined on a case-by-case basis in consideration of each employee’s
16 particular circumstances and the scope of requisite tasks.

Breakdown of 2011-2015 change in Revenue Requirement from change in Fixed Assets

Description	2011 Opening Balance CGAAP	2011 Approved CGAAP	2011 Actual CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
NET ASSETS - OPENING BALANCE	N/A	1,897.8	N/A	2,183.5	2,251.9	2,356.0	N/A	2,435.1
ICM								383.8
Streetlighting								39.8
NET ASSETS - ADJ. OPENING BALANCE	N/A	1,897.8	N/A	2,183.5	2,251.9	2,356.0	N/A	2,858.8
Land and Buildings	59.7	68.5	61.3	63.1	67.3	69.1	68.7	143.4
TS Primary Above 50	20.0	26.9	10.5	11.0	11.0	11.1	11.1	29.7
Distribution System	199.7	211.3	222.6	226.5	229.3	245.5	244.2	309.8
Poles and Wires	2,625.4	2,818.4	2,893.6	3,037.9	3,179.0	3,298.9	3,252.0	3,826.8
Line Transformers	691.7	720.6	731.7	757.4	791.9	810.3	779.6	835.9
Services and Meters	298.7	324.4	303.7	317.2	278.1	298.7	298.7	349.0
General Plant	135.2	142.5	130.1	134.4	141.6	167.2	167.1	158.9
Equipment	160.4	176.8	180.1	178.5	181.8	189.7	189.7	198.0
IT Assets	194.2	252.5	44.6	50.5	56.3	87.4	87.4	98.9
Other Distribution Assets	70.1	72.2	323.9	348.9	380.2	402.4	404.9	522.3
Contributions and Grants	(271.5)	(281.3)	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
GROSS FIXED ASSETS	4,183.5	4,532.5	4,607.8	4,809.0	4,977.7	5,226.0	5,149.0	6,100.2
ACCUMULATED DEPRECIATION	(2,285.7)	(2,427.4)	(2,424.2)	(2,557.1)	(2,621.7)	(2,771.2)	(2,713.9)	(2,817.4)
NET ASSETS - CLOSING BALANCE	1,897.8	2,105.1	2,183.5	2,251.9	2,356.0	2,454.8	2,435.1	3,282.8
AVERAGE NET FIXED ASSETS	N/A	2,001.5	N/A	2,217.7	2,304.0	2,405.4	N/A	3,070.8
Change from 2011 OEB Approved				216.3	302.5	404.0		1,069.3
Base Revenue Requirement Impact (Change in NFA x WACC)				15.0	21.0	28.0		66.2

WACC 6.94% 6.94% 6.94% 6.19%

Average Net Fixed Assets by Major Plant Account	2011 Approved CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2015 Test MIFRS
ICM - adjustment to opening balance					191.9
Streetlighting - adjustment to opening balance					19.9
Land and Buildings	64.1	62.2	65.2	68.2	106.0
TS Primary Above 50	23.5	10.7	11.0	11.0	20.4
Distribution System	205.5	224.6	227.9	237.4	277.0
Poles and Wires	2,721.9	2,965.8	3,108.5	3,238.9	3,539.4
Line Transformers	706.1	744.6	774.7	801.1	807.7
Services and Meters	311.5	310.5	297.7	288.4	323.9
General Plant	138.8	132.2	138.0	154.4	163.0
Equipment	168.6	179.3	180.2	185.7	193.8
IT Assets	223.3	47.6	53.4	71.9	93.1
Other Distribution Assets	71.1	336.4	364.5	391.3	463.6
Contributions and Grants	(276.4)	(305.5)	(327.7)	(346.5)	(363.4)
GROSS FIXED ASSETS	4,358.0	4,708.4	4,893.4	5,101.9	5,836.4
ACCUMULATED DEPRECIATION	(2,356.5)	(2,490.7)	(2,589.4)	(2,696.5)	(2,765.7)
NET ASSETS	2,001.5	2,217.7	2,304.0	2,405.4	3,070.8
Change from 2011 OEB Approved		216.3	302.5	404.0	1,069.3
Base Revenue Requirement Impact (Change in NFA x WACC)		15.0	21.0	28.0	66.2

WACC 6.94% 6.94% 6.94% 6.19%

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO CANADIAN UNION OF PUBLIC EMPLOYEES LOCAL ONE

UNDERTAKING NO. J2.29-CUPE-9:

Reference(s): CUPE Interrogatory 2 e)

SUPPLEMENTAL RESPONSE:

Further to the original response to Technical Conference Undertaking J2.29-CUPE-9, Toronto Hydro is providing the information on the 2015-2018 price increases for the civil and electrical design and construction contractors. The annual increase values represent a weighted average of the terms negotiated with six individual contractors, calculated on the basis of 2013 volumes of unit price work allocated among the contractors. Consistent with the OEB's Decision on Confidentiality (January 7, 2015), Toronto Hydro is filing this information confidentiality.

Table 1: Weighted Average Annual Increases for Civil and Electrical Design and Construction Contractors

Year	Civil	Electrical
2015	████	████
2016	████	████
2017	████	████

Based on this information, Toronto Hydro expects external contractors to retain a cost advantage over internal labour during the timeframe in question, based on the methodology in Exhibit 2B, Section C3.4. The utilization of design and construction contractor services enables the utility to complete the requisite volume of capital work in a safe and efficient manner, while providing the resourcing scalability and flexibility to account for changes in capital funding levels.